TOPSIDE FACILITIES' ABILITY TO HANDLE A NEW BLEND OF CRUDE OIL

by

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DECLARATION

I, **SANDRO CÉSAR**, declare that all the work in this thesis, save for the ones appropriately acknowledged, represents my own unaided work, apart from the normal guidance of my supervisors. This thesis represents my own opinions and not necessarily those of the Cape Peninsula University of Technology and its sponsors.

This thesis has not been submitted for any degree or examination in any other University.

(Signature)

Signed in Luanda, on this 26th day of August 2022

ABSTRACT

Angola is the second largest oil producing country in sub-Saharan Africa, producing around 1.4 million barrels of oil and 17.9 billion cubic feet of gas per day of production. The recovery of crude oil and natural gas from underground sources requires separation and stabilisation treatment of all the individual phases since both exist as a hydrocarbon-water mixture in the rock formation.

This study introduces an approach to the factorial design of an offshore topside process facility, considering the effect of an oil field fluids' composition and arrival temperature on the production facility's behaviour, which was not considered during the facility's original design phase. The objectives of this study were to: 1.) evaluate and perform verifications to confirm the suitability of the existing facility to meet the desired outlet conditions by processing fluid from the new Múcua field which has an arrival temperature of -7ºC at the top of production riser-c (PR-c); 2.) evaluate the equipment handling capability past the total liquids design capacity by means of a detailed process train evaluation of each topside system with a clear identification of potential bottlenecks and its optimisation for debottlenecking; 3.) develop blowdown system verifications considering the recommended updated design cases and operating conditions.

A new fluid blend including fluid from the Múcua field through PR-c was used for the simulations of case studies A to F using Aspen Tech HYSYS, based on the PR-c alignment either to the high pressure (HP) separator (with gas lift) or to the Test separator (without gas lift), for the six operational scenarios with operating temperatures, -7, 5, 36 and 50°C, and operating pressures of 7 and 19 barg. Herein the relationship between these variables was investigated and the results compared with the original design specifications of the equipment for possible bottlenecks, which provided data for a governing case selection. An estimation of the safe production outcomes with the new fluids addition as a function of the pressure and temperature was therefore obtained.

From the simulations and MySEP evaluations, the gas flow rate at the intermediate pressure (IP) and low pressure (LP) separator was found to be greater than the original design for cases A, B, D and E, with a high liquid carryover in the gas stream and verifications on the separators' gas outlet pressure control valves (PCVs) providing evidence of their lack of adequacy for the full gas flow rate as per the original design. The main injection gas compressing system showed no major concerns to accommodate all six case studies, despite the slightly higher condensate flow rate for cases A, B and C at the 2nd stage scrubber than the design flow rate specification. The actual volumetric flow rate passing through the 1st stage flash gas compressor suction cooler for cases A, B, D and E was greater than the original design value,

therefore the flash gas compressor system was found unlikely to handle all the gas from cases A, B, D and E due to a relatively high pressure drop across the coolers. This led to a portion of the process gas being flared from the LP/IP separator, which is undesired as it poses environmental constraints and as such was found to be the major bottleneck. While there were no concerns found for the blowdown scenario and flare system, the gas dehydration and fuel gas, the produced water system and cooling medium system, the overall heating medium duty requirement was exceeded for cases D and E, therefore requiring a greater heating load for the crude oil heater to heat the incoming fluids to the operational temperature of 90°C needed to meet the product's true vapour pressure (TVP) specifications.

Case F was selected as the governing case based on the operating parameters and production figures prior to the introduction of the new field fluids into the system. From the outcomes of the simulation and evaluations with the Múcua fluid tie-in under Case F's configuration, it was found out that the water flow rate at the LP separator was greater than the original design and the existing line size was validated to be able to handle the increased flow rate. However, the pressure drop could be a problem since the water flow rate for the 2nd stage flash gas compression scrubber was found to be above the design case as well, the production flow rates would therefore need to be increased gradually and closely monitored to address this bottleneck.

From this study, it was concluded that in order to start-up the facility with the Múcua field fluid tied-in without major bottlenecks under case F configuration with a production expectancy of 81170 barrels of oil per day, 73.06 million standard cubic feet per day across the HP separator and a cargo of TVP ≤ 14.7 psia at storage conditions: 1.) the crude oil heaters should be upgraded from 100 to 128 plates to have increased flexibility and less gases flashing in the cargo tanks; 2.) the heating medium temperature should be increased to the maximum capacity sustained by the exchangers Hydrogenated Nitrile Rubber (HNBR) gaskets; 3.) the crude oil coolers should be bypassed as the crude/crude exchangers are expected to cool the dead oil to ≤ 50°C; 4.) the subsea chemical injection requirements should be revised to improve separation; 5.) monitor the Múcua fluids water cut and arrival temperatures; as well as 6.) monitor the flash gas compressor systems performance.

ACKNOWLEDGEMENTS

I would like to express my deepest gratitude to God for the gift of life and for permitting my dreams to come true in this lifetime. Thank you for allowing me to make mistakes, to learn, to grow up, for listening to my prayers and for enlightening me throughout my academic journey. I have not yet found out what I have done to deserve it all.

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I wish to thank Dr. Myalelo Nomnqa for accepting a last-minute request to co-supervise and Mrs. Elizma Alberts for her wise counsel, sympathetic ear, and support towards this goal.

DEDICATION

For my mom Merciana Duarte, for the strength to continue through the valley of darkness always with a light of hope, and not giving up when things looked bleak.

You decide how you view the world each day.
Therefore, choose to make it inspiring,
because to create something from nothing is
one of the greatest feelings. It is Heaven.

Prince Roger Nelson O(+> (1958 - 2016)

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LIST OF ABBREVIATIONS

API	American petroleum institute
BDV	Blow down valve
BOPD	Barrels of oil per day
BLPD	Barrels of liquid per day
BWPD	Barrels of water per day
BS&W	Basic sediment and water
EDR	Exchanger Design & Rating
FGC	Flash gas compressor
FIT	Flow induced turbulence
FPSO	Floating production storage and offloading
HNBR	Hydrogenated nitrile rubber
HP	High pressure
IGC	Injection gas compressor
IGF	Induced Gas Flotation
IP	Intermediate pressure
LCV	Level control valve
LP	Low pressure
MM	Million
mlc	Meters of liquid column
OIW	Oil in water
PCV	Pressure control valve
PFD	Process Flow Diagram
PI	Plant information
ppm	Parts per million
PR	Production riser
PVT	Pressure volume temperature
ptb	Pounds per thousand barrels

PW	Produced water
RVP	Reid vapour pressure
scfd	Standard cubic feet per day
scf/STB	Standard cubic foot per stock tank barrel
SS TVD	Subsea true vertical displacement
SW	Seawater
TEG	Tri-ethylene glycol
TR	Test riser
TVP	True vapour pressure
VRU	Vapour recovery unit
WC	Water cut
WAG	Water alternating gas
WAT	Wax appearance temperature

LIST OF SYMBOLS

Roman Symbol	Description	Unit
Cv	Valve flow coefficient at a pressure drop of 1 bar	m^3/min
k-value	Gas load factor	m/s
M or Ma	Mach number	-
P	Pressure	bar or Pa
P_c	Critical pressure for a component of interest	Pa
Q	Volumetric flow rate	m^3/h
R	Gas constant	J/mol.K
T	Absolute temperature	°C or K
T_c	Critical temperature for a component of interest	°C or K
v	Velocity	m/s
V	Volume	m^3
V_m	molar volume	m^3/mol
Greek Symbol		
ΔP	Pressure drop	bar or Pa
ρ	Density	kg/m^3
μ	Viscosity	cP
ω	Acentric factor for a component of interest	-

Formulaes

CH_4	Nitrogen
CO_2	Carbon dioxide
H_2S	Hydrogen sulphide
N_2	Nitrogen

GLOSSARY

Bubble Point: Temperature at a certain pressure at which the first gas bubble evaporates from the oil solution in the reservoir (Glover, 2010).

Crude Oil: A naturally occurring, unrefined petroleum product composed of hydrocarbon deposits and other organic materials (Devold, 2013).

Cricondenbar: The highest pressure at which two phases can co-exist at equilibrium (Ahmed, 2010).

Cricondentherm: The highest temperature at which two phases can co-exist at equilibrium (Ahmed, 2010).

Critical Point: State of pressure and temperature at which all intensive properties of the gas and liquid phases are equal. The phases can no longer be distinguished (Ahmed, 2010).

Dew Point: Temperature at which the first drop of liquid condenses from the reservoir gas phase (Glover, 2010).

Factorial Design: Type of research methodology in which selected values of two or more independent variables are manipulated in all possible combinations so that their interactive effect upon the dependent variable may be studied (McBurney and White, 2007).

Floating production storage and offloading (FPSO): Typically, a reclaimed and modified tanker or large purpose-built hull moored to the seabed used for hydrocarbons extraction, phase separation and treatment (Leffler *et al.,* 2011).

Gas Flaring: Combustion of gases generated during oil and gas recovery processes (Devold, 2013).

Gas Injection: Process of injecting natural gas (miscible and immiscible) or nitrogen (immiscible) into the reservoir, to maintain pressure in the reservoir, create a gas cap and push oil to a producing well (Lyons *et al.*, 2015).

Gas Lift: An artificial lift method that uses an external source of high pressure gas to supplement gas formation to lift the well fluids (Bradley and Gipson, 1987).

Hydrocarbon: An organic compound composed entirely of hydrogen and carbon (Silberberg, 2004).

HYSYS: A chemical process simulator used to mathematically model processes from unit operations to full chemical plants and refineries (Moran, 2015).

MySEP: Computer software used for the design, evaluation and simulation of separators and scrubbers. It can predict separation efficiency and liquid/gas carry over in the gas/liquid, based on details of the separator such as length, width, type of inlet and outlet devices (Moran, 2015).

Natural Gas: A hydrocarbon gas mixture naturally occurring, composed primarily of methane, with a small percentage of carbon dioxide, nitrogen, hydrogen sulphide or helium (Lyons *et al.,* 2015)

OsiSoft Plant Information (PI) Process Book: A graphics package that allows users to create dynamic and interactive trends featuring real-time plant information (Moran, 2015).

Petroleum Reservoir: Is a subsurface pool of hydrocarbons contained in porous or fractured rock formations (Ahmed, 2007).

Produced Water: Water produced as a by-product during the extraction of oil and natural gas from reservoirs (Speight, 2014).

Pressure-Volume-Temperature (PVT): Phase and volumetric behaviour of petroleum reservoir fluids (Ahmed, 2007).

Riser: A pipe that connects an offshore floating structure to a subsea system either for production, injection and export, or for drilling, completion, and workover purposes (Bai and Bai, 2012).

Shut-in Pressure: Reservoir pressure measured when all the gas or oil outflow has been shut off (Ahmed, 2007).

Swivel: The heart of the subsea-to-topside fluid transfer system, ensuring that all fluids, controls and power are safely transferred from wells, flow lines, manifolds and risers to the rotating vessel and its processing plant under all environmental conditions (El-Reedy, 2012).

Topside Facilities: Upper part of an offshore oil platform structure above the sea level and outside the splash zone, consisting of multiple modules, interconnected with piping, electrical and instrumentation systems to form a complete production facility composed of the oil/water/gas treatment, storage and export systems, utility and process support systems, as well as living quarters (Mitra, 2009).

Water Cut: The ratio of the water that is produced in a well compared to the volume of the total liquids produced (Speight, 2014).

Well: A boring in the earth designed to bring petroleum hydrocarbons to the surface (Mian, 1992).

CHAPTER 1

INTRODUCTION

CHAPTER 1: INTRODUCTION

1.1. Background to the Research Problem

According to Takacs (2015), the fluids mostly present in oil well production operations are water and hydrocarbons, which range from methane to very heavy and sophisticated compounds. During hydrocarbon extraction, as pressure and temperature change along the path from the well bottom to the surface, phase relations and physical parameters of the flowing fluids also change. Therefore, it is crucial to take into consideration all these changes when designing process equipment and determining optimum operating conditions (El-Reedy, 2012; Stewart and Arnold, 2011).

The floating production storage and offloading (FPSO) facility used for the scope of this research, has been designed to accommodate fluids from Angola's Block 51/60 West Hub, which consists of the fields: Tamarindo, Maboque, Gajaja, Loengo and Ginguenga (Company, 2013). The field of study for this research is Múcua, which was not considered in the original design of the vessel and might present problems and plant upsets due to certain specific characteristics, such as the fluid's expected low arrival temperature.

1.2. Motivation for the Research Problem

Angola is the second largest oil producing country in Sub-Saharan Africa with an output of approximately 1.4 million barrels of oil and 17.9 billion standard cubic feet of gas per day of production. Due to a significant drop in oil prices and an extensive lack of foreign currencies in the market, very limited investment in exploration or production fields has occurred from 2014 to 2018, thus restricting the development and implementation of new technology for sustainable production, as well as environmental pollution alleviation in the country (Export.gov, 2019).

However, according to Angonoticias (2019), announcements of investments and discoveries are expected to boost oil production starting in 2020 and 2021. The country holds 9 billion barrels of proven oil resources and 11 trillion standard cubic feet of proven natural gas reserves, which represent great potential for further economic development (Africa Oil Week, 2019). Upon successful tie-in of the Múcua field into the FPSO processing system, the oil production rate is expected to increase by approximately 20 000 barrels of oil per day (Company, 2019).

Although optimisation and analytical technologies play a vital role in enabling the oil and gas industry to achieve its goals, limited research information has been published on optimisation of production facilities addressing significant changes in the raw materials composition. Moreover, it is not common practice to tie into production facilities, well fluids with significantly different composition from the ones considered during the design, construction, and commissioning of such facilities (Furman *et al.*, 2017).

1.3. Statement of the Research Problem

The production facilities of the FPSO used for this study have not been designed with respect to the composition and properties of the fluids from the Múcua field (Company, 2019). The extent of the topsides facilities' ability to handle the new fluid blend, which includes Múcua's fluids, is unknown, as well as the bottlenecks for the facilities to efficiently accommodate the new blend and the expected increase in the liquid production throughput past the current design capabilities.

1.4. Research Rationale

Despite the efforts of water and gas injection to compensate for the loss of the reservoirs' natural pressure, because of fluid extraction, the best well configuration set up of the reservoirs in operation, has been able to provide a maximum average throughput of only 60 000 barrels of oil per day, which amounts to about 60% of the plant's design processing capacity for the oil stream (Company, 2019).

The debottleneck and process design evaluations for the Múcua tie-in are important not only from the perspective of increasing the production throughput, but because the expected additional flow rates may exceed the plant's design flow rate handling capacity. Therefore, a need exists for the operating parameters of each individual piece of equipment to be compared with its original design to identify and supersede potential bottlenecks, taking into account the maximum load that each can safely accommodate.

1.5. Research Questions

The following questions revolve on the development of this project to supersede the challenges expected to be encountered after Múcua tie-in takes place:

- Will the current FPSO's topside design be able to handle the new blend of crude oil smoothly?
- What will be the impact of the new blend's temperature and composition on the plant's ability to meet outlet conditions?

- Can the topside's process facilities be optimised for debottleneck?
- Will the topside facility have sufficient blowdown and relief capacity based on the anticipated composition and operating conditions?

1.6. Hypothesis

The debottleneck process design study accounting for the Múcua tie-in, would permit an updated overview of the equipment's handling capability to process the new blend of an FPSO designed for exploration in the active fields of Block 51/60. This would in turn contribute to an increase in certainty of the subsea configurations and topside equipment set-up for maximum safe production yields, as well as to the decision of operations timeframe extension for oil exploration within the Block 51/60.

1.7. Research Aims and Objectives

The aim of this research project is to conduct a factorial design study in order to determine: 1.) the topside facilities' ability to handle the new fluid blend composed of well fluids from the Múcua field; as well as 2.) the ability of the existing equipment to handle an increase past the total liquid designed capacity.

Therefore, the objectives of this research would be an evaluation of the sections summarised below:

a. Process train evaluation for each system- including utilities such as fuel gas system, cooling and heating systems.
b. Verification of the suitability of the existing facilities for the lowest fluid temperature of -7ºC at the top of PR-c and the impact on the ability to meet the outlet conditions.
c. Identification of potential bottlenecks.
d. Optimisation of the topside process for debottlenecking.

1.8. Significance of the Research

The development of the Múcua field would maximize, where practical, the re-use of the facilities installed for the initial design phase (e.g., umbilical's, risers, manifolds, and flow lines), and will be timed to coincide with the capacities of the FPSO topside facilities amended by the FPSO specification. The success of this process study would translate into an optimised performance, as it will identify weaknesses in the current design and allow better alternatives to be chosen prior to the desired changes being made, considering the new changed parameters of the raw materials.

1.9. Delineation of the Study

This study will not cover:

- The assessment of different techniques associated with oil extraction and processing.
- The post-treatment of crude oil produced water and gas past separation and stabilisation.
- An economic evaluation of the process changes, at either a pilot and/or industrial scale.
- Subsea treatment of the production fluids as wax crystal deposition, emulsion issues and pour point problems are not envisaged for the lowest temperatures expected (-7°C).
- Ice/hydrate formation scenario analysis.
- Seawater treatment, water and chemical injection systems and requirements as they are independent systems.
- Any deviations from the 0% water cut for the Múcua production fluids.

In summary, this chapter provides an overview on the background to the research problem; an explanation of the primary motivations for the study; the aims and objectives, relevance, as well as the delineation of the study conducted.

CHAPTER 2

LITERATURE REVIEW

CHAPTER 2: LITERATURE REVIEW

2.1. Introduction

Petroleum reservoir fluids are naturally occurring mixtures of oil, gas and water that exist at temperatures ranging from -20 to 150°C and high pressures ranging from 180 to 600 bar. Their compositions typically include many hydrocarbons and a few non-hydrocarbons, like nitrogen, carbon dioxide and hydrogen sulphide (Guo *et al,* 2008).

According to MacCain (1990), the physical properties of these mixtures depend primarily on composition and the pressure-vapour-temperature (PVT) conditions, as they determine how easily the hydrocarbons are going to flow from a well in their current state and allow process designers to select the most cost-effective extraction methods. Crude oil and natural gas are made up of many compounds with a wide range of molecular weights. The lighter and simpler compounds are recovered as natural gas after surface separation, while the heavier and more complex compounds are recovered from crude oil under storage tank conditions (Whitson and Brulé, 2000).

This chapter focuses on important insights in reservoir data, with characteristics of the well fluids being highlighted, including information relevant to its extraction, as well as the design and operation of the primary processing facilities of hydrocarbons.

2.2. Petroleum Reservoirs

The oil and gas industry is the largest industry in Angola, accounting for over one-third of the gross domestic product and more than 90% of the country's exports (World Bank, 2020; Export.gov, 2019). According to Whitson and Brulé (2000) and Ahmed (2007), accurate data such as pressure and temperature for the phase behaviour of the reservoir's fluids is required to improve oil and gas recovery. However, it is expensive to investigate the full range of phase behaviour that can occur during a recovery process or a separation chain as hydrocarbon fluids vary in quantity and quality from reservoir to reservoir (Guo *et al,* 2008).

2.2.1. Classification of Reservoirs and Fluid Systems

Petroleum reservoirs can be categorised as oil or gas reservoirs, depending on the composition of the reservoir's hydrocarbon mixture, the initial reservoir's pressure, temperature and the surface production's pressure and temperature (Ahmed, 2007). Furthermore, these broad classifications are subdivided based on the reservoir's pressure and temperature with respect to the critical temperature and cricondentherm in the pressure-temperature (PT) diagram of the reservoir fluid, into five main types (Ahmed, 2010; MacCain, 1990):

- Dry gas
- Wet gas
- Gas condensate
- Volatile oil
- Black oil

Figure 2.1 represents a typical P-T diagram of a multicomponent system with a specific overall composition. According to Ahmed (2010), “these diagrams are used to classify reservoirs and the naturally occurring hydrocarbon systems, as well as to describe the phase behaviour of the reservoir fluids for separation purposes”. Although a different hydrocarbon system would have a different phase diagram, the general configuration is similar (Glover, 2010).

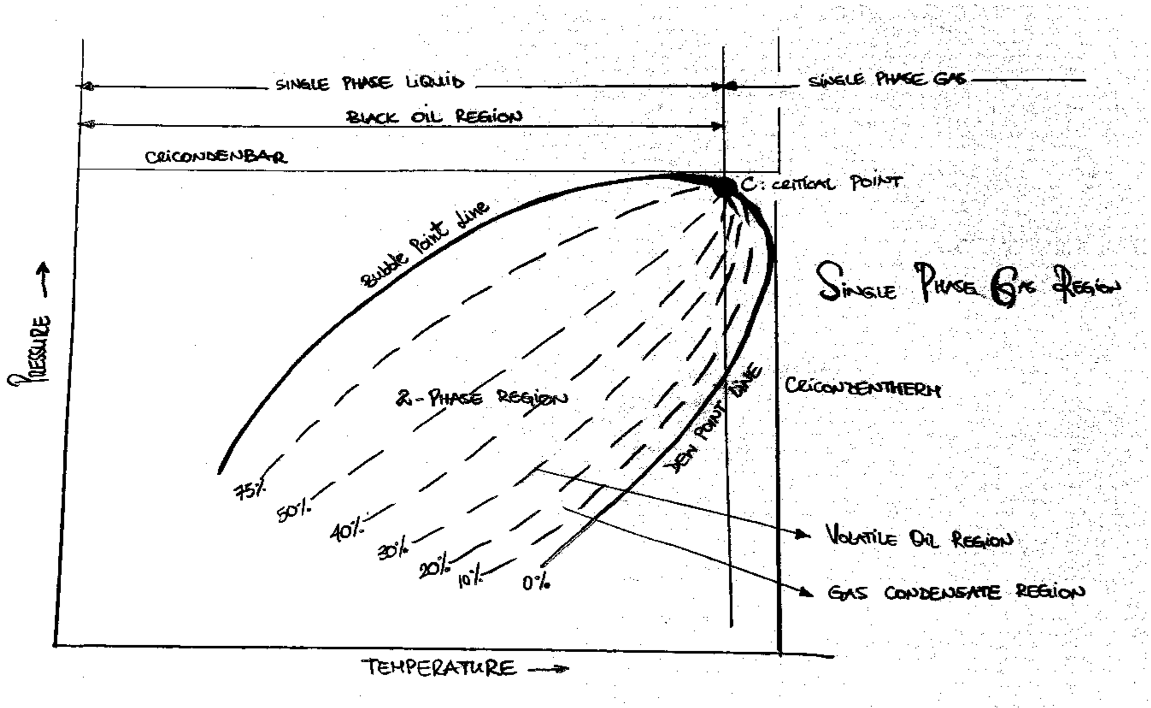

Figure 2.1: Typical P-T diagram for a multicomponent system (adapted from Glover, 2010)

A bubble point curve and a dew point curve make up the two-phase region. The critical point is defined as the intersection of the bubble point curve and the dew point curve, at which point the properties of gas and liquid mixtures become identical (Gundersen, 2013). Regardless of temperature, the two phases cannot coexist above the cricondenbar and regardless of pressure, the two phases cannot coexist at the cricondentherm. Furthermore, if a fluid exists above the bubble point curve, it is classified as under saturated because it contains no free gas, whereas if it exists below the bubble point curve, it is classified as saturated because it contains free gas (Ahmed, 2010; Glover, 2010).

2.2.1.1. Dry Gas Reservoir

Aside from nitrogen and carbon dioxide, the hydrocarbon mixture is primarily composed of methane, which is present as a gas in both the reservoir and the surface facilities (Gundersen, 2013). Water is the only liquid associated with the gas from a dry gas reservoir, and the temperature in the phase diagram is higher than the critical temperature, and the surface conditions are outside the two-phase envelope (Ahmed, 2010; Glover, 2010; Whitson and Brulé, 2000).

2.2.1.2. Wet Gas Reservoir

Wet gas is mostly made up of light hydrocarbons like methane, ethane, propane, and butane. The temperature is above the critical temperature, and the production path in the P-T diagram (Figure 2.1) penetrates the two-phase envelope, resulting in the production of gas at the surface with a small amount of liquid (Ahmed, 2010; Glover, 2010; Guo *et al,* 2008).

2.2.1.3. Gas Condensate Reservoir

The fluids are initially in a vapour phase, which expands as pressure and temperature decrease. When the dew point line is reached, increasing amounts of liquids condensate from the vapour phase; however, if the temperature and pressure fall further, the condensed liquid may re-evaporate. The oil produced at the surface is the result of a vapour present in the reservoir (Ahmed, 2010; Glover, 2010; Guo *et al,* 2008).

2.2.1.4. Volatile Oil Reservoir

The liquid oil phase coexists with the vapour phase, which has gas condensate compositions. The production path causes minor additional condensation, and re-evaporation is possible. When compared to gas reservoir types, the fraction of gases decreases while the fraction of denser hydrocarbon liquids increases (Gundersen, 2013; Ahmed, 2010; Glover, 2010).

2.2.1.5. Black Oil Reservoir

The reservoir temperature is significantly lower than the system's critical temperature. As a result, the hydrocarbon in the reservoir exists at depth as a liquid. The production path begins with a pressure reduction with only minor expansion in the liquid phase, and once the bubble point line is reached, gas begins to emerge from solution, with a composition that changes very little along the production path (Gundersen, 2013; Ahmed, 2010; Glover, 2010).

2.3. Oil and Gas Separation

According to Whitson and Brulé (2000), “all reservoirs are predominantly isothermal because of their large thermal inertia”. Figure 2.2 illustrates a PT diagram of an undersaturated reservoir fluid, including the production path to the surface. On production, the fluid pressure drops with a slight temperature reduction occurring as the fluid travels up the borehole. When the P-T characteristics of the gas and liquid are examined separately, it is clear that the P-T point representing the separator conditions falls on the dew point line of the gas separator diagram and on the bubble point line of the oil separator diagram. This simply means that the shape of the P-T diagram varies greatly for different mixtures of hydrocarbon gases and liquids, and it is critical to understand the phase envelope, because it can be used to classify and understand major hydrocarbon reservoirs (Glover, 2010; Ahmed, 2007).

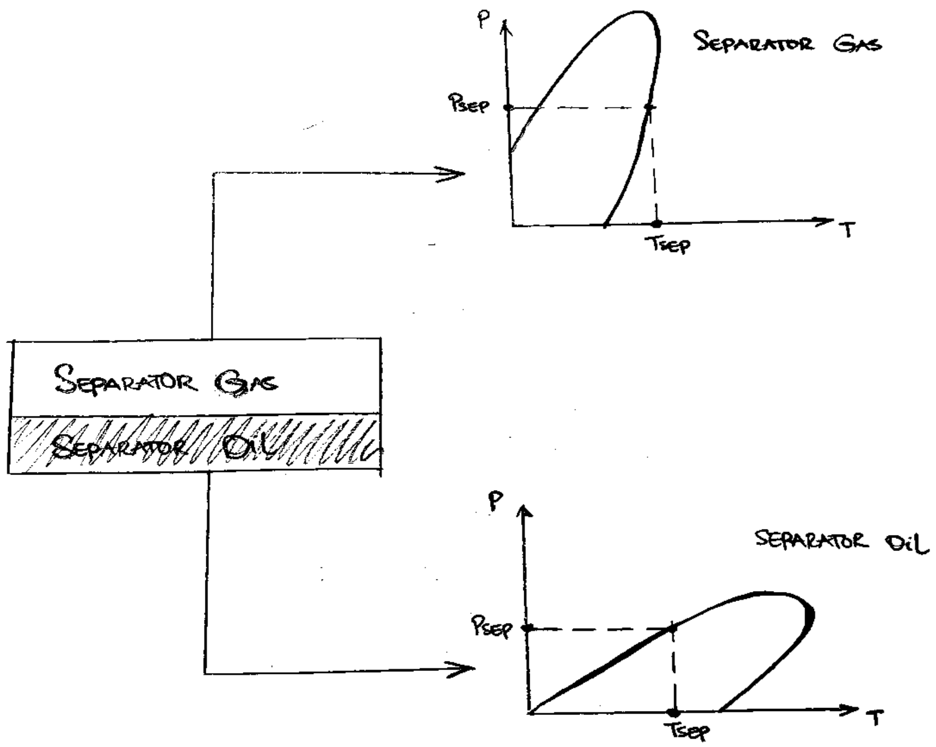

Figure 2.2: PT phase diagram for reservoir fluid separators (adapted from Glover, 2010)

2.4. Floating Production Storage and Offloading (FPSO) Facilities

A floating production storage and offloading (FPSO) facility is a floating production facility that receives hydrocarbon fluids from a subsea reservoir via risers and flow lines and separates it into oil, gas, water, and impurities within the in-house topside production facilities (Minerals Management Services, 2001). According to Leffler *et al.* (2011), stabilised oil is stored in the facilities’ tanks before being offloaded onto tankers for further refining in-land. Gas is used as fuel for in-house power generation, exported to shore via a pipeline or re-injected back to the subsea reservoirs; while water is treated either for overboard discharge or re-injection back to the reservoirs as well (Lyons *et al.,* 2015).

Most FPSOs are ship-shaped and secured to the seabed via mooring systems, which can accommodate a wide range of water depth and environmental conditions for continuous operations in the same location for two decades or more (Randolph and Gourvenec, 2011; Paik and Thayamballi, 2007).

2.4.1. Topsides Operational Process

The function of the oil processing system and associated equipment is to stabilise live crude oil produced from subsea wells to meet storage and export specifications for basic sediment and water (BS&W), temperature, salinity, and vapour pressure. A conventional oil processing system can be split into six phases, as described in Table 2.1 (Lyons *et al.,* 2015):

Table 2.1: Phases of hydrocarbon fluids treatment (adapted from Lyons *et al.,* 2015)

Phase	Major Processes	Product
Fluid Transfer	Transfer of fluids from reservoirs to topside facilities	Hydrocarbon fluids
Separation	Three phases separation and heating	Crude oil, Produced Water, and natural gas
Oil stabilisation	Washing, coalescing, and cooling	Dead crude oil
Gas treatment	Cooling, scrubbing, gas compression, dehydration, and heating	Flare gas, fuel gas and Injection/Lift gas
Produced water treatment	Flashing, hydrocyclone, flotation and cooling	Free oil disposable water
Seawater treatment	Filtering and reverse osmosis	Fresh water for oil desalting

2.4.1.1. Fluid Transfer System

On a conventional FPSO, the transfer of fluids and utilities between the topside and the subsea wells is facilitated by a turret system. The turret system comprises of a fluid and utilities transfer system connected to the subsea wells and manifolds by means of flexible risers (Bluewater.com 2020; El-Reedy, 2012). The swivel stack is the heart of the fluid transfer system. Its function is to transfer fluids and utilities from the fixed part to the rotating part of the turret (El-Reedy, 2012; Promor.com, 2020; Company, 2015a).

2.4.1.2. Phase Separation

The first and most critical stage of field-processing operations is the separation of well stream gas from the free liquids (Gou *et al.,* 2011). The hydrocarbon fluid system's phase separation occurs in stages within different pressure separator vessels, providing a working volume for crude oil, water and gas separation. Separators work on gravity and/or centrifugal segregation and are typically made of carbon steel. They have a large settling section with sufficient height or length to allow liquid droplets to settle out of the gas stream and adequate surge room for the slugs liquid (Guo *et al.,* 2011; Stewart and Arnold, 2008).

Based on the flow rates and physical properties, separators are designed to achieve the maximum liquid content in the gas based on removal of more than 98% of all liquid droplets, maximum water content in the crude outlet and maximum crude content in the water outlet. On entry into the separation vessel, the incoming product is subjected to a pressure drop, causing entrained gas to flash off, which is piped to the compression system for processing or vented to flare, in the case of excess gas (Guo *et al.,* 2011; Stewart and Arnold, 2008; Abdel-Aal *et al.,* 2003).

The separators are equipped with an internal weir in which the separation of the liquid and gas separation is achieved. Furthermore, in the weir, the oil and water emulsion is also separated. The oil and water emulsion, flowing under a natural pressure gradient into each vessel's reception section, separates to form an interface. The water produced is taken off under level control before the weir, whilst the oil flows over the weir into the outlet section of the vessel to be taken off under local level control (Guo *et al.,* 2011; Stewart and Arnold, 2008).

To help achieve maximum separation performance, separators normally contain the following internal equipment (Stewart and Arnold, 2008; Company, 2013; Kirk Process, 2020):

- Cyclonic inlet device for primary gas/liquid separation and prevention of foaming which enhances the feed spin around.
- De-foaming pack for low gas flow where the efficiency of the inlet device may be lessened.
- Vane pack with wire mesh demister to coalesce the small liquid droplets in the gas.
- Coalescing plate packs to enhance liquid/liquid separation and to promote degassing.
- Calming baffles to distribute the fluids inside the vessel and dampen liquid movements.
- Weir for fluid segregation (i.e., water and crude oil).
- Mist eliminators to remove contaminants from process air emissions that might not settle out by gravity and evolve as droplets.
- Vortex breakers on the liquid outlets.

2.4.1.3. Oil Stabilisation

The salinity specification of the crude oil is achieved through crude oil washing by injection of hot fresh water to dilute the salt content of the oil, before it is fed to the electrostatic treater for dewatering (Speight, 2014). The water content specification of the crude is achieved by means of an electrostatic treater, which is a coalescer vessel with off takes fitted with deflection plates for efficient liquid dispersion (Schlumberger, 2020).

Manning and Thompson (1995) explain that the water-oil emulsion enters the treater and spills over a weir past the section, where separated gas, is driven to the top, and the remaining liquid then travels upward and spills over a weir into the surge section. The emulsion flows from the surge section to the treating section via a spreader, where the final separation of water and oil occurs in the bottom area of the vessel (between the baffle plates), aided by residence time and the electrostatic action of the electrodes. The surge section's primary function is to keep the vessel completely full of liquid with no gas on top, ensuring that no stabilised oil leaves the treating section unless an equal amount of fluid enters it. The final settling takes place in the treating section, which has a flow spreader that ensures uniform liquid distribution. The emulsion from the spreader is directed toward the high voltage, alternating current electrical grids (i.e., electrodes), which are charged by the fitted transformers, while the upper grid is grounded (Manning and Thompson, 1995; Stewart and Arnold, 2008; Ambrosio, 2014).

When heated emulsion enters an electrostatic field, water droplets gain an electrical charge, causing them to elongate and polarise. This causes it to acquire a positive charge on one end and a negative charge on the other, but the alternating current on the lower electrical grid causes reverse polarity (Ambrosio, 2014). As a result, water droplets move and collide with each other with enough force to break the thin film that surrounds them. The water droplets then congregate into larger droplets and settle to the bottom of the treating section for removal, while the oil rises to the top (Stewart and Arnold, 2008).

2.4.1.4. Gas Processing

The main functions of this system are to receive the gas produced from the separators and compress it to be used as lift gas to aid oil production and to be re-injected into the reservoir to maintain pressure (Lyons *et al.,* 2015). Heat exchangers are provided to cool the incoming gas stream before it is routed to the actual compressor via suction scrubbers, which are installed for removing any entrained liquids from the gas stream prior to compression (Paik and Thayamballi, 2007; Leffler *et al.,* 2011).

Cooled gas on entering the scrubber passes through a vane inlet device, which facilitates good distribution of the gas within the scrubber. Such combination of cooling and expansion of gas causes entrained liquid droplets to form and collect as condensate in the bottom of the vessel. The liquid level in the scrubber is controlled by a vortex breaker and a level control valve. The gas leaves the top of the vessel via a vane pack through a wire mesh demister to flow to the compressor (Paik and Thayamballi, 2007; Company, 2013).

In the oil and gas industry, a typical gas compression train comprises of two-barrel type, vertically split compressors, in a tandem arrangement and driven via a speed increasing gearbox by a turbine. The compressors and gearboxes are connected by flexible, non-lubricated couplings and are equipped with a lubrication oil system, a seal gas system, a separation gas system, and all accessories necessary for safe and efficient operation (Crawford, 2016; Smirnov *et al., 2017*).Whenever it is required, a lower power compressor is also employed to boost the gas pressure from the intermediate and low-pressure separators so it can be fed to the injection gas compressors for subsequent disposal into the reservoir (Ohama *et al.,* 2006).

2.4.1.4.1. Gas Dehydration

The purpose of the gas dehydration system is to prevent hydrates and minimise potential carbon dioxide corrosion rates in downstream facilities, as well as in the gas lift and injection systems, when the high pressure gas is cooled to seabed temperatures (Leffler *et al.,* 2011).

Multi cyclone scrubbers are provided to remove free liquid droplets from the incoming gas stream thereby reducing the required water to be absorbed by the downstream contactors. On entering the scrubber, the gas distribution system directs the gas stream downwards into the first separation chamber via the vane pack, which encourages a swirling motion (Lyons, 2015; Mohamad, 2009).

According to Mohammad (2009), in a typical scrubber used in a FPSO, the gas is fed to the bottom of the scrubber and rises upwards into the second separation chamber where the free liquids fall-out and naturally descend to the base of the scrubber, which acts as a reservoir. Within the second separation chamber, the gas continues to swirl which allows entrained liquids to fall out to the base of the scrubber. From the second separation chamber, the gas passes upwards into the third stage separation chamber, which incorporates an axial flow cyclone bundle, which acts as a mist eliminator by coalescing any entrained liquids. Any liquids collected in the third separation chamber naturally falls to the liquid reservoir via the centrally located drainpipe and exits the scrubber via the vortex breaker (Lyons, 2015; Mohamad, 2009; Company, 2016b).

In the contactors, wet gas is exposed to lean glycol, which has an affinity for water and will absorb moisture from the gas thus, reducing the water dew point (Sulzer, 2008; Lyons, 2015; Mohamad, 2009). The contactor is a pressure vessel equipped with structured packing which provides a large surface area for gas/glycol contact. On entering the contactor, gas is evenly distributed over the cross-sectional area of the vessel and diverted downwards by the inlet deflector forcing any free liquids toward the base of the vessel. The gas reverses direction and flows upwards into the packed section of the vessel for counter-current contact with lean glycol. Before leaving the contactor, the dehydrated gas passes through a mesh pad, which removes any entrained glycol from the gas stream (Leffler *et al.,* 2011; Company, 2016b).

2.4.1.4.2. Flare Relief System

The function of the flare system is to dispose of hydrocarbon gas and liquids released from the process trains, and utilities and dispose of the vented gas by flaring in a safe area at a safe distance from the processing unit (Company, 2016c). A typical flare system provides a means for handling both high pressure (HP) and low pressure (LP) flare products and comprises of flare drums, condensate pumps, a flare ignition panel, sonic/pipe flare tips and a vertical flare stack (El-Reedy, 2012).

Wet gas entering the flare drums from the collection headers, is subjected to a pressure drop that causes entrained liquids to condense and form a liquid level within the drums. A liquid collection boot at the bottom of each vessel incorporates an external heating jacket. The heating effect enhances the gas/liquid separation within the vessels, ensuring that all condensate leaving the drums has been freed of gas and stabilised prior to discharge to the cargo tanks. (Company, 2016c; Fang and Duan, 2014; El-Reedy, 2012).

2.4.1.5. Produced Water Treatment

Produced water recovered from the separators are processed in flash vessels, hydrocyclones and induced gas flotation (IGF) unit systems (Lyons *et al.,* 2015). The purpose of the flash vessel is to flash-off gas from water, while the purpose of the liquid/liquid de-oiling hydrocyclone and IGF system is to remove gas and oil from the produced water for overboard discharge via slop tanks. Within the slop tanks, a two-stage gravity and heat aided separation and skimming process is utilised, which results in water with the desired oil in water and total suspended solids content at an acceptable temperature to be discharged overboard (Orszulik, 2007; Stewart and Arnold, 2008; Enhydra, 2020). According to Hyne (2014), the hydrocyclone consists of a pressure vessel complete with high-capacity liners operating in parallel inside the vessel with the flow distributed evenly between each liner.

The water from the high pressure separator enters at a tangent into the hydrocyclone liner, where its velocity is converted to tangential velocity in the inlet area, imparting a centripetal force on the fluids. Tangential velocity and centrifugal force increase as the fluid moves down the conical section, pushing the denser fluid (i.e., water) to the outside wall of the liner and exiting in the underflow. The less dense fluid (i.e., oil) is displaced towards the inner core of the cyclone and by maintaining the pressure of the overflow stream lower than the underflow stream, the central core flows in the opposite direction of the denser fluid and exits through the reject orifice at the upstream end of the hydrocyclone (Enhydra, 2020; Orszulik, 2007; Wyunasep.com, 2020).

By maintaining a pressure differential between the inlet stream to the outlet reject oil and between the inlet stream to the outlet clean water, the geometry of the hydrocyclone results in a thin hydrocarbon case flowing in the opposite direction of the cleaned water outlet and exiting from the swirl chamber side with the clean water exiting from the tail section of the hydrocyclone liner. Pressure ratio control is used to ensure that the reject pressure drop follows the water pressure drop (Enhydra, 2020; Orszulik, 2007).

Clean water enters the IGF vessel, through a tangential nozzle located slightly below the gas/liquid interface level, which is geometrically spaced to eliminate the effect of surge or slug flow (Stewart and Arnold, 2008). Gas bubbles are injected into the recycled water to ensure a constant supply of flotation gas and a low spin rate to provide enough centrifugal force for immediate oil/water separation. The gas is recycled from the flotation vessel's top to an eductor located downstream of the recycle pump. The flotation effect and centrifugal forces within the vessel bring the oil droplets to the surface, where they are concentrated for subsequent skimming (Robinson, 2013).

2.4.1.6. Seawater Treatment

2.4.1.6.1. Filtration

The function of the seawater treatment system is to treat raw chlorinated seawater to produce a freshwater stream with a reduced salt content for crude oil washing, for reservoir injection, as well as providing cooling to various topside consumers (Fang and Duan, 2014).

Coarse filters remove particulates above 100 µm from raw chlorinated seawater (Company, 2013). In a coarse filter vessel, water enters the vessel through an inlet nozzle and flows into the lower half of the filter body, upwards through the turntable and to the inside of the filter elements. Flowing from the inside to the outside of the filter elements, the water passes through the fine screens, which purify the flow by separating smaller particles from the water (Company, 2015b; Fang and Duan, 2014).

The multi-media filtration system consists of filtration vessels and air blowers. Within the filter vessels, various types of media are utilised in layers of varying heights as stated by Company (2013). On entering the media filter vessels, seawater flows over the filter beds and passes downwards through the layers of filter media until it reaches the collection system in the base of the vessel. Pollutants are trapped and accumulate in the filter media, while filtered seawater exits from the base of the vessel (Colt and Huguenin, 2002).

2.4.1.6.2. Wash Water Generation

Cartridge filters oversee the removal of any residual suspended solids to aid the downstream membranes. The filter’s housing is cylindrical and has a diaphragm plate inside the shell, which separates the top dirty section from the bottom clean section. Filter cartridges are plugged into machined holes in the diaphragm plate so that incoming dirty water must pass through the filter cartridges from outside to inside, and then down the cartridge into the clean chamber below, while dirt is retained in the filter media. The filter feeds into the reverse osmosis plant for desalting (Colt and Huguenin, 2002; Lyons *et al.,* 2015; Fang and Duan, 2014; Company, 2015b).

Reverse osmosis is a pressurised process that uses a semi-permeable membrane to separate solutes from a solvent and has become the most promising desalination technique in most regions of the world (Asadollahi *et al.,* 2017). According to Warsinger *et al*. (2016), the major advantage of desalination using reverse osmosis treatment is the consistency of the produced water quality since it is more than 95% efficient in the removal of dissolved salts and organic material from the influent water.

The fundamental principle of reverse osmosis is that when two fluids with different concentrations of dissolved solids are exposed to each other, they will mix until the concentration is uniform. As a result, when two fluids are separated by a semi-permeable membrane, the fluid with the lower concentration of dissolved solids will move through the membrane into the fluid with the higher concentration, leaving the dissolved solids behind (Binnie *et al.,* 2002).

Natural osmosis happens, when seawater and fresh water are separated by a semi-permeable membrane and the freshwater flows towards the seawater through the membrane at a certain pressure defined as the osmotic pressure. Reverse osmosis is the opposite, where forced passage of seawater through a membrane is achieved by applying counter-pressure against the osmotic pressure (Aquanext, 2020; Maqbool *et al.,* 2019; Wilf and Bartels, 2005).

The spiral-wound membranes are the most used membrane type in reverse osmosis desalination plants. They are made in flat sheets that are sealed like envelopes around the permeate collector, which is backed with permeate spacer material. One end of the membrane envelope is connected to a central perforated tube. The envelopes are rolled up to form a spiral wound module, with mesh spacers packed between membrane envelopes to allow seawater to pass through (Buecker, 2016; Toray, 2020).

The membranes are enclosed in series in pressure vessels to which high pressure is applied to permeate water through the membranes. The total number of membranes, pressure vessels and the parallel arrangement of the pressure vessels depends on the permeate flow required and the applied pressure (Fluid Sep, 2020).

2.5. Process Design Optimisation

During a life cycle of hydrocarbons exploration, operating conditions of the wells and the feed stream composition to the topside process constantly change, thus there is a constant need for real-time optimisation of operating conditions and control strategies of the topside process, considering various change in natural occurring operating scenarios such as reservoir's change in temperature and loss of pressure, that might occur during these life cycles (Kim and Hwang, 2018; Bieker *et al.*, 2007).

According to Roobaert *et al.* (2012), projects developed adhering to best practice in areas such as process optimisation benefit from the application of systematic detailed design based on experience and proven results, namely improved quality, and consistency. During conceptual design optimisation, extensive process simulations of the processing plant are performed for each component, allowing reliable predictions of plant performance in the presence of transient variables, which are used for evaluating the impact of component failure, as well as the development of control and automation philosophies (Mikkelsen *et al.,* 2013).

Factorial designs are incredibly valuable as a preliminary study for process optimisation, permitting them to judge whether there is a connection between factors, while lessening the chance of test mistakes and perplexing factors. A factorial design is frequently used to comprehend the impact of at least two autonomous factors upon a single dependent variable

(Shuttleworth, 2009). According to Mukerjee and Wu (2006), factorial designs are a type of true experiment in which multiple controlled independent variables are manipulated to provide the main effects of two or more individual independent variables at the same time, as well as interactions among variables that may only be detected when the variables are examined together.

The types of factorial designs are the between-subject factorial designs, where each participant is only subjected to one of the study's conditions; the within-subject factorial designs, where each participant is subjected to all the study's conditions; and the mixed-factorial designs, which is used when the study has at least one between-subject factor and one within-subject factor (Shuttleworth, 2009; McBurney and White, 2007).

In Oil and Gas industry, topsides process simulation is usually performed using Aspen HYSYS under a simulation model developed using the Peng-Robinson Equation of State (Eq. 2.1), which expresses fluid properties in terms of the critical properties and acentric factor of each species involved (Tangsriwong *et al.*, 2020; Mondal *et al.*, 2015; Gutierrez *et al.,* 2014).

$$\mathrm{P} = \frac{\mathrm{RT}}{\mathrm{V_m} - \mathrm{b}} - \frac{\mathrm{a} \propto}{\mathrm{V_m}^2 + 2\mathrm{bV_m} - \mathrm{b}^2} \tag{2.1}$$

Equations 2.2 to 2.4 are used to find the unknown variables in Equation 2.1.

$$\mathrm{a} = \frac{0.45724\mathrm{R}^2\mathrm{T_c}^2}{\mathrm{P_c}} \tag{2.2}$$

$$\mathrm{b} = \frac{0.07780\mathrm{RT_c}}{\mathrm{P_c}} \tag{2.3}$$

$$\propto = (1 + (0.37464 + 1.54226\omega - 0.2699\omega^2))(1 - \left(\frac{\mathrm{T}}{\mathrm{T_c}}\mathrm{T_r}\right)^{0.5}))^2 \tag{2.4}$$

The Peng-Robinson Equation of State is commonly the suggested property bundle in HYSYS. Improvements to this condition of state, empower its precision for an assortment of frameworks over a wide scope of conditions. It thoroughly comprehends most single-stage, two-stage, and three-stage frameworks with a serious extent of productivity and unwavering quality. For pressure drops, conditions are predicted by Aspen Exchanger Design & Rating (EDR), based on the correlation between the volumetric flow rate and pressure drop as stated in Equation 2.5 (Tangsriwong *et al.*, 2020; Edwin *et al.*, 2017; Gutierrez *et al.,* 2014)

$$\frac{\Delta \mathrm{P_1}}{\Delta \mathrm{P_2}} = \frac{\mathrm{Q_1}^2 \times \rho_1}{\mathrm{Q_2}^2 \times \rho_2} \tag{2.5}$$

In summary, offshore oil and gas production has been done using similar systems and equipment everywhere in the world with the main objectives of maximising production with the lowest related cost. In this chapter, attention was given to the hydrocarbon reservoir classifications and the main details of the conventional physical processes, equipment and utilities employed in the phase separation and stabilization of each of the main components of the hydrocarbon mixture, namely oil, gas and water prior to storage or disposal. The following chapters will present an overview on the design characteristics of the facility used for the purpose of this study, the materials and methods selected for the investigation along with the packages used in Aspen for the simulation as well as in-depth discussions of the findings from the simulations and recommendations to be implemented in order to operate the facility within the appropriate design and safety parameters

CHAPTER 3

TOPSIDES’ DESIGN SPECIFICATIONS AND MÚCUA TIE-IN OVERVIEW

CHAPTER 3: TOPSIDES' DESIGN SPECIFICATIONS AND MÚCUA TIE-IN OVERVIEW

3.1. Introduction

Oil is produced utilising various techniques depending on geography. The main endeavours started in the mid-twentieth century by means of high temperature water used to isolate bitumen from sand and from that point forward the procedure has developed into the complex strategies used today (CAPP, 2020).

This chapter provides information on Angola Block 51/06 reservoir's data and the key design parameters of the equipment installed in the FPSO for the hydrocarbon fluids processing to the desired specifications and on the main properties of the new reservoir to be tied-in to the FPSO for oil and gas exploration.

3.2. Reservoirs' Data

Block 51/60 covers an area of 3 000 km^2 in the Angolan offshore waters. It is located 350 km off the Luanda Province. Water depth ranges from 200 to more than 1 500 m. The field information for Angola Block 51/60 West Hub has been updated as follows (Company, 2013):

- Tamarindo and Ginguenga: Reservoirs located about 5 to 7 km west of the FPSO. Comprised of 7-off producers to the FPSO and an enhancing oil recovery system composed by 4-off water alternating gas (WAG)s and 1-off water injector.
- Maboque: Reservoir located 15 to18 km north east of the FPSO. 6-off production wells are tied back to the FPSO, and 5-off water injectors support the oil recovery.
- Loengo: Reservoir located 10 km south west of the FPSO. Tie back to Tamarindo subsea facilities of 2-off clustered producers and 2-off daisy chained water injectors.
- Gajaja: Reservoir located 16 km south east of the FPSO. Tie back to Maboque subsea facilities of 2-off producers and 1-off water injector.

Information about Block 51/60 reservoirs main properties, as well as the fluid composition on a dry basis is recorded in Tables 3.1 and Table 3.2, respectively.

Table 3.1: Reservoir properties (adapted from Company, 2013)

Properties	Tamarindo	Ginguenga	Maboque	Loengo	Gajaja
Reservoir Pressure [bar]	293	286.1	204.8	394.4	305
Reservoir Temperature [°C]	76	70	62	101	95

Table 3.1 (continued): Reservoir properties (adapted from Company, 2013)

Properties		Tamarindo	Ginguenga	Maboque	Loengo	Gajaja
Depth [m SS TVD]		2801	2781	2047	4026	3105
Saturation Pressure [bar]		185	266.3	192.7	164.1	246.2
Stock Tank Oil Gravity [°API]		32.7	24.7	27.9	33.0	34
Average Gas-Oil Ratio [SCF/STB]		690	578	86	596.0	816
Saturated Live Oil Density [g/cm^3]		0.72	0.78	0.78	-	-
Saturated Live Oil Viscosity [cP]		0.9	2.58	16.68	-	-
Dead Oil Viscosity [cP]	@ 20°C	20	112	30	-	15.3
	@ 30°C	12.1	61.1	19	-	8.7
	@ 40°C	8.2	32.2	12.5	-	4

Table 3.2: Reservoir's fluid composition on a dry basis (adapted from Company, 2013)

Component		Reservoir's Fluid Composition on Dry Basis Overall (Oil + Gas) [wt. %]				
Name	**Molecular Weight [g/mol]**	**Tamarindo**	**Ginguenga**	**Maboque**	**Loengo**	**Gajaja**
C_1	16.04	5.86	6.27	5.08	4.63	8.26
C_2	30.07	1.26	0.21	0.59	1.48	1.94
C_3	44.10	2.67	0.58	0.39	2.78	2.22
i-C_4	58.12	0.64	0.20	0.44	0.65	0.57
n- C_4	58.12	1.67	0.56	0.50	1.69	1.51
i-C_5	72.15	0.89	0.39	0.71	0.90	0.93
n- C_5	72.15	1.08	0.48	0.63	1.02	1.13
m-cyclo-C_5	70.1	-	0.43	-	0.77	1.13
C_6	84.00	1.91	0.96	1.33	1.80	2.02
Benzene	78.11	-	0.15	0.06	0.05	0.09
Cyclo- C_6	84.16	-	0.21	-	0.34	0.37
m-Cyclo- C_6	84.16	-	0.53	-	0.95	0.98
C_7	96.00	3.34	1.12	2.69	2.26	2.28
Toluene	92.14	-	0.06	0.23	0.22	0.29
C_8	107.00	4.02	1.67	3.09	3.19	3.02
C_2-Benzene	106.17	-	0.15	0.09	0.28	0.20
mp-xylene	106.17	-	0.14	-	0.16	0.53

Table 3.2 (continued): Reservoir's fluid composition on a dry basis (adapted from Company, 2013)

Component		Reservoir's Fluid Composition on Dry Basis Overall (Oil + Gas) [wt. %]				
Name	**Molecular Weight [g/mol]**	**Name**	**Molecular Weight [g/mol]**	**Name**	**Molecular Weight [g/mol]**	**Name**
o-xylene	106.17	-	0.14	0.18	0.36	0.16
C_9	121.00	3.37	1.50	2.28	2.87	2.75
C_{10}	134.00	3.58	2.30	3.06	4.07	3.65
C_{11}	147.00	3.04	2.05	2.63	3.60	3.09
C_{12}	161.00	2.88	2.09	2.54	3.52	2.88
C_{13}	175.00	3.20	2.49	3.07	3.88	3.15
C_{14}	190.00	2.77	2.26	2.97	3.53	2.81
C_{15}	206.00	3.11	2.56	2.74	3.74	3.13
C_{16}	222.00	2.66	2.24	2.44	3.27	2.74
C_{17}	237.00	2.65	2.29	2.93	3.16	2.63
C_{18}	251.00	2.83	2.50	2.48	3.02	2.73
C_{19}	263.00	2.67	2.31	1.89	3.19	2.63
C_{20}	275.00	2.26	1.99	2.05	2.66	2.30
C_{21}	291.00	2.17	1.99	1.87	2.52	2.18
C_{22}	305.00	2.10	1.84	1.82	2.49	2.05
C_{23}	318.00	1.97	1.82	1.73	2.33	1.99
C_{24}	331.00	1.85	1.73	1.63	2.21	1.84
C_{25}	345.00	1.91	1.65	1.56	2.20	1.94
C_{26}	359.00	1.63	1.69	1.52	1.93	1.52
C_{27}	374.00	1.65	1.77	1.55	2.15	1.79
C_{28}	388.00	1.65	1.72	1.54	1.97	1.61
C_{29}	402.00	1.73	1.80	1.51	2.03	1.61
C_{31}	430.00	-	1.61	1.33	1.90	1.50
C_{32}	444.00	-	1.55	1.21	1.95	1.50
C_{33}	458.00	-	1.48	1.12	1.61	1.19
C_{34}	472.00	-	1.33	1.05	1.74	1.29
C_{35}	486.00	-	1.33	1.00	1.75	1.22
Molecular Weight: Overall [g/mol]		108.70	132.40	130.00	111.11	91.33
Molecular Weight – Oil [g/mol]		210.60	274.51	250.30	201.71	193.65
Molecular Weight – Gas [g/mol]		23.70	20.27	23.73	28.08	21.02
Mol % [Oil]		45.50	44.56	41.20	47.82	40.74
Mol % [Gas]		54.50	55.44	58.80	52.18	59.26

3.2.1. Hydrocarbon Fluids' Arrival Conditions

The subsea production fluids' arrival pressure is 23 barg (i.e., top of riser) with minimum and maximum arrival temperatures of 36 and 63°C, respectively. The shut-in pressure at the production and test manifold is 200 barg. The equipment and piping system upstream of the Production and Test manifold was designed for 345 barg at 80°C (Company, 2013).

3.3. Product's Specifications and Conditions

Table 3.3 provides a summary of the stabilised crude oil, produced water, gas lift and injection specifications and conditions.

Table 3.3: Product's specifications and conditions (Company, 2013)

Stream	Parameter	Value
Oil	BS&W [vol%]	≤ 0.5
	RVP at 37.8°C [psia]	≤ 10
	TVP at 50°C [psia]	≤ 14.7
	Salt content [ptb]	≤ 35
	Maximum rundown temperature [°C]	50
Water	Free oil in water [ppm]	30
	Total suspended solids [ppm]	10
	Maximum discharge temperature [°C]	50
Gas	Water content [lb/MMscfd]	1.5
	Gas lift/injection operating pressure at top of riser [barg]	289
	Gas lift/injection operating temperature [°C]	65
	Design pressure [barg]	345
	Design temperature [°C]	80

3.4. Topsides Process Overview Systems

Table 3.4 highlights the current topside systems handling capacity for processing the hydrocarbons of the 5 reservoirs listed in section 3.2.

Table 3.4: FPSO topsides' processing facility capacity (extracted from Company, 2013)

Parameter	Value
Oil Production [BOPD]	100 000
Maximum Liquids Production [BLPD]	125 000
Gas Lift [MMscfd]	70
Gas Production [MMscfd]	80
Total Gas Processing (Gas Production + Gas Lift) [MMscfd]	115
Gas Injection [MMscfd]	100
Produced Water Handling [BWPD]	100 000

3.4.1. Oil Separation and Treatment

Figure 3.1 illustrates the oil processing train installed in the FPSO's Topside Facilities

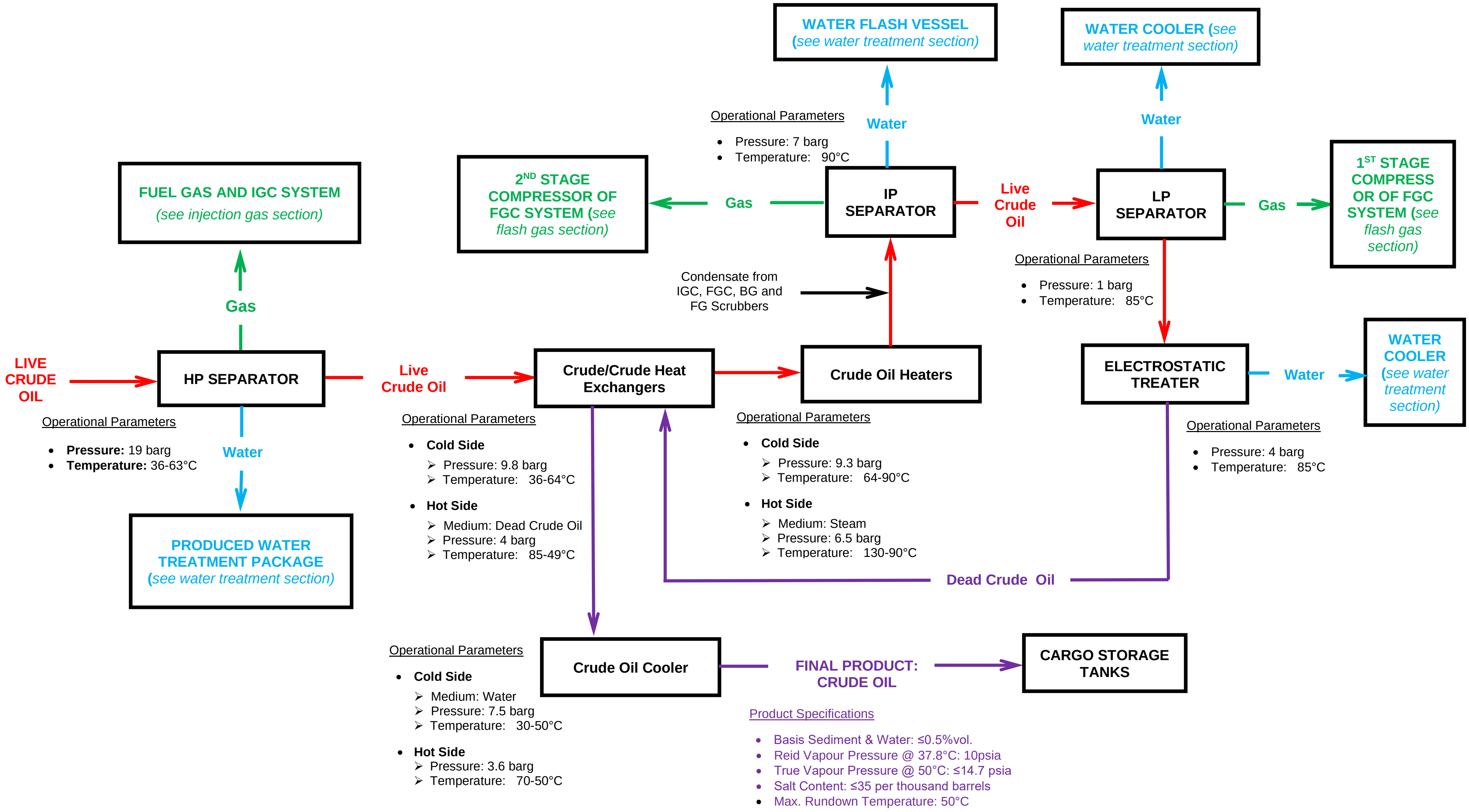

Figure 3.1: Block flow diagram of the oil processing train (adapted from Company, 2016e)

The separators installed in the FPSO under evaluation in this study, are three-phase vessels constructed of carbon steel lined with 3 mm glass flake, designed for water carryover of 10 vol% from the high pressure (HP) to the intermediate pressure (IP) separator, 5 vol% from the IP to the low pressure (LP) separator, 1.5 vol% from the LP to the electrostatic treater and 0.5 vol% from the electrostatic treater. The HP separator operates at 19.0 barg, has an expected operating temperature range of 36 to 63°C and is designed with a slug handling capacity of 40.36 m^3 between normal liquid level and high-level alarm. Gas from the HP separator flows to the 3-stage compression systems to acquire the required pressure for injection and oil lift purposes.

The crude oil leaving the HP separator is routed to the crude/crude heat exchangers (2 x 50%), to exchange heat with the hot stabilised crude oil from the electrostatic treater and the temperature is further increased to 90°C by means of a heating medium in the crude oil heaters (2 x 50%), prior to entering the IP separator. The produced water flows under level control to the produced water treatment units. The heated crude oil leaving the crude oil heaters commingles with the condensate from the flash gas compressors (FGC), injection gas compressors (IGC), blanket gas and fuel gas scrubbers and enters the IP separator at 7.0 barg at approximately 90°C. Gas from the IP separator is routed to the FGC system.

The crude oil from the IP separator flows under level control to the LP separator for crude stabilisation. Produced water from the IP separator flows under level control to the produced water flash vessel. The LP separator operating at 1.0 barg and 85°C stabilises the crude oil to the true vapour pressure (TVP) and Reid vapour pressure (RVP) specifications by removing volatile components from the crude to avoid flashing in the cargo tanks. The stabilised crude oil leaving the LP separator is pumped to the electrostatic treater by the crude oil pumps (2 x 100%), which pressurise the crude oil from 1 to 6 barg, through a mixing valve for the required reduction in water content. The produced water leaving the LP separator may be routed upstream or downstream of the produced water cooler (depending on the flow rate and cooling requirement) prior to disposal to the slops tank, while gas from the LP separator is routed to the FGC system.

The salinity specification of the stabilised crude oil is achieved by injecting ±85°C wash water at the discharge of the crude oil pump to dilute the salt content to 35 ptb. The mixing valve is required to facilitate salt removal from the crude product. Wash water at 6.0 barg is added upstream of the mixing valve at the rate of 70 m^3/h. The mixing valve requires a 2.0 bar pressure drop. The electrostatic treater with an operating pressure and temperature of 4.0 barg and 85°C, respectively removes the remaining water in the crude oil pumped from the LP separator to 0.5 vol% basic sediment and water (BS&W) using an electrostatic coalescing process.

A portion of the produced water from the electrostatic treater is recycled to the LP separator via a flow control valve to reduce the wash water consumption. This recycle stream has a reduced salinity compared to the raw produced water and acts to reduce the total salinity in the produced water carryover to the electrostatic treater.

The stabilised crude oil from the electrostatic treater is cooled by heat exchange with the crude oil from the HP separator in the crude/crude heat exchangers (2 x 50%), before it is cooled to a maximum rundown temperature of 50°C in the seawater cooled crude oil coolers (2 x 50% duty). The stabilised crude oil is sent to the cargo tanks for storage. The produced water leaving the electrostatic treater may be routed upstream or downstream of the produced water cooler (depending on the flow rate and cooling requirement) prior to disposal to the slops tank.

Based on the flow rates and physical properties considered in the design basis (as shown in Table 3.5), the separators were designed to achieve the following separation specifications:

- Maximum liquid content in the gas of 0.1 Gal/MMscf, based on the removal of 98% of all liquid droplets equal to or larger than 10 microns
- Maximum water content in the crude outlet:
  - HP separator: 10% (v/v) based on the removal of all droplets of 500 µm and larger
  - IP separator: 5% (v/v) based on the removal of all droplets of 350 µm and larger
  - LP separator: 1.5% (v/v) based on the removal of all droplets of 280 µm and larger
- Maximum crude content in the water outlet of 1000 ppm on removal of oil droplets of 180 µm and larger.

Table 3.5: Separators design basis (adapted from Company, 2016a)

Parameters	Maximum Oil and Gas Case				Maximum Water Case			
[m^3/h]	HP	IP	LP	Test	HP	IP	LP	Test
Oil flow rate	710	729	702	173	175	722	701	170
Gas flow rate	7099	1366	4923	9776	5525	1217	3825	1078
Water flow rate	171.5	2	69	-	687	82	106	155

Tables 3.6, 3.7, 3.8 and 3.9 provide brief design specifications of the main equipment used within the facility for oil separation and stabilisation, namely: separators, heat exchangers, pumps, and the electrostatic treater.

Table 3.6: Separator's design and operating parameters (adapted from Company, 2016a)

Parameter	HP Separator	IP Separator	LP Separator	Test Separator
Design Pressure [barg]	30	10	10	30
Design Temperature [°C]	-10 / 80	-10 / 110	-10 / 110	-10 / 80
Operating Pressure [barg]	19	7	1	6 - 19
Operating Temperature [°C]	36 to 63	90	85	-2 - 63

Table 3.7: Heat exchangers design duties (adapted from Company, 2016a)

Parameter	Crude/Crude Exchangers	Crude Oil Heaters	Crude Oil Coolers
Type of Exchanger	Plate and Gasket	Plate and Gasket	Plate and Gasket
Design Duty [kW]	5930	6077	3190

Table 3.8: Crude oil pumps main design parameters (adapted from Company, 2016a)

Parameter	Values
Type of Pump	Centrifugal
Design Capacity [m^3/h]	730
Differential Head [m]	71.2
Power [kW]	151

Table 3.9: Electrostatic treater design parameters (adapted from Company, 2016a)

Parameter	Values
Oil Design Flow Rate [m^3/h]	Max Oil Case: 702 / Max water case 701
Water Inlet Design Flow Rate [m^3/h]	Max Oil Case: 70 / Max Water Case: 83
Oil Inlet Minimum Flow Rate [m^3/h]	Turndown Case: 89
Water Inlet Minimum Flow Rate [m^3/h]	Turndown Case: 9.9
Inlet Design Salt Content in Oil [mg/L]	211930
Max water-cut without short-circuiting [vol%]	± 30
Minimum wash water requirement [%]	7-8 (subject to salt content in the treater inlet)

3.4.2. Gas Processing

The gas compression system handles the gas streams from the HP Separator (19.0 barg), IP Separator (7.0 barg) and LP Separator (1.0 barg). The combined gas streams are compressed to the required gas lift and injection pressure of 289 barg at the top of the riser in five stages. The gas from the discharge of the second stage IGC (stage four) at about 144.4 barg is dehydrated to a water content of 1.5 lb/MMscf in a triethylene glycol gas dehydration system.

3.4.2.1. Flash Gas Compression

Flash gas compression (FGC) is provided to boost the pressure of the gas from the IP separator, LP separator and vapour recovery unit (VRU) to the injection gas compressor package suction pressure. The FGC trains (2 x 100%) comprise of an LP and an HP compressor (2 stages), driven by one high voltage variable frequency drive electric motor via a twin output gearbox. The compressors are rotary dry screw units with gas sealing provided by a seal oil system derived from the lubricating system.

Gas from the LP separator flows to the 1st stage suction cooler, where it is cooled to 45°C by heat exchange with a cooling medium before flowing to the 1st stage suction scrubbers, where the gas enters via an inlet deflector and condensate is removed via a vortex breaker and pumped back to the IP separator by a suction drain pump. The gas leaves the top of the vessel via a vane packed wire mesh demister to flow to the 1st stage FGC, where it is pressurised to 6 barg before it is discharged to the 2nd stage cooler. The discharged gas flowing to the 2nd stage cooler is joined with the gas from the IP separator and recycled gas from the 2nd stage FGC discharge.

Gas from the 1st stage compressor discharge and recycle gas are mixed with the gas from the IP separator, then directed to the 2nd stage FGC cooler. The commingled gas is cooled to 45°C by heat exchange with a cooling medium before flowing to the 2nd stage FGC scrubber. Cooled gas enters the suction scrubber via an inlet deflector (Train A) or half open pipe (Train B) where condensate is removed via a vortex breaker and pumped back to the IP separator via the 2nd stage drain pump. The gas leaves the top of the vessel via a vane packed wire mesh demister to flow to the 2nd stage FGC suction, for pressurisation to 19.3 barg before it is piped into the IGC System.

Tables 3.10, 3.11, 3.12 and 3.13 provide the design specifications of the FGC system

Table 3.10: FGC coolers' design duties and flow rates (adapted from Company, 2014a)

Parameter	1st Stage Cooler	2nd Stage Cooler
Type of Exchanger	Shell and Tube	Shell and Tube
Design Duty [kW]	1477	2193
Gas Design Flow Rate [kg/h]	14 745	28 495

Table 3.11: FGC scrubbers' design flow rates (adapted from Company, 2014a)

Parameter	1st Stage Scrubber	2nd Stage Scrubber
Design Gas Flow Rate [kg/h]	12 595	22 798
Design Oil Flow Rate [m^3/h]	2.78	8.71
Design Water Flow Rate [m^3/h]	1.69	0.8

Table 3.12: FGC drain pumps' design parameters (adapted from Company, 2014a)

Parameter	1st Stage Pump	2nd Stage Pump
Type	Centrifugal	Centrifugal
Design Capacity [m^3/h]	4.5	4.5
Differential Head [m]	108	55
Duty Absorbed [kW]	9.4	4.5

Table 3.13: FGC main design parameters (adapted from Company, 2014a)

Parameter	1st Stage Compressor	2nd Stage Compressor
Type of Compressor	Dry Screw	Dry Screw
Design Pressure [barg]	10	30
Design Temperature [°C]	-15 / 200	-15 / 200
Suction Pressure [barg]	0.45	6
Suction Temperature [°C]	45	45
Discharge Pressure [barg]	6	19.3
Discharge Temperature [°C]	123	113
Design Duty [kW]	720	935
Design Flow Rate [MMscfd]	6.7	12.5

Table 3.13 (continued): FGC main design parameters (adapted from Company, 2014a)

Parameter	1st Stage Compressor	2nd Stage Compressor
Design Molecular Weight [kg/kmol]	48.76	36.65
Turndown Flow Rate [MMscfd]	4.45	8.27
Turndown Molecular Weight [kg/kmol]	27.72	22.89
Turndown Duty [kW]	512	671

To prevent ingress of oxygen into the cargo tanks, a slight overpressure (0.039 to 0.059 bar) is maintained in the cargo system by hydrocarbon gas blanketing and vapor recovery. During cargo loading, vapors are emitted from the cargo tanks due to displacement and evaporation or boil off. These vapors are recovered by a VRU compressor and pressurised to the pressure required for entry into the FGC system, where further pressurisation takes place.

The VRU consists of a liquid ring compressor with a closed-loop seal water system. Cooling of the seal water is achieved by a plate type heat exchanger using water as the cooling medium. Gas at 0.04 to 0.15 barg is routed from the cargo tanks via the hydrocarbon gas header to the inlet of the VRU. Within the compressor, gas pressure is boosted to 1.35 barg and the stream is routed to a gas-liquid separator. From the separator, gas is routed to the flash gas compression FGC system via FGC suction cooler. The seal water from the separator flows under level control to the inlet of the heat exchanger where it is cooled by heat exchange with the cooling medium flowing counter-currently through the exchanger before the seal water is routed back to the liquid ring compressor as operating liquid.

The compressor has a capacity of 1 244 m^3/h (1 MMscfd), a shaft power of 80 kW and runs at a speed of up to 1 190 rpm. The operating water temperature into the liquid ring compressor is designed to 45ºC and the liquid temperature of the compressor discharge is estimated to be about 55ºC (Company, 2013). A block flow diagram of the flash gas compressor and the vapor recovery unit systems is represented in Figure 3.2 and Figure 3.3, respectively.

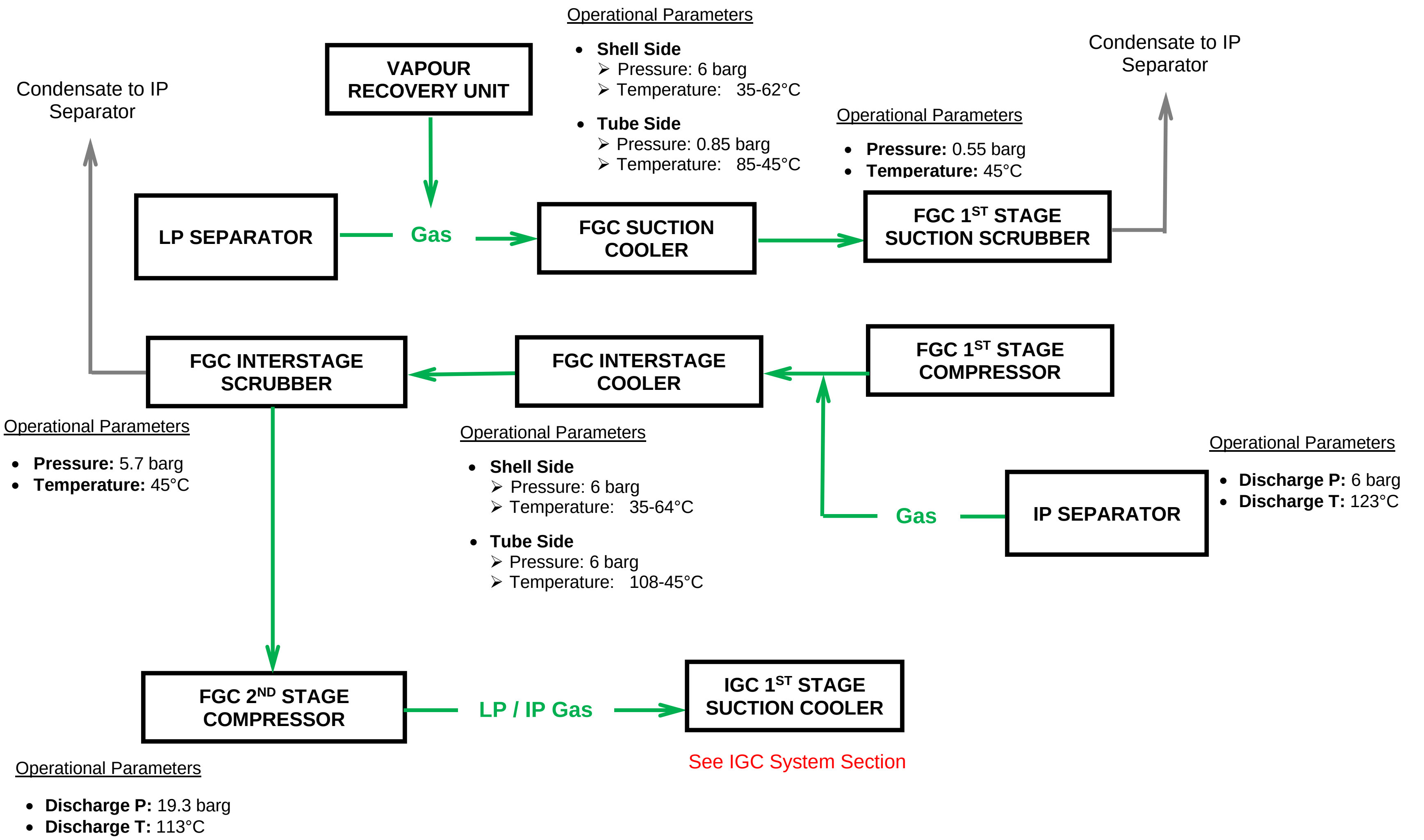

Figure 3.2: Block flow diagram of the flash gas compression system (adapted from Company, 2016e)

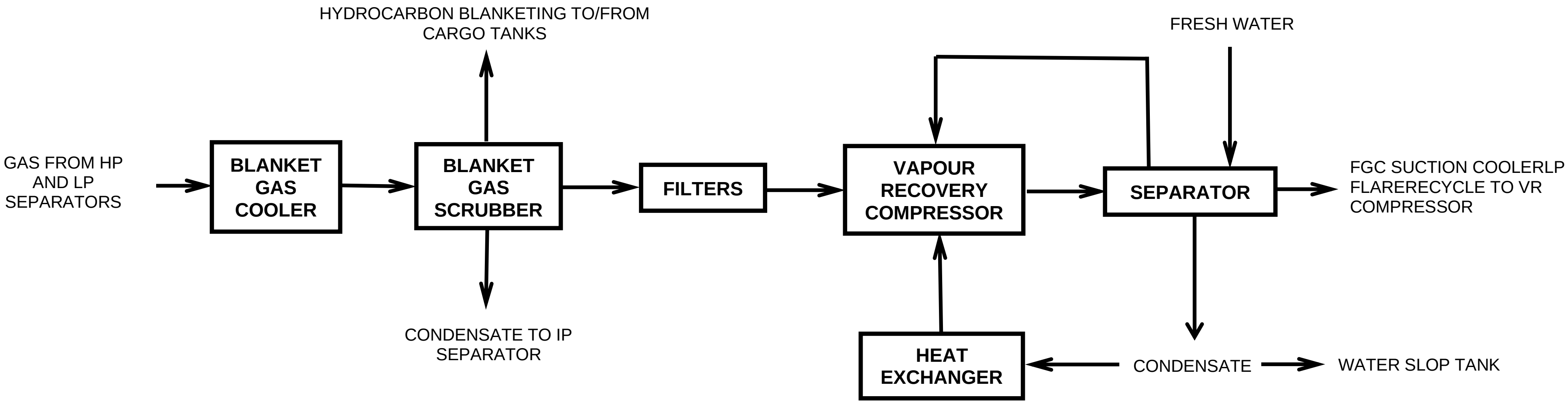

Figure 3.3: Block Flow Diagram of the vapour recovery unit system (adapted from Company, 2016e)

3.4.2.2. Main Injection Gas Compressor

The injection gas compressor (IGC) packages (3 x 50%) are three-stage centrifugal driven by gas/liquid fuel turbines. Each compression stage is provided with a suction cooler and a suction scrubber, where the accumulated hydrocarbon condensate is removed by a pressure gradient for re-injection into the oil processing train.

The suction coolers cool the temperature of the incoming gas to approximately 45°C before it is routed to the proceeding compressor stage via suction scrubbers for entrained liquids removal from the gas stream. The LP/IP compressors (i.e., first and second stages) are of the barrel type, vertically split, and the centrifugal compressor pressurises the gas to 56 and 144.4 barg, respectively while the HP compressor (i.e., third stage) pressurises the gas to approximately 293 barg before routing the gas to the injection/lift riser via a Discharge Cooler, where a gas temperature of 65°C is achieved.

Tables 3.14, 3.15 and 3.16 provide the design specifications of the IGC System.

Table 3.14: IGC coolers' design duties (adapted from Company, 2014b)

Parameter	1st Stage Cooler	2nd Stage Cooler	3rd Stage Cooler	Final Discharge Cooler
Type of Exchanger	Shell and Tube	Shell and Tube	Shell and Tube	Shell and Tube
Design Duty [kW]	1127	4996	4986	3105

Table 3.15: IGC scrubbers' design flow rates (adapted from Company, 2014b)

Parameter	1st Stage Scrubber	2nd Stage Scrubber	3rd Stage Scrubber
Type	2 stage with vane pack	2 stage with vane pack	Multi Cyclone
Design Gas Flow Rate [kg/h]	61037	61630	54221
Design Oil Flow Rate [m^3/h]	1.1	2.6	-
Design Water Flow Rate [m^3/h]	0.6	0.2	-

Table 3.16: IGC main design parameters (adapted from Company, 2014b)

Parameter	1st Stage Compressor	2nd Stage Compressor	3rd Stage Compressor
Type of Compressor	Centrifugal	Centrifugal	Centrifugal
Design Pressure [barg]	170	170	345

Table 3.16 (continued): IGC main design parameters (adapted from Company, 2014b)

Parameter	1st Stage Compressor	2nd Stage Compressor	3rd Stage Compressor
Design Temperature [°C]	-15 / 180	-15 / 180	-15 / 170
Suction Pressure [barg]	18	56	144.4
Suction Temperature [°C]	44	45	45
Discharge Pressure [barg]	56	144.4	293
Discharge Temperature [°C]	144	141	130
Maximum Speed [rpm]	14851	14851	14851
Duty Absorbed [kW]	3464	3387	2613
Gas Capacities (Each Train) [MMscfd]	57.5	57.5	50
Each Gas Turbine Power [MW]	13.4	13.4	13.4

Figure 3.4 comprises of a block flow diagram of the injection gas compressor system installed in the Topside's section of the FPSO

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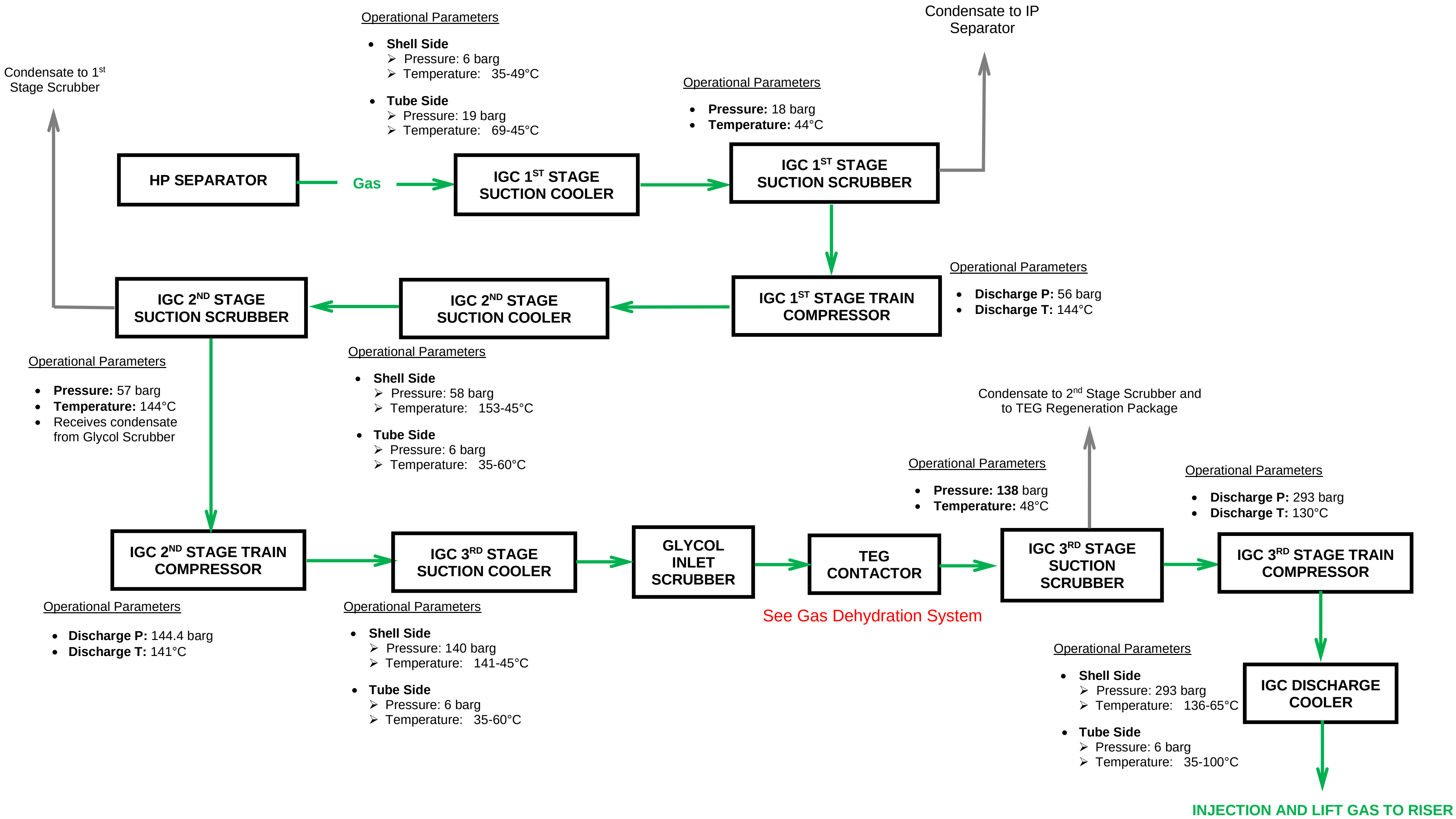

Figure 3.4: Block flow diagram of the injection gas compression system (adapted from Company, 2016e)

3.4.2.3. Gas Dehydration

Gas dehydration is provided downstream of the 2nd stage injection gas compressors and consists of 2 x 50% duty rated glycol scrubbers and 2 x 50% tri-ethylene (TEG) duty rated glycol contactors, which share a common TEG regeneration package. A side stream of the dehydrated gas is taken-off prior to third stage compression and is used as fuel gas.

Gas dehydration is required to maintain a sufficiently low water dew point to ensure that potential carbon dioxide corrosion rates in downstream facilities are minimised and hydrates do not form in the downstream facilities and by ensuring that the water dew point of the gas is lowered to below the minimum ambient seawater temperature of 4°C, the need for continuous methanol injection is avoided.

Table 3.17 represents the design parameters of the glycol scrubbers, while Table 3.18 represents the main design parameters of the TEG contactors and Figure 3.5 illustrates the TEG regeneration system by means of a block flow diagram.

Table 3.17: Triethylene glycol scrubbers' design duty and flow rates (Company, 2016b)

Parameter	Values
Type	Vertical Multi Cyclone
Design Gas Flow Rate [kg/h]	57.3
Turndown Gas Flow Rate [kg/h]	33.7

Table 3.18: Triethylene glycol contactors design parameters (Company, 2016b)

Parameter	Values
Specification [lb/MMscfd]	< 1.5
Design Gas Flow Rate [MMscfd]	57.3
Turndown Gas Flow Rate [MMscfd]	33.7
Molecular Weight	20.3 – 23.62
Inlet Water Content	54.9 – 59.4

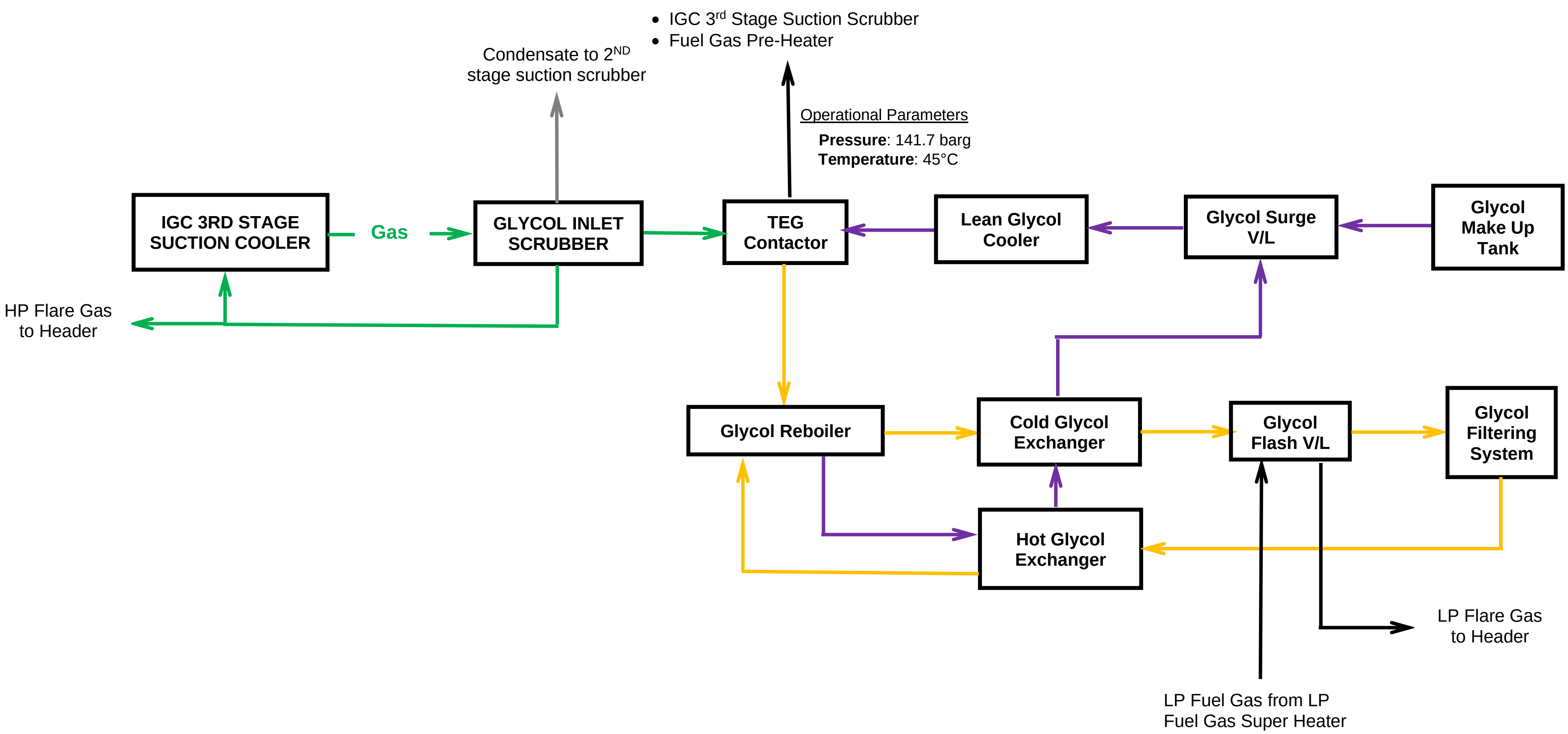

Figure 3.5: Block flow diagram of the gas dehydration system (adapted from Company, 2016e)

3.4.2.4. Fuel Gas

The normal fuel gas off-take is located downstream of the gas dehydration system at approximately 141.4 barg. The fuel gas is pre-heated and superheated by means of hot water, as the heating medium, before it is distributed to users. Condensate recovered in the fuel gas scrubber is sent to the IP separator. A line from the HP separator is provided to supply LP fuel gas to the steam boilers if the injection gas compressors are not available. The LP fuel gas is mainly used for the steam boilers with small amounts used as stripping gas, pilot gas and purge gas, while HP fuel gas is used at the turbine prime movers (i.e., power generation, gas compressors and water injection pumps).

Tables 3.19 and 3.20 show the design parameters of the main equipment of the fuel gas system and Figure 3.6 presents a block flow diagram of the overall fuel gas system employed in the FPSO.

Table 3.19: Heat exchangers design duties (adapted from Company, 2014c)

Parameter	Fuel Gas Pre-Heater	LP Fuel Gas Superheater	HP Fuel Gas Superheater
Type of Exchanger	Multi Tube	Double Pipe	Double Pipe
Design Duty [kW]	369	104	157

Table 3.20: Fuel gas scrubbers design flow rates (adapted from Company, 2014c)

Parameter	Value
Design Gas Flow Rate [kg/h]	22723
Design Oil Flow Rate [m^3/h]	1.8
Design Water Flow Rate [m^3/h]	-

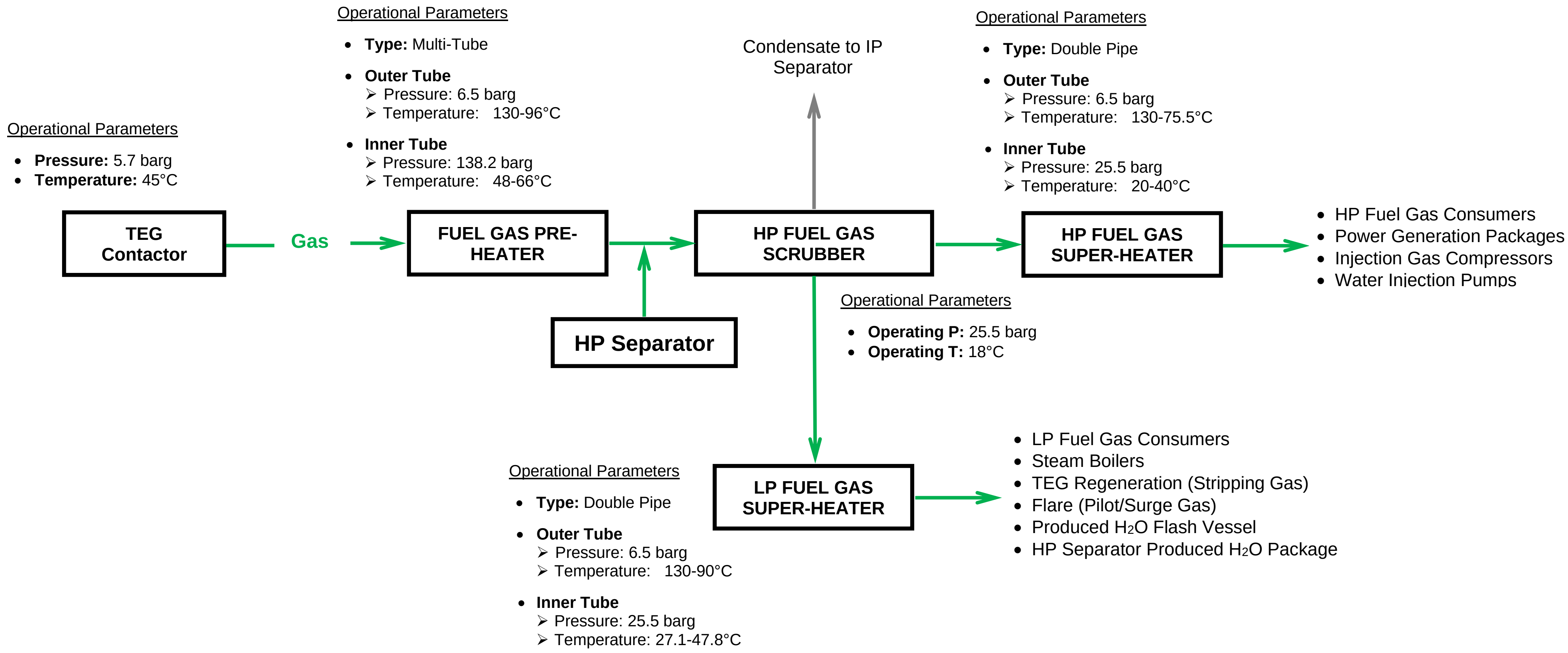

Figure 3.6: Block flow diagram of the fuel gas system (adapted from Company, 2016e)

3.4.2.5. Flare System

The flare system is sized to handle the highest emergency relief rate, the continuous production flaring rate during start-up or production disruption, and the maximum topsides blowdown relief demand. The HP flare drum receives releases from the HP and test separators, IGC, gas dehydration, HP fuel gas system and the IGF unit, while the LP flare drum receives relief gas from process and utility systems. Flare pumps are provided to pump condensate that collects in the flare drums to the cargo tanks.

The HP flare tip contains six sonic gas discharge nozzles designed to provide a short smokeless frame and is fitted with two pilot burners. The LP flare tip is a pipe flare close coupled to the HP flare tip, fitted with a single pilot burner for ignition of the main flame. Main equipment design parameters are shown in Tables 3.21, 3.22 and 3.23. Figure 3.7 represents the flare relief system.

Table 3.21: HP and LP flare drums design flow rates (adapted from Company, 2016c)

Parameter	HP Flare Drum	LP Flare Drum
Gas Design Flow Rate [MMscfd]	175	44
Liquid Design Flow Rate [BLPD]	125000	25000

Table 3.22: Flare condensate pumps main design parameters (adapted from Company, 2016c)

Parameter	Value
Type of Pump	Centrifugal
Design Capacity [m^3/h]	50
Differential Head [m]	29.7
Power [kW]	6.3

Table 3.23: Flare tip design specifications (adapted from Company, 2016c)

Parameter	Value
Design Capacity HP/LP [MMscfd]	175 / 96.5

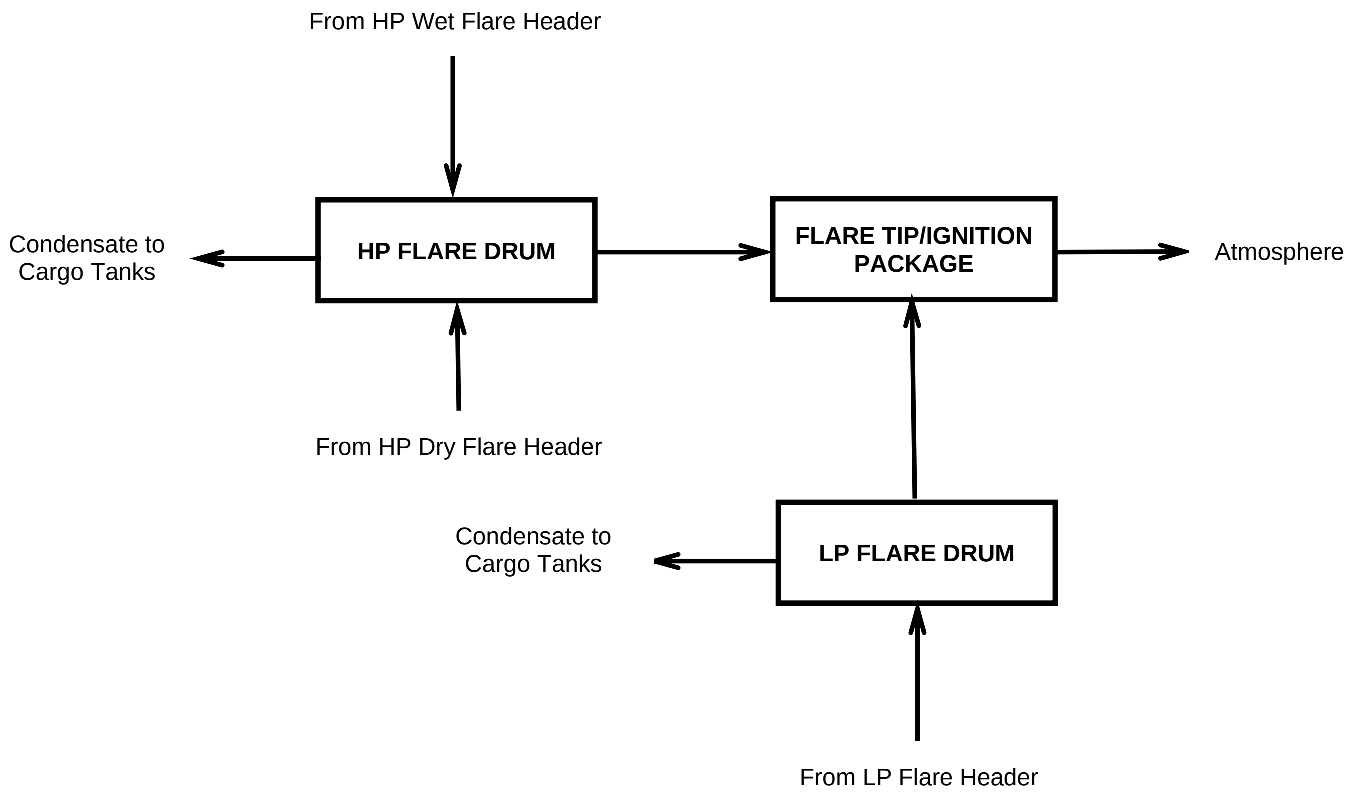

Figure 3.7: Block flow diagram of the flare relief system (adapted from Company, 2016e)

3.4.3. Produced Water Treatment

Produced water from the HP separator is routed to the hydrocyclone, induced gas flotation unit and a seawater aided water cooler, which is designed to achieve the required oil-in-water (OIW) specification of 30 ppm, for direct discharge overboard or discharge to the slop tanks in case of off specification water. The reject oil from the hydrocyclone is routed to the slop tanks.

Produced water from the IP separator is routed to a flash vessel under level control so that the hydrocarbon gas is removed from the water. The gas from the flash vessel is directed to the LP flare and the water is routed to an LP water cooler to achieve a temperature of 50°C prior to discharge to the slops tank. In the slops tank, the water can settle by gravity separation to meet the overboard specifications of 30 ppm of free oil and 10 ppm of total dissolved solids. Produced water from the LP separator and electrostatic treater do not pass through the flash vessel and are routed either upstream or downstream of the LP water cooler, depending on the flow rates and cooling requirements. Design specifications of the equipment used in produced water treatment are listed in Tables 3.24, 3.25, 3.26 and 3.27 and an overall block diagram is illustrated in Figure 3.8.

Table 3.24: Heat exchangers' design duties (adapted from Company, 2015c)

Parameter	HP Produced Water Cooler	IP/LP Produced Water Cooler
Type of Exchanger	Plate and Gasket	Plate and Gasket
Design Duty [kW]	10696	6462
Design Flow Rate [m^3/h]	665.6	165

Table 3.25: Hydrocyclone design specifications (adapted from Company, 2015c)

Parameter	Value
Minimum Design Flow Rate [m^3/h]	212
Design Rejected Oil Flow Rate [m^3/h]	1.6
Inlet Maximum OIW content [ppm]	2000
Design Capacity [m^3/h]	667.2
Specification [ppm]	100

Table 3.26: Induced gas flotation design specifications (adapted from Company, 2015c)

Parameter	Value
Minimum Design Flow Rate [m^3/h]	33
Design Capacity [m^3/h]	665.6
Specification [ppm]	30 mg/l OIW content

Table 3.27: Produced water flash vessel design specifications (adapted from Company, 2015c)

Parameter	Value
Design Capacity [m^3/h]	330
Design Gas Flow Rate [MMscfd]	0.5

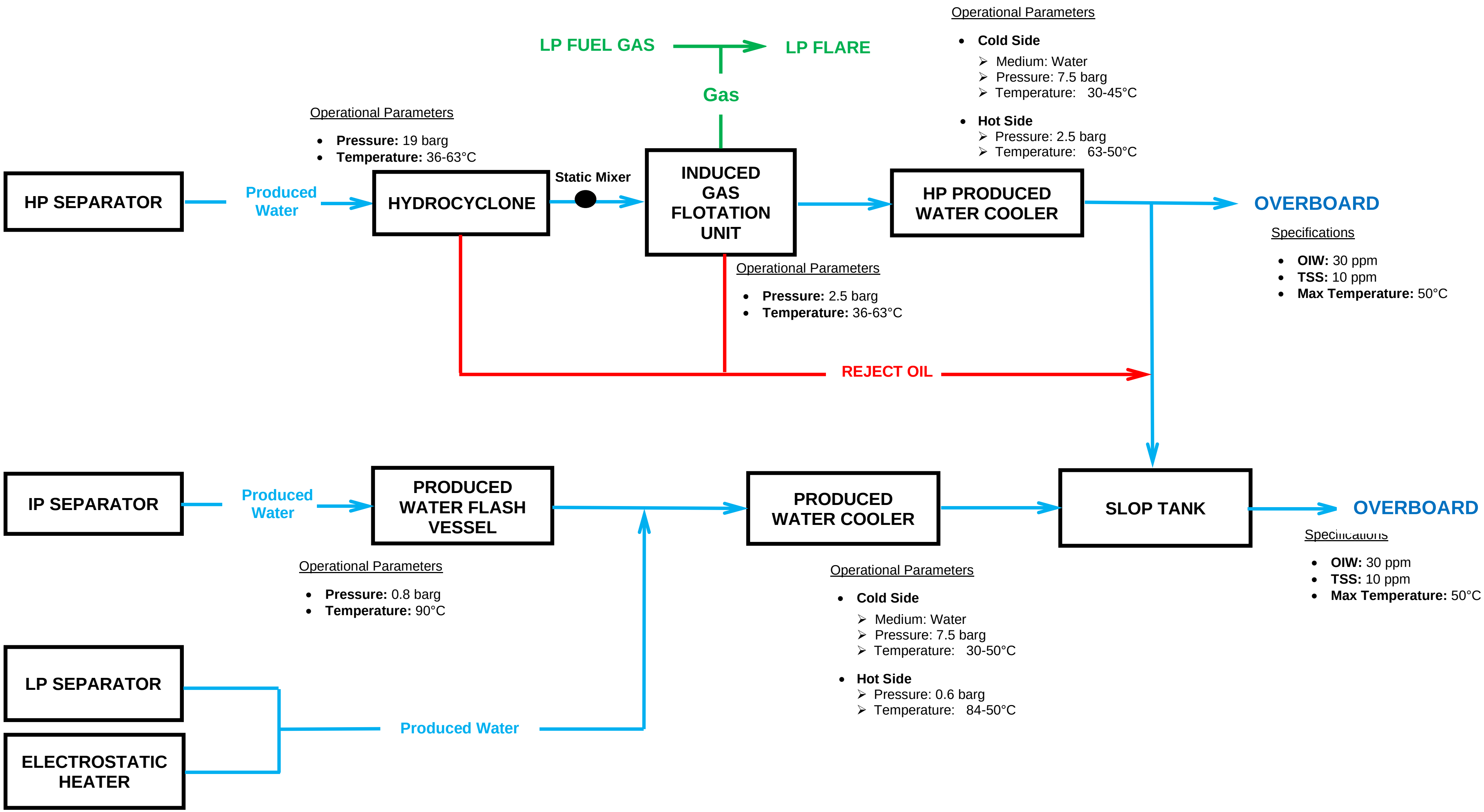

Figure 3.8: Block flow diagram of the produced water system (adapted from Company, 2016e)

3.4.4. Utility Systems

3.4.4.1. Wash Water

Coarse filters (2 x 100%) are designed for a flow rate of 3 400 m^3/h and removal of particulates down to 100 µm and 3 x 50 % multi-media filters are provided for a total flow of 1 330 m^3/h to remove at least 98% of particulates greater than 5 µm from the seawater. The seawater feed temperature to the seawater reverse osmosis system should be as low as possible to achieve high membrane efficiency. As such, the water entering the fine filters is taken directly from the coarse filter's outlet. Fresh water is generated by means of reverse osmosis membranes and a heater ensures the wash water has a temperature of 85°C, which is required for crude washing to avoid cooling of the crude at the injection point. Design reference for the filtration and RO are listed in Tables 3.28, 3.29 and 3.30. A block flow diagram of the system is represented in Figure 3.9.

Table 3.28: Seawater filters' design specifications (adapted from Company, 2015b)

Parameter	Coarse Filters	Multimedia Filters	Cartridge Filters
Capacity [m^3/h]	3400	665	667
Specification	98% > 100 µ	95% > 5 µ	Element Rating: 5µ No of Elements: 276
Rated Power [kW]	0.37 [each motor]	21.3 [air blower]	-

Table 3.29: Reverse osmosis membrane specifications (adapted from Company, 2015b)

Parameter	Value
Type	Reverse Osmosis
Outlet Capacity [m^3/h]	80
Design Pressure [barg]	82.7
Design Temperature [°C]	0 to 80
Flow per Train [m^3/h]	100
Number of Elements	6
Number of Pressure Vessels	13

Table 3.30: Wash water heater specifications (adapted from Company, 2015b)

Parameter	Value
Type of Exchanger	Plate and Gasket
Design Duty [kW]	6440

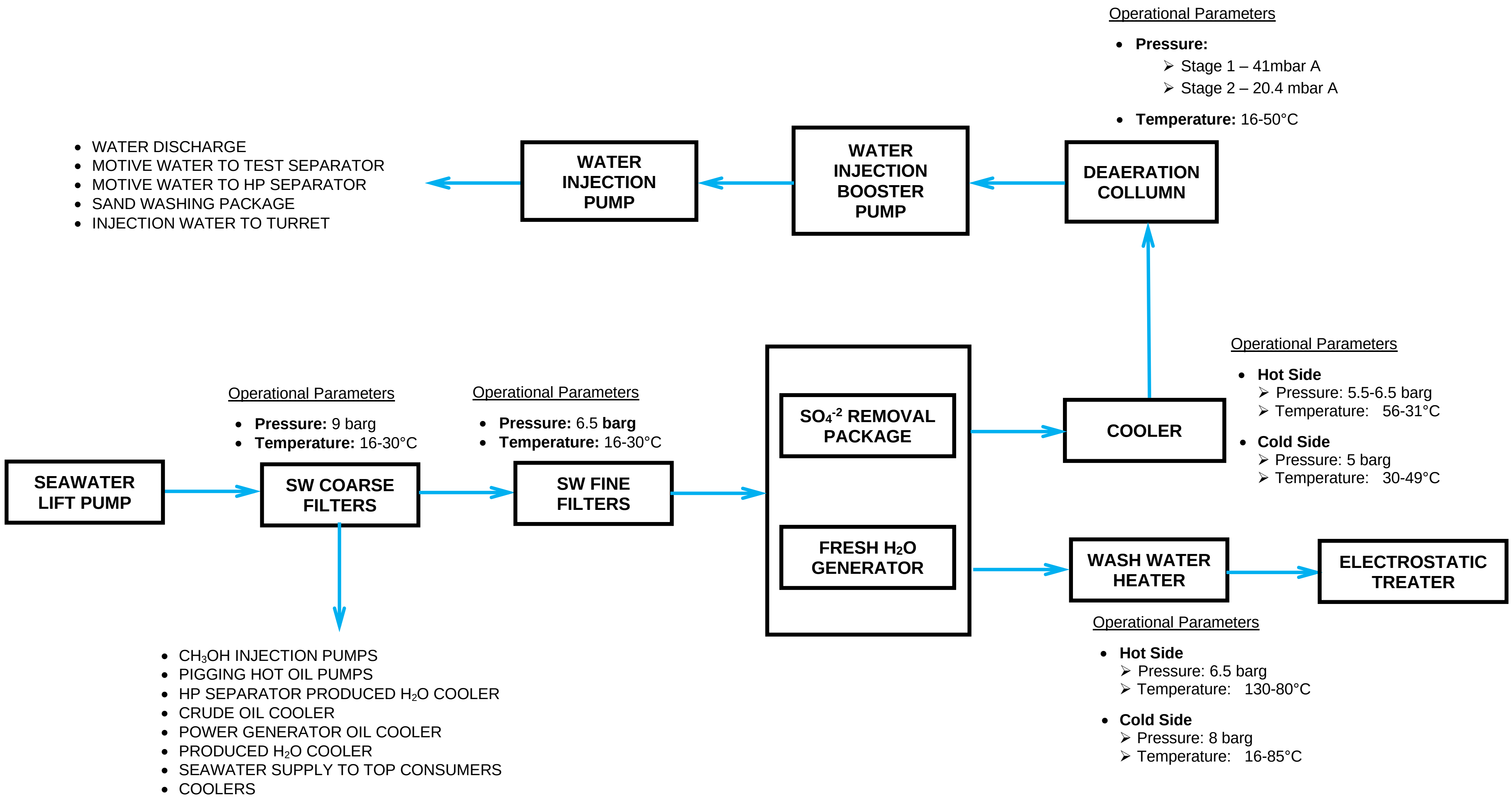

Figure 3.9: Block flow diagram of the seawater treatment system (adapted from Company, 2016e)

3.4.4.2. Cooling and Heating Medium

The cooling medium system is a closed loop inhibited fresh water cooling system with supply and return temperatures of 35°C and approximately 56°C, respectively. The cooling medium is cooled by indirect contact with seawater in the heat exchangers (3 x 50%), which is supplied from the outlet of the coarse filters and discharged overboard on exiting the exchangers. A tank is used as an expansion vessel and the circulation pumps are provided in a 3 x 50% configuration. Design specifications of the system are listed in Tables 3.31 and 3.32.

Table 3.31: Cooling medium circulation pumps' specifications (adapted from Company, 2016d)

Parameter	Value
Type	Centrifugal
Design Capacity [m^3/h]	740
Differential Head [mlc]	47.8
Design Duty [kW]	114.4

Table 3.32: Cooling medium exchangers' specifications (adapted from Company, 2016d)

Parameter	Value
Type	Plate and Gasket
Design Duty [kW]	17653

The heating medium system is an inhibited freshwater heating system with heating medium supply and return temperatures of 130°C and approximately 87°C, respectively. Heating medium is supplied to the crude oil heaters, wash water heater, fuel gas preheater and super heaters, HP and LP flare drum boots. The design intent of the heating medium steam supply control is to provide the required heat to the heating medium fluid through exchangers (3 x 33%) by LP steam from the steam boilers supplied to the shell side of the exchangers. A tank is used as an expansion vessel and the circulation pumps are provided in 2 x 100% configuration. Design specifications of the system are listed in Tables 3.33 and 3.34.

Table 3.33: Heating medium circulation pumps' specifications (adapted from Company, 2014d)

Parameter	Value
Type	Centrifugal
Design Capacity [m^3/h]	385
Differential Head [mlc]	37.2
Power [kW]	49.5

Table 3.34: Heating medium exchangers' specifications (adapted from Company, 2014d)

Parameter	Value
Type	Shell and Tube
Design Duty [kW]	6100

3.5. Múcua Tie-In: A Process Overview

The Múcua field is located in Block 51/06 approximately 180 km off the coast and about 20 km west from the FPSO under evaluation. The first well is to be drilled in a water depth of 1636 meters. This first phase, foresees a daily oil production of approximately 20 000 barrels of oil per day (BOPD), as one production well tie-back to the existing 4-slot Ginguenga's production manifold by means of one new rigid flow line of about 17 km. The produced fluids are to be routed to the existing floating production storage and offloading (FPSO) treatment facilities via the existing production riser, PR-c, either to the high pressure (HP) separator or to the Test separator.

3.5.1. Múcua Reservoir PVT Characterisation

There is a 0% water cut for the Múcua production fluids and the production fluids are to be adequately treated with chemical injection for any emulsion issues due to the low temperature envisaged upon extraction (Company, 2019). The new reservoir properties and its fluid's composition are shown in Table 3.35 and Table 3.36 respectively and the production and gas lift riser line-ups are shown in Table 3.37.

Table 3.35: Múcua reservoir properties (adapted from Company, 2019)

Properties	Value
Reservoir Pressure [bara]	309
Reservoir Temperature [°C]	89
Depth [m SS TVD]	3751
Saturation Pressure [bara]	212.98
Stock Tank Oil Gravity [°API]	29
Average Gas-Oil Ratio [scf/STB]	663
Saturated Live Oil Density [g/cm^3]	0.88

Table 3.36: Múcua reservoir fluid composition on dry basis (adapted from Company, 2019)

Component		Reservoir's Fluid Composition on Dry Basis Overall (Oil + Gas) [wt. %]
Name	**Molecular Weight [g/mol]**	**Múcua**
C_1	16.04	5.98
C_2	30.07	0.83
C_3	44.10	2.09
i-C_4	58.12	0.59
n- C_4	58.12	1.52
i-C_5	72.15	0.83
n- C_5	72.15	0.97
m-cyclo-C_5	70.1	0.01
C_6	84.00	1.60
Benzene	78.11	0.05
Cyclo- C_6	84.16	-
m-Cyclo- C_6	84.16	-
C_7	96.00	2.82
Toluene	92.14	0.17
C_8	107.00	3.14
C_2-Benzene	106.17	0.08
mp-xylene	106.17	0.21
o-xylene	106.17	0.14
C_9	121.00	2.37
C_{10}	134.00	2.95
C_{11}	147.00	2.69
C_{12}	161.00	2.77
C_{13}	175.00	3.16
C_{14}	190.00	2.73
C_{15}	206.00	2.54
C_{16}	222.00	2.22
C_{17}	237.00	2.78
C_{18}	251.00	2.26
C_{19}	263.00	1.72
C_{20}	275.00	1.80
C_{21}	291.00	1.71
C_{22}	305.00	1.64
C_{23}	318.00	1.55
C_{24}	331.00	1.46

Table 3.36 (continued): Múcua reservoir fluid composition on dry basis (adapted from Company, 2019)

Component		Reservoir's Fluid Composition on Dry Basis Overall (Oil + Gas) [wt. %]
Name	**Molecular Weight [g/mol]**	**Múcua**
C_{25}	345.00	1.39
C_{26}	359.00	1.36
C_{27}	374.00	1.36
C_{28}	388.00	1.36
C_{29}	402.00	1.34
$C_{30\,(+)}$	416.00	1.30
C_{31}	430.00	1.20
C_{32}	444.00	1.17
C_{33}	458.00	1.05
C_{34}	472.00	0.97
C_{35}	486.00	0.94
$C_{36\,(+)}$	-	29.08
Molecular Weight: Overall [g/mol]		118.0

Table 3.37: Fields and separators line-ups to production and gas lift risers

Riser's Description	Tamarindo	Ginguenga + Múcua	Maboque	Loengo	Gajaja
PR-a: HP Separator	X				
PR-b: HP Separator	X			X	
PR-c: HP or Test Separator		X			
PR-d: HP Separator			X		X
TR-a: Test Separator			X		
Gas Lift	GL1		GL3a	GL1	GL3a

Overall, in this section the FPSO under analysis has been described in detail from a design point of view. Raw crude oil properties have been highlighted and all the processes from subsea extraction up to the final products along with the design operational parameters and limitations of the equipment installed to produce 125 000 barrels of liquid per day have been thoroughly explained.

CHAPTER 4

MATERIALS AND METHODS

CHAPTER 4: MATERIALS AND METHODS

4.1. Introduction

There is a large range of possibilities to test hypotheses in research problems. Research results depend on how observations and interferences are made, the number, quantity of levels, as well as the type of independent variables. When dealing with only one independent variable, a single factor experimental design is normally used, but when having more than one independent variable with more than one level, a factorial design is used for scientific experiments (McBurney and White, 2007; Kerlinger, 2007).

In this research, six blend design cases were evaluated by means of Aspen Tech HYSYS simulations and the operating parameters for individual equipment were compared with the original design to identify potential bottlenecks, with a detailed study focusing only on a governing case.

This chapter highlights the process conditions and the main parameters considered for the factorial design cases used as basis for the Aspen Tech HYSYS simulations, discussion on the performance evaluation of separators and scrubbers using MySEP and the experimental set-up for the topside processing unit.

4.2. Experimental Set-Up

A summarised process flow diagram of the production unit under evaluation within the scope of this study is illustrated in Figure 4.1, with each unit operation described in Table 4.1.

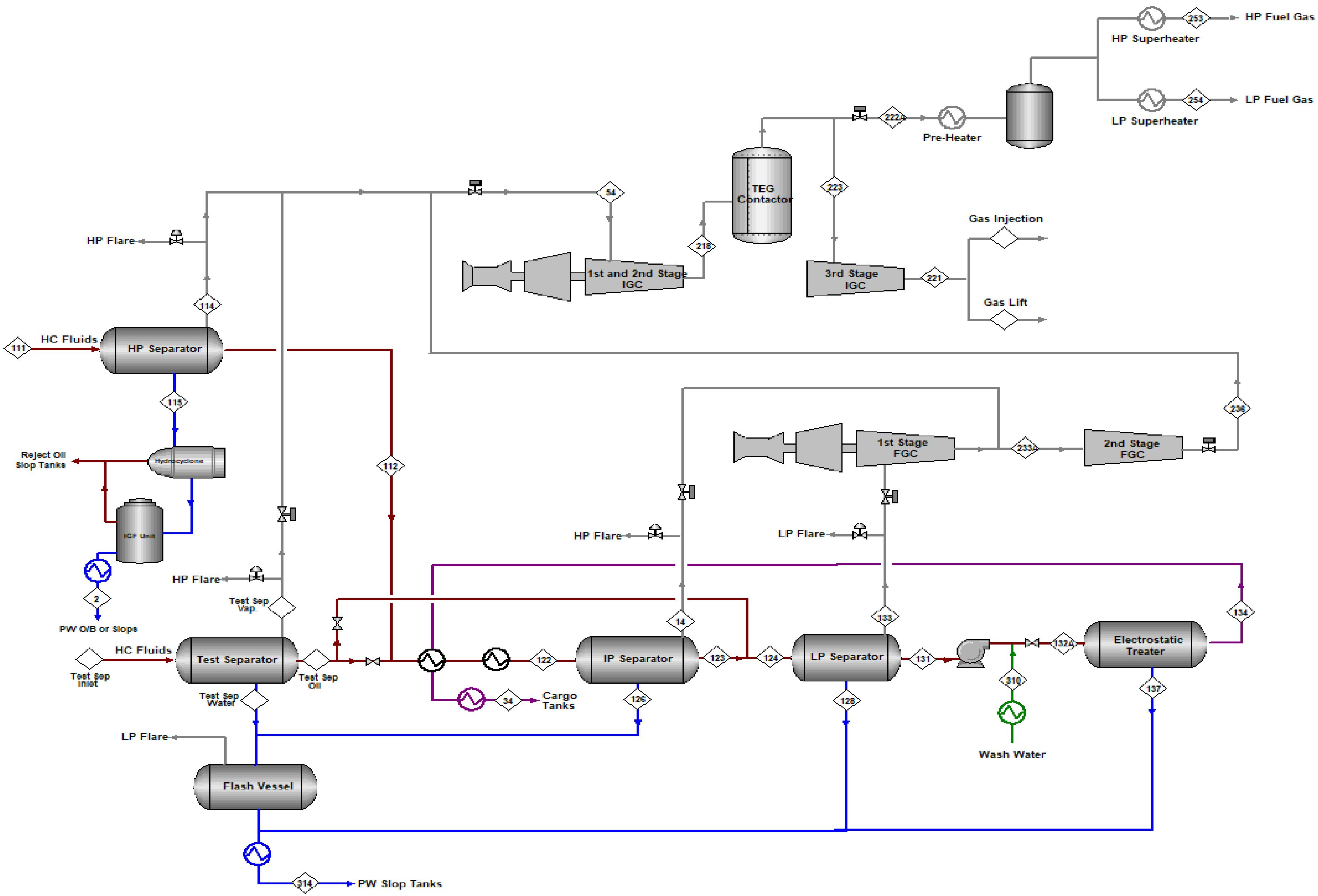

Figure 4.1: Process flow diagram of the topside processing unit (adapted from Company, 2016e)

Table 4.1: Process flow diagram legend

HYSYS Stream Number	Description
2	Treated water from HP Separator
14	Outlet Gas from IP Separator
54	Inlet Gas to 1st Stage IGC Package
111	Inlet HC fluids to HP Separator
112	Outlet Oil from HP Separator
114	Outlet Gas from HP Separator
115	Outlet Water from HP Separator
122	Inlet Stream to IP Separator
123	Outlet Oil from IP Separator
124	Inlet Stream to LP Separator
126	Outlet Water from IP Separator
128	Outlet Water from LP Separator
131	Outlet Oil from LP Separator
132A	Inlet Stream to Electrostatic Treater
133	Outlet Gas from LP Separator
134	Outlet Oil from Electrostatic Treater
137	Outlet Water from Electrostatic Treater
218	Outlet Gas from 2nd Stage IGC Discharge Cooler
223	Inlet Gas to 3rd Stage IGC Package
221	Compressed Gas from IGC Packages
222A	Fuel Gas Outlet from TEG Contactors
233A	Inlet Gas to 2nd Stage FGC Package
236	Outlet Gas from 2nd Stage FGC Package
253	HP Fuel Gas to Consumers
254	LP Fuel Gas to Consumers
310	Inlet Wash Water U/S the Electrostatic Treater
Gas Lift	Gas Lift to Turret
Gas Injection	Gas Injection to Turret
Test Sep Inlet	Inlet HC fluids to Test Separator
Test Sep Vap.	Outlet Gas from Test Separator
Test Sep Liq.	Outlet Water from Test Separator
Test Sep Oil	Outlet Oil from Test Separator

4.3. Blend Cases and Criteria Definition

A within-subject factorial design, in which the temperature of the HP separator, the pressure and temperatures of the Test separator are subjected to all the study's conditions, along with process simulations were used to study the effect of such temperatures and pressures of on the production of stabilised crude oil and natural gas. Two variables of pressure (i.e., 7 and 19 barg), which are the design operational pressure of Test separator (Company, 2019) and four variables of temperature (i.e. -7, 5, 36 and 50°C) which are the estimated arrival temperature of fluids to HP and Test separator's inlet depending on the subsea configuration (Company, 2019), were used to identify the significant effects and interactions of the topsides' processing equipment in the production of crude oil and natural gas from the new fluid blend incorporating fluid from the Múcua field.

The new blend composition listed in Table 4.2, was determined based on subsea studies and simulations for the most optimum subsea configuration to accommodate the desired flow rates (Company, 2019) and this was used as the basis of the plant's handling capacity stream for the topside study.

Table 4.2: New blend definition (Company, 2019)

Flow Rate	Value
Total Oil [BOPD]	100000
Total Water [BWPD]	50000
Total Liquid [BLPD]	150000
Max Total Gas Process (Gas Lift + Associated Gas) [MMscfd]	113
Gas Lift [MMscfd]	40
Gas Injection [MMscfd]	100
Fuel Gas (estimated based on operating consumption) [MMscfd]	10
Field	**% On Total Oil Rate**
Ginguenga	0
Maboque	40
Tamarindo	11
Gajaja	20
Loengo	9
Múcua	20

Table 4.2 also indicates the intention of processing a total liquid flow rate of 150 000 barrels of liquid per day (BLPD). However, this flow rate exceeds the total liquid maximum production rate design of 125 000 BLPD as referenced in Table 3.4. Considering that the maximum liquid production of 125 000 BLPD is associated with an estimated minimum water cut of 20% based

on the current production profile, an evaluation is required before exceeding the current facilities designed maximum liquid production flow rate prior to incorporating the Múcua field fluid into the operation through the FPSO.

Tables 4.3 contains the operating pressures and temperatures of the HP and Test Separator's new fluid blend design for cases A to F cases that were used for the evaluation, which were chosen based on the operational design pressures of both separators and the arrival fluids estimated based on the line up configurations estimation as recorded in Table 4.4 (Company. 2019).

Table 4.3: Design cases for the new fluid blend

Design Cases	HP Separator		Test Separator	
	Pressure [barg]	Temperature [°C]	Pressure [barg]	Temperature [°C]
New Blend Case A	19	50	19	5
New Blend Case B	19	50	19	-7
New Blend Case C	19	50	7	5
New Blend Case D	19	36	19	5
New Blend Case E	19	36	19	-7
New Blend Case F	19	36	7	5

The balance of the flow rates from the plant's configuration in Table 4.4 to reach the total flow rate indicated in Table 4.1 are meant to be sent to the HP Separator. For the gas lift, 40 MMscfd is the average total gas lift rate, out of which only 10 MMscfd is envisaged to be injected at TR-a, base. Therefore, depending on the riser's alignment, it may go either to the HP Separator or to the Test Separator. If Múcua (PR-c riser) is aligned to Test Separator, then no gas lift is envisaged to the Test Separator. This is summarised in Table 4.4. In addition, Table 4.4 shows the water cut considered for each stream case to the Test Separator. The balance to reach the total water flow rate of 50 000 barrels of water per day (BWPD) was considered for the streams routed to the HP separator.

Table 4.4: Criteria for flow allocation of the cases for the tie-In Process

Design Cases	Streams to Test Separator				
	Riser alignment	BOPD	Reservoir fluids	WC	Gas lift [MMscfd]
Case_A	TR-a	20 000	Maboque	40%	≥ 10

Table 4.4 (continued): Criteria for flow allocation of the cases for the tie-In Process

Design Cases	Streams to Test Separator				
	Riser alignment	BOPD	Reservoir fluids	WC	Gas lift [MMscfd]
Case B	PR-c	20 000	Múcua	0%	0
Case C	TR-a	20 000	Maboque	40%	≥ 10
Case D	TR-a	20 000	Maboque	40%	≥ 10
Case E	PR-c	20 000	Múcua	0%	0
Case F	TR-a	20 000	Maboque	40%	≥ 10

4.4. HYSYS Simulation Basis

The viscosity of the New Blend fluid with an arrival temperature range of 36 to 50°C to the HP separator is expected to be slightly higher than the original design. Additionally, a new correlation was developed for the Múcua fluid's arrival temperature of -7°C. To simulate this, when the Múcua line is routed to the Test separator, the total fluids from the test separator are routed to the intermediate pressure (IP) separator and not to the LP separator which is the case when the test separator is operating at 7 barg. No further impact is envisaged for the topside's operation due to the viscosity difference between the new blend and the original design blend, as it is negligible.

4.5. Simulation Validation and Governing Case Selection

The simulation was setup based on the original plant operational design information with the inlet well fluid stream being adjusted to match the new fluid blend. The gas lift flow rate, the produced water flow rate and separator allocation was adjusted accordingly for each case requirement based on the New Blend definition as per Table 4.2.

In addition:

- New hypothetical components were created based on the PVT characterization data in Table 4.2 and all streams were adjusted to stock tank conditions (i.e., 15.6°C and 1.013 bara / 14.7 psia).
- The hydrocarbon liquid volumetric flow rates were adjusted to match the provided new blend composition.
- The stream from each field to the HP separator was connected to the *MIX-OIL-New Blend* mixer to create the *New Blend* stream.
- The stream to the Test separator was defined from the *TR-a_Maboque* or *PR-c_Múcua,* which was used to define the stream to the Test Separator (Figure 4.1) via

TR-a_Maboque or *PR-c_Múcua* depending on the case. The *New Blend* stream was used to define the crude oil stream feeding into the HP separator (Figure 4.1). The arrival condition of temperature and pressure was adjusted to match the arrival conditions indicated in Table 4.3.

- The *Well Water* stream, *TR-a_Maboque* stream, *PR-c_Múcua* stream, *Test Well Water (Dummy)* stream and *Gas Lift* stream were adjusted to match the provided blend flow rate information (Table 4.4).
- The blanket gas was adjusted to 1 MMscfd at the inlet of the flash gas compressor (FGC) train.
- The fuel gas flow rate was defined as 10 MMscfd for the Múcua tie-In evaluation (Company, 2019). The original design fuel gas flow rate was 21 MMscfd (Company, 2013).
- The water carryover in oil from the Test separator was considered to be zero (assuming full separation efficiency).
- The rest of the parameters in the simulation were as per the original plant operational design.

The governing case study chosen for the production throughput simulation was considered on the basis that it was the closest to the operating conditions prior to the tie in, which was validated against the operating conditions retrieved from the OsiSoft plant information (PI) Process Book and the Daily Production Report dated 29 March 2020 listed in Table A.1 (Appendix A). An overview print screen for each analysed case showing the process simulation as an overall picture of the main processing equipment can be found in Tables B.1 to B.5 in Appendix B.

In summary, this section covered all the characteristics, basis, parameters, and stream identification used for the Aspen Tech HYSYS simulations, including all the assumptions made. The Peng-Robinson Equation of State was chosen as the property bundle to develop the model of dynamic simulation as it is the most suitable for hydrocarbon compounds (Tangsriwong *et al.*, 2020), except for the pressure drop within the FGC system, for which Aspen Exchanger Design & Rating was used as it is the most suitable package to estimate and monitor pressure drops within gas systems (Haydary, 2019).

CHAPTER 5

RESULTS AND DISCUSSION

5.1. Introduction

A whole process train evaluation for the new blend with Múcua tie-in, as well as the anticipated lower operating temperatures for the Test separator was conducted based on the Aspen Tech HYSYS simulations. The inlet streams conditions of the new blend were compared with the equipment's original design handling capacity and the potential bottlenecks were identified.

Overall, this chapter interprets and discusses the topside process evaluations acquired by HYSYS simulations, computer-based evaluations of separators using MySEP, line-sizing calculations, blowdown scenarios and the flare system.

5.2. Topside Process Train Evaluation

Six cases (i.e., Cases A to F) were investigated in this study as defined in Table 4.2. The results presented were obtained based on the information provided in Tables 4.3 and 4.4. Deviations from the assumptions made, such as 0% water cut for the Múcua production fluid were not covered by this work and therefore require re-evaluation of the facility to determine acceptability. Design verification checks were performed for the major topsides' equipment and discussions have summarised in the sub-sections 5.2.1 to 5.2.15.

5.2.1. HP Separator

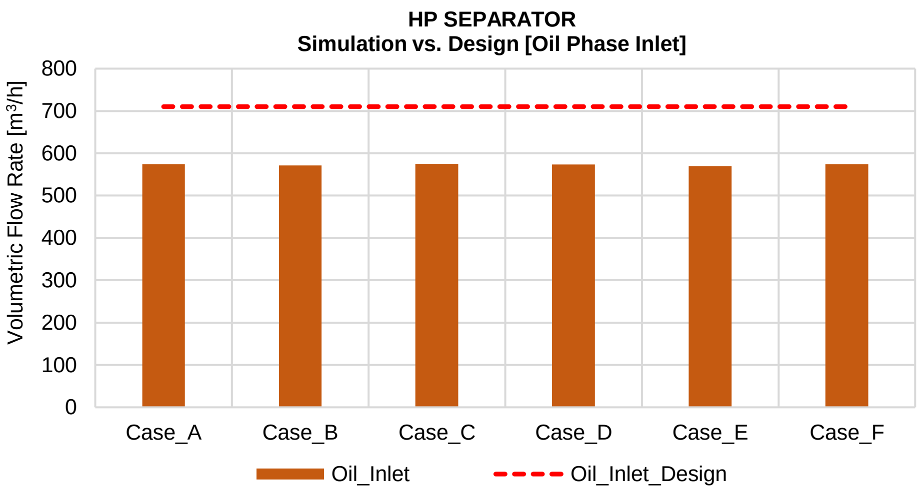

Figure 5.1: HP separator inlet stream's oil phase volumetric flow rate

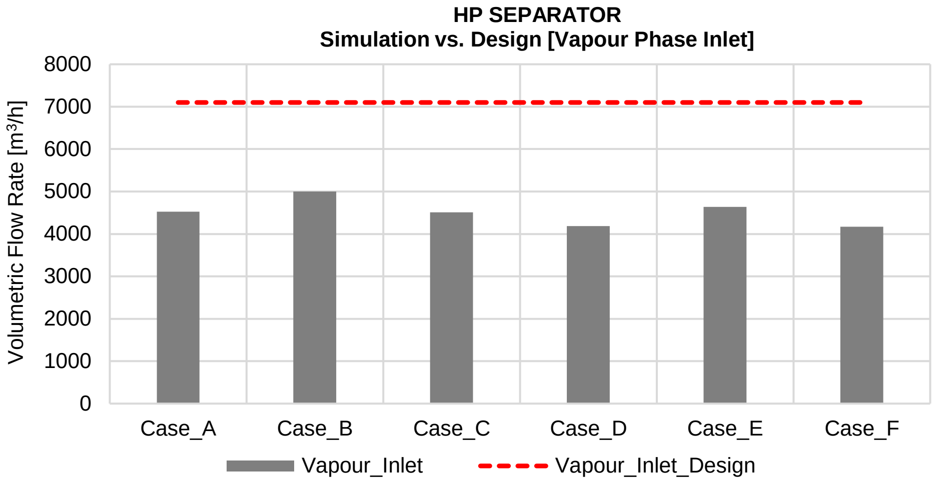

Figure 5.2: HP separator inlet stream's gas phase volumetric flow rate

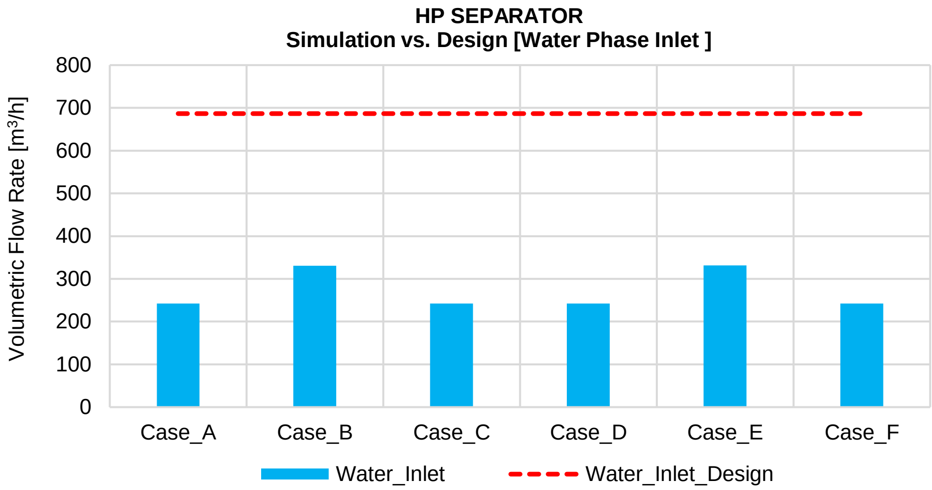

Figure 5.3: HP separator inlet stream's water phase volumetric flow rate

Figure 5.1 to 5.3 presents the volumetric flow rate results for the assessment of the HP separator by Aspen Tech HYSYS. It was observed that the operating parameters for all six cases are within the design limit for the HP separator capacities (i.e., 7099.1 m^3/h, 710.2 m^3/h and 686.6 m^3/h, respectively for the HP separator inlet stream's vapour, gas and water phase volumetric flow rates) and therefore, no concern was identified for this equipment and no further evaluation was conducted for this equipment.

5.2.2. IP Separator

It can be observed in Figures 5.4 and 5.5, that the original design oil phase volumetric flow of 729.3 m3/h through the IP separator is exceeded for cases A and B by 1.2%; and by 1.5% for cases D and E; while the gas flow rate simulated for cases A, B, D, E and F exceeded the design volumetric gas flow rate of 1363.3 m3/h by 14%, 17%, 33%, 35% and 4% for cases A, B, D, E and F, respectively. Considering this, the adequacy of the separator to handle the increased gas and oil flow rates was further validated using the MySEP computer software program, for which the findings are recorded in Appendix C, Table C.2. Figure 5.6 represents the IP separator inlet stream's water phase volumetric flow rate, with none of the cases found to exceed the design value of 81.7 m^3/h.

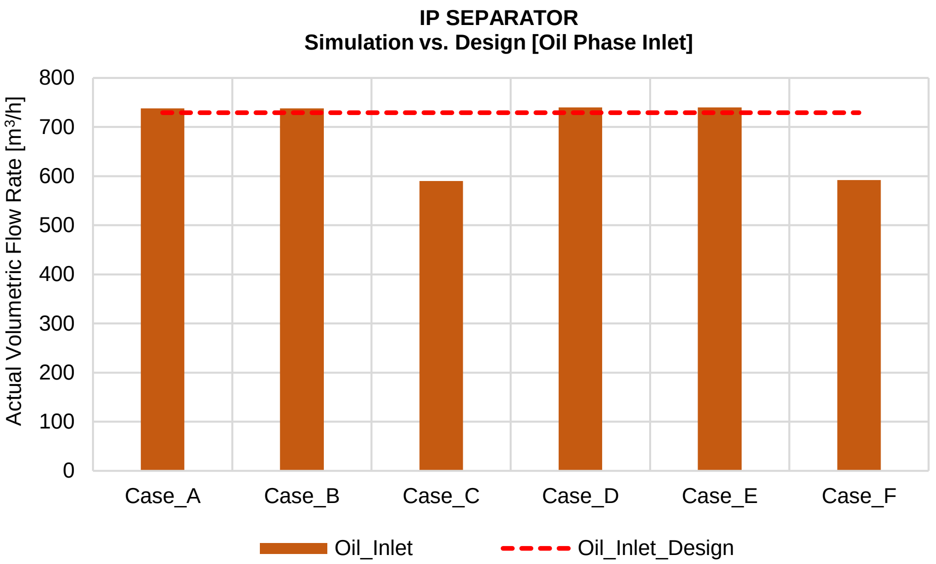

Figure 5.4: IP separator inlet stream's oil phase volumetric flow rate

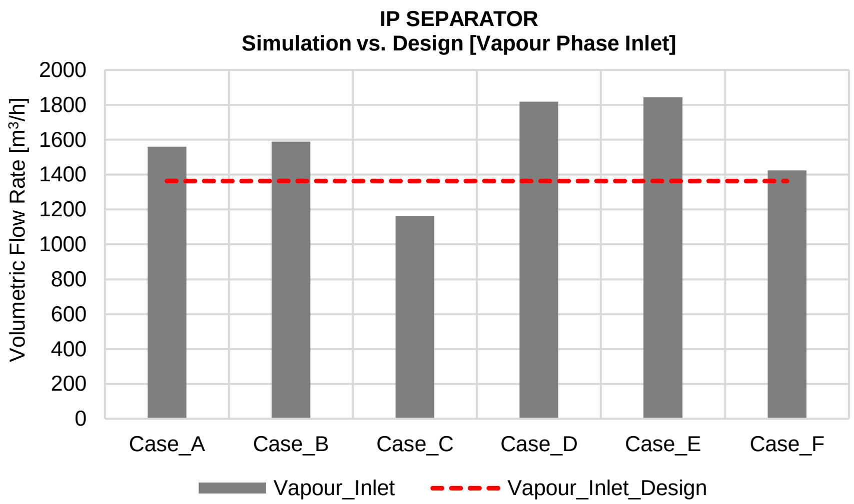

Figure 5.5: IP separator inlet stream's gas phase volumetric flow rate

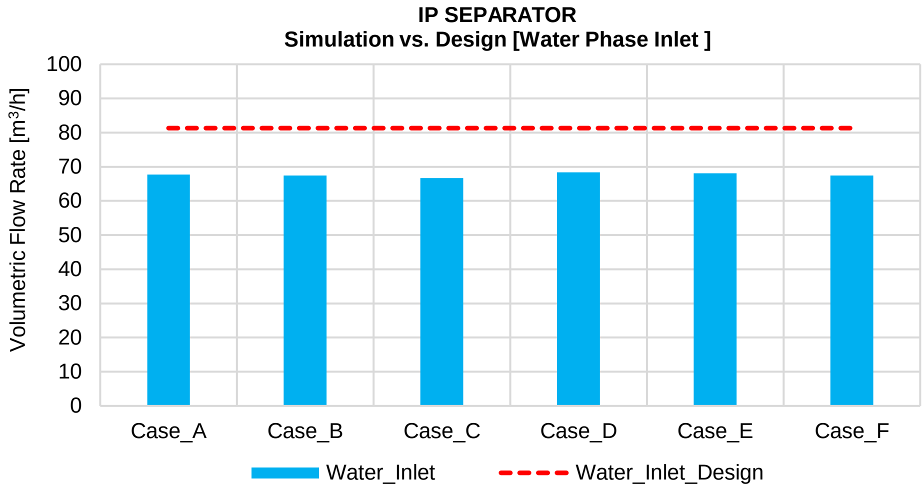

Figure 5.6: IP separator inlet stream's water phase volumetric flow rate

According to the results obtained from the MySEP evaluation, the new blend condition has resulted in a maximum gas load factor (K-value) of 0.36 m/s for the vane pack, which is higher than the manufacturer specification of 0.28 m/s and correlates to a greater liquid carry-over in the gas stream than the original design. However, the amount of liquid carry-over is negligible from a volumetric flow rate perspective (i.e., 0.068 m^3/hr maximum for case E). In addition, the downstream flash gas compressor (FGC) 2^{nd} stage cooler is a shell and tube design where the slightly higher liquid loading is expected not to have any detrimental effect on the cooler performance with respect to the fouling, as it is assumed that its design considers a fouling margin (Company, 2013). Considering that the downstream compressors have scrubbers to capture the liquid condensate, even with a higher liquid carry-over, the scrubber is designed to knock down the condensate and provide sufficient protection to the compressor (Company, 2013). This will be further enunciated in the FGC scrubber's evaluation in section 5.2.9.

The oil residence time was found to be less than the recommended value of 5 minutes (Appendix C, Table C.2). However, the separation efficiency is above 98.5% for all the cases. The maximum hydrocarbon liquid outlet velocity is 2.31 m/s for cases D and E, which is higher than the recommended value of 2.0 m/s. The maximum hydrocarbon liquid outlet velocity is only a consideration in relation to the convergence of flow towards the liquid outlet and for ensuring there is not too much additional distribution in the vessel (Company. 2019). Since the velocity constraint is exceeded at the hydrocarbon liquid outlet where the effect on liquid distribution is not a consideration (i.e., it is behind the weir), the higher velocity for the liquid outlet is not expected to be a concern.

The impact of the greater flow rate to the line sizing calculation is validated in Appendix D, Table D.1. Such evaluation concluded that the critical parameters (i.e., fluid velocity, flow induced turbulence, acoustically induced vibration, ρv^2 and Mach number) are all within the design limit, but pressure drop could be an issue because of the higher gas flow rates. The oil line and produced water line were not validated since the flow rate was within the design limit as per Tables 5.4 and 5.6.

The adequacy of the pressure control valve (PCV) leading to the HP flare was validated for handling the high flow rate for case E only, as it presented the highest gas flow rate of all the cases. The IP separator features two PCVs, namely T71-PCV-003 and T71-PCV-013, as highlighted in the process flow diagram (PFD) in Appendix E, Figure E.1. The T71-PCV-013 has a much larger valve flow coefficient (Cv) of 962 compared to 141 for T71-PCV-003, which was originally designed to allow operation at a low operating pressure (Appendix F, Table F.16 and Table F.17). T71-PCV-013 is deemed able to accommodate all the cases based on its datasheet. According to its datasheet, T71-PCV-003 is sized for a maximum flow rate of 8986 Sm^3/h (7.63 MMscfd) only. However, even though T71-PCV-003 is unable to allow flow to occur for any of the cases, when T71-PCV-013 is arranged for split range control with T71-PCV-003, it could then be considered as an acceptable combination.

The capacity of T71-PCV-010 at the outlet of the IP Separator going to the FGC was evaluated and found not able to allow flow for cases A, B, D, and E. The valve is sized for a maximum flow rate of 8986 Sm^3/h as per its datasheet (Appendix F, Table F.18). In this case, the FGC system would be likely overwhelmed and would not be able to handle the new blend condition. Based on the results obtained and recorded in Appendix G, Table G.2, the oil side level control valve (LCV) T62-LCV-007 and produced water side T62-LCV-005 have flow rates lower than its design values of 759.7 and 80.0 m^3/h respectively, therefore there is no concern for these two control valves.

5.2.3. LP Separator

From the results obtained during the LP separator simulation as represented in Figures 5.7 to 5.9, it was noted that the gas flow rate for cases A, B, D and E (i.e., 5907.5 m^3/h, 5907.7 m^3/h, 6173.6 m^3/h and 6173.6 m^3/h, respectively) exceeded the design gas flow rate of 4923.2 m^3/h by 20% for both cases A and B and by 25% for cases D and E. The actual oil and water flow rates for cases A, B, D, E and F (i.e., 704.4 m^3/h, 704.4 m^3/h, 704.9 m^3/h, 704.9 m^3/h and 702.4 m^3/h, respectively for the oil flow rates; and 105.8 m^3/h, 105.8 m^3/h, 105.9 m^3/h and 105.9 m^3/h, respectively for the water flow rates) exceeded the design volumetric oil and water flow rates of 702.3 m^3/h and 105.6 m^3/h, respectively by approximately 0.4% for all the cases, which could be considered negligible from a process design perspective.

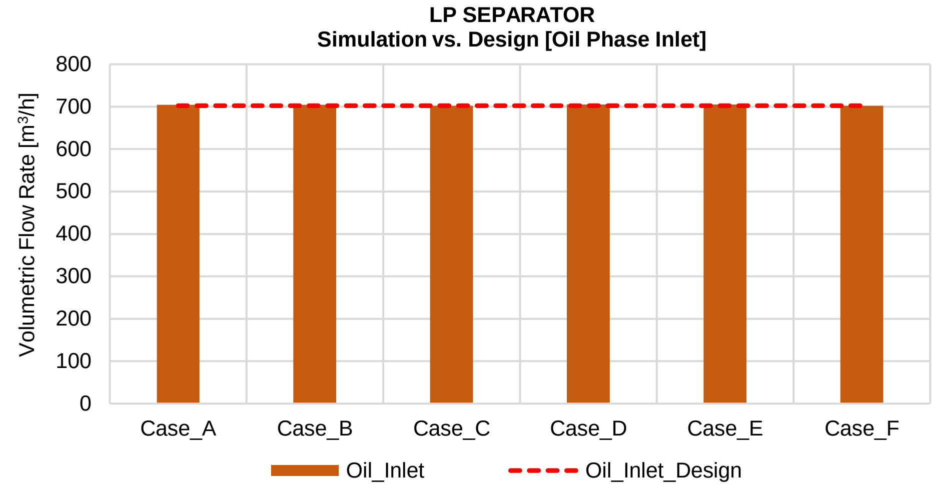

Figure 5.7: LP separator inlet stream's oil phase volumetric flow rate

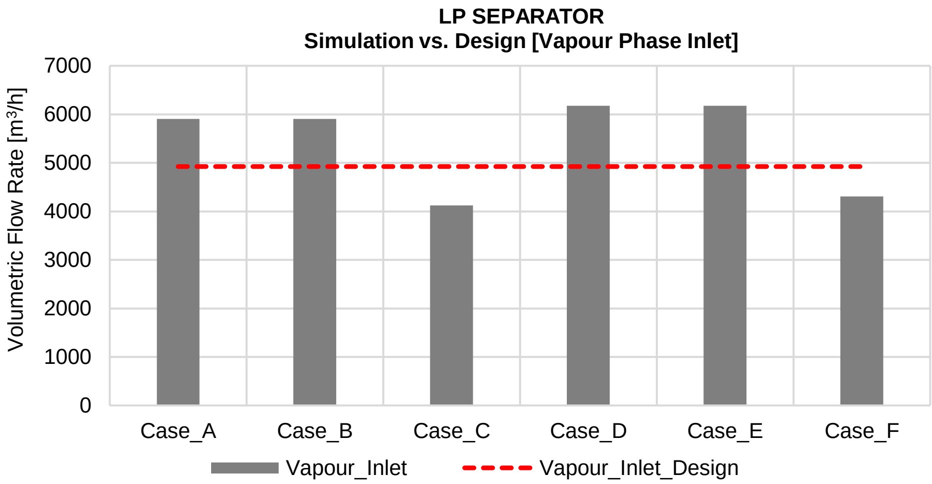

Figure 5.8: LP separator inlet stream's gas phase volumetric flow rate

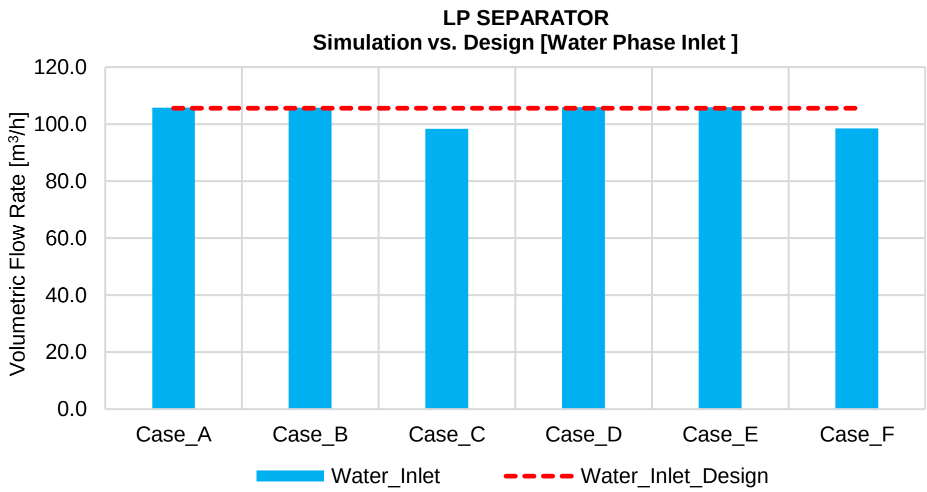

Figure 5.9: LP separator inlet stream's water phase volumetric flow rate

The adequacy of the LP separator to handle increased gas, oil and water flow was further validated using the MySEP computer software program, from which findings are recorded in

Appendix C, Table C.3. The new blend condition has resulted in a maximum gas load factor of 0.361 m/s, which is higher than the manufacturer defined K-value of 0.278 m/s as per its datasheet in Appendix C, Table C.3. This correlates to a relatively greater liquid carry-over in the gas stream compared to the original design. The maximum liquid carry-over rate is 0.005 m^3/h for cases A, B, D and E (Appendix C, Table C.3, and the impact to the downstream is inconsequential as the downstream scrubbers will be able to handle the liquids, the oil residence time, and the hydrocarbon liquid outlet velocity even though there is deviation from the required criteria. These deviations are justified to be not of concern as highlighted further in the FGC scrubber's evaluation in section 5.2.9.

Considering that the LP Separator has a relatively larger flow rate for gas for cases A, B, D and E (i.e., 5907.5 m^3/h, 5907.7 m^3/h, 6173.6 m^3/h and 6173.6 m^3/h) compared to the original design flow rate of 4923.2 m^3/h, the impact to the line sizing calculation was validated and recorded in Appendix D, Table D.1. This evaluation yielded the conclusion that the existing line size can handle the increased flow rates and all the critical parameters are within the design limit, however pressure drop could be an issue due to the higher flow rates.

The adequacy of T71-PCV-004 leading to the LP flare was validated by means of comparison between its datasheet (Appendix F, Table F.21) and the actual flow rates obtained for the simulation, for handling the increased flow rate. Assessment shows that the gas flow rate is too high for cases A, B, D, and E, as the maximum gas flow rate per the manufacturer datasheet (Appendix F, Table F.21), is 8182 Sm^3/h (6.95 MMscfd), while cases D and E flow rate of 6173.6 m^3/h (10193 Sm^3/h or 8.6 MMscfd), was predicted as recorded in Appendix G, Table G.3.

5.2.4. Electrostatic Treater

Figures 5.10 and 5.11 represents the assessment of the volumetric flow rate of the inlet stream to treater.

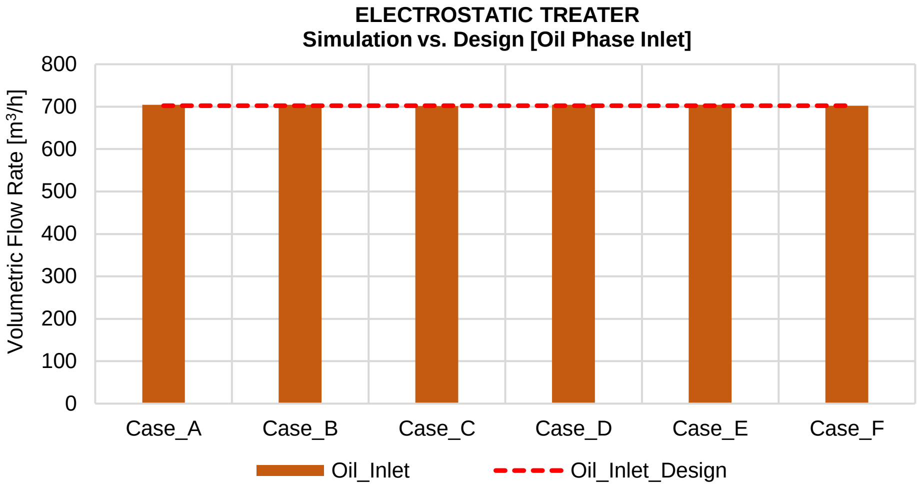

Figure 5.10: Electrostatic treater inlet stream's oil phase volumetric flow rate

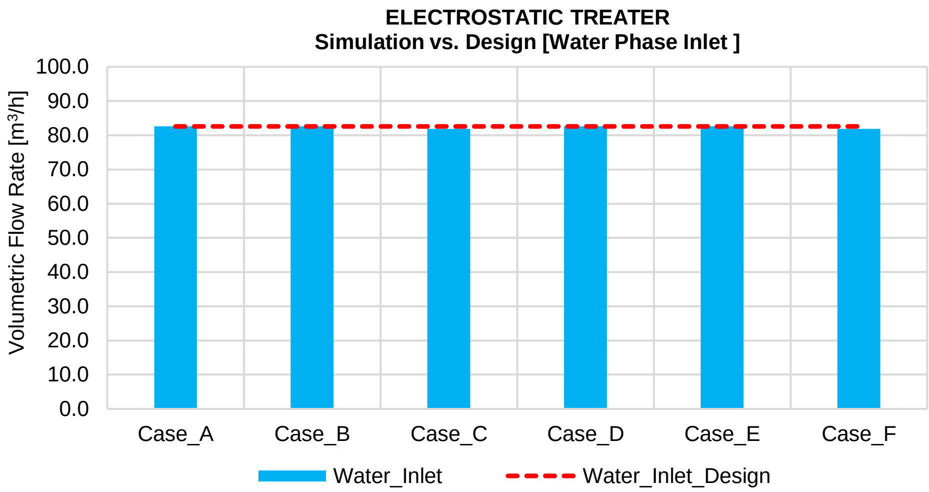

Figure 5.11: Electrostatic treater inlet stream's water phase volumetric flow rate

The actual oil flow rates for cases A, B, D and E (i.e., 704.3 m^3/h, 704.3 m^3/h, 704.7 m^3/h and 704.7 m^3/h, respectively), exceed the design volumetric oil flow rate of 702.3 m^3/h, of the electrostatic treater. However, for the cases D and E, the excess flow rate is around 0.34% above the design volumetric flow rate and this is assumed to be within the margin of what the electrostatic treater can accommodate.

5.2.5. Test Separator

From Figures 5.12 to 5.14, which are representations of the oil phase, gas phase and water phase volumetric flow rate results obtained from the Aspen Tech HYSYS simulation of the test separator's inlet stream, the actual gas flow rate for cases C and F (i.e., 2457.9 m^3/h and 2460.9 m^3/h, respectively) were found to be exceeding the design volumetric flow rate of

1902.0 m^3/h for the test separator by 29%. This is due to the combination of the lower operating pressure of the test separator with the Maboque's fluids' temperature.

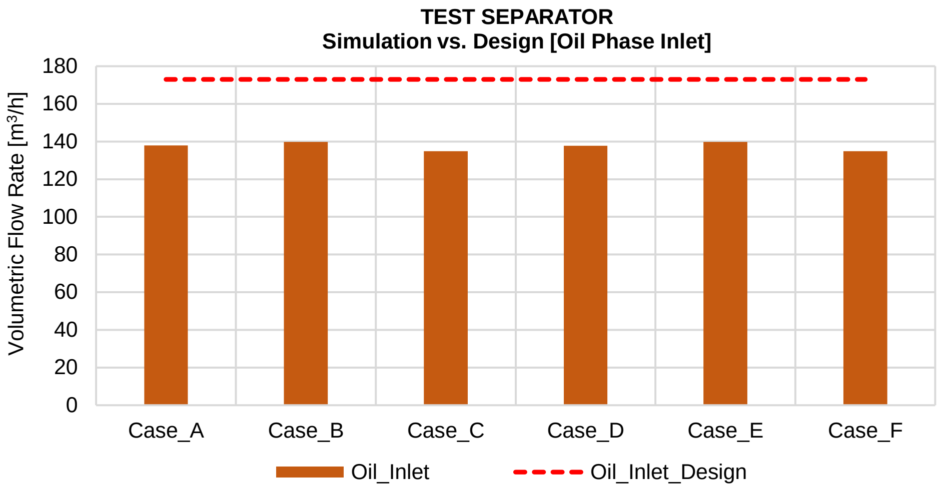

Figure 5.12: Test separator inlet stream's oil phase volumetric flow rate

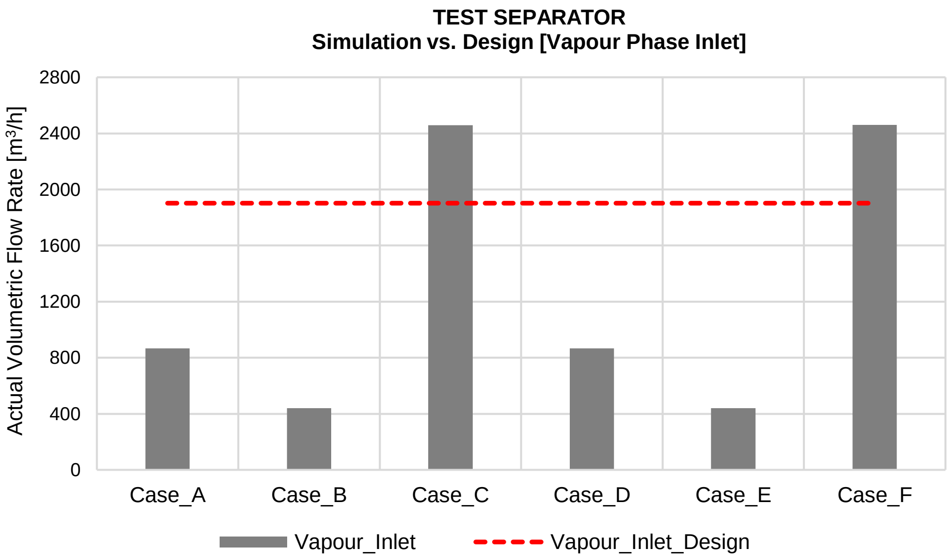

Figure 5.13: Test separator inlet stream's gas phase volumetric flow rate

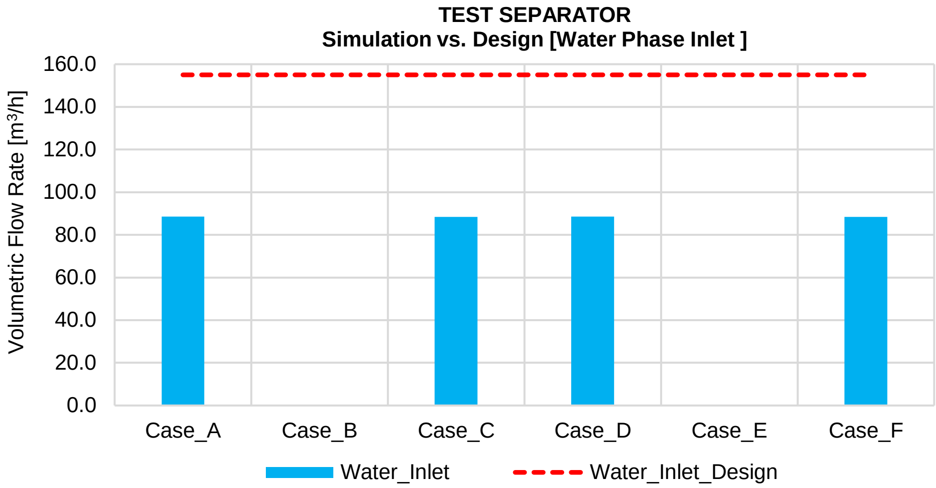

Figure 5.14: Test separator inlet stream's water phase volumetric flow rate

The new blend condition resulted in a maximum gas load factor for the vane pack (carry-over rate) of 0.116 m/s for cases C and F, obtained from MySEP evaluation (Appendix C, Table C.4), which is lower than the value defined by the manufacturer of 0.135 m/s, as per test separator's datasheet (Appendix F, Table F.5). It may be concluded that there are no concerns regarding the test separator. It is also worth noting that in the low pressure cases, the gas must be diverted to the flare, as there is no system installed to recover the gas when the test separator is operating below the injection gas compressor (IGC) suction pressure of 19 barg (Company, 2014b).

5.2.6. Crude Oil Pumps

Figure 5.15 and 5.16 shows the results for the head and power's assessment of the crude oil pumps by HYSYS.

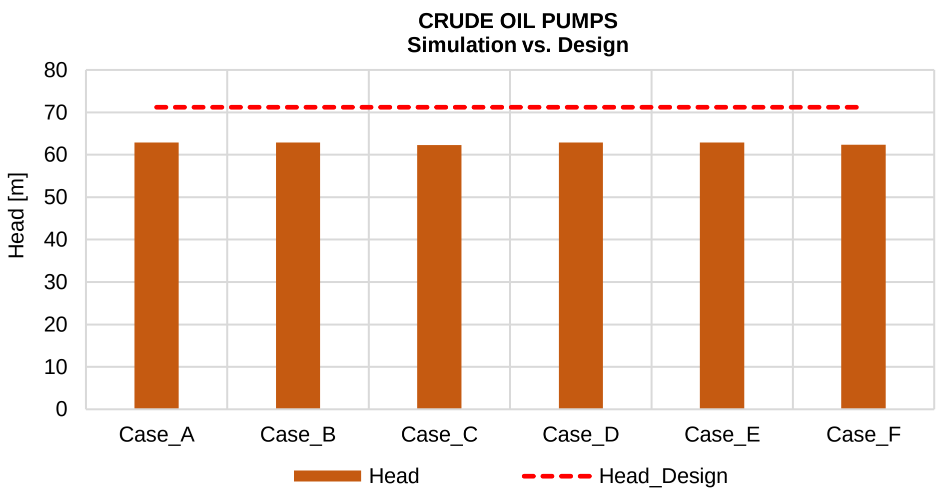

Figure 5.15: Crude oil pumps head assessment

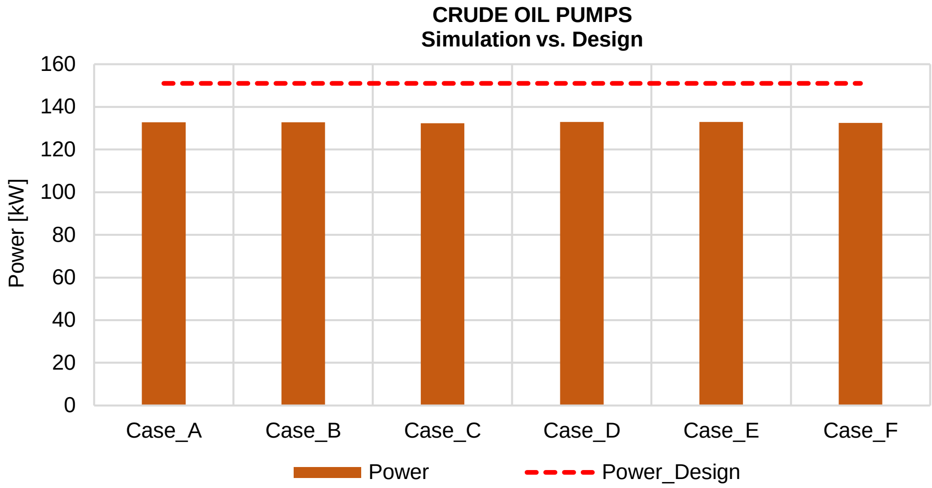

Figure 5.16: Crude oil pumps power assessment

It was found that the operating parameters for all six cases were within the design limit of 71.2 m head and 151 kW power for the crude oil pumps. Therefore, no concern was identified for this equipment and no further evaluation needed to be conducted.

5.2.7. Crude Oil Heat Exchangers

The required duty of the crude/crude exchangers, as well as the crude oil heaters for cases D and E exceeded the original design limit of 11860 kW and 12154 kW by 659/1177 kW and 1588/1970kW, respectively as represented in Figure 5.17 and 5.18. This is likely due to the lower operating temperatures of the test separator. Currently 100 plates are installed in each oil heater's frame, but according to the datasheet (Appendix F, Table F.6), each frame can be fitted with up to 128 plates, therefore a further evaluation was performed for the oil heater as recorded in Appendix F, Table F.7. By adding 28 plates to each frame, the duty is expected to increase from 6077 to 7080 kW for each crude exchanger, totalising 14160 kW when both are in operation.

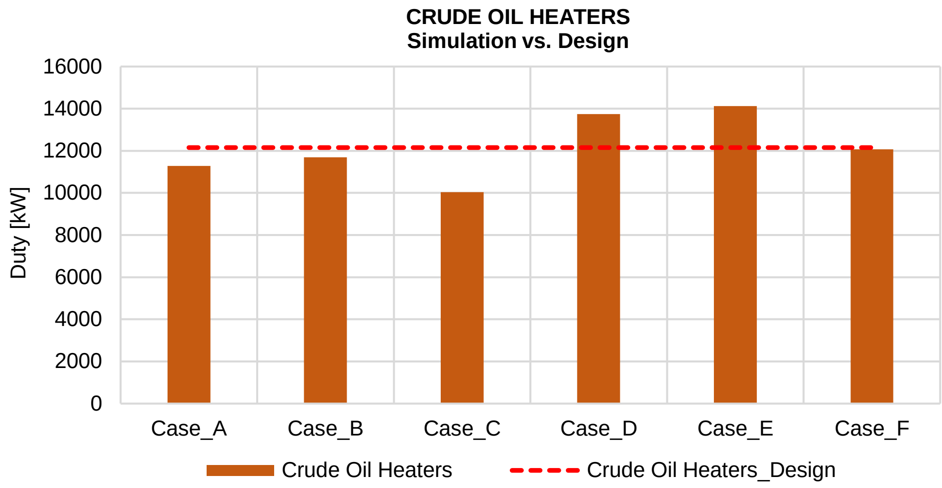

Figure 5.17: Crude oil heaters duties

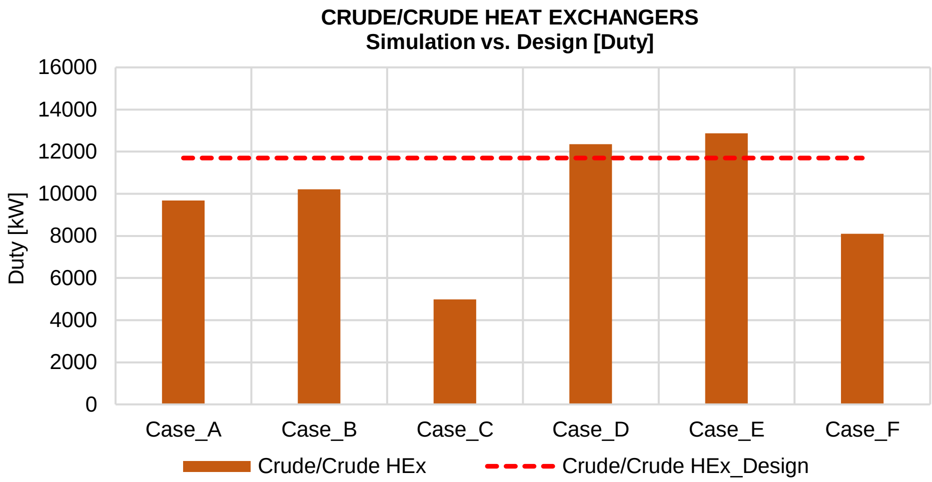

Figure 5.18: Crude/Crude exchangers duties

There were found no concerns in the assessment of the crude oil coolers as shown below in Figure 5.19.

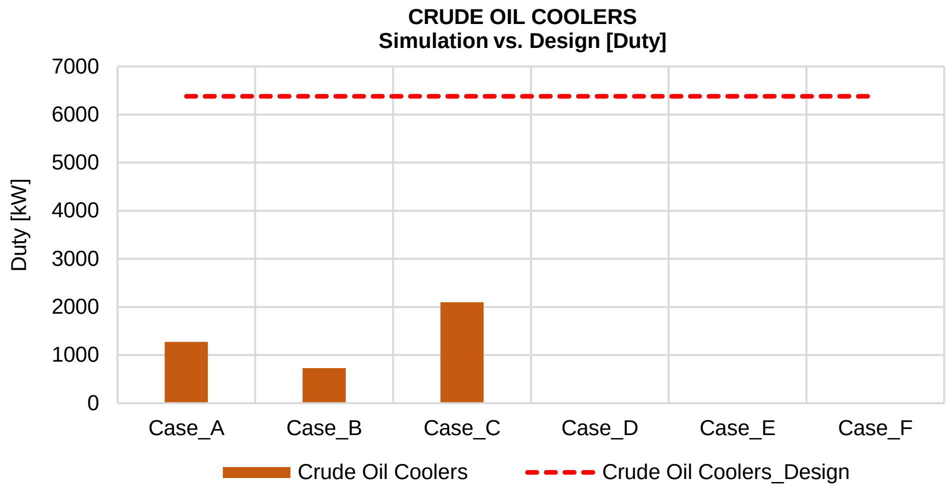

Figure 5.19: Crude oil heaters duties

5.2.8. Injection Gas Compressors (IGC)

Figure 5.20, 5.21, 5.22 and 5.23 show the results for the assessment of the inlet to the injection gas compressors (IGC) suction coolers. It was found that the required duty for all six cases was within the design limit of 14 214 kW for the combined duty of the IGC coolers. No concern was identified for the coolers and therefore, no further evaluation was needed.

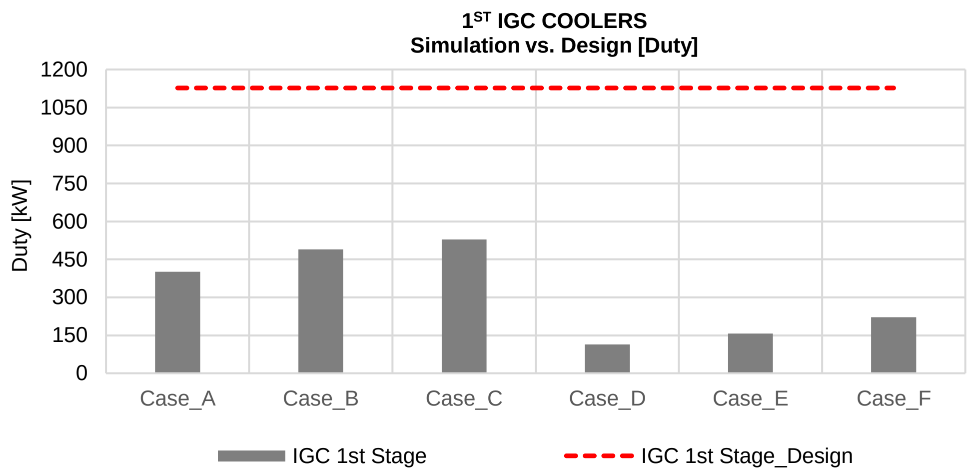

Figure 5.20: 1st stage injection gas compressor cooler duties

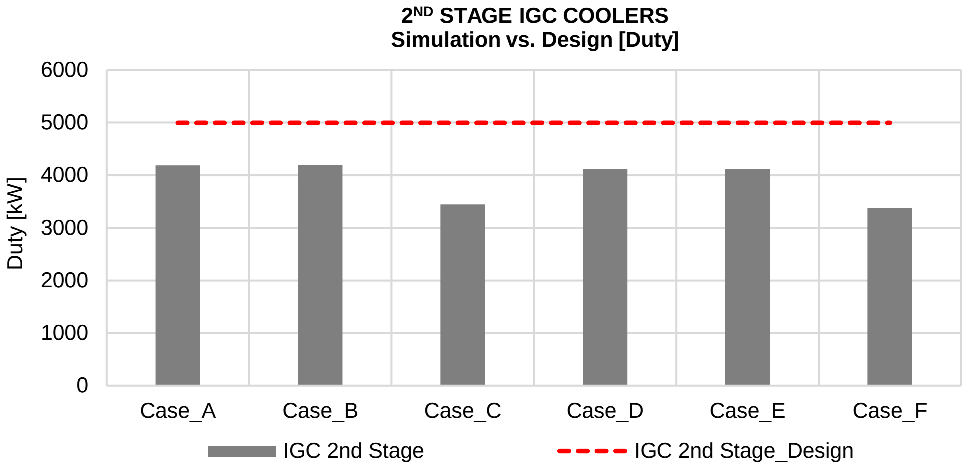

Figure 5.21: 2nd stage injection gas compressor cooler duties

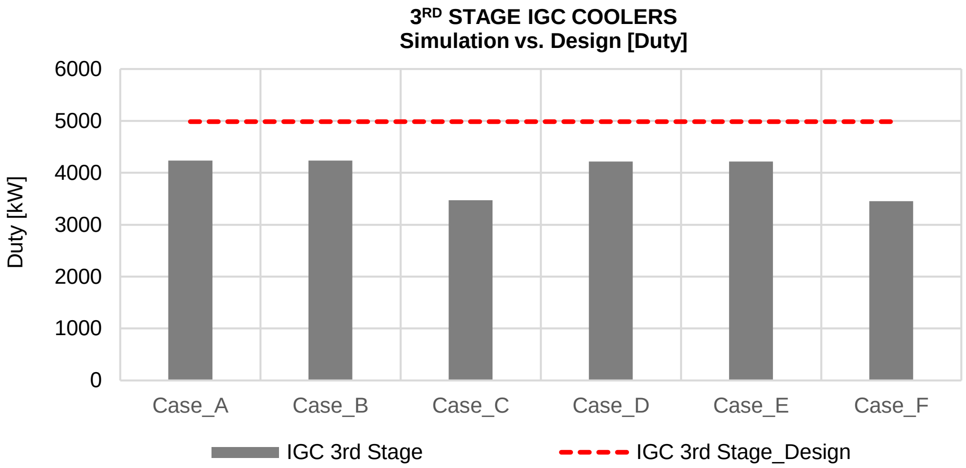

Figure 5.22: 3rd stage injection gas compressor cooler duties

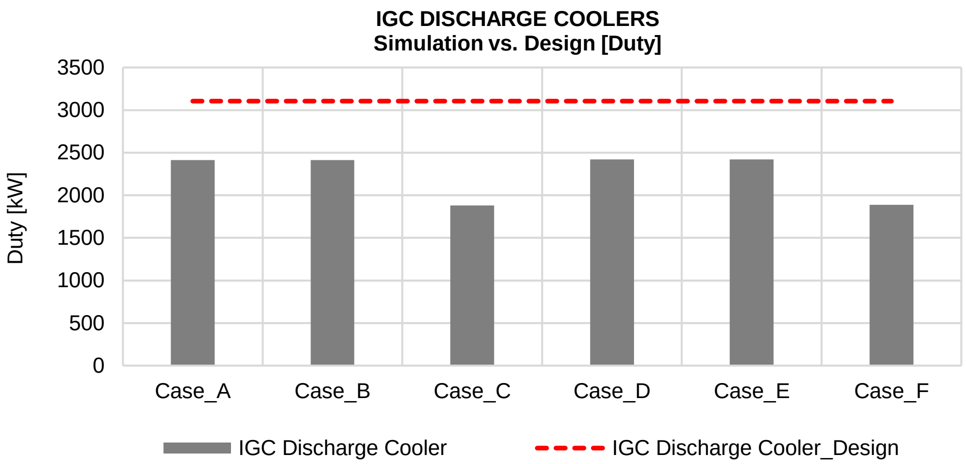

Figure 5.23: Injection gas compressor discharge cooler duties

It was noted that the operating parameters for all six cases were within the design limits of 1.1, 3741.0 and 0.6 m^3/hr, respectively for the oil phase, gas phase and water phase of the IGC 1st stage suction scrubber as seen in Figures 5.24, 5.25 and 5.26. Therefore, no concern was identified, and no further evaluation was conducted.

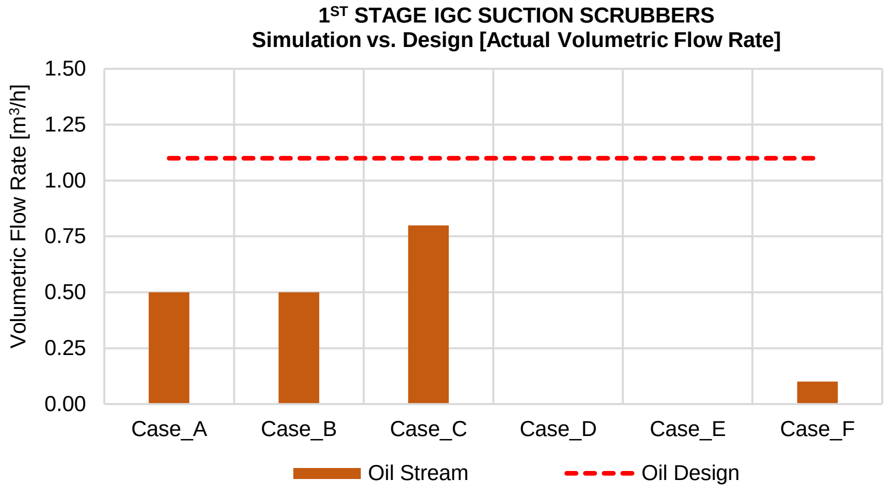

Figure 5.24: 1st stage injection gas compressor suction scrubber oil phase

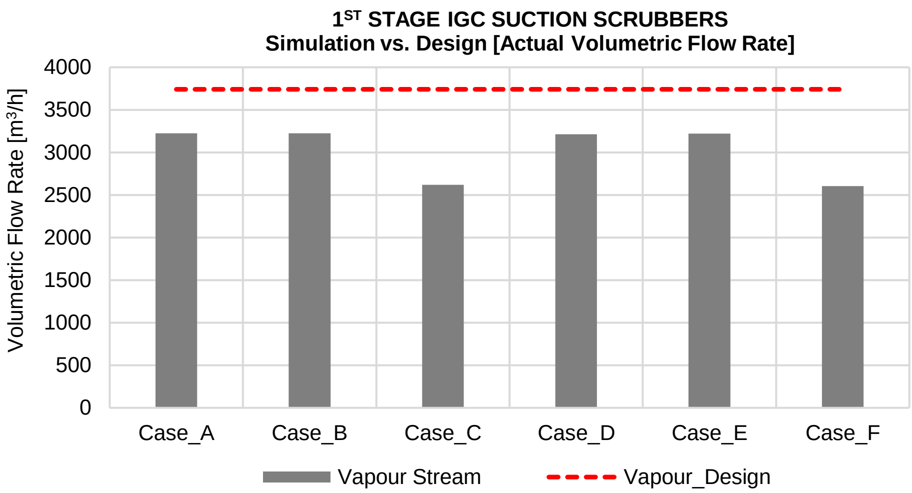

Figure 5.25: 1st stage injection gas compressor suction scrubber gas phase

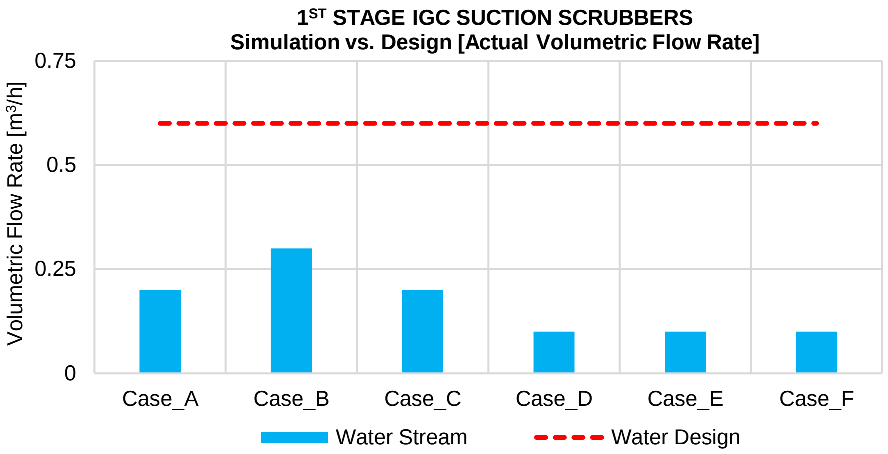

Figure 5.26: 1st stage injection gas compressor suction scrubber water phase

For the 2nd stage suction scrubbers, as shown in Figures 5.27 to 5.29, the actual oil volumetric flow rate was higher than the original design of 2.6 m^3/hr by 4% for case A (2.7 m^3/hr), 0.1% for case B (2.6 m^3/hr) and 19.2% for case C (3.1 m^3/hr). MySEP evaluation led to the conclusion that there are no concerns. The adequacy of the existing LCV, T71-LCV-111/211/511, on the liquid outlet line was evaluated for the worst scenario namely case C and it was noted that the original design has a maximum volumetric flow rate of 5 m^3/h (as per the LCV datasheet in Appendix F, Table F.22). Therefore, the design valve flow coefficient (Cv) will be able to cover the maximum required flow rate of 3.1 m^3/h (case C), for this study (Appendix G, Table G10).

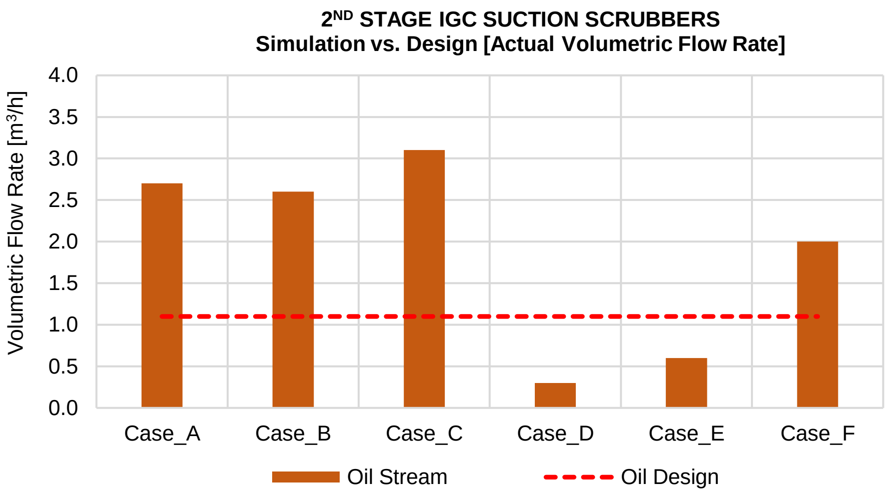

Figure 5.27: 2nd stage injection gas compressor suction scrubber oil phase

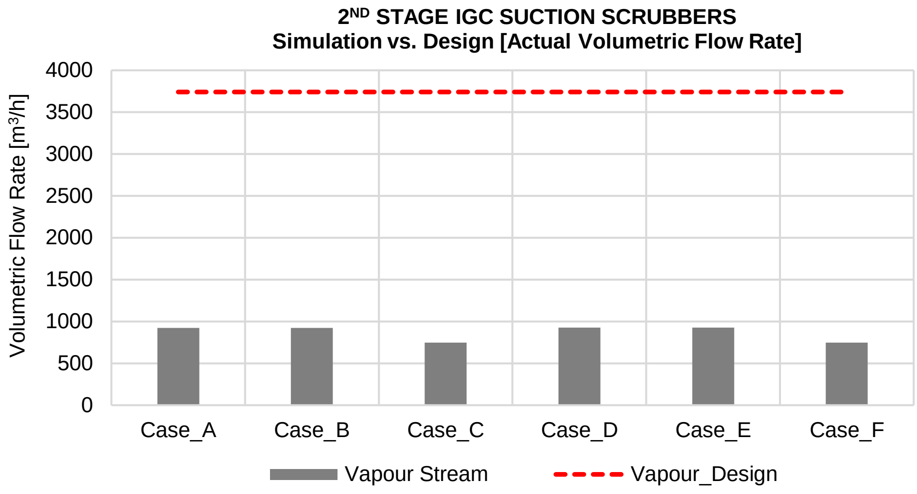

Figure 5.28: 2nd stage injection gas compressor suction scrubber gas phase

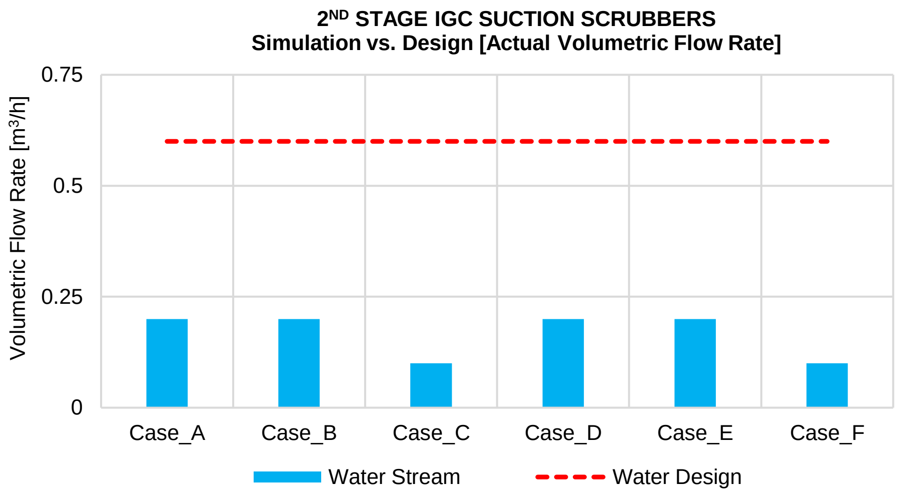

Figure 5.29: 2nd stage injection gas compressor suction scrubber water phase

Figure 5.30 shows the results for the assessment of the 3rd stage IGC suction scrubber. It was found that the operating parameters for all six cases were within the design limit of 359.0 m3/hr for the IGC 3rd stage suction scrubbers. No concern was therefore identified, and no further evaluation was conducted for this equipment.

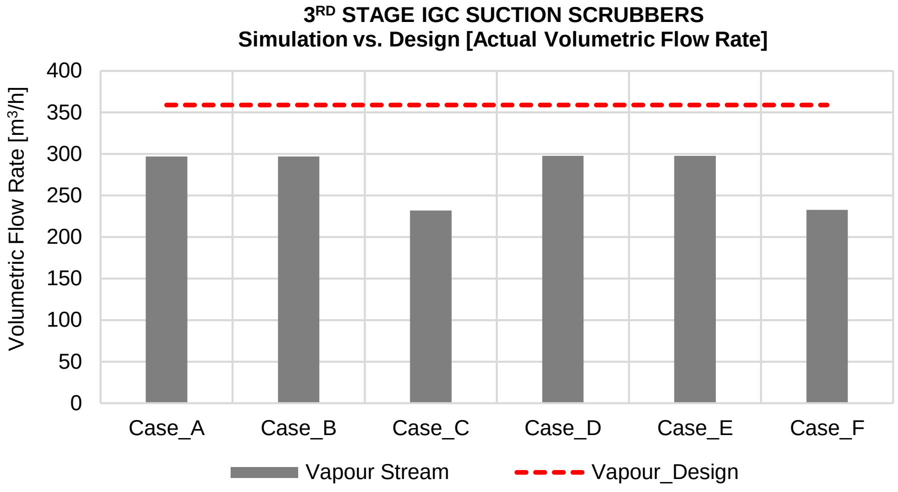

Figure 5.30: 3rd stage injection gas compressor suction scrubber gas phase

From the Aspen Tech HYSYS simulation outcomes of the IGC for the new blend cases as represented in Figures 5.31, 5.32 and 5.33. It was observed in Figure 5.31 that cases A and B had the highest volumetric gas flow rate at the inlet to the 1st stage IGC system with 101.2 MMscfd (2 x 50.6 MMscfd). The design capacity of the IGC for the 1st and 2nd stages (refer to Figures 6.31 and 6.32) is 57.5 MMscfd per unit or 115 MMscfd with two units online. The IGC system should not have major concern in operating the new blend condition. The new blend generally has a relatively heavier molecular weight of 23 g/mol (Appendix G, Table G.12), compared to the original design of 20.3 g/mol (Appendix F, Table F.8), but is within the established allowable design ranges and therefore should not have an impact on the IGC performance. It was therefore concluded that there is no concern for the IGC to handle the new blend.

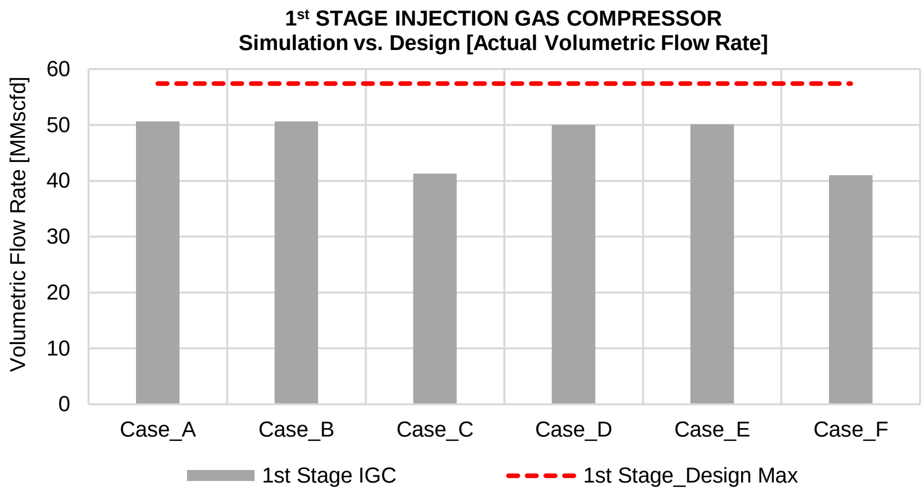

Figure 5.31: 1st stage injection gas compressors volumetric flow

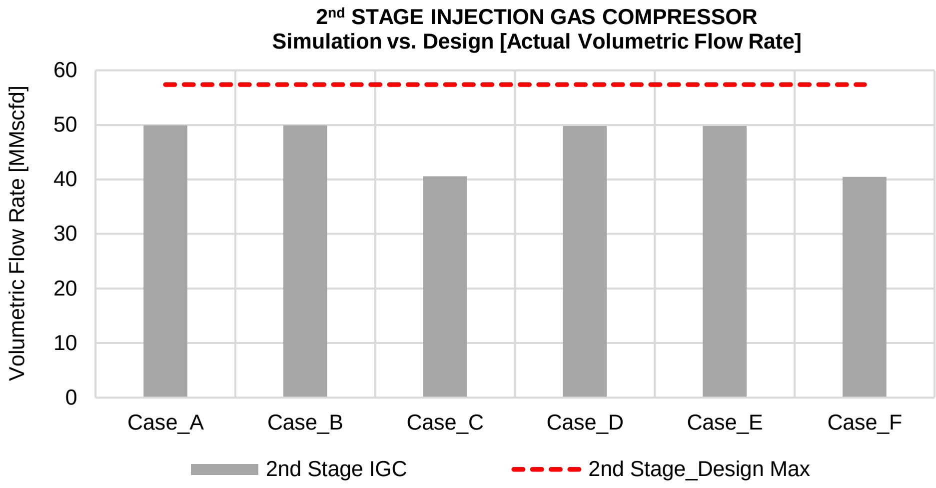

Figure 5.32: 2nd stage injection gas compressors volumetric flow

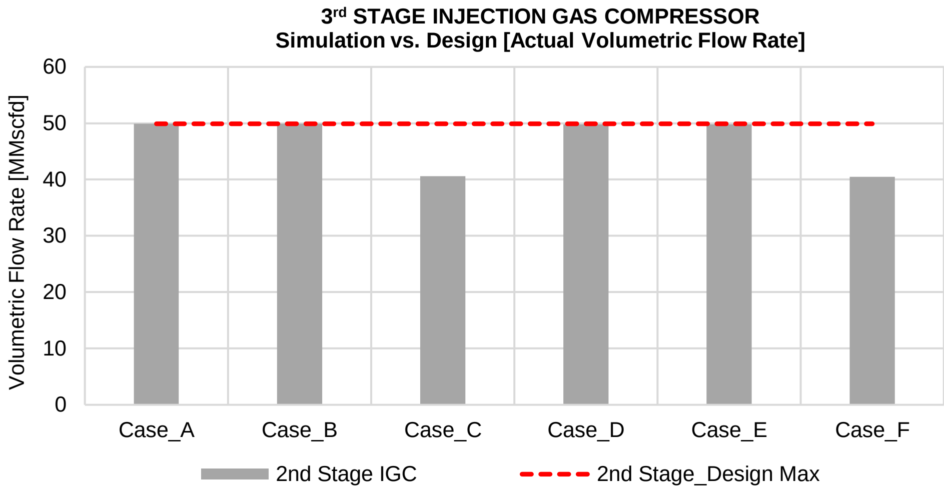

Figure 5.33: 3rd stage injection gas compressors volumetric flow

5.2.9. Flash Gas Compressors (FGC)

Figures 5.34 and 5.35 shows the results for the assessment of the 1st and 2nd stage flash gas compressor (FGC) suction coolers inlet stream flow rates; and Figures 5.36 and 5.37 shows the results for the duty assessment of the 1st and 2nd stage FGC suction coolers via Aspen Tech HYSYS simulation.

It was noted that the actual volumetric flow rate passing through the 1st stage FGC suction cooler is greater than the original design value of 5404.0 m^3/hr for cases A, B, D and E (i.e., 7171.9 m^3/hr, 7172.1 m^3/hr, 7475.7 m^3/hr and 7459.9 m^3/hr, respectively). A detailed pressure drop investigation across the 1st and 2nd stage suction cooler was therefore conducted to better assess the suitability of such equipment to handle the new Múcua fluid blend.

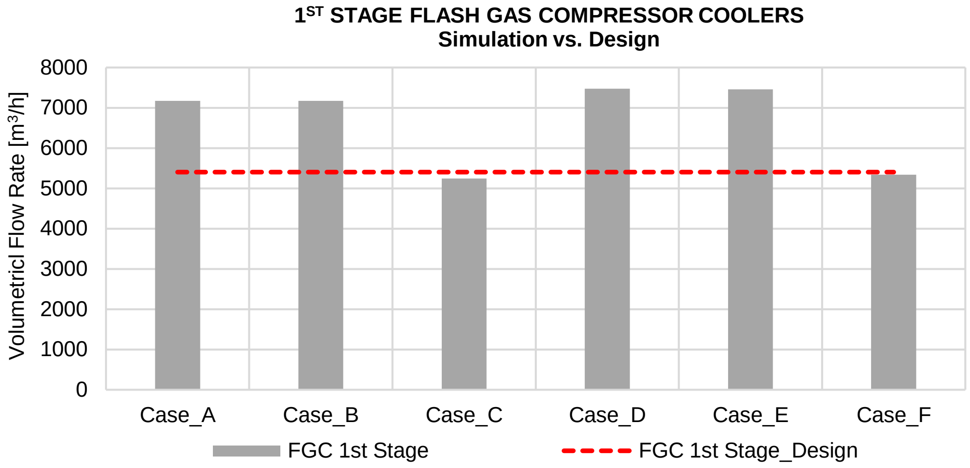

Figure 5.34: 1st stage flash gas compressor cooler inlet flow rate

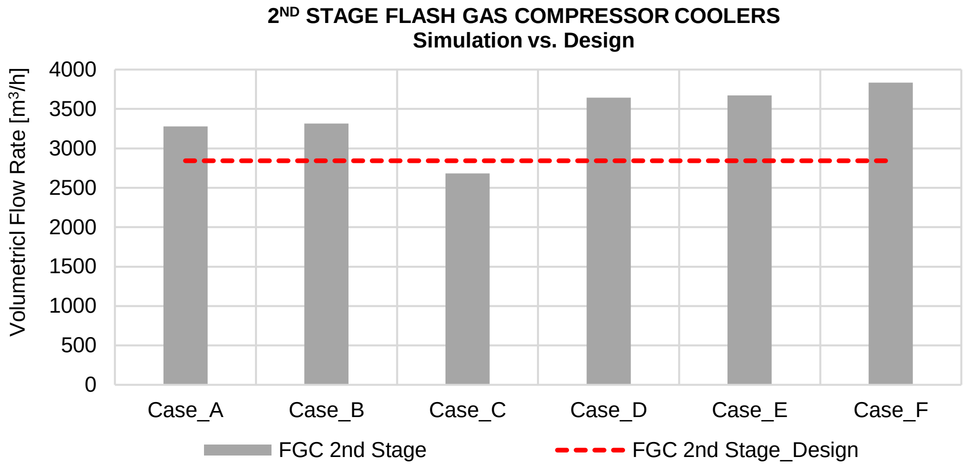

Figure 5.35: 2^{nd} stage flash gas compressor cooler inlet flow rate

The high flow rate is the main driver for the high duties observed for cases A, B, D and E in Figure 5.36. The 2 FGC trains (A and B) have different designs for the 1^{st} and 2^{nd} stage suction coolers (i.e., the coolers have different tube inner diameters), length and effective area therefore the pressure drop is different for the same operating conditions). The train A FGC coolers consists of old equipment, while the train B coolers are a newer design and have a relatively larger capacity.

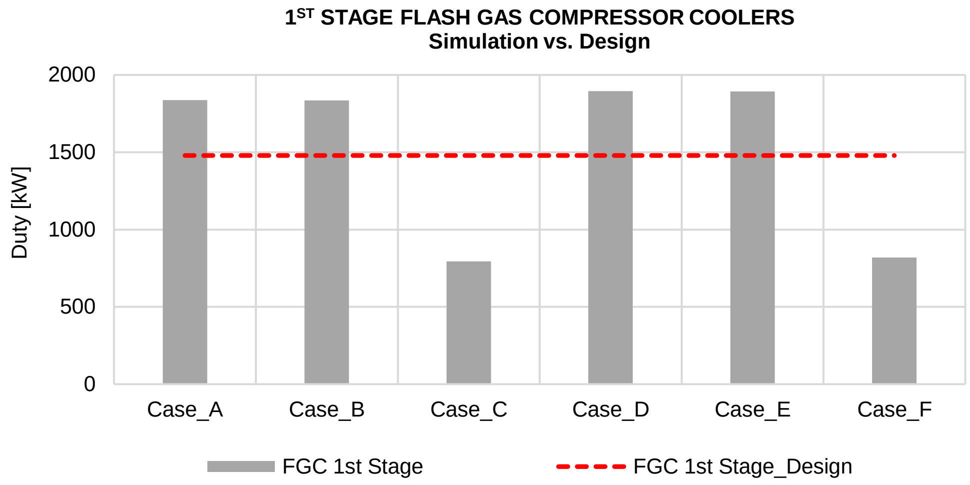

Figure 5.36: 1st stage flash gas compressor cooler duties

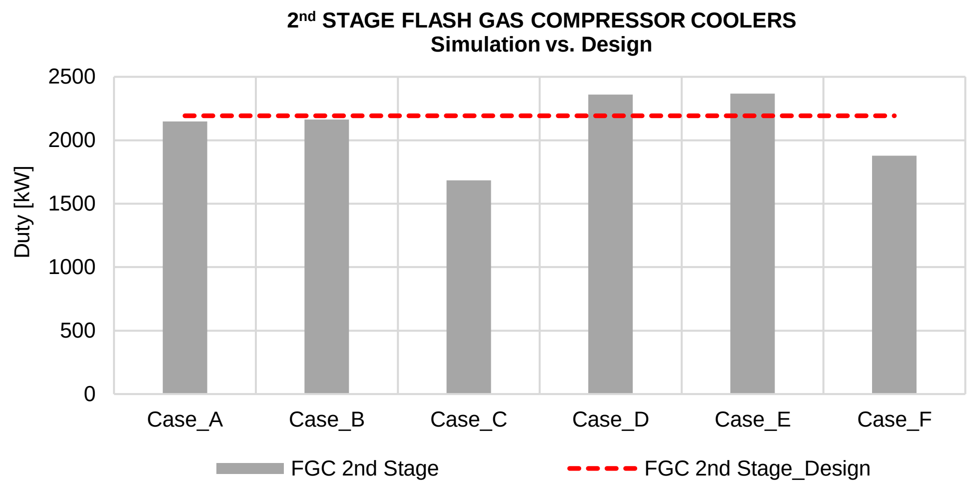

Figure 5.37: 2nd stage flash gas compressor cooler duties

For the new operating conditions for the new Múcua fluid blend, where the gas flow rate is greater than the original design, the train A cooler resulted in a greater pressure drop compared to the train B cooler. Considering that the performance of the train A and B would be impacted significantly by the inlet pressure of the 1st and 2nd stage, the pressure drop across the cooler was investigated in detail via Aspen Tech HYSYS modelling. The evaluation was individually performed for the FGC train A and B by considering the design differences of the coolers between both trains.

Two detailed hydraulic calculations were setup in Aspen Tech HYSYS per the following actual isometrics: one from the gas outlet of the LP separator across the 1st suction cooler until the inlet of the 1st stage FGC inlet nozzle; and another hydraulic check from the gas outlet of the IP Separator to the 2nd stage FGC inlet nozzle. The intention of the hydraulic check was to predict the pressure drop of the gas flow from the IP separator and LP separator along the process line and across the suction cooler. To predict the pressure, drop across the cooler, the original manufacturer provided pressure drop of 0.5 bar was used as a basis. The pressure drop for the new condition was predicted by Aspen Exchanger Design & Rating (EDR) to be 0.73bar and 0.58 bar for train A and B respectively based on the correlation between the volumetric flow rate and pressure drop as highlighted in Appendix B, Figure B.5.

The operating conditions at the 1st and 2nd stage inlet of the compressor were then generated through the detailed Aspen Tech HYSYS simulation and summarised in Table 5.1 for train A and Table 5.2 for train B.

Further details on the ability of the FGC Train A and Train B to accommodate the new conditions are needed to be conducted by the manufacturer using propriety calculations, which were not considered for the scope of this thesis. Thus, it is concluded that the new blend presented higher flow rates for cases A, B, D and E at the 1st stage inlet (i.e., > 6.9MMscfd) with high flow rates observed for all the cases at the 2nd stage inlet (i.e., > 13.0 MMscfd) and as such, any excess gas from the IP and LP separators would have to be flared due to the limitations of 13Mmscfd for the FGC.

Table 5.1: FGC Train A performance based on pressure drop evaluation

Operating Data			**Case_A**		**Case_B**		**Case_C**		**Case_D**		**Case_E**		**Case_F**	
			1st Stage	**2nd Stage**	**1st Stage**	**2nd Stage**	**1st Stage**	**2nd Stage**	**1st Stage**	**2nd Stage**	**1st Stage**	**2nd Stage**	**1st Stage**	**2nd Stage**
Vapour Flow Rate	at inlet	MMSCFD	7.47	14.14	7.44	14.14	6.55	13.50	7.98	15.69	8.15	15.56	6.55	13.50
Vapour Mass Flow	at inlet	kg/h	18345.1	26544.0	18265.7	26429.3	14810.5	25089.2	19734.1	29560.1	20124.0	29153.2	14805.9	25073.1
SUCTION CONDITIONS														
Operating Pressure	at compressor flange	barg	-0.04	4.60	0.45	4.60	0.34	4.58	-0.15	4.60	-0.32	4.60	0.34	4.60
Operating Temperature	at compressor flange	°C	44.27	44.55	44.40	44.54	44.67	44.54	44.10	44.47	43.80	44.47	44.66	44.57
Actual Volume Flow	vapour	m^3/h	9991.3	3147.2	9844.2	3143.2	6279.4	3014.5	12032.1	3487.6	15303.4	3459.2	6276.7	3004.0
Molecular Weight	vapour	kg/kmol	49.22	37.61	49.21	37.47	45.31	37.23	49.58	37.76	49.48	37.55	45.31	37.23
Mass Density	vapour	kg/m^3	1.84	8.43	1.86	8.41	2.36	8.32	1.64	8.48	1.32	8.43	2.36	8.35
Cp/(Cp-R)	vapour	-	1.11	1.14	1.11	1.14	1.12	1.14	1.11	1.14	1.11	1.14	1.12	1.14
Compressibility Factor	vapour	-	0.98	0.95	0.98	0.95	0.98	0.95	0.99	0.95	0.99	0.95	0.98	0.95
DISCHARGE CONDITIONS														
Operating Pressure	at compressor flange	barg	6	19	6	19	6	19	6	19	6	19	6	19
Operating Temperature	at compressor flange	°C	142.14	120.92	141.5	120.6	132.8	121.3	147.0	120.6	157.2	120.56	132.77	121.16
Actual Volume Flow	vapour	m^3/h	1738.9	1044.17	1728.0	1041.4	1499.1	998.5	1880.5	1155.3	1975.8	1145.7	1498.6	997.7
Molecular Weight	vapour	kg/kmol	49.22	37.61	49.21	37.50	45.31	37.23	49.58	37.76	49.48	37.55	45.31	37.22
Mass Density	vapour	kg/m^3	10.54	25.42	10.57	4.78	9.88	25.13	10.49	25.59	10.18	25.45	9.88	25.13
Cp/(Cp-R)	vapour	-	1.083	1.110	1.083	1.11	1.09	1.11	1.08	1.11	1.08	1.11	1.09	1.11
Compressibility Factor	vapour	-	0.95	0.90	0.95	0.90	0.95	0.90	0.95	0.90	0.95	0.90	0.95	0.90

Table 5.2: FGC Train B performance based on pressure drop evaluation

Operating Data			Case_A		Case_B		Case_C		Case_D		Case_E		Case_F	
			1st Stage	2nd Stage	1st Stage	2nd Stage	1st Stage	2nd Stage	1st Stage	2nd Stage	1st Stage	2nd Stage	1st Stage	2nd Stage
Vapour Flow Rate	at inlet	MMSCFD	7.10	13.28	7.08	13.26	6.46	12.60	7.51	14.8	7.58	14.73	6.46	12.60
Vapour Mass Flow	at inlet	kg/h	17329.2	24823.4	17256.8	24696.2	14583.1	23297.3	18475.8	27871.7	18686.2	27568.6	14579.9	23292.9
SUCTION CONDITIONS														
Operating Pressure	at compressor flange	barg	0.33	4.99	0.33	5.00	0.53	5.00	0.28	5.00	0.15	4.99	0.53	5
Operating Temperature	at compressor flange	°C	44.58	44.60	44.6	44.60	44.70	44.65	44.52	44.53	44.45	44.53	44.73	44.65
Actual Volume Flow	vapour	m^3/h	6834.9	2751.6	6781.8	2740.3	5413.2	2612.0	7522.0	3068.5	8422.6	3050.47	5411.9	2611.7
Molecular Weight	vapour	kg/kmol	48.89	37.47	48.87	37.32	45.25	37.05	49.30	37.66	49.42	37.50	45.24	37.04
Mass Density	vapour	kg/m^3	2.54	9.02	2.54	9.01	2.69	8.92	2.46	9.08	2.22	9.04	2.69	8.92
Cp/(Cp-R)	vapour	-	1.11	2751.6	1.11	1.14	1.12	1.14	1.11	1.14	1.11	1.14	1.12	1.14
Compressibility Factor	vapour	-	0.98	0.94	0.98	0.94	0.98	0.95	0.98	0.94	0.98	0.94	0.98	0.95
DISCHARGE CONDITIONS														
Operating Pressure	at compressor flange	barg	6	19	6	19	6	19	6	19	6	19	6	19
Operating Temperature	at compressor flange	°C	114.86	117.2	114.5	116.8	113.8	117.5	115.9	116.8	119.7	116.8	113.8	117.5
Actual Volume Flow	vapour	m^3/h	1526.5	968.4	1518.1	965.1	1398.0	920.9	1616.5	1078.7	1649.5	1070.8	1397.8	920.8
Molecular Weight	vapour	kg/kmol	48.89	37.47	48.87	37.32	45.25	37.05	49.30	37.66	49.42	37.50	45.24	37.04
Mass Density	vapour	kg/m^3	11.35	25.63	11.37	25.59	10.43	25.30	11.43	25.84	11.33	25.74	10.43	25.30
Cp/(Cp-R)	vapour	-	1.08	1.11	1.09	1.11	1.10	1.11	1.09	1.11	1.09	1.11	1.10	1.11
Compressibility Factor	vapour	-	0.94	0.90	0.94	0.90	0.95	0.90	0.94	0.90	0.94	0.90	0.95	0.90

Figures 5.38 to 5.43 are graphical representations of the results for the volumetric flow rates for the oil phase, water phase and gas phase assessments of the 1st and 2nd stage FGC suction scrubbers.

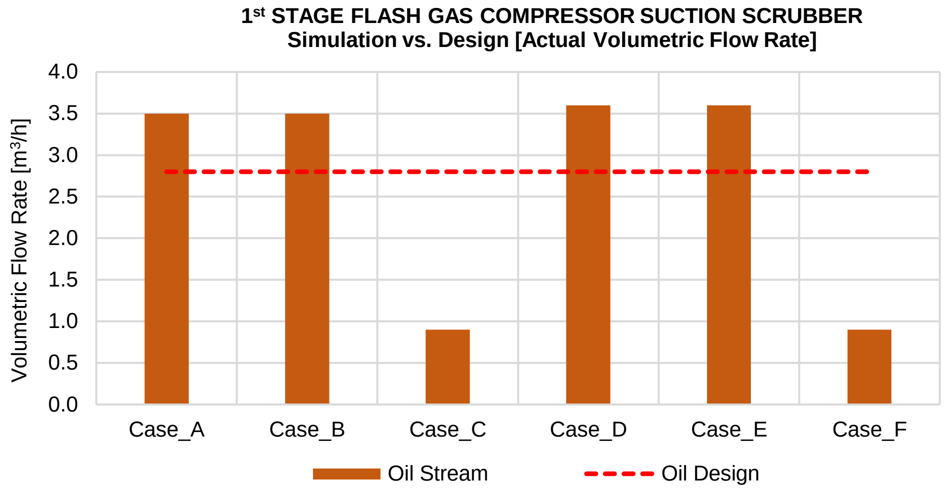

Figure 5.38: 1st stage flash gas compressor suction scrubber oil phase

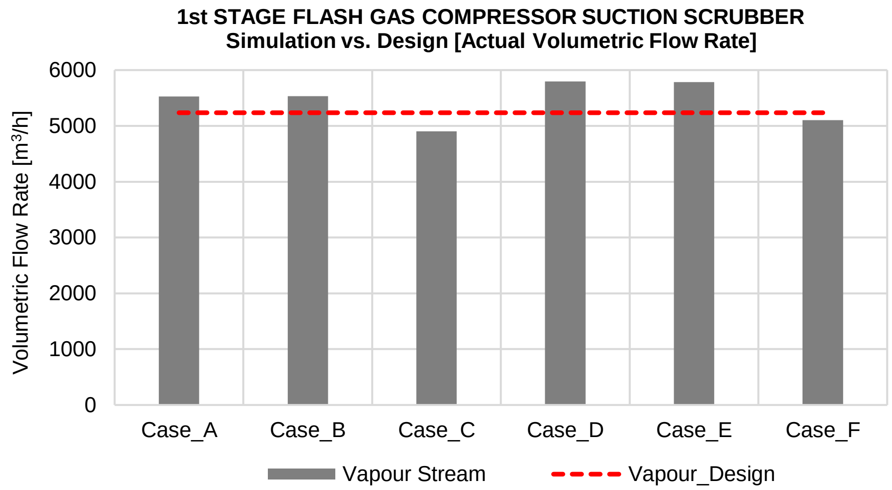

Figure 5.39: 1st stage flash gas compressor suction scrubber gas phase

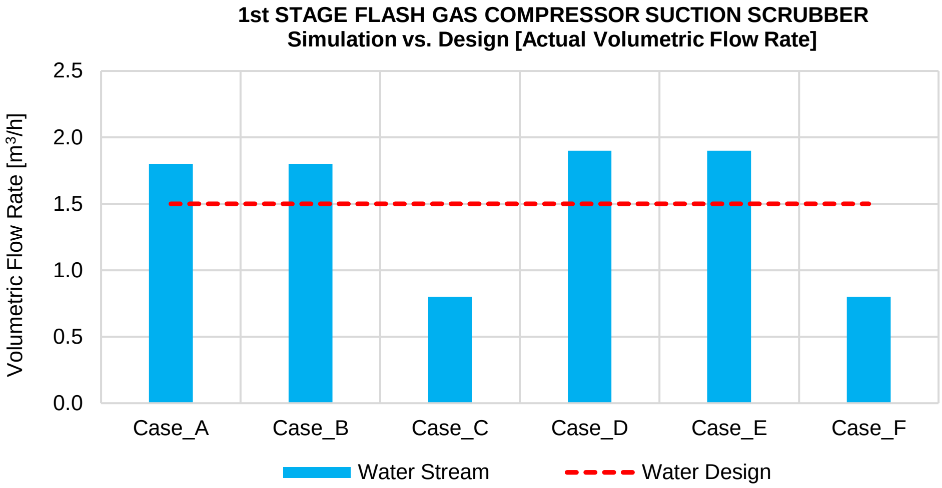

Figure 5.40: 1st stage flash gas compressor suction scrubber water phase

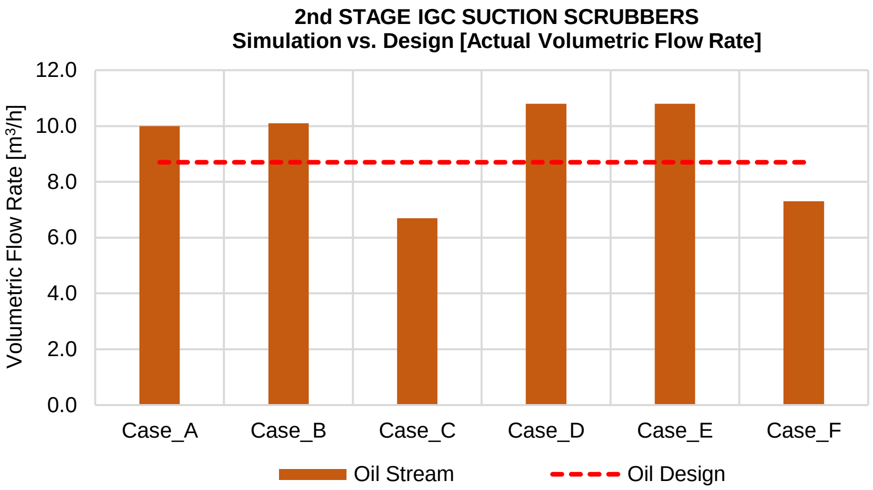

Figure 5.41: 2nd stage flash gas compressor suction scrubber oil phase

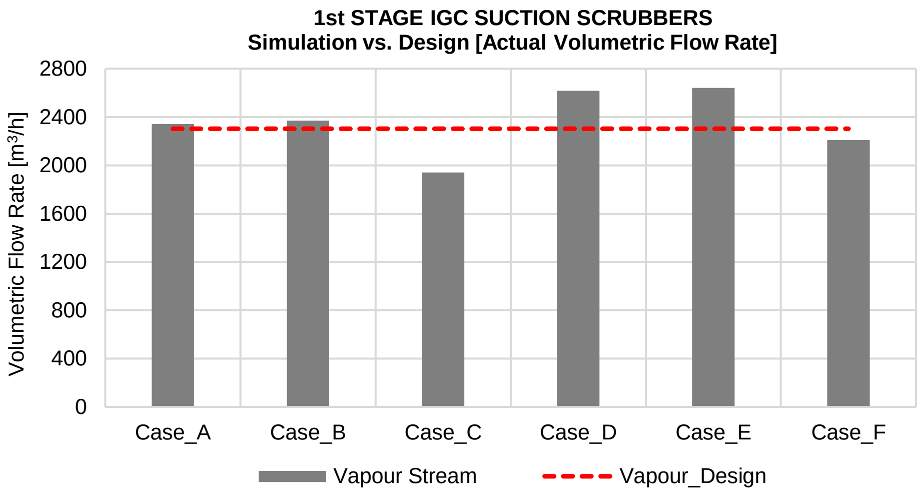

Figure 5.42: 2nd stage flash gas compressor suction scrubber gas phase

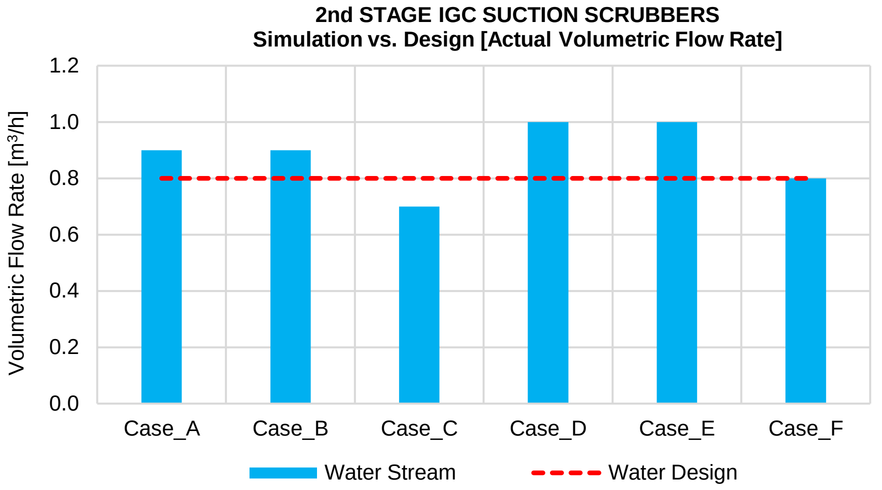

Figure 5.43: 2nd stage flash gas compressor suction scrubber water phase

It was found that cases A, B, D and E exceeded the design volumetric flow rate of 5236.0 m^3/hr and 2302.8 m^3/hr for both the 1st and 2nd stage FGC scrubbers for the gas streams. In addition, the original design liquid flow rates for the oil of 2.8 m^3/hr for the 1st stage and 8.7 m^3/hr for the 2nd stage were also exceeded for these cases. With both stages operating beyond design, flaring would be expected at the LP and IP separator gas outlets. In summary, cases A, B, D and E will likely overwhelm the capacity of the FGC. Therefore, to produce the volume of oil specified (refer to Table 4.2), excess gas from the IP separator and LP separator would have to be flared.

Having gas flaring from the separators is not a safety concern but poses issues from environmental and/or regulatory perspectives. The approximate amount of flaring estimated by the Aspen Tech HYSYS simulation that will be needed at the separators is shown in Table 6.3.

Table 5.3: Flare rates from IP and LP separator estimated by HYSYS

Simulation Case	Case_A		Case_B		Case_C		Case_D		Case_E		Case_F	
	LP Sep	IP Sep	LP Sep	IP Sep	LP Sep	IP Sep	LP Sep	IP Sep	LP Sep	IP Sep	LP Sep	IP Sep
Flare Gas Rate [MMscfd]	0.845	1.215	0.800	1.286	0.000	1.077	1.325	2.696	1.399	2.586	0.000	1.077

5.2.10. Gas Dehydration

As shown in Figure 5.44 and 5.45, the operating parameters for all cases are within the design limit for the gas dehydration system.

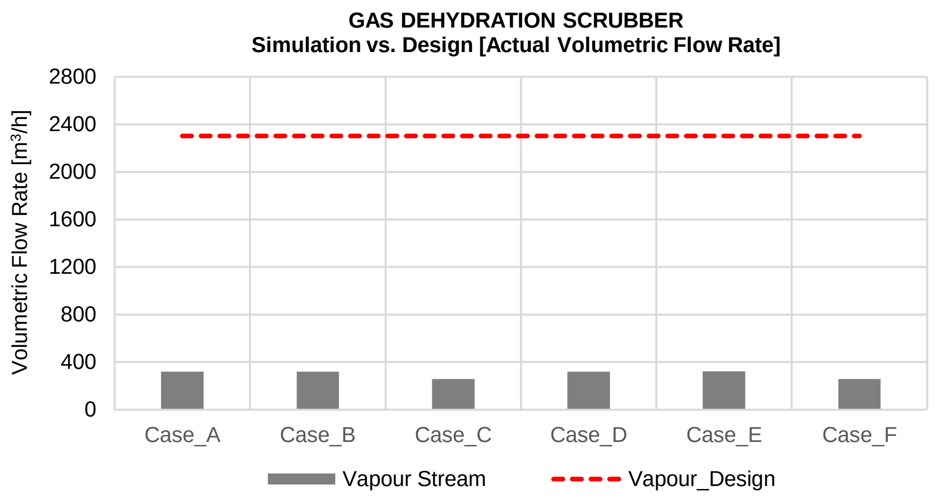

Figure 5.44: Gas dehydration scrubber gas phase

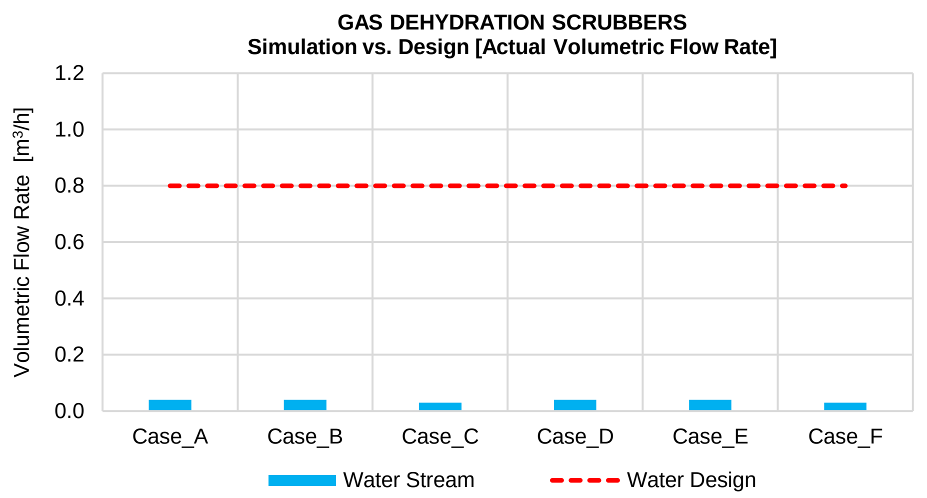

Figure 5.45: Water dehydration scrubber water phase

5.2.11. Produced Water Flash Vessel

The produced water treatment for the new Múcua fluid blend conditions is within the design limit of the produced water design rate of 100 000 BWPD (i.e., 662.5 m^3/h). Therefore, it is expected that the produced water flash vessel in the produced water treatment system should be able to handle the new operating conditions. Figure 5.46 shows the results for the assessment of the produced water flash vessel by Aspen Tech HYSYS simulation.

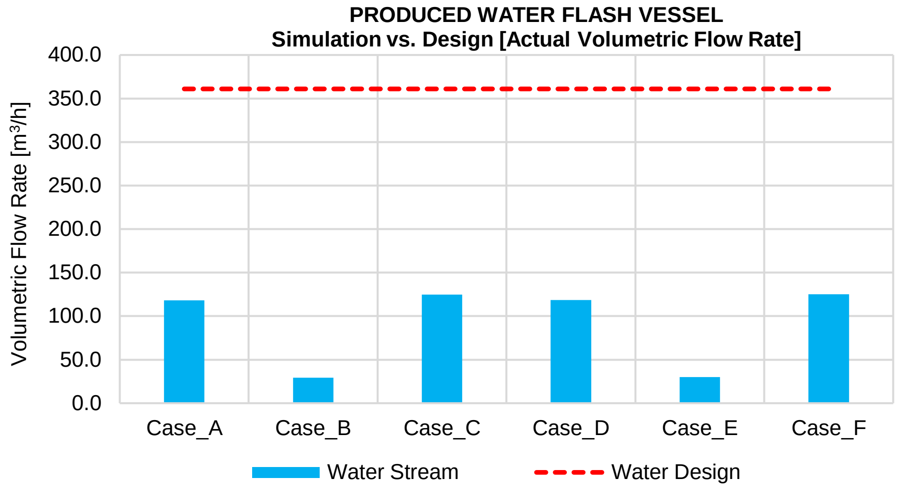

Figure 5.46: Produced water flash vessel volumetric flow rates

5.2.12. Produced Water Cooler

Based on Figure 5.47, the produced water cooler was found to be within design limit (i.e., 6028 kW) for the new operating conditions, thus there is no concern for this vessel

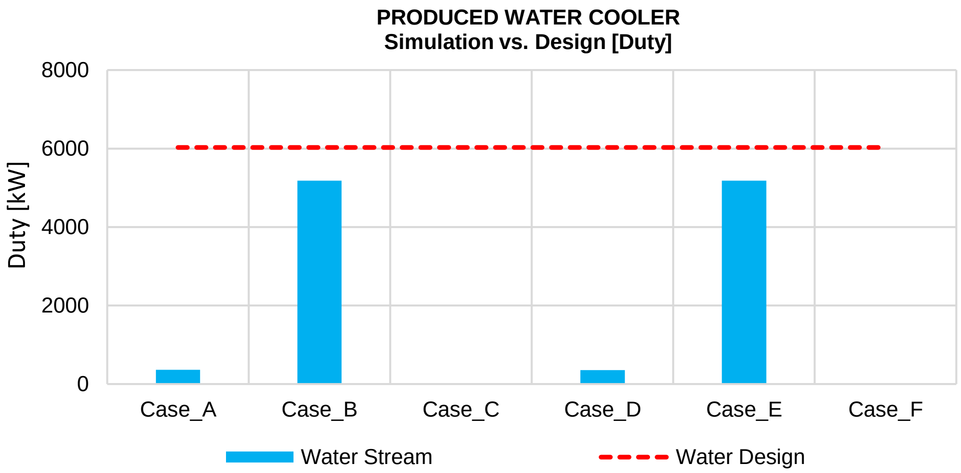

Figure 5.47: Produced water cooler duties

5.2.13. Utilities

5.2.13.1. Cooling and Heating Medium

The cooling medium capacity is evaluated by comparing the overall duty of major cooling medium consumers with the system's original design. Figure 5.48 represents the cooling duty requirement for the major topsides heat exchangers, namely IGCs, FGCs and Crude Oil Coolers

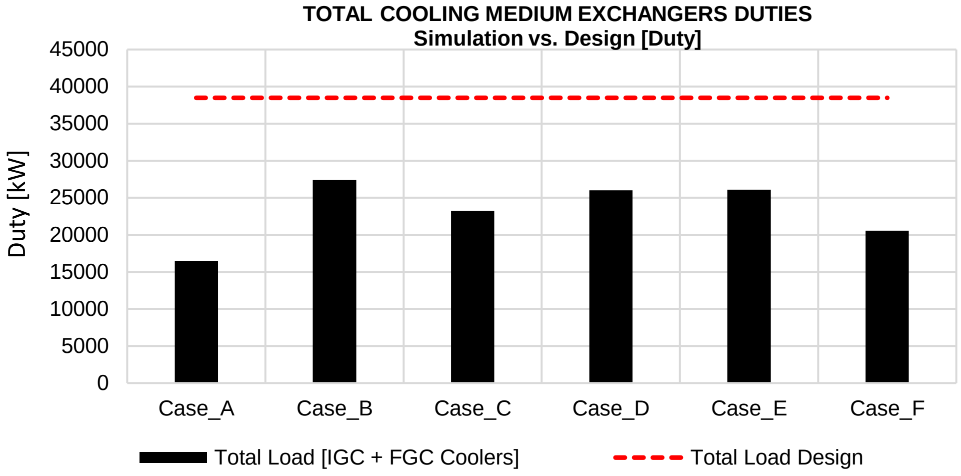

Figure 5.48: Total cooling medium exchangers duties

The total cooling duty required by the major heat exchangers for cases A, B, C, D, E and F was found to be 26463 kW, 26665 kW, 21133 kW, 25996 kW, 26099 kW and 20573 kW, respectively which is less than the original design value of 32100 kW for these heat exchangers. Therefore, the existing cooling medium system is able to handle the overall cooling requirement for the new operating conditions. In addition, considering that there is no extra duty requirement for the existing cooling medium, the seawater requirement for the seawater/cooling medium heat exchanger will not impacted either.

The heating medium capacity was evaluated by comparing the overall duty of the major heat consumers with the original design value of 12774 kW. Figure 5.49 represents the heating duty requirement for the major topsides heat exchangers, namely the crude oil heaters and fuel gas heaters (i.e., the pre-heater, high pressure, and low pressure superheaters).

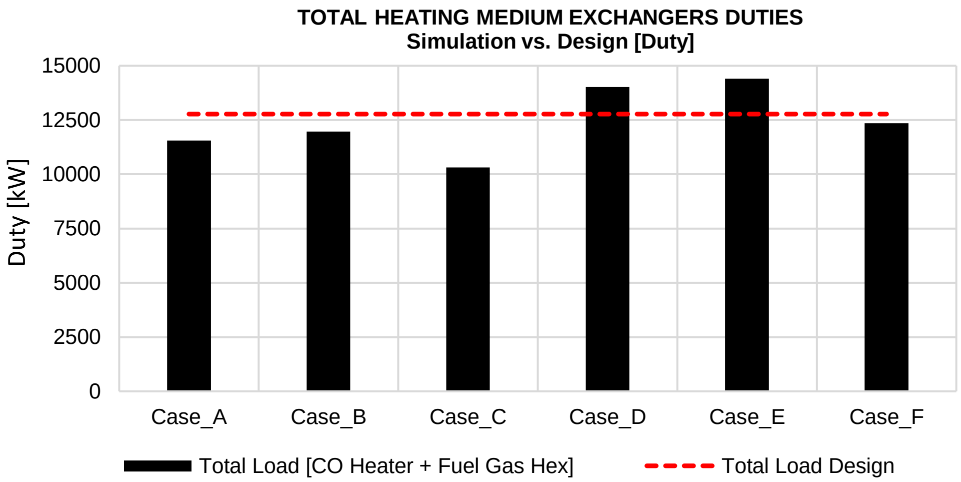

Figure 5.49: Total heating medium exchangers duties

The overall required heating medium capacity for cases D and E (i.e., 14016 kW and 14399 kW) exceeded the total design heating capacity of 12774 kW by 10% and 13%, respectively due to the lower operating temperature of the test separator. The cases shown in Figure 5.49 considers 90°C outlet from the crude oil heaters. For cases C and F where the test separator liquid outlet is routed to the LP separator (in order to bypass the IP separator due to a lower operating pressure of 6 barg), the test separator liquid bypasses the crude oil heaters. In these cases, although the Reid vapour pressure (RVP) specification was met, the true vapour pressure (TVP) specification was not met in the Aspen Tech HYSYS simulation, as shown in Figures 5.50 and 5.51.

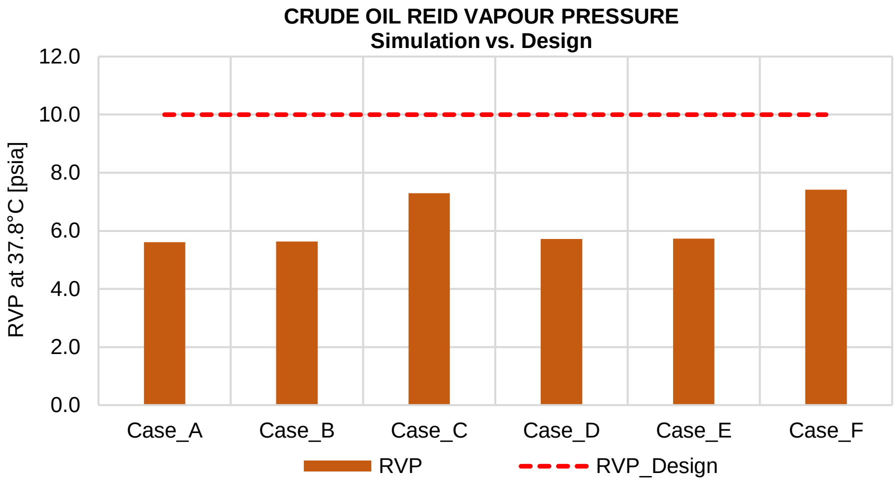

Figure 5.50: Crude oil Reid vapour pressure simulation vs design

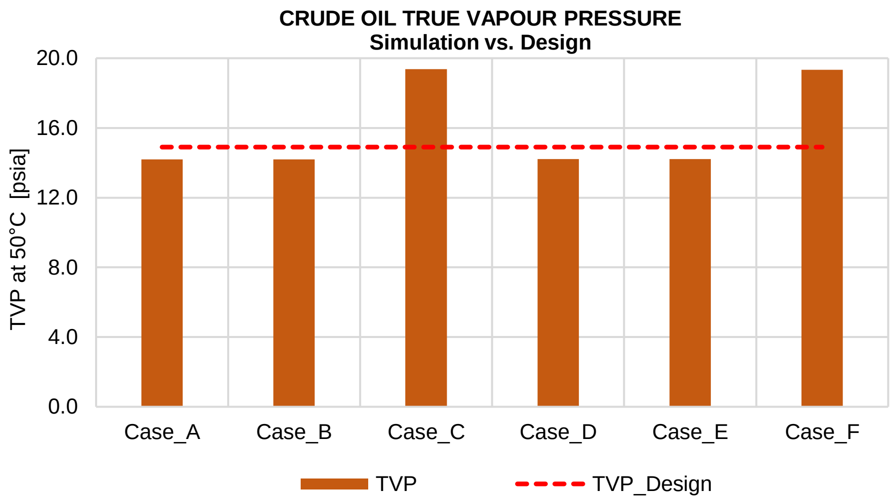

Figure 5.51: Crude oil True vapour pressure simulation vs design

A higher crude oil heater outlet temperature of more than the normal 90°C was required for cases C and F to account for the test separator fluids bypassing the heater to achieve the design TVP.

5.2.13.2. Seawater

The required seawater cooling duty for the major heat exchangers using seawater as the cooling medium was within the design limit of 23105 kW as shown in Figure 6.52. Therefore, the requirement of the seawater duty is not impacted by the new operating conditions.

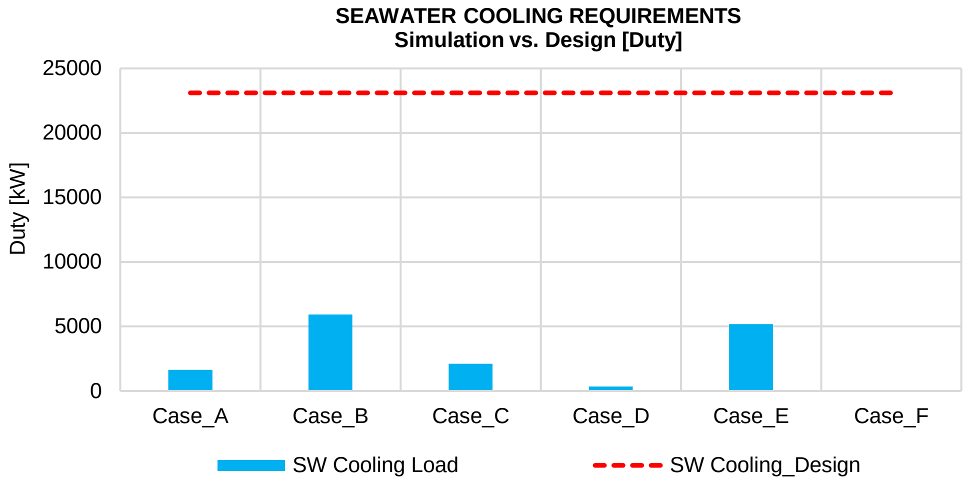

Figure 5.52: Seawater cooling requirements

5.2.13.3. Fuel Gas System

The fuel gas system operating conditions for the tie-in evaluation were within the design limit of the fuel gas system. The original design of the system is based on 21 MMscfd of the original blend. For the evaluation of the new blend, only 10 MMscfd was considered. Therefore, it is expected that the equipment in the fuel gas system should be able to handle the new blend.

All the operating parameters for the new blend and operating parameters for the Múcua tie-in were within the range of the fuel gas scrubber design as shown in Figures 5.53 and 5.54. The corrected Wobbe index for all the cases is shown in Figure 5.55 and is within the design limit of turbine, which is 37 - 49 MJ/Sm^3 as defined by the Turbine manufacturer (Appendix F, Table F.11). Therefore, the operating conditions for the new fluid blend met the requirements of the fuel gas supply. In addition, the required duties for the fuel gas heat exchangers were within the design limit (Figure 5.56, 5.57 and 5.58) and as such, the capacities of fuel gas exchangers are not a concern.

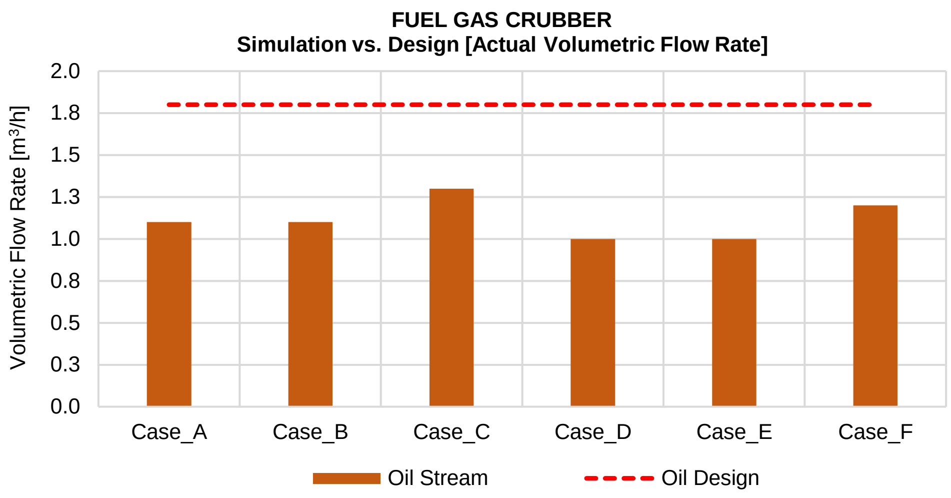

Figure 5.53: Fuel gas scrubber oil phase

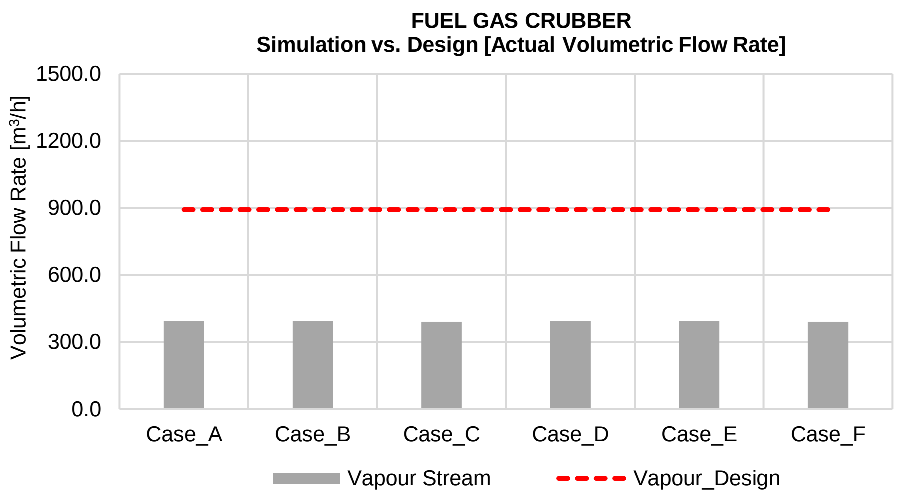

Figure 5.54: Fuel gas scrubber gas phase

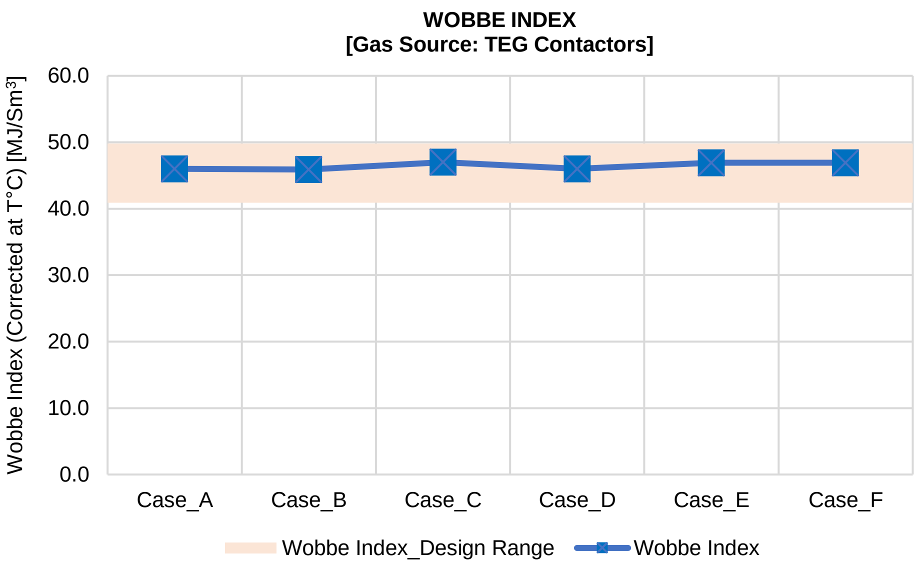

Figure 5.55: Fuel gas Wobbe index normal operations

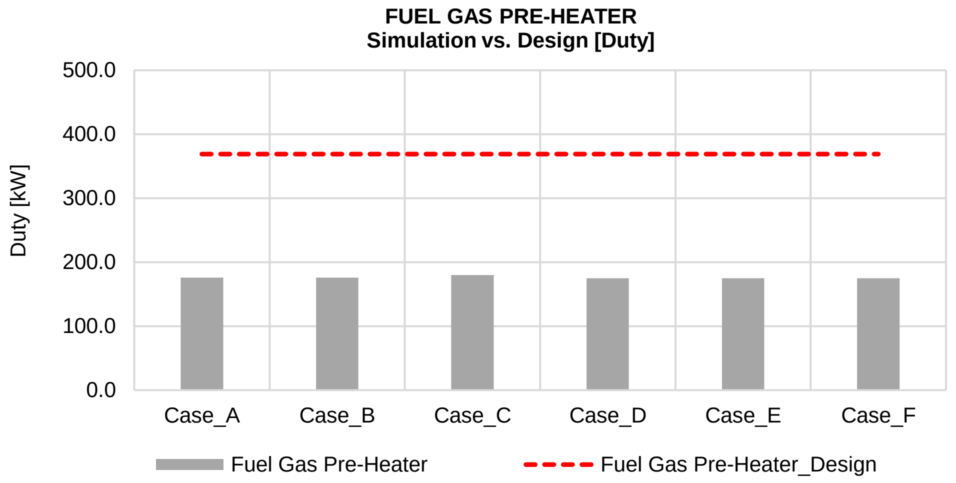

Figure 5.56: Fuel gas pre-heater duties

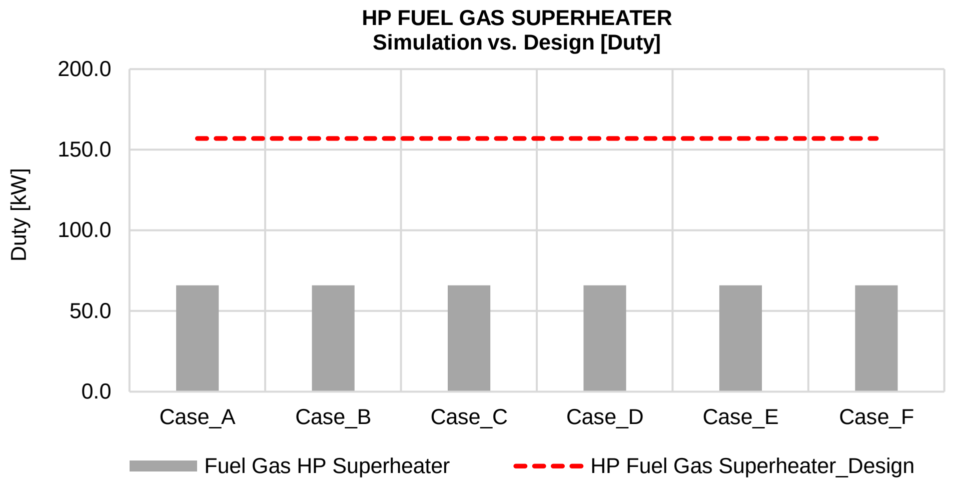

Figure 5.57: HP fuel gas superheater duties

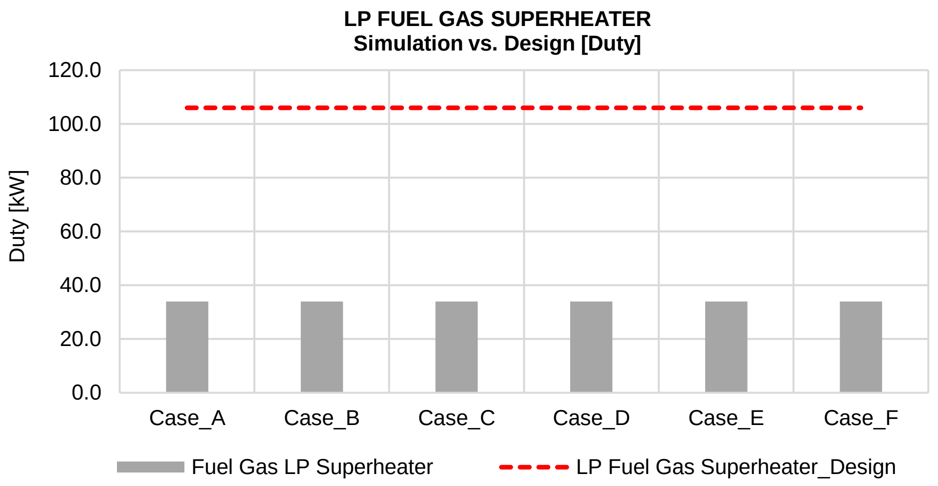

Figure 5.58: LP fuel gas superheater duties

5.2.14. Blow down Scenario

An evaluation was conducted for the low temperature operation of the test separator to determine the impact on the system. The blowdown from the test separator is mainly the depressurisation process through a blow down valve (BDV) tagged T62-BDV-022 (located in separate gas outlet stream of the test separator connected to the flare system), in the scenario of compressor trip. The blow down usually co-occurs with the blow down from the other production separator within a short period. In this study, the blowdown was evaluated for case B and E where the test separator operated at 19 barg (highest pressure) and -7 °C (lowest temperature).

The blow down rate from the major topsides blow down valves should remain approximately the same as the original design value of 175 MMscfd (Company, 2013), although the blowdown rates may be slightly different due to the compositional difference of the new fluid blend from the original design. Due to the low operating temperature of the test separator for cases B and E, the blow down rate from T62-BDV-022 was expected to be slightly greater than the original design value of 7.4 MMscfd at 63°C. However, considering that the original design for the HP flare header (full adiabatic blowdown of 175 MMscfd) includes a 10% margin of 17 MMscfd (Company, 2014e), the slightly different blow down rate from new operating condition will not be of concern.

5.2.14.1. Impact of Low Temperature in the Piping and Flare Network

During the blow down of the test separator through T62-BDV-022, extreme low temperature is expected to be seen downstream of the blow down valve. In addition, the contents of the test separator and the inside wall of the vessel may be subjected to temperature slightly lower than the initial temperature of the blow down due to the flashing hydrocarbon liquid which accounts for decreasing pressure inside the vessel during the blowdown process.

The low temperatures indicated in Figure 5.59 were evaluated with respect to the minimum design temperature of the material of construction of the test separator. The Aspen Tech HYSYS blow down evaluation indicated a temperature downstream of the blow down valve of -23°C. This is within the material design limit of -46°C (Company, 2014e). The vessel wall temperature from the Aspen Tech HYSYS evaluation was -8°C for the portion where liquid is in contact and -4°C for the portion where metal is in contact with the vapour. The vessel wall minimum design temperature is -10°C, which is close to the Aspen Tech HYSYS evaluation and should not be a concern as heat gain from the ambient conditions will increase the metal wall temperature. Hence this operating scenario is well within limits of the design conditions as shown in Figure 6.59, which represents the dynamic simulation results from the Aspen Tech HYSYS evaluation of cases B and E.

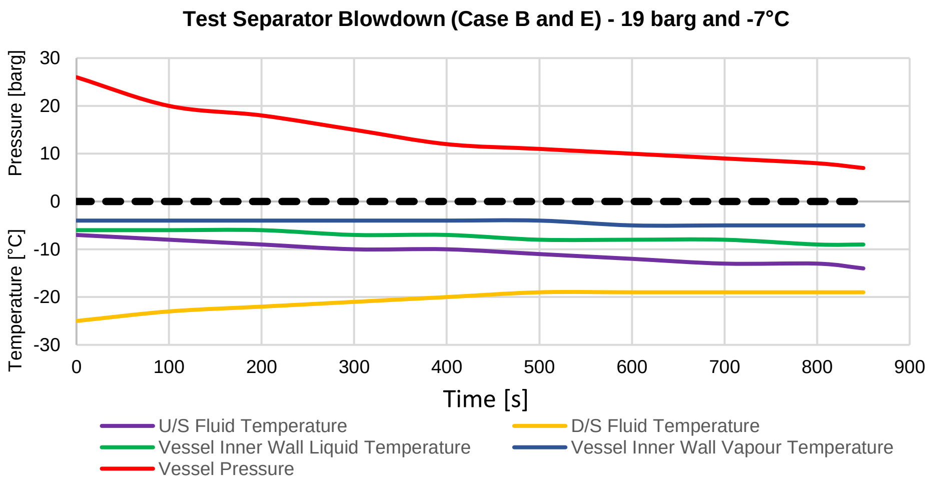

Figure 5.59: Test separator blowdown for case b and e HYSYS evaluation results

During blowdown, as per the dynamic simulation result indicated in Figure 6.59, the fluid in the test separator may be exposed to temperatures as low as -8°C. However, Múcua wells are not injected with water and hence there is no risk of ice formation within the vessel.

5.2.14.2. Hydrate Formation inside Test Separator

In this study, the overall assumption is that hydrate formation is not a concern considering there is continuous low dosage hydrate inhibitor (LDHI) injected into the subsea structures. The downstream operating condition.

5.2.14.3. Ice Formation

With an operating temperature of -7°C in the test separator, the flaring/blow down of the test separator would generate a cold gas stream in the flare header (Company, 2019). When this cold gas stream encounters the wet streams from the HP separator, there is a concern of ice/hydrate formation in the flare header. Worst case scenario, the ice/hydrate accumulation may block the flare header partially or fully, compromising the safety integrity of the flare system. The ice/hydrate formation concern is minimal during the operation of cases A, C, D and F due to the operating temperature of the test separator of 5°C. The test separator blowdown will be short-term and usually co-occurring with the blow down HP and IP separators. The predicted warm streams from the HP and IP separators (Company, 2014e), will be sufficient to warm up the cold stream from the test separator above the freezing point of water and out of the hydrate formation zone.

The concern for ice/hydrate formation is particularly applicable for Cases B and E. The ice formation in the flare header may happen due to the following factors:

- The presence of a cold stream on a continuous basis. During the operation of Case E, the test separator is continuously flaring cold gas into the flare header.
- The presence of a wet stream on a continuous basis. Most of the water content in the wet stream is coming from water saturation under the test separator operating conditions. The water carry-over (if any) also contributes, but in a small percentage to the overall water content. The mixing of the cold and wet streams generates a condition in the ice/hydrate formation envelope, which is dependent on the overall condition of the gas composition, dew point and temperature (Company, 2014e).

The scope of this report does not analyse in detail the scenarios of ice/hydrate formation (refer to section 1.9 in Chapter 1), since rigorous engineering evaluation needs to be conducted to justify and/or quantify a few scenarios of ice/hydrate formation. It was therefore concluded that the risk of the flare header being blocked by ice/hydrate formation is minimal, particularly when the cold test separator flare gas is mixed with the wet gas from the IP separator.

5.2.15. Flare System Capacity

The total topsides high pressure blow down is 175 MMscfd (Table 3.21). As per the discussion in section 5.2.14, the existing HP flare header capacity should be able to cover the blow down scenario for the new operating conditions considering the 10% design margin.

For the production flaring scenario, the debottleneck cases have a smaller gas production rate when compared to the original design (refer to Appendix G, Tables G.1 and G.2). For cases B and E, the gas production rate totalised 85.7 and 89.2 MMscfd, respectively (i.e., HP separator: 76.9 and 79.0 MMscfd and IP separator: 8.8 and 10.2 MMscfd, respectively for cases B and E); while for cases C and F it totalised 89 and 86.9 MMscfd, respectively (i.e. HP separator: 71.4 and 69.3 MMscfd, respectively for cases C and F, with 17.6 MMscfd for the test separator for both cases). Therefore, there was found to be no concern for the continuous, production flaring.

Like the HP flare header evaluation in section 5.2.14, the blowdown rate in the LP flare header will not significantly change when compared to the original design. Considering the 10%

margin that the original design features, the LP flare header capacity will have no issues under the new operating conditions.

5.3. Governing Case Selection

The options available for the topsides facility to allow the new fluid blend to obtain the true vapour pressure (TVP) specification with the bottleneck of crude oil heaters and the flash gas compressor (FGC) systems are very limited. From the Aspen Tech HYSYS simulations it was found that the FGC system was found to be unable to safely handle the flow rates for cases A, B, D and E; while for cases C and F, the gas flow rates were very close to the maximum design flow rate (Table 5.1 and 5.2). Increasing the pressures in the IP or LP separators would lead to less gases being routed to the FGC system and therefore cause more cargo manual venting requirements, which is undesirable, since it is normally an activity controlled by the operator in the cargo control room, which is prone to lack of proper control in case of distractions.

From the overall analysis the configurations and conditions for cases A, B, D and E faced challenges to safely process the oil and gas from the new fluid blend. Therefore, the test separator was found neither viable to be operating at 19 barg, nor able to process Múcua's production riser-c (PR-c) fluids.

Case C and case F presented the least bottlenecks and were found to be most ideal cases regarding configuration and conditions. For these cases, the test separator liquid outlet was routed directly to the LP separator due to the lower operating pressure of 6 barg, thus bypassing the crude oil heaters as well as the IP separator. In cases C and F, the TVP specification was not met in the Aspen Tech HYSYS simulation. However, in reality, a low temperature override controller is located upstream of the electrostatic treater to boost the output of the heaters to achieve a temperature of 90°C at the inlet to the treater (Company, 2016a). To account for this and obtain realistic duty requirements for cases C and F, the output temperature of the crude oil heaters was adjusted to achieve the TVP specifications in the Aspen Tech HYSYS simulations. The results are shown in Table 5.4.

Table 5.4: TVP adjusted heating duty of crude oil exchangers for cases C and F

Duty [kW]	Crude/Crude Exchangers	Crude Oil Heaters	Total Heating Load (Design Case)
Design Case	11860	12154	12774
Case C	7360	14551	14831
Case F	10490	16822	17101

The actual operating configuration of the heating medium exchangers is 3 x 33% (Company, 2014d), therefore the design duty of the heating medium exchangers is 3 x 6071 kW (Table 3.7), yielding 18213 kW, which is 1112 kW more than the required duty of 17101 kW, to meet the process heating requirements for case F. Thus, the heating medium system is not expected to be a bottleneck. Although the heating medium system exchangers can supply the required heating duty, the crude oil heaters containing 100 plates are not able to achieve the required amount of heating, which is surely a bottleneck (section 5.2.7).

The current operating pressure and temperature conditions of the test separator (i.e., 6 barg and 15°C), obtained from the OsiSoft plant information (PI) Process Book for 29 March 2020 as listed in Table A.1 (Appendix A), were used as the basis to select the governing case. The governing case was found to be case F over case C, because in the original design prior to the Múcua fluid tie-in the HP separator was operating at 19 barg and 52.3°C. Case C is based on these values (refer to Table 5.3 in Chapter 5), meaning that the temperature of the 20 000 BOPD from Maboque through test riser-a (TR-a) (refer to Table 5.4 in Chapter 5) would not have a visible effect on the HP separator operating temperature, which is unrealistic considering the additional flow rate of 20 000 BOPD, against the total production rate before the tie-in of 60 000 BOPD.

5.4. Current Operating Conditions with Múcua tie-in Simulation

The operating conditions listed in Table 5.5 were used to simulate the actual process parameters using the configurations and conditions of case F to predict the plant's behaviour for the Múcua fluid tie-in (i.e., New Fluid Blend). Some data was obtained from the OsiSoft PI Process Book and some from the production report (refer to Table A.1 in Appendix A). All the flow rates indicated are actual flow rates, except for the gas flow rates which are based on standard conditions.

Table 5.5: Operating conditions of the plant on 29 March 2020 without Múcua tied-in

HP Separator [PR-a, PR-b, PR-c and PR-d Risers]	
Oil stream outlet [BOPD]	47921.0
Water stream outlet [BWPD]	30661.0
Total Fluids Inlet [BLPD]	78582.0
Gas Flow (incl. Gas Lift) [MMscfd]	63.84
Operating Temperature [°C]	52.8

Table 5.5 (continued): Operating conditions of the plant on 29 March 2020 without Múcua tied-in

HP Separator [PR-a, PR-b, PR-c and PR-d Risers]	
Operating Pressure [barg]	19.0
Gas Lift to HP Separator [MMscfd]	25.41
Test Separator [TR-a Riser]	
Oil stream outlet [BOPD]	26337.0
Water in Flow 40% WC [BWPD]	10534.8
Water stream outlet [BWPD]	114.0
Total Fluids Inlet [BLPD]	26451.0
Water in oil outlet [BS&W 40 vol%]	10580.4
Gas Flow (All flared) [MMscfd]	7.3
Operating Temperature [°C]	15.0
Operating Pressure [barg]	6.0
Gas Lift to Test Separator [MMscfd]	0
Gas Processing	
IGC Train A 3rd Stage Discharge [MMscfd]	27.0
IGC Train C 3rd Stage Discharge [MMscfd]	27.0
Fuel Gas [MMscfd]	8.23
Gas Lift [MMscfd]	25.41
HP Flare [MMscfd]	16.85
LP Flare [MMscfd]	4.34
Gas Injection [Field]	20.65
Gas Produced from Reservoir [MMscfd]	50.07
Compressed Gas [MMscfd]	54.0

In addition, the following assumptions were considered based on the operating information:

- Both crude oil heaters are in service (i.e., 2 x 50%).
- 2 x injection gas compressor (IGC) trains online (i.e. 2 x 50%).
- All liquids from the test separator are routed to the LP separator due to the low operating pressure of the test separator and there is not efficient water separation in the test separator due to the low temperature.
- The water cut from the HP Separator is assumed to be 10%.

- The Múcua fluids are considered to have a 0% water cut.
- There is no gas lift to the test separator.
- 60 000 BOPD are produced as per the daily operations report summary.
- The additional 20 000 BOPD from Múcua at -7 ˚C are routed to the HP separator.
- An 80 000 BOPD production target.

The simulations study with the above considerations resulted in the following main findings captured in Table 5.6.

Table 5.6: Separators' evaluation (Actual and Múcua: Case F)

Phase	Parameter [units]	HP separator		IP separator		LP separator		Test separator		Electrostatic treater	
		Actual + Múcua	Design Case	Actual+ Múcua	Design Case	Actual + Múcua	Design Case	Actual + Múcua	Design Case	Actual + Múcua	Design Case
Vapour	Std Gas Flow [MMscfd]	73.06	107	7.2	7.6	2.51	6.9	7.24	29.0	-	-
Oil	Actual Volume Flow [m^3/h]	461.2	710.2	472	729.3	559.4	702.3	105.0	173.0	559.3	702.3
Water	Actual Volume Flow [m^3/h]	220.2	686.6	53.7	81.7	108.3	105.6	72.82	155.0	48.94	82.6

Table 5.7: Operating parameters of the oil train's equipment simulation results (Actual and Múcua: Case F)

Parameter	HP separator	IP separator	LP separator	Test separator	Electrostatic treater	Crude/Crude Exchangers	Crude Oil Heaters	Crude Oil Coolers
Pressure [barg]	19	6	1	6	4	8.3	6	1.9
Temperature [°C]	43.9	97.3	66.9	15	67.1	58.9	98.4	50

The HP separator is expected to operate at 19 barg (Table 5.5), with the temperature expected to decrease from 52.8°C (Table 5.5) to 43.9°C (Table 5.7) due to the tie-in with Múcua. With the Múcua fluid tie-in the inlet flow rate of the light liquid is expected to be 461.2 m^3/h (i.e., 69 620 BOPD) and the gas to be 47.65 MMscfd (plus the fixed gas lift flow rate of 25.41 MMscfd (Table 5.5), totalising 73.06 MMscfd as shown in Table 5.6.

The oil coming from the treater, is expected to heat the fluid from the HP separator from 43.9 to 58.9°C, in turn cooling the dead oil to 50°C in the crude/crude exchangers. While the crude oil heaters heat the fluid from 58.9 to 98.4°C considering the design duty of 12 142 kW (Table 5.8).; no further cooling of the dead crude oil will be required, since it has already been cooled to 50°C in the crude/crude exchangers.

Table 5.8: Oil train heat exchangers' duties (Actual and Múcua: Case_F)

Duty [kW]	Crude/Crude Exchanger	Crude Oil Heaters	Crude Oil Cooler
Design Case	11860	12154	6380
Actual + Múcua	4559	12142	0

The test separator is expected to operate at the conditions of 6 barg and 15°C, as well as the current design flow rate conditions, since the Múcua fluid will not be routed to it. Therefore, similar to the original design conditions 7.2 MMscfd of gas is expected to be flared (Table 5.6), while together the oil and water are routed to LP separator due to there being no liquid separation on account of the low temperature and operating pressure of 6 barg.

The IP separator is expected to operate at the original design operating pressure of 6 barg, at a temperature of 97.3°C based on this study. This temperature could be decreased; however, this would cause the TVP of the dead crude oil to increase in the cargo tanks. There is not expected to be any gas flaring necessary from the IP separator, since the test separator outlet fluids will bypass it. The LP separator is expected to also operate at the original design operating pressure of 1 barg, at a temperature of 66.9°C as recorded in Table 5.7, although the fluid flow rate is expected to exceed the water flow rate compared to the original design. Based on the simulation using case F as the governing case the treater is expected to operate at the original design operating pressure of 4 barg and at a temperature of 67.1°C (Table 5.7).

The duties of the IGC and FGC systems are within the original design capacity, as shown in Tables 5.9 and 5.10. However, for the 2nd stage FGC scrubber, it was noticed that the water flow rate is above the original design as highlighted in Table 5.11. This may cause a bottleneck and must be monitored closely by increasing the production rates gradually during operation.

Table 5.9: IGC and FGC coolers' duties (Actual and Múcua: Case F)

Coolers Duty [kW]	1st Stage IGC	2nd Stage IGC	3rd Stage IGC	IGC Discharge	1st Stage FGC	2nd Stage FGC
Design Case	1127	4996	4986	3105	1479	2193
Actual + Múcua	273.5	3363	3399	1966	379.8	1603

Table 5.10: IGC and FGC duties HYSYS evaluation (Actual and Múcua: Case F)

Compressor's Duty [kW]	1st Stage IGC	2nd Stage IGC	3rd Stage IGC	1st Stage FGC	2nd Stage FGC
Design Case	3464	3387	2613	512	671
Actual + Múcua	2624	2123	1794	281.2	517.9

Table 5.11: IGC and FGC scrubbers (Actual and Múcua: Case F)

Phase	Parameter	1st Stage IGC		2nd Stage IGC		3rd Stage IGC	
		Actual + Múcua	Design Case	Actual + Múcua	Design Case	Actual + Múcua	Design Case
Vapour	Std Gas Flow [MMSCFD]	40.81	57.0	40.5	57.0	36.22	50.0
Oil	Actual Volume Flow [m^3/h]	0.1	1.1	1.2	2.6	-	-
Water	Actual Volume Flow [m^3/h]	0.1	0.6	0.1	0.2	-	-
Phase	**Parameter**	**1st Stage FGC**		**2nd Stage FGC**			
		Actual + Múcua	**Design Case**	**Actual + Múcua**	**Design Case**		
Vapour	Std Gas Flow [MMSCFD]	3.0	6.3	8.2	11.0		
Oil	Actual Volume Flow [m^3/h]	0.4	2.8	5.2	8.7		
Water	Actual Volume Flow [m^3/h]	0.4	1.5	0.9	0.8		

The tri-ethylene glycol (TEG) contactors and the fuel gas systems are within the design capability with regards to the scrubbers' performance, as well as the heater's requirements as per the tabulated results in Tables 5.12 and 5.13.

Table 5.12: Glycol and fuel gas scrubbers (Actual and Múcua: Case_F)

Phase	Parameter	Glycol Scrubber		Fuel Gas Scrubber	
		Actual + Múcua	Design Case	Actual + Múcua	Design Case
Vapour	Std Gas Flow [MMSCFD]	40.3	57.3	8.1	21.0

Phase	Parameter	Glycol Scrubber		Fuel Gas Scrubber	
		Actual + Múcua	**Design Case**	**Actual + Múcua**	**Design Case**
Oil	Actual Volume Flow [m^3/h]	-	-	0.77	1.8
Water	Actual Volume Flow [m^3/h]	0.03	0.05	-	-

Table 5.13: Fuel gas heaters' (Actual and Múcua: Case_F)

Heaters	Duty [kW]		
	Fuel Gas Pre-Heater	**HP Fuel Gas Superheater**	**LP Fuel Gas Superheater**
Design Case	369	157	104
Actual + Múcua	143.2	54.8	27.8

Based on the Aspen Tech HYSYS simulation, it is expected that a standard ideal liquid volumetric flow rate of 81 170 BOPD (i.e., basic sediment and water (BS&W) of 0.5% and American petroleum institute (API) of 33.99) will be processed in the cargo tanks (Figure 5.60). At 50°C the TVP, based on the study, is 21.5 psia and Reid vapour pressure (RVP) 7.6 psia at 37.8°C as tabulated in Table 5.14.

Table 5.14: RVP and TVP prediction (Actual and Múcua: Case_F)

Parameters	Actual + Múcua	Design Case
RVP at 37.8°C [psia]	7.6	≤ 10
TVP at storage conditions at 50°C [psia]	21.48	≤ 14.7

Based on this the TVP is off-specification and there is expected to be 0.4215 MMscfd of gas flashing in the cargo tanks constantly. This can be handled by the vapour recovery unit (VRU) which is designed for 1.0 MMscfd in order to keep the cargo tanks at 14.7 psia for storage conditions. Figure 5.60 represents a process flow diagram of the simulation case including the Múcua fluid tie-in under case F configuration with the flow rates for the oil, gas and water streams indicated.

This chapter interpreted and discussed: 1.) the topside process evaluations acquired by HYSYS simulations; 2.) the computer-based evaluations of separators using MySEP; 3.) line-sizing calculations; 4.) blowdown scenarios; and 5.) the flare system.

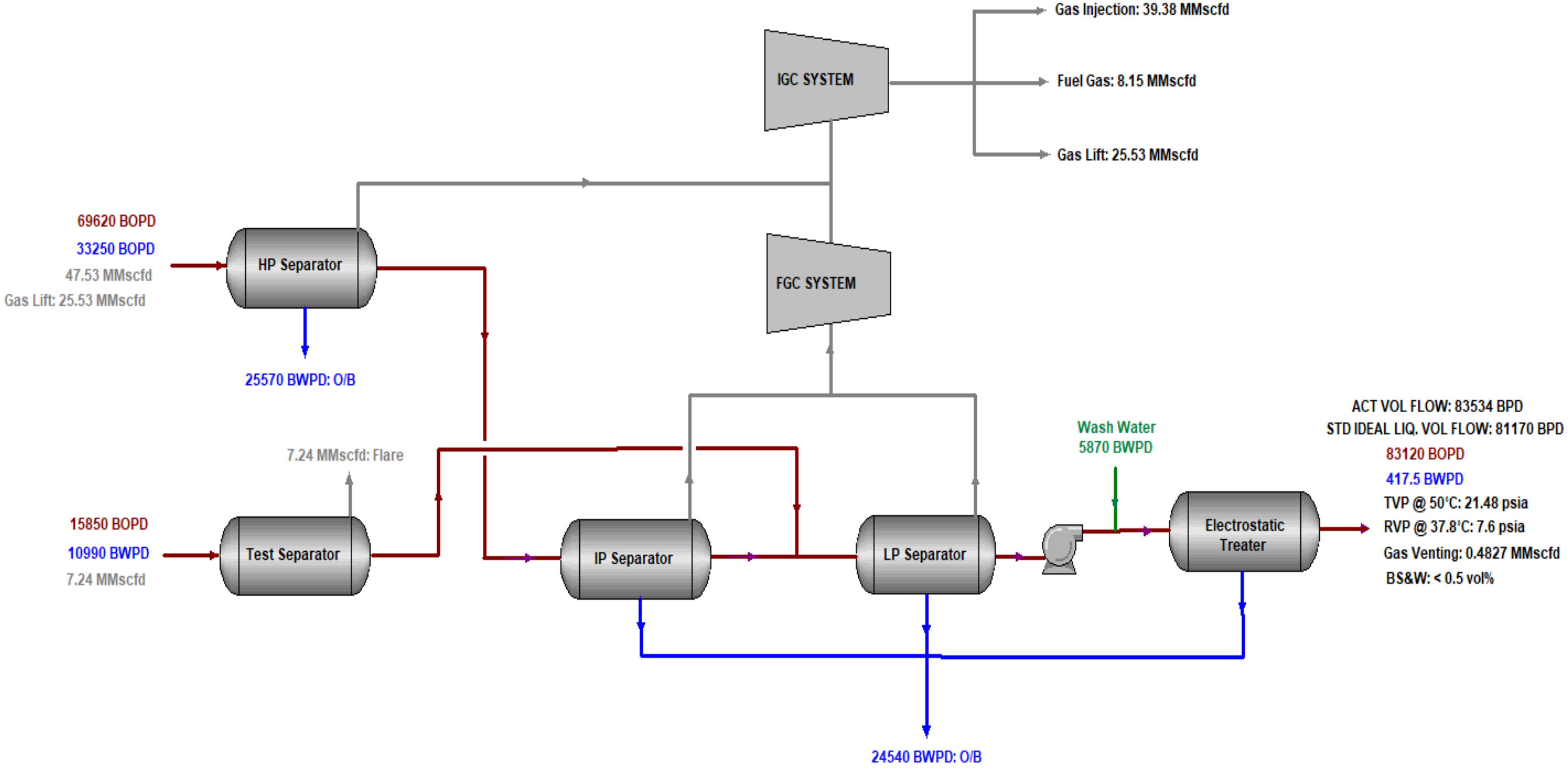

Figure 5.60: Process flow diagram with flow rates – Actual + Múcua (Case F configuration) simulation results

CHAPTER 6

CONCLUSION AND RECOMMENDATIONS

CHAPTER 6: CONCLUSION AND RECOMMENDATIONS

An entire process train evaluation for the new fluid blend with Múcua tie-in, as well as the new lower operating temperature for the test separator was conducted; and there was found not to be any concerns for the high pressure (HP) and test separators ability to handle the new blend cases (i.e., cases A to F) if the production fluids are treated by chemical injection for emulsion and low temperature issues. The gas flow rate at the intermediate pressure (IP) and low pressure (LP) separators were found to be greater than the original design for cases A, B, D and E. In terms of separator's performance, there was a high liquid carry-over in the gas stream of the separators and verifications of the IP and LP separators gas outlet's pressure control valve (PCV) leading to the HP/LP flare and flash gas compressor (FGC) system concluded that they are not adequate for the full gas flow rate of these cases as per the original design.

The suction coolers of the injection gas compressor (IGC) system showed no concern in terms of the exchanger's performance based on the simulated duty requirements even though the condensate flow rate for cases A, B and C at the IGC 2nd stage scrubber is slightly higher than the design flow rate. There was no concern for the compressor to handle the new fluid blend as the flow rate and the duties were found to be lower than the cases used for rating the compressors and turbines.

The FGC Train A was found unlikely to handle all the gas in cases A, B, D and E due to the relatively high pressure drop across the coolers. Once the FGC system is overwhelmed, it is expected to have a portion of the process gas being flared from the LP and IP separators, which is undesirable. The FGC Train B was found to be able to handle more gas than Train A, however detailed original manufacturer analysis is required to determine the suitability of each FGC train to accommodate blend cases A, B, D and E. Per the results of the simulations, the actual volumetric flow rates passing through the 1st stage FGC suction cooler for cases A, B, D and E is greater than the original design value and such was found to be a major bottleneck.

No concerns were found for the blowdown scenario and flare system, the gas dehydration, cooling medium, fuel gas, and seawater, as well as the produced water system, even though for some cases the overboard water temperature may be lower than 50°C.

The design heating load for the new fluid blend was found to be adequate for cases A, B, C and F. The overall heating medium duty requirement was exceeded for cases D and E. This is primarily due to the lower operating temperature of the HP separator requiring a greater heating load for the crude oil heater to heat the incoming fluids to the required operational temperature of 90°C and meet the temperature vapour pressure (TVP) specifications.

Case F was selected over case C as the governing case for the detailed study based on the operating parameters prior to the introduction of the new fluid blend. Based on the Aspen Tech HYSYS simulation results of the Múcua fluid tie-in under case F configurations and conditions, it was found that the heavy liquid (i.e., water) flow rate at the LP separator was greater than the original design. The impact to the line sizing was validated and it was found that the existing line size can handle the increased flow rate and is within the design limit, but pressure drop could be an issue. The water flow rate for the 2nd stage FGC scrubber was found to be above the original design. To address this bottleneck, the production flow rates would have to be monitored and increased gradually.

Therefore, for some flexibility in operation and as mitigations for the new fluid's addition, the following actions are proposed as recommendations:

- To upgrade the crude oil heaters from 100 to 128 plates to achieve the desired TVP specification, without needing to continuously vent 0.4827 MMscfd of gas flashing in the cargo tanks, as it would be flashed off in the IP/LP separator and result in the least amount of gases flashing in the cargo tanks.
- To increase the heating medium from the current temperature of 120 to 130°C.
- To send a gas warm stream from the IP separator to the flare header to keep the temperature of the flare main header above the freezing point for flaring from the test separator during low temperature (i.e., 5°C and below) and low pressures.
- Bypass the crude oil coolers since the dead oil is already cooled to 50°C in the crude/crude exchangers.
- To revise the subsea chemical injection requirements, such as hydrate inhibition, demulsification and wax inhibition in order to improve separation.
- To closely monitor the FGC 2nd stage scrubbers' liquid level and FGC system performance during start-up as the flow rates simulated are expected to pass the design for all the six cases.
- Closely monitor the Múcua fluids water cut and arrival temperatures since this research and all the recommendations are solely based on 0% water cut.
- To have the manufacturer of the FGC evaluate the maximum rated capacities as there is likely no further margin for its operation.

The study was performed for a standard ideal liquid volumetric flow rate of approximately 81 170 BOPD and considering 73.06 MMscfd of gas flowing at the HP separator gas outlet line. In summary, with the above mitigations in place there is not expected to be any major bottlenecks for start-up.

Computer aided design is an essential part of industrial practice. There are several world-renowned software tools of which Aspen HYSYS is one of them and its advantages are unquestionable particularly in the field of process outlet conditions for conventional oil and gas systems. However, there is still opportunity for development. With regard to the current study future investigation could be performed after the proposed changes are implemented so as to observe the real operating data against the data predicted for the governing case selected by means of simulations in order to have an exact account of the suitability of the simulation assumptions and parameters used, which should be adjusted, and the simulations run again if necessary.

CHAPTER 7

REFERENCES

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APPENDICES

APPENDIX A: PRODUCTION REPORT AND PROCESSING PARAMETERS

Table A.1: Production report and processing parameters

Vessel: [redacted] **Report Date: 29-Mar-20**

Production

Filename: NGA-2020-03-29.xls

Security Level Status: 1 Normal

Oil & Gas Production

Oil Uptime	24 hrs 00 min	100.0%	Gas Lift Uptime	24 hrs 00 min	100.0%
Oil Production Target	77,000 bbls	12,242 m³	Gas Injection Uptime	24 hrs 00 min	100.0%
Oil meter to storage, Gross	60,739 bbls	9,657 m³	Gas Produced	50.070 mmscf	1.4 MNm³
Oil meter to storage, NSV	60,545 bbls	9,626 m³	Gas Lift	25.410 mmscf	0.7 MNm³
Oil Import	0 bbls	0 m³	Gas Injected	20.650 mmscf	0.6 MNm³
Offspec Crude	0 bbls	0 m³	Gas Exported	0.000 mmscf	0.0 MNm³
Total onboard at 24:00hrs	863,753 bbls	137,325 m³	Gas Imported	0.000 mmscf	0.0 MNm³
Pigging Oil Volume	61,020 bbls	9,701 m³	Fuel Gas	8.230 mmscf	0.2 MNm³
GOR Calculated	827 scf/bbl		Gas Flared HP	16.850 mmscf	0.5 MNm³
Oil Shortfall	16,455 bbls	2,616 m³	Gas Flared LP	4.340 mmscf	0.1 MNm³
Oil Shortfall Responsibility	Client		Gas Flared Max. Allowable	1.500 mmscf	0.0 MNm³
			Excess Flaring Responsibility	OPS	

Water Injection

Water Injection Uptime	24 hrs 00 min	100.0%	Water Inj Pump A Uptime	24 hrs 00 min	100.0%
Water Injection Target	51,759 bbls	8,229 m³	Water Inj Pump B Uptime	24 hrs 00 min	100.0%
Water Injected	51,759 bbls	8,229 m³			
Water Injection Shortfall	0 bbls	0 m³			
WI Shortfall Responsibility					

Produced Water

Produced Water Overboard from Process	0 bbls	0 m³	Produced Water from process to slops	48,446 bbls	7,702 m³
Avg ppm OIW from Process to Sea	45.0 ppm	OCM			
Oil Volume to Sea	0.00 bbls	0 m³			
Discharge Overboard Temp	50 Temp °C				

APPENDIX B: HYSYS PROCESS SIMULATIONS SCREENSHOTS

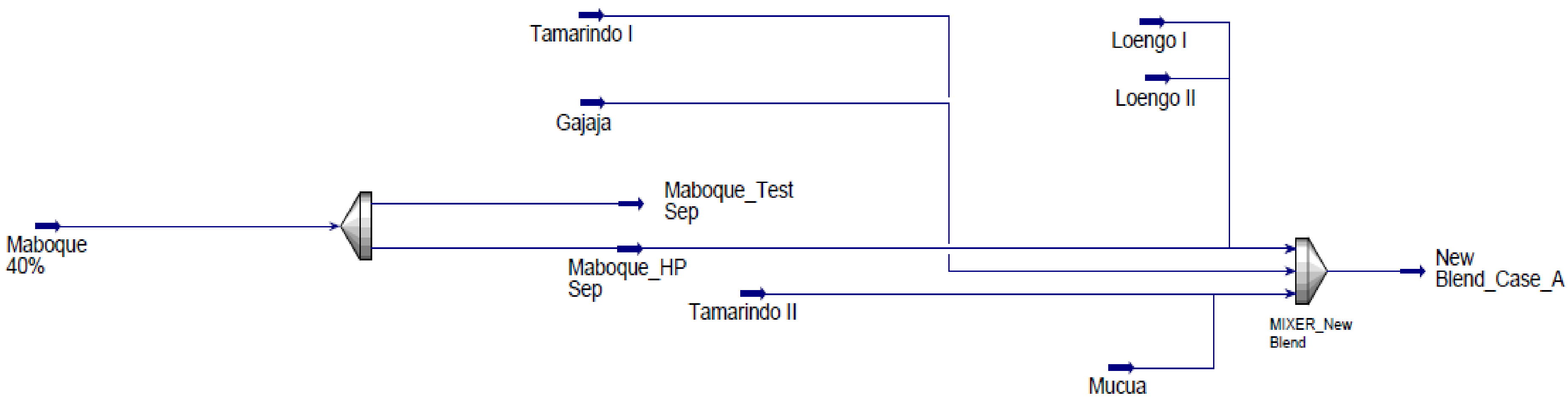


Figure B.1: Simulation's inlet streams (Cases A, C, D and F)

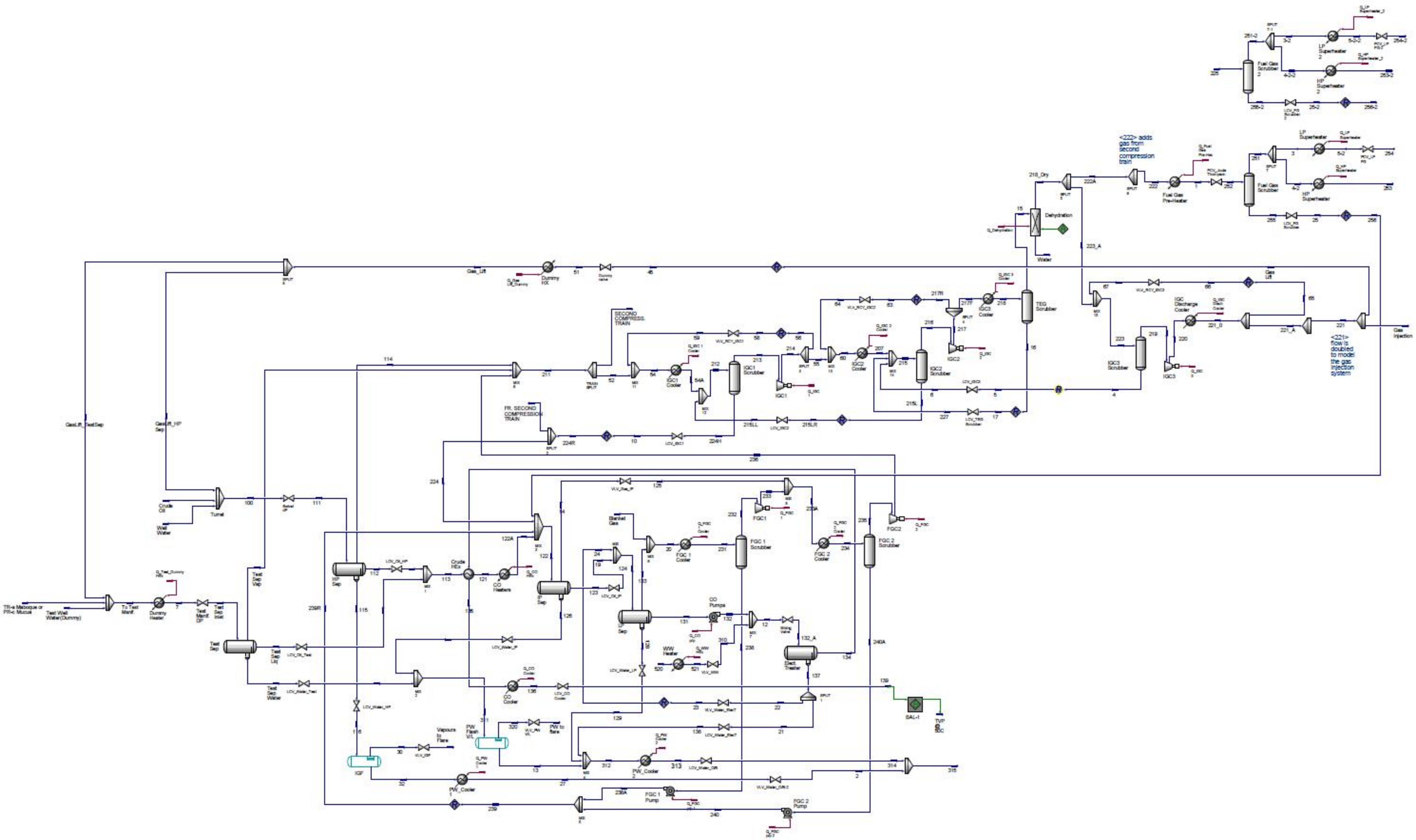


Figure B.2: Simulations (Cases A, C, D and F)

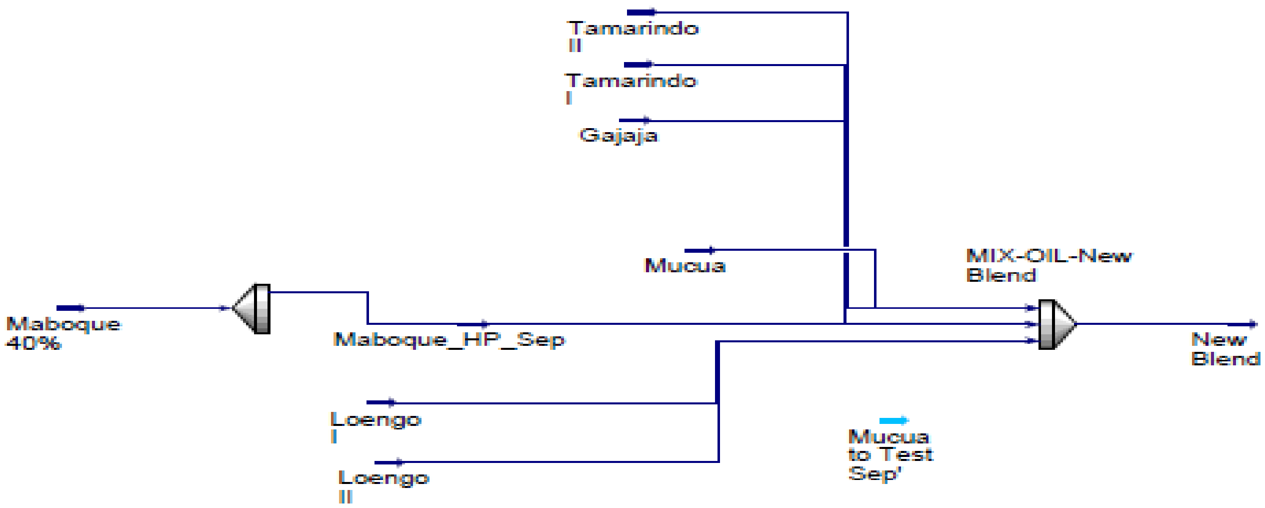


Figure B.3: Simulation's inlet streams (Cases B and E)

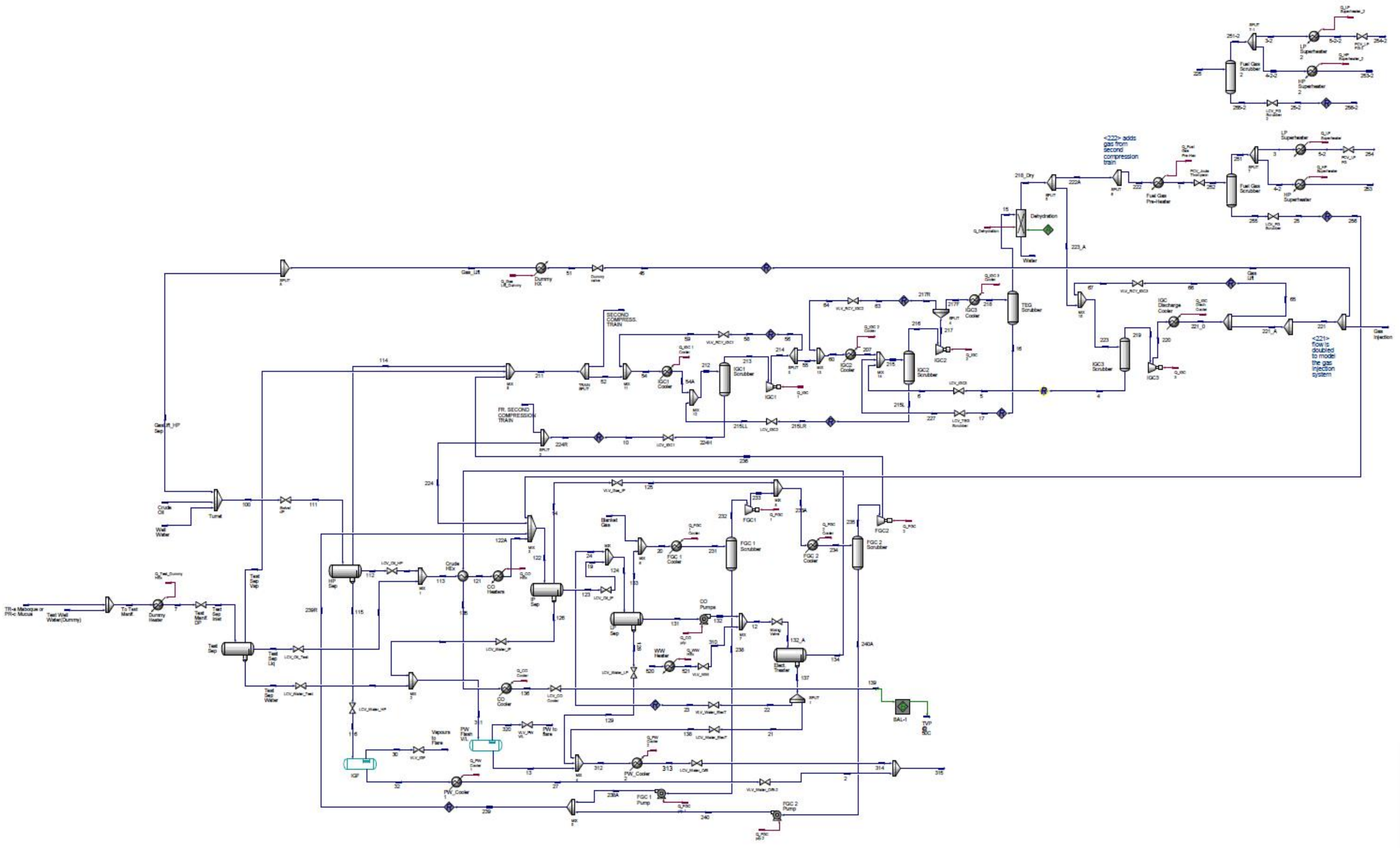


Figure B.4: Simulations (Cases B and E)

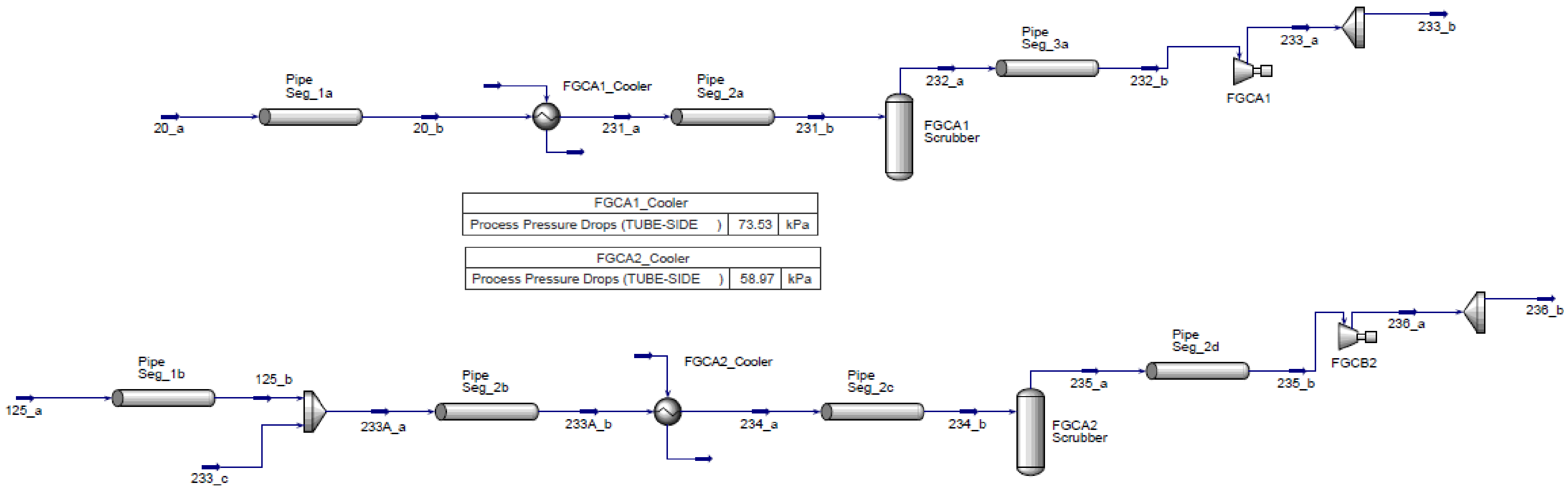


Figure B.5: Flash gas compressor's cooler pressure drop simulation's (Cases B and E)

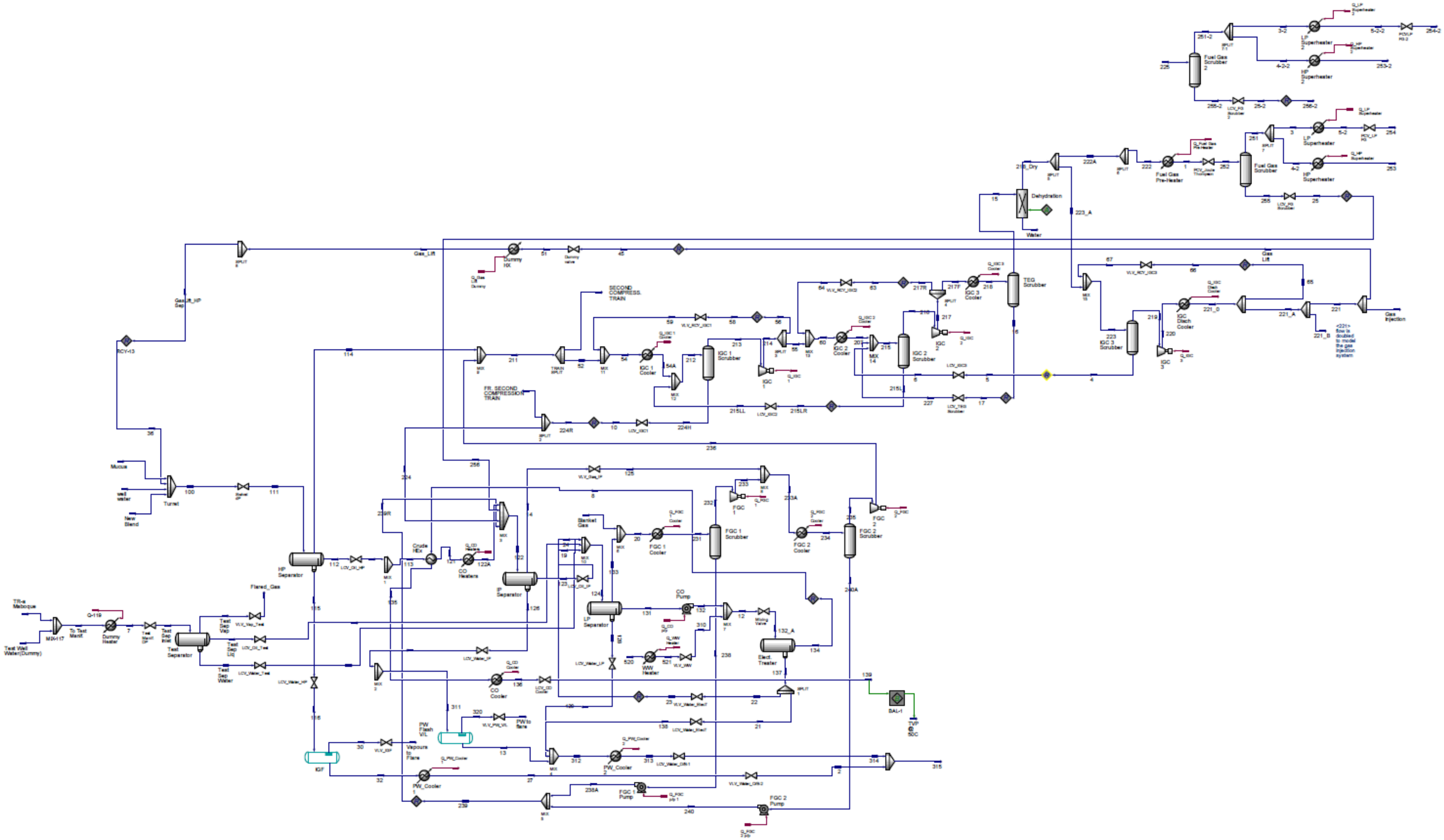


Figure B.6: Simulation (Case_F with Mucua tie-in)

APPENDIX C: MYSEP EVALUATION REPORTS

Table C.1: IGC 2nd stage scrubber MySEP evaluation

INPUT DATA				
	Units	Design_Case 1	Case_A	Case_C
Operating Conditions				
Operating Pressure	barg	52.70	57.00	57.00
Operating Temperature	°C	45.00	45.00	45.00
Gas				
Gas Flow Rate	MMSCFD	50	50	41
Gas Molecular Weight	kg/kmol	23.3	23.09	23.22
Gas Density	kg/m^3	55.4	62.19	63.08
Compressibility Factor	-	0.854	0.814	0.807
Gas Viscosity	cP	0.0140	0.0139	0.0139
Determine Gas Density By Gas Law?	no			
Hydrocarbon Liquid				
HC Liquid Flow Rate	BOPD	1401	409	463
HC Liquid Density	kg/m^3	506.00	543.72	530.44
HC Liquid Viscosity	cP	0.11	0.13	0.12
HC Liquid Surface Tension	dyne/cm	11.00	8.37	7.98
Aqueous Liquid				
Aqueous Liquid Flow Rate	BWPD	22.00	24.00	19.00
Aqueous Liquid Density	kg/m^3	994.00	994.00	994.10
Aqueous Liquid Viscosity	cP	0.60	0.59	0.59
Aqueous Liquid Surface Tension	dyne/cm	68.82	68.57	68.60

VESSEL DESIGN OVERVIEW					
	Units	Design_Case	Case_A	Case_C	Max
Mode	Design				
Vessel Orientation	Vertical				
Separation Type	2-Phase				
Vessel ID [mm]	1200				
Vessel Tan-Tan [mm]	2650				
Head Type	Elliptical				
Body Flange	No				
Gas Side Summary					
Vessel K-Value	m/s	0.090	0.081	0.067	0.090
Gas Velocity	m/s	0.257	0.227	0.183	0.257
Inlet Section	mbar	12.00	10.00	7.00	12.00
Distribution Baffles	mbar	0.00	0.00	0.00	0.00
Mesh Agglomerator	mbar	1.00	1.00	1.00	1.00
Cyclones	mbar	44.00	40.00	28.00	44.00
Demisting # [none]	mbar	0.00	0.00	0.00	0.00
Gas Outlet Nozzle	mbar	5.00	4.00	3.00	5.00
Total	mbar	62.00	55.00	38.00	62.00
Gas Outlet d100	micron	23.00	24.00	27.00	27.00
Total Carryover	m3/hr	0.002	0.000	0.000	0.002
	USG/MMSCF	0.19	0.05	0.02	0.19
Vessel Separation Efficiency	%	99.98	99.99	100.00	100.00

Table C.1 (continued): IGC 2nd stage scrubber MySEP evaluation

INLET PIPING AND NOZZLES					
	Min. ID [mm]	N.B. [inch]	Actual I.D. [mm]		
Inlet Piping	-	10.000	215.800		
Nozzles					
Inlet	174.32	10.00	243.00		
Gas Outlet	170.48	10.00	243.00		
Liquid Outlet	40.83	2.00	51.00		
Inlet Piping					
	Units	Design_Case	Case_A	Case_C	Max
Max Droplet Size [Predicted]	micron	596.00	471.00	596.00	596.00
Mist Fraction [Predicted]	%	22.140	13.730	6.390	22.140
Mist Flow Rate	m^3/hr	2.087	0.394	0.204	2.087
Nozzles					
Inlet Velocity	m/s	6.33	5.55	4.48	6.33
Inlet Momentum	kg/ms^2	2383	1961	1307	2383
Gas Outlet Velocity	m/s	6.27	5.53	4.46	6.27
Gas Outlet Momentum	kg/ms^2	2180	1901	1254	2180
Liquid Outlet Velocity	m/s	1.28	0.39	0.43	1.28

LIQUID-LIQUID SECTION					
	Units	Design_Case	Case_A	Case_C	Max
Setpoints and Residence Time					
Level	Setpoint [mm]	Time [min]			Volume [m^3]
HHLL	800	0.72	2.36	2.13	0.11
HLL	700	1.44	4.73	4.25	0.23
NLL	500	1.44	4.73	4.25	0.23
LLL	300	0.54	1.77	1.59	0.08
LLLL	225	1.62	5.32	4.78	0.25
Degassing					
Length	mm	800	800	800	-
Liquid Velocity	m/s	0.002	0.001	0.001	0.002
Mixture Degassing d100	micron	35.00	20.00	21.00	35.00

Table C.1 (continued): IGC 2nd stage scrubber MySEP evaluation

GAS-LIQUID SECTION					
	Units	Design_Case	Case_A	Case_C	Max
Inlet Device					
Type	Vane Pack				
Length [mm]	850				
Removal d100 (predicted)	micron	0.00	0.00	0.00	0.00
Mist Sep. Effic. (Predicted)	%	0.00	0.00	0.00	0.00
Carryover Rate	m^3/h	2.09	0.39	0.20	2.09
Section Efficiency	%	77.86	86.27	93.61	93.61
Gravity Separation Section					
Design Liquid Level [mm]	800				
Vessel K-Value	m/s	0.090	0.081	0.067	0.090
Removal d100 (predicted)	micron	0.000	0.000	0.000	0.000
Sep. Effic. (Predicted)	%	0.000	0.000	0.000	0.000
Carryover Rate	m^3/h	2.087	0.394	0.204	2.087
Section Efficiency	%	0.00	0.00	0.00	0.00
Agglomerator					
Type	Mesh				
Device Orientation	Horizontal				
Agglomerator Area [m^2]	0.97				
Diameter [mm]	1200				
Thickness [mm]	100				
Drainage Through Area [%]	14				
K-Value	m/s	0.105	0.095	0.078	0.105
Gas Velocity	m/s	0.299	0.264	0.213	0.299
Sep. Effic. (Predicted)	%	99.930	99.900	99.930	99.930
Carryover Rate	m^3/h	0.002	0.000	0.000	0.002
Device Efficiency	%	99.93	99.90	99.93	99.93
Demisting Device # 1					
Type	Cyclones				
Deck Orientation	Horizontal				
Number of Cyclones	13.00				
Assembly Length [mm]	500				
Cyclone Diameter [mm]	85				
Swirl Angle [°]	40				
Swirl Inside Diameter [mm]	43				
Separation Length [mm]	167				
Gas Flow / Cyclone	m^3/h	80.568	70.997	57.267	80.568
Liquid Flow / Cyclone	m^3/h	0.000	0.000	0.000	0.000
Gas ρv^2	kg/m^2	862.000	751.000	496.000	862.000
Removal d100 (predicted)	micron	69.000	71.000	80.000	80.000
Sep. Effic. (Predicted)	%	2.830	2.780	2.840	2.840
Carryover Rate	m^3/h	0.002	0.000	0.000	0.002
Device Efficiency	%	2.83	2.78	2.84	2.84

Table C.2: IP separator MySEP evaluation

INPUT DATA							
	Units	Design_Case	Case_A	Case_B	Case_D	Case_E	Case_F
Operating Conditions							
Operating Pressure	barg	7.00	7.00	7.00	7.00	7.00	7.00
Operating Temperature	°C	90.00	88.71	88.69	88.73	88.73	89.01
Gas							
Gas Flow Rate	MMSCFD	8	9	9	10	10	8
Gas Molecular Weight	kg/kmol	36.4	32.94	32.66	33.48	33.24	33.52
Gas Density	kg/m^3	10	9.11	9.03	9.27	9.21	9.29
Compressibility Factor	-	0.966	0.963	0.963	0.962	0.962	0.961
Gas Viscosity	cP	0.0120	0.0125	0.0123	0.0123	0.0122	0.012
Determine Gas Density By Gas Law?	no						
Hydrocarbon Liquid							
HC Liquid Flow Rate	BOPD	1109092	111381	111399	111745	111741	89353
HC Liquid Density	kg/m^3	822.10	794.10	793.98	793.40	793.30	787.61
HC Liquid Viscosity	cP	6.30	2.22	2.22	2.19	2.19	1.95
HC Liquid Surface Tension	dyne/cm	19.00	18.05	18.05	17.95	17.96	17.89
Aqueous Liquid							
Aqueous Liquid Flow Rate	BWPD	302.00	10218.00	10177.00	10323.00	10273.00	10177.00
Aqueous Liquid Density	kg/m^3	1061.00	957.57	957.62	957.60	957.60	957.40
Aqueous Liquid Viscosity	cP	0.40	0.32	0.32	0.32	0.32	0.31
Aqueous Liquid Surface Tension	dyne/cm	64.00	60.71	60.73	60.76	60.72	60.67

VESSEL DESIGN OVERVIEW								
	Units	Design_Case	Case_A	Case_B	Case_D	Case_E	Case_F	Max
Mode	Design							
Vessel Orientation	Horizontal							
Separation Type	3-Phase							
Vessel ID [mm]	3600							
Vessel Tan-Tan [mm]	10000							
Weir	Yes							
Split Flow	No							
Weit to Downstream Tan Distance [mm]	1000							
Boot	No							
Gas Side Summary								
Vessel K-Value	m/s	0.018	0.020	0.020	0.024	0.024	0.019	0.024
Gas Velocity	m/s	0.164	0.187	0.191	0.218	0.221	0.171	0.221
Inlet Section	mbar	35.00	43.00	43.00	48.00	49.00	31.00	49.00
Distribution Baffles	mbar	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Agglomerator [None]	mbar	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Vane Pack	mbar	6.00	7.00	8.00	10.00	10.00	6.00	10.00
Demisting #2 [None]	mbar	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas Outlet Nozzle	mbar	3.00	4.00	4.00	5.00	5.00	3.00	5.00
Total	mbar	44.00	53.00	54.00	63.00	64.00	40.00	64.00
Gas Outlet d100	micron	32.00	36.00	36.00	40.00	40.00	34.00	40.00
Total Carryover	m^3/hr	0.016	0.035	0.038	0.065	0.068	0.027	0.068
	USG/MMSCF	13.75	25.87	27.18	40.75	41.85	21.56	41.85
Vessel Separation Efficiency	%	100.00	100.00	100.00	99.99	99.99	100.00	100.00
Liquid Side Summary								
Oil Residence Time	min	3.180	3.150	3.150	3.140	3.140	3.920	3.920
Water Removal d100	micron	170.000	123.000	123.000	122.000	122.000	101.000	170.000
Water Residence Time	min	565.92	16.72	16.79	16.55	16.63	16.79	565.92
Oil Removal d100	micron	3.00	20.00	20.00	20.00	20.00	19.00	20.00

Table C.2 (continued): IP separator MySEP evaluation

INLET PIPING AND NOZZLES			
	Min. ID [mm]	N.B. [inch]	Actual I.D. [mm]
Inlet Piping	-	14.000	333.340
Nozzles			
Inlet	396.17	16.00	396.40
Gas Outlet	144.26	8.00	203.20
Oil Outlet	361.81	16.00	337.00
Water Outlet	109.97	6.00	152.40

Inlet Piping	Units	Design_Case	Case_A	Case_B	Case_D	Case_E	Case_F	Max
Max Droplet Size [Predicted]	micron	1984.00	1699.00	1664.00	1405.00	1384.00	1885.00	1984.00
Mist Fraction [Predicted]	%	0.140	0.220	0.240	0.490	0.520	0.150	0.520
Mist Flow Rate	m^3/hr	1.015	1.795	1.931	3.944	4.169	0.967	4.169
Nozzles								
Inlet Velocity	m/s	4.72	5.32	5.38	5.90	5.96	4.68	5.96
Inlet Momentum	kg/ms^2	6539	7959	8058	8899	8979	5733	8979
Gas Outlet Velocity	m/s	11.70	13.34	13.59	15.54	15.76	12.17	15.76
Gas Outlet Momentum	kg/ms^2	1370	1621	1669	2240	2286	1376	2286
Oil Outlet Velocity	m/s	2.27	2.30	2.30	2.31	2.31	1.84	2.31
Water Outlet Velocity	m/s	0.03	1.03	1.03	1.04	1.04	1.03	1.04

LIQUID-LIQUID SECTION	Units	Design_Case	Case_A	Case_B	Case_D	Case_E	Case_F	Max
Setpoints and Residence Time								
Level	Setpoint [mm]	Time [min]						Volume [m^3]
HHLL	2600	0.87	0.86	0.86	0.86	0.86	1.07	10.60
HLL	2320	0.89	0.88	0.88	0.87	0.87	1.09	10.79
NLL	2050	0.88	0.87	0.87	0.86	0.86	1.08	10.65
LLL	1790	0.88	0.86	0.86	0.86	0.86	1.08	10.64
LLLL	1530	0.90	0.89	0.89	0.89	0.89	1.11	10.95
Top of Weir	1400	345.65	10.21	10.25	10.11	10.16	10.25	11.52
HIL	1050	138.56	4.09	4.11	4.05	4.07	4.11	4.62
NIL	900	172.01	5.08	5.10	5.03	5.05	5.10	5.73
LIL	700	116.92	3.45	3.47	3.42	3.44	3.47	3.90
LLIL	550	276.99	8.18	8.22	8.10	8.14	8.22	9.23
Degassing								
Length	mm	3151	3151	3151	3151.000	3151.000	3151.000	3151.000
Oil Degassing d100	micron	92.000	56.000	56.000	56.000	56.000	47.000	92.000
Water Degasing d100	micron	2.00	8.00	8.00	8.00	8.00	8.00	8.00
Liquid -Liquid Separation								
Design Oil-Water Level [mm]	900							
Separation Length Oil Layer [mm]	3540							
Separation Length Water Layer [mm]	3151							
Plate Pack Coalescer	Yes							
Plate Spacing [mm]	10							
Plate Angle [°]	45							
Plate Length [mm]	1220							
Top Elevation [mm]	2600							
Open Area [%]	100							
Oil Residence Time	min	3.18	3.15	3.15	3.14	3.14	3.92	3.92
Oil Velocity	m/s	0.051	0.051	0.051	0.051	0.051	0.041	0.051
Water Removal d100	micron	170.00	123.00	123.00	122.00	122.00	101.00	170.00
Oil Reynolds Number	-	132.00	367.00	367.00	373.00	373.00	333.00	373.00
Water Residence Time	min	565.92	16.72	16.79	16.55	16.63	16.79	565.92
Water Velocity	m/s	0.000	0.009	0.009	0.010	0.009	0.009	0.010
Oil Removal d100	micron	3.00	20.00	20.00	20.00	20.00	19.00	20.00
Water Reynolds Number	-	15.00	573.00	570.00	579.00	576.00	572.00	579.00

Table C.2 (continued): IP separator MySEP evaluation

GAS-LIQUID SECTION								
	Units	Design_Case	Case_A	Case_B	Case_D	Case_E	Case_F	Max
Inlet Device								
Type	Inlet Cyclones							
Number of Tubes	2							
Tube ID [mm]	450							
Vortex Finder ID [mm]	318							
Swirl Angle [°]	45							
Separation Length [mm]	225							
Assembly Length [mm]	950							
Bottom Elevation [mm]	765							
Removal d100 [Predicted]	micron	157	153	150	140.0	139.0	157.0	157.0
Mist Sep. Effic. [Predicted]	%	98.75	98.22	98.21	97.65	97.61	98.55	98.75
Section Sep. Effic. [User Defined]	%	99.00	99.00	99.00	99.00	99.00	98.55	99.00
Carryover Rate	m^3/hr	7.31	8.06	8.05	8.09	8.08	9.56	9.56
Section Efficiency	%	99.00	99.00	99.00	99.00	99.00	98.55	99.00
Gravity Separation Section								
Design Liquid Level [mm]	2600							
Gas-Liquid Separation Length [mm]	5000							
Vapour Space Height [mm]	1000							
Vessel K-Value	m/s	0.018	0.020	0.020	0.024	0.024	0.019	0.024
Removal d100 [Predicted]	micron	32.000	36.000	36.000	39.000	39.000	33.000	39.000
Sep. Efficiency [Predicted]	%	99.70	99.34	99.28	98.51	98.41	99.61	99.70
Carryover Rate	m^3/hr	0.022	0.053	0.058	0.121	0.129	0.038	0.129
Section Efficiency	%	99.70	99.34	99.28	98.51	98.41	99.61	99.70
Demisting Device # 1								
Type	Vane Pack							
Deck Orientation	Vertical							
Max Allowable K-Value [m/s]	0.208							
Vane Pack Area [m^2]	0.152							
Bottom Elevation [mm]	3265							
Assembly Length [mm]	750							
Vane Spacing [mm]	20							
Bend Angle [°]	60							
K-Value	m/s	0.277	0.307	0.311	0.361	0.364	0.284	0.364
Gas Velocity	m/s	2.497	2.846	2.900	3.316	3.362	2.597	3.362
Gas ρv^2	kg/m^2	62.00	74.00	76.00	102.00	104.00	63.00	104.00
Removal d100 [Predicted]	micron	46.00	44.00	44.00	41.00	40.00	46.00	46.00
Sep. Efficiency [Predicted]	%	26.37	33.94	35.28	46.23	47.56	28.36	47.56
Carryover Rate	m^3/hr	0.016	0.035	0.038	0.065	0.068	0.027	0.068
Device Efficiency	%	26.37	33.94	35.28	46.23	47.56	28.36	47.56

Table C.3: LP separator MySEP evaluation

INPUT DATA							
	Units	Design_Case 1	Design_Case 2	Case_A	Case_B	Case_D	Case_E
Operating Conditions							
Operating Pressure	barg	1.00	1.00	1.00	1.00	1.00	1.00
Operating Temperature	°C	82.00	85.00	82.53	82.50	82.24	82.24
Gas							
Gas Flow Rate	MMSCFD	7	5	8	8	9	9
Gas Molecular Weight	kg/kmol	44.51	42.11	45.51	45.46	45.81	45.76
Gas Density	kg/m^3	3.1	2.9	3.17	3.16	3.19	3.19
Compressibility Factor	-	0.979	0.982	0.979	0.978	0.978	0.978
Gas Viscosity	cP	0.0100	0.01	0.0098	0.0120	0.0098	0.0098
Determine Gas Density By Gas Law?	no						
Hydrocarbon Liquid							
HC Liquid Flow Rate	BOPD	106016	105820	106334	106334	106409	106406
HC Liquid Density	kg/m^3	834.70	828.89	807.90	807.90	807.88	807.87
HC Liquid Viscosity	cP	7.40	6.90	3.02	3.02	3.02	3.02
HC Liquid Surface Tension	dyne/cm	21.30	20.70	20.08	20.08	20.07	20.07
Aqueous Liquid							
Aqueous Liquid Flow Rate	BWPD	10416.00	15938.00	15977.00	15978.00	15982.00	15982.00
Aqueous Liquid Density	kg/m^3	1065.20	1065.20	962.44	962.45	962.66	962.66
Aqueous Liquid Viscosity	cP	0.40	0.40	0.34	0.34	0.34	0.34
Aqueous Liquid Surface Tension	dyne/cm	66.00	66.00	61.87	61.88	61.93	61.92

VESSEL DESIGN OVERVIEW								
	Units	Design_Case 1	Design_Case 2	Case_A	Case_B	Case_D	Case_E	Max
Mode	Design							
Vessel Orientation	Horizontal							
Separation Type	3-Phase							
Vessel ID [mm]	3600							
Vessel Tan-Tan [mm]	12000							
Head Type	Elliptical							
Weir	Yes							
Split Flow	No							
Weit to Downstream Tan Distance [mm]	1500							
Boot	No							
Gas Side Summary								
Vessel K-Value	m/s	0.036	0.027	0.045	0.045	0.047	0.047	0.047
Gas Velocity	m/s	0.593	0.460	0.711	0.711	0.745	0.743	0.745
Inlet Section	mbar	3.00	3.00	4.00	4.00	4.00	4.00	4.00
Distribution Baffles	mbar	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Agglomerator [None]	mbar	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Vane Pack	mbar	6.00	4.00	9.00	9.00	10.00	10.00	10.00
Demisting #2 [None]	mbar	0.00	0.00	0.00	0.00	0.00	0.00	
Gas Outlet Nozzle	mbar	2.00	1.00	1.00	1.00	3.00	3.00	3.00
Total	mbar	11.00	7.00	16.00	16.00	17.00	17.00	17.00
Gas Outlet d100	micron	31.00	35.00	28.00	31.00	27.00	28.00	35.00
Total Carryover	m^3/hr	0.001	0.000	0.004	0.005	0.005	0.005	0.005
	USG/MMSCF	0.62	0.09	2.81	4.08	3.94	3.85	4.08
Vessel Separation Efficiency	%	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Liquid Side Summary								
Oil Residence Time	min	3.990	4.000	3.980	3.980	3.970	3.970	4.000
Water Removal d100	micron	198.000	189.000	156.000	156.000	156.000	156.000	198.000
Water Residence Time	min	19.00	12.42	12.39	12.39	12.38	12.38	19.00
Oil Removal d100	micron	21.00	26.00	29.00	29.00	29.00	29.00	29.00

Table C.3 (continued): LP separator MySEP evaluation

INLET PIPING AND NOZZLES								
	Min. ID [mm]	N.B. [inch]	Actual I.D. [mm]					
Inlet Piping	-	18.000	434.740					
Nozzles								
Inlet	881.97	36.00	914.40					
Gas Outlet	203	14.00	337.00					
Oil Outlet	353.06	14.00	337.00					
Water Outlet	136.83	6.00	154.00					
Inlet Piping								
	Units	Design_Case 1	Design_Case 2	Case_A	Case_B	Case_D	Case_E	Max
Max Droplet Size [Predicted]	micron	1206.00	1631.00	944.00	944.00	891.00	894.00	1631.00
Mist Fraction [Predicted]	%	0.480	0.140	1.200	1.200	1.540	1.520	1.540
Mist Flow Rate	m^3/hr	3.701	1.168	9.759	9.740	12.476	12.303	12.476
Nozzles								
Inlet Velocity	m/s	2.41	1.96	2.84	2.84	2.96	2.95	2.96
Inlet Momentum	kg/ms^2	688	584	829	829	866	864	866
Gas Outlet Velocity	m/s	15.33	11.91	18.40	18.40	19.27	19.23	19.27
Gas Outlet Momentum	kg/ms^2	729	411	1072	1071	1185	1178	1185
Oil Outlet Velocity	m/s	2.19	2.18	2.19	2.19	2.20	2.20	2.20
Water Outlet Velocity	m/s	1.03	1.57	1.58	1.58	1.58	1.58	1.58

LIQUID-LIQUID SECTION								
	Units	Design_Case 1	Design_Case 2	Case_A	Case_B	Case_D	Case_E	Max
Setpoints and Residence Time								
Level	Setpoint [mm]	Time [min]						Volume [m^3]
HHLL	2600	0.95	0.95	0.94	0.94	0.94	0.94	11.09
HLL	2350	1.00	1.00	1.00	1.00	0.99	0.99	11.68
NLL	2100	0.92	0.92	0.92	0.92	0.92	0.92	10.79
LLL	1875	0.93	0.93	0.92	0.92	0.92	0.92	10.85
LLLL	1650	1.66	1.66	1.66	1.66	1.66	1.66	19.45
Top of Weir	1400	11.57	7.56	7.55	7.54	7.54	7.54	13.31
HIL	1050	4.64	3.03	3.03	3.03	3.03	3.03	5.34
NIL	900	5.77	3.77	3.76	3.76	3.76	3.76	6.63
LIL	700	3.92	2.56	2.56	2.56	2.56	2.56	4.51
LLIL	550	9.31	6.09	6.07	6.07	6.07	6.07	10.71
Degassing								
Length	mm	7391	7391	7391	7391.000	7391.000	7391.000	7391.000
Oil Degassing d100	micron	104.000	101.000	68.000	68.000	68.000	68.000	104.000
Water Degasing d100	micron	10.00	12.00	12.00	12.00	12.00	12.00	12.00
Liquid -Liquid Separation								
Design Oil-Water Level [mm]	900							
Separation Length Oil Layer [mm]	7391							
Separation Length Water Layer [mm]	7391							
Plate Pack Coalescer	Yes							
Plate Spacing [mm]	10							
Plate Angle [°]	45							
Plate Length [mm]	1000							
Top Elevation [mm]	2600							
Open Area [%]	100							
Oil Residence Time	min	3.99	4.00	3.98	3.98	3.97	3.97	4.00
Oil Velocity	m/s	0.047	0.047	0.047	0.047	0.047	0.047	0.047
Water Removal d100	micron	198.00	189.00	156.00	156.00	156.00	156.00	198.00
Oil Reynolds Number	-	105.00	112.00	251.00	251.00	251.00	251.00	251.00
Water Residence Time	min	19.00	12.42	12.39	12.39	12.38	12.38	19.00
Water Velocity	m/s	0.010	0.015	0.015	0.015	0.015	0.015	0.015
Oil Removal d100	micron	21.00	26.00	29.00	29.00	29.00	29.00	29.00
Water Reynolds Number	-	513.00	785.00	836.00	836.00	834.00	834.00	836.00

Table C.3 (continued): LP separator MySEP evaluation

GAS-LIQUID SECTION								
	Units	Design_Case 1	Design_Case 2	Case_A	Case_B	Case_D	Case_E	Max
Inlet Device								
Type	None							
Removal d100 [Predicted]	micron	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mist Sep. Effic. [Predicted]	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Carryover Rate	m^3/hr	3.70	1.17	9.76	9.74	12.48	12.30	12.48
Section Efficiency	%	99.52	99.86	98.80	98.80	98.46	98.48	99.86
Gravity Separation Section								
Design Liquid Level [mm]	2600							
Gas-Liquid Separation Length [mm]	8217							
Vapour Space Height [mm]	1000							
Vessel K-Value	m/s	0.036	0.027	0.045	0.045	0.047	0.047	0.047
Removal d100 [Predicted]	micron	43.000	37.000	49.000	54.000	50.000	50.000	54.000
Sep. Efficiency [Predicted]	%	99.91	99.98	99.68	99.57	99.58	99.59	99.98
Carryover Rate	m^3/hr	0.003	0.000	0.031	0.042	0.052	0.051	0.052
Section Efficiency	%	99.91	99.98	99.68	99.57	99.58	99.59	99.98
Demisting Device # 1								
Type	Vane Pack							
Deck Orientation	Vertical							
Max Allowable K-Value [m/s]	0.212							
Vane Pack Area [m^2]	0.3							
Bottom Elevation [mm]	3217							
Assembly Length [mm]	250							
Vane Spacing [mm]	20							
Bend Angle [°]	60							
K-Value	m/s	0.278	0.210	0.343	0.343	0.361	0.360	0.361
Gas Velocity	m/s	4.559	3.541	5.471	5.470	5.730	5.716	5.730
Gas ρv^2	kg/m^2	64.00	36.00	95.00	95.00	105.00	104.00	105.00
Removal d100 [Predicted]	micron	31.00	35.00	28.00	31.00	27.00	28.00	35.00
Sep. Efficiency [Predicted]	%	80.44	58.36	88.35	87.43	89.76	89.71	89.76
Carryover Rate	m^3/hr	0.001	0.000	0.004	0.005	0.005	0.005	0.005
Device Efficiency	%	80.44	58.36	88.35	87.43	89.76	89.71	89.76

Table C.4: Test separator MySEP evaluation

INPUT DATA				
	Units	Design_Case 1	Case_C	Case_F
Operating Conditions				
Operating Pressure	barg	19.00	7.00	7.00
Operating Temperature	°C	62.00	5.00	5.00
Gas				
Gas Flow Rate	MMSCFD	29	18	18
Gas Molecular Weight	kg/kmol	21.1	20.84	20.82
Gas Density	kg/m^3	15.9	7.46	7.45
Compressibility Factor	-	0.953	0.969	0.969
Gas Viscosity	cP	0.0130	0.01	0.01
Determine Gas Density By Gas Law?	no			
Hydrocarbon Liquid				
HC Liquid Flow Rate	BOPD	26097	20356	20342
HC Liquid Density	kg/m^3	859.70	882.70	882.88
HC Liquid Viscosity	cP	24.00	17.95	18.03
HC Liquid Surface Tension	dyne/cm	22.00	23.97	23.99
Aqueous Liquid				
Aqueous Liquid Flow Rate	BWPD	0.00	13345.00	13345.00
Aqueous Liquid Density	kg/m^3	1028.00	1023.00	1022.59
Aqueous Liquid Viscosity	cP	0.50	1.50	1.50
Aqueous Liquid Surface Tension	dyne/cm	68.10	75.51	75.51

VESSEL DESIGN OVERVIEW					
	Units	Design_Case 1	Case_C	Case_F	Max
Mode	Design				
Vessel Orientation	Horizontal				
Separation Type	3-Phase				
Vessel ID [mm]	3600				
Vessel Tan-Tan [mm]	6000				
Head Type	Elliptical				
Weir	Yes				
Split Flow	No				
Weit to Downstream Tan Distance [mm]	1000				
Boot	No				
Gas Side Summary					
Vessel K-Value	m/s	0.038	0.033	0.033	0.038
Gas Velocity	m/s	0.277	0.355	0.355	0.355
Inlet Section	mbar	2.00	4.00	4.00	4.00
Distribution Baffles	mbar	0.00	0.00	0.00	0.00
Agglomerator [None]	mbar	0.00	0.00	0.00	0.00
Vane Pack	mbar	2.00	1.00	1.00	2.00
Demisting #2 [None]	mbar	0.00	0.00	0.00	0.00
Gas Outlet Nozzle	mbar	1.00	0.00	0.00	1.00
Total	mbar	4.00	5.00	5.00	5.00
Gas Outlet d100	micron	53.00	51.00	51.00	53.00
Total Carryover	m^3/hr	0.000	0.000	0.000	0.000
	USG/MMSCF	0.00	0.00	0.00	0.00
Vessel Separation Efficiency	%	100.00	100.00	100.00	100.00
Liquid Side Summary					
Oil Residence Time	min	4.110	5.270	5.270	5.270
Water Removal d100	micron	1568.000	1307.000	1312.000	1568.000
Water Residence Time	min	0.00	4.58	4.58	4.58
Oil Removal d100	micron	0.00	495.00	495.00	495.00

Table C.4 (continued): Test separator MySEP evaluation

INLET PIPING AND NOZZLES					
	Min. ID [mm]	N.B. [inch]	Actual I.D. [mm]		
Inlet Piping	-	24.000	590.000		
Nozzles					
Inlet	525.62	24.00	570.00		
Gas Outlet	168.8	16.00	406.40		
Oil Outlet	174.85	6.00	154.18		
Water Outlet	125.03	6.00	152.40		
Inlet Piping					
	Units	Design_Case 1	Case_C	Case_F	Max
Max Droplet Size [Predicted]	micron	2000.00	2000.00	2000.00	2000.00
Mist Fraction [Predicted]	%	0.010	0.010	0.010	0.010
Mist Flow Rate	m^3/hr	0.014	0.016	0.017	0.017
Nozzles					
Inlet Velocity	m/s	2.27	2.91	2.92	2.92
Inlet Momentum	kg/ms^2	443	722	723	723
Gas Outlet Velocity	m/s	4.10	5.25	5.26	5.26
Gas Outlet Momentum	kg/ms^2	268	206	206	268
Oil Outlet Velocity	m/s	2.57	2.01	2.00	2.57
Water Outlet Velocity	m/s	0.00	1.35	1.35	1.35

LIQUID-LIQUID SECTION					
	Units	Design_Case 1	Case_C	Case_F	Max
Setpoints and Residence Time					
Level	Setpoint [mm]	Time [min]			Volume [m^3]
HHLL	2050	1.41	1.81	1.81	4.07
HLL	1850	2.96	3.80	3.80	8.53
NLL	1450	1.48	1.90	1.90	4.28
LLL	1250	0.89	1.14	1.14	2.56
LLLL	1050	1.11	1.42	1.43	3.20
Top of Weir	1150	0.00	2.68	2.68	3.95
HIL	900	0.00	1.99	1.99	2.93
NIL	700	0.00	1.78	1.78	2.62
LIL	500	0.00	1.15	1.15	1.70
LLIL	350	0.00	1.66	1.66	2.44
Degassing					
Length	mm	1525	1525	1525	1525.000
Oil Degassing d100	micron	793.000	592.000	593.000	793.000
Water Degasing d100	micron	0.00	171.00	171.00	171.00
Liquid -Liquid Separation					
Design Oil-Water Level [mm]	700				
Separation Length Oil Layer [mm]	2004				
Separation Length Water Layer [mm]	1525				
Plate Pack Coalescer	No				
Oil Residence Time	min	4.11	5.27	5.27	5.27
Oil Velocity	m/s	0.023	0.018	0.018	0.023
Water Removal d100	micron	1568.00	1307.00	1312.00	1568.00
Oil Reynolds Number	-	4334.00	4641.00	4618.00	4641.00
Water Residence Time	min	0.00	4.58	4.58	4.58
Water Velocity	m/s	0.000	0.020	0.020	0.020
Oil Removal d100	micron	0.00	495.00	495.00	495.00
Water Reynolds Number	-	0.00	22087.00	22123.00	22123.00

Table C.4 (continued): Test separator MySEP evaluation

GAS-LIQUID SECTION					
	Units	Design_Case 1	Case_C	Case_F	Max
Inlet Device					
Type	None				
Removal d100 [Predicted]	micron	0.0	0.0	0.0	0.0
Mist Sep. Effic. [Predicted]	%	0.00	0.00	0.00	0.00
Carryover Rate	m^3/hr	0.014	0.016	0.017	0.017
Section Efficiency	%	99.99	99.99	99.99	99.99
Gravity Separation Section					
Design Liquid Level [mm]	2050				
Gas-Liquid Separation Length [mm]	3941				
Vapour Space Height [mm]	950				
Vessel K-Value	m/s	0.038	0.033	0.033	0.038
Removal d100 [Predicted]	micron	53.000	50.000	50.000	53.000
Sep. Efficiency [Predicted]	%	99.97	99.98	99.98	99.98
Carryover Rate	m^3/hr	0.000	0.000	0.000	0.000
Section Efficiency	%	99.97	99.98	99.98	99.98
Demisting Device # 1					
Type	Vane Pack				
Deck Orientation	Vertical				
Max Allowable K-Value [m/s]	0.214				
Vane Pack Area [m^2]	0.542				
Bottom Elevation [mm]	2306				
Assembly Length [mm]	1060				
Vane Spacing [mm]	20				
Bend Angle [°]	60				
K-Value	m/s	0.135	0.116	0.116	0.135
Gas Velocity	m/s	0.982	1.257	1.259	1.259
Gas ρv^2	kg/m^2	15.00	12.00	12.00	15.00
Removal d100 [Predicted]	micron	74.00	56.00	56.00	74.00
Sep. Efficiency [Predicted]	%	25.96	40.28	40.43	40.43
Carryover Rate	m^3/hr	0.000	0.000	0.000	0.000
Device Efficiency	%	25.96	40.28	40.43	40.43

APPENDIX D: LINE SIZING VALIDATION

Table D.1: Line sizing validation analysis results

PROCESS CALCULATION SHEET CAL-PR-004 : TWO-PHASE LINE SIZING		
	PROJECT NO.	HI39510
	FACILITY	FPSO-N'AGOMA
	CALCULATION NO.	CAL-PR-004
Software Technical Sheet: ES49985-PEPRPRPF999004 Rev.V2 Issue Date: 21-Nov-16		

REV.	LINE SPECIFICATION				PROCESS DATA									LINE DATA				CALCULATION			CRITERIA	
					LIQUID		GAS/VAPOR			OPERATING DATA												
	NOMINAL DIAMETER	SERVICE CODE	NUMBER	PIPE MATERIAL CLASS	ACTUAL VOLUME FLOWRATE	ACTUAL DENSITY	STANDARD FLOWRATE	ACTUAL DENSITY	MOL. WEIGHT	OPERATING PRESSURE	OPERATING TEMPERATURE	OPERATION MODE	CORROSION INHIBITOR INJECTION?	PIPE SCHEDULE	PIPE MATERIAL	INTERNAL DIAMETER	ROUGHNESS	ACTUAL VOLUME FLOWRATE	MIXTURE DENSITY	ACTUAL VELOCITY	C-FACTOR	EROSIONAL VELOCITY
	inch	-	-	-	bpd	kg/m³	MMscfd	kg/m³	kg/kmol	barg	°C	-	-	-	-	mm	mm	m³/h	kg/m³	m/s	-	m/s
CASE A&C	24	PM	M611018	BD3A	126,640.0	814.1	72.02	17.5	21.3	19.79	49.7	Continuous	No	20	Duplex	590.9	0.03	5,204.6	145.9	5.27	300	24.84
														-	-	-	-	-	-	-	-	-
CASE B	24	PM	M611018	BD3A	135,600.0	825.5	81.70	17.8	21.6	19.86	49.75	Continuous	No	20	Duplex	590.9	0.03	5,836.5	142.1	5.91	300	25.17
														-	-	-	-	-	-	-	-	-
CASE D&F	24	PM	M611018	BD3A	126,060.0	823.0	70.00	17.6	20.7	19.44	35.59	Continuous	No	20	Duplex	590.9	0.03	4,943.2	153.6	5.01	300	24.20
														-	-	-	-	-	-	-	-	-
CASE E	24	PM	M611018	BD3A	135,470.0	834.3	79.76	17.6	21.0	19.21	35.74	Continuous	No	20	Duplex	590.9	0.03	5,638.2	147.6	5.71	300	24.69
														-	-	-	-	-	-	-	-	-
														-	-	-	-	-	-	-	-	-
														-	-	-	-	-	-	-	-	-
CASE A&C	24	PL	T621001	BD3A	126,640.0	814.1	72.02	17.5	21.3	19.79	49.7	Continuous	No	20	Duplex	590.9	0.03	5,204.6	145.9	5.27	300	24.84
														-	-	-	-	-	-	-	-	-
CASE B	24	PL	T621001	BD3A	135,600.0	825.5	81.70	17.8	21.6	19.86	49.75	Continuous	No	20	Duplex	590.9	0.03	5,836.5	142.1	5.91	300	25.17
														-	-	-	-	-	-	-	-	-
CASE D&F	24	PL	T621001	BD3A	126,060.0	823.0	70.00	17.6	20.7	19.44	35.59	Continuous	No	20	Duplex	590.9	0.03	4,943.2	153.6	5.01	300	24.20
														-	-	-	-	-	-	-	-	-
CASE E	24	PL	T621001	BD3A	135,470.0	834.3	79.76	17.6	21.0	19.21	35.74	Continuous	No	20	Duplex	590.9	0.03	5,638.2	147.6	5.71	300	24.69
														-	-	-	-	-	-	-	-	-
TEST SEP INLET														-	-	-	-	-	-	-	-	-
														-	-	-	-	-	-	-	-	-
CASE A&D	16	PM	M611020	BD3A	34,220.0	877.9	16.04	18.8	19.8	19.3	4.79	Continuous	No	10	Duplex	393.7	0.03	1,069.1	201.0	2.44	300	21.16
														-	-	-	-	-	-	-	-	-
CASE B&E	16	PM	M611020	BD3A	21,120.0	824.0	8.59	18.2	18.0	19.5	-7.345	Continuous	No	10	Duplex	393.7	0.03	564.0	218.1	1.29	300	20.31
														-	-	-	-	-	-	-	-	-
CASE C&F	16	PM	M611020	BD3A	33,690.0	883.0	17.61	7.5	20.8	7	4.526	Continuous	No	10	Duplex	393.7	0.03	2,670.4	80.6	6.09	300	33.41
														-	-	-	-	-	-	-	-	-
														-	-	-	-	-	-	-	-	-
														-	-	-	-	-	-	-	-	-
CASE A&D	16	PL	M611020	BD3A	34,220.0	877.9	16.04	18.8	19.8	19.3	4.79	Continuous	No	10	Duplex	393.7	0.03	1,069.1	201.0	2.44	300	21.16
														-	-	-	-	-	-	-	-	-
CASE B&E	16	PL	M611020	BD3A	21,120.0	824.0	8.59	18.2	18.0	19.5	-7.345	Continuous	No	10	Duplex	393.7	0.03	564.0	218.1	1.29	300	20.31
														-	-	-	-	-	-	-	-	-
CASE C&F	16	PL	M611020	BD3A	33,690.0	883.0	17.61	7.5	20.8	7	4.526	Continuous	No	10	Duplex	393.7	0.03	2,670.4	80.6	6.09	300	33.41

Table D.1 (continued): Line sizing validation analysis results

REV.	LINE SPECIFICATION: NOMINAL DIAMETER	SERVICE CODE	NUMBER	PIPE MATERIAL CLASS	PROCESS DATA: VOLUME FLOWRATE		ACTUAL DENSITY	VISCOSITY	INLET PRESSURE	INLET TEMP.	MOL. WEIGHT	C factor	LINE DATA: PIPE SCHEDULE	PIPE MATERIAL	INTERNAL DIAMETER	ROUGHNESS	CALCULATION: ACTUAL VOLUME FLOWRATE	MASS FLOWRATE	REYNOLDS NUMBER	FRICTION FACTOR CALCULATION				ACTUAL VELOCITY	ACTUAL ΔP_{100}	CRITERIA: EROSIONAL VELOCITY LIMIT	NOISE VELOCITY LIMIT
	Inch	-	-	-	-	Units	kg/m³	cP	barg	°C	kg/kmol	-	-	-	mm	mm	m³/h	kg/h	-	f	As	Bs	Cs	m/s	bar/100m	m/s	m/s
TEST GAS OUTLET (CASE A)	12	PG	T711133	BD3A	16.2	MMscfd	18.2	0.011	19.0	4.8	19.83	300	20	Duplex	311.1	0.03	881.2	16,002.3	1,653,853	0.012889	8.955	8.803	8.808	3.22	0.004	70.40	50.31
PCV INLET	10	PG	T712069	BD3A	16.2	MMscfd	18.2	0.011	14.1	4.8	19.83	300	10S	Duplex	264.6	0.03	881.2	16,002.3	1,944,349	0.013047	8.868	8.752	8.755	4.45	0.009	70.40	50.31
PCV OUTLET	10	BH	T762253 (Note 2)	AL3E	16.2	MMscfd	1.8	0.010	1.0	4.8	19.83	165	40	CS	254.5	0.05	8,868.2	15,962.8	2,218,689	0.014150	8.465	8.406	8.407	48.44	0.117	122.98	60.00
TEST GAS OUTLET (CASE B)	12	PG	T711133	BD3A	8.6	MMscfd	18.7	0.029	18.7	-7.2	18.08	300	20	Duplex	311.1	0.03	416.8	7,776.9	300,110	0.015398	8.360	8.036	8.061	1.52	0.001	69.45	49.72
PCV INLET	10	PG	T712069	BD3A	8.6	MMscfd	18.7	0.029	18.7	-7.2	18.08	300	10S	Duplex	264.6	0.03	416.8	7,776.9	352,823	0.015212	8.379	8.089	8.109	2.11	0.002	69.45	49.72
PCV OUTLET	10	BH	T762253 (Note 2)	AL3E	8.6	MMscfd	1.8	0.010	1.0	4.8	19.83	165	40	CS	254.5	0.05	4,738.7	8,529.6	1,185,543	0.014511	8.398	8.299	8.301	25.88	0.034	122.98	60.00
TEST GAS OUTLET (CASE C)	12	PG	T711133	BD3A	17.6	MMscfd	16.9	0.012	19.0	50.0	21.39	300	20	Duplex	311.1	0.03	1,110.9	18,774.2	1,749,479	0.012843	8.965	8.820	8.824	4.06	0.006	72.98	51.89
PCV INLET	10	PG	T712069	BD3A	17.6	MMscfd	16.9	0.012	19.0	50.0	21.39	300	10S	Duplex	264.6	0.03	1,110.9	18,774.2	2,056,772	0.013010	8.876	8.764	8.767	5.61	0.013	72.98	51.89
PCV OUTLET	10	BH	T762253 (Note 2)	AL3E	17.6	MMscfd	1.8	0.010	1.0	4.8	19.83	165	40	CS	254.5	0.05	9,669.4	17,405.0	2,419,140	0.014114	8.472	8.417	8.417	52.82	0.139	122.98	60.00
TEST GAS OUTLET (CASE D)	12	PG	T711133	BD3A	16.2	MMscfd	18.2	0.011	18.7	4.8	19.83	300	20	Duplex	311.1	0.03	880.1	15,982.5	1,629,590	0.012901	8.952	8.799	8.804	3.22	0.004	70.40	50.31
PCV INLET	10	PG	T712069	BD3A	16.2	MMscfd	18.2	0.011	18.7	4.8	19.83	300	10S	Duplex	264.6	0.03	880.1	15,982.5	1,915,824	0.013057	8.866	8.748	8.751	4.45	0.009	70.40	50.31
PCV OUTLET	10	BH	T762253 (Note 2)	AL3E	16.2	MMscfd	1.8	0.010	1.0	4.8	19.83	165	40	CS	254.5	0.05	8,879.2	15,982.5	2,221,435	0.014149	8.466	8.406	8.407	48.50	0.118	122.98	60.00
TEST GAS OUTLET (CASE E)	12	PG	T711133	BD3A	8.6	MMscfd	17.4	0.011	18.7	-7.2	18.08	300	20	Duplex	311.1	0.03	446.4	7,776.9	803,748	0.013663	8.775	8.544	8.556	1.63	0.001	71.88	51.21
PCV INLET	10	PG	T712069	BD3A	8.6	MMscfd	17.4	0.011	18.7	-7.2	18.08	300	10S	Duplex	264.6	0.03	446.4	7,776.9	944,925	0.013693	8.726	8.538	8.546	2.25	0.002	71.88	51.21
PCV OUTLET	10	BH	T762253 (Note 2)	AL3E	8.6	MMscfd	1.8	0.010	1.0	4.8	19.83	165	40	CS	254.5	0.05	4,738.7	8,529.6	1,185,543	0.014511	8.398	8.299	8.301	25.88	0.034	122.98	60.00
TEST GAS OUTLET (CASE F)	12	PG	T711133	BD3A	17.7	MMscfd	7.1	0.011	6.7	4.8	20.82	300	20	Duplex	311.1	0.03	2,569.1	18,305.0	1,891,841	0.012782	8.979	8.841	8.845	9.39	0.013	112.39	60.00
PCV INLET	10	PG	T712069	BD3A	17.7	MMscfd	7.1	0.011	6.7	4.8	20.82	300	10S	Duplex	264.6	0.03	2,569.1	18,305.0	2,224,139	0.012960	8.887	8.781	8.784	12.98	0.029	112.39	60.00
PCV OUTLET	10	BH	T762253 (Note 2)	AL3E	17.7	MMscfd	1.8	0.010	1.0	4.8	19.83	165	40	CS	254.5	0.05	9,685.9	17,434.6	2,423,259	0.014113	8.472	8.417	8.418	52.91	0.140	122.98	60.00
HP GAS OUTLET (CASE A)	16	PG	T711001	BD3A	71.6	MMscfd	16.6	0.012	18.7	49.5	21.38	300	10	Duplex	393.7	0.03	4,596.0	76,201.2	5,704,566	0.011773	9.288	9.215	9.216	10.49	0.027	73.68	52.31
PCV INLET	16	PG	T711001	BD3A	71.6	MMscfd	16.6	0.012	18.7	49.5	21.38	300	10	Duplex	393.7	0.03	4,596.0	76,201.2	5,704,566	0.011773	9.288	9.215	9.216	10.49	0.027	73.68	52.31
PCV OUTLET	14	BH	T762030 (Note 2)	AL3E	71.6	MMscfd	1.8	0.010	1.0	4.8	19.83	165	30	CS	336.5	0.05	39,264.9	70,676.8	7,427,584	0.013118	8.758	8.731	8.731	122.61	0.527	122.98	60.00
HP GAS OUTLET (CASE B)	16	PG	T711001	BD3A	79.0	MMscfd	16.6	0.013	18.7	49.4	21.48	300	10	Duplex	393.7	0.03	5,079.9	84,529.0	6,074,882	0.011751	9.293	9.224	9.225	11.59	0.033	73.54	52.23
PCV INLET	16	PG	T711001	BD3A	79.0	MMscfd	16.6	0.013	18.7	49.4	21.48	300	10	Duplex	393.7	0.03	5,079.9	84,529.0	6,074,882	0.011751	9.293	9.224	9.225	11.59	0.033	73.54	52.23
PCV OUTLET	14	BH	T762030 (Note 2)	AL3E	79.0	MMscfd	1.8	0.010	1.0	4.8	19.83	165	30	CS	336.5	0.05	43,353.2	78,035.8	8,200,967	0.013101	8.761	8.736	8.737	135.38	0.642	122.98	60.00
HP GAS OUTLET (CASE C)	16	PG	T711001	BD3A	76.1	MMscfd	16.6	0.010	18.7	49.4	21.39	300	10	Duplex	393.7	0.03	4,884.8	81,087.0	7,284,393	0.011694	9.306	9.247	9.248	11.15	0.031	73.63	52.29
PCV INLET	16	PG	T711001	BD3A	76.1	MMscfd	16.6	0.010	18.7	49.4	21.39	300	10	Duplex	393.7	0.03	4,884.8	81,087.0	7,284,393	0.011694	9.306	9.247	9.248	11.15	0.031	73.63	52.29
PCV OUTLET	14	BH	T762030 (Note 2)	AL3E	76.1	MMscfd	16.6	0.010	1.0	4.8	19.83	165	30	CS	336.5	0.05	4,528.5	75,173.2	7,900,126	0.013108	8.760	8.734	8.734	14.14	0.065	40.50	52.29
HP GAS OUTLET (CASE D)	16	PG	T711001	BD3A	69.5	MMscfd	16.9	0.012	18.7	35.4	20.74	300	10	Duplex	393.7	0.03	4,248.7	71,802.2	5,375,252	0.011795	9.283	9.207	9.208	9.69	0.024	72.98	51.89
PCV INLET	16	PG	T711001	BD3A	69.5	MMscfd	16.9	0.012	18.7	35.4	20.74	300	10	Duplex	393.7	0.03	4,248.7	71,802.2	5,375,252	0.011795	9.283	9.207	9.208	9.69	0.024	72.98	51.89
PCV OUTLET	14	BH	T762030 (Note 2)	AL3E	69.5	MMscfd	1.8	0.010	1.0	4.8	19.83	165	30	CS	336.5	0.05	38,139.9	68,651.8	7,214,774	0.013124	8.757	8.729	8.729	119.10	0.498	122.98	60.00
HP GAS OUTLET (CASE E)	16	PG	T711001	BD3A	76.9	MMscfd	17.0	0.012	18.7	35.5	20.88	300	10	Duplex	393.7	0.03	4,706.8	80,014.8	5,990,064	0.011756	9.292	9.222	9.223	10.74	0.029	72.76	51.75
PCV INLET	16	PG	T711001	BD3A	76.9	MMscfd	17.0	0.012	18.7	35.5	20.88	300	10	Duplex	393.7	0.03	4,706.8	80,014.8	5,990,064	0.011756	9.292	9.222	9.223	10.74	0.029	72.76	51.75
PCV OUTLET	14	BH	T762030 (Note 2)	AL3E	76.9	MMscfd	1.8	0.010	1.0	4.8	19.83	165	30	CS	336.5	0.05	42,217.3	75,991.1	7,986,061	0.013106	8.761	8.735	8.735	131.83	0.609	122.98	60.00
HP GAS OUTLET (CASE F)	16	PG	T711001	BD3A	69.3	MMscfd	16.9	0.012	18.7	35.4	20.73	300	10	Duplex	393.7	0.03	4,235.6	71,581.7	5,358,745	0.011796	9.283	9.206	9.207	9.66	0.024	72.98	51.89
PCV INLET	16	PG	T711001	BD3A	69.3	MMscfd	16.9	0.012	18.7	35.4	20.73	300	10	Duplex	393.7	0.03	4,235.6	71,581.7	5,358,745	0.011796	9.283	9.206	9.207	9.66	0.024	72.98	51.89
PCV OUTLET	14	BH	T762030 (Note 2)	AL3E	69.3	MMscfd	1.8	0.010	1.0	4.8	19.83	165	30	CS	336.5	0.05	38,030.1	68,454.2	7,194,013	0.013124	8.757	8.729	8.729	118.75	0.495	122.98	60.00

Table D.1 (continued): Line sizing validation analysis results

REV.	LINE SPECIFICATION				PROCESS DATA								LINE DATA				CALCULATION									CRITERIA	
	NOMINAL DIAMETER	SERVICE CODE	NUMBER	PIPE MATERIAL CLASS	VOLUME FLOWRATE		ACTUAL DENSITY	VISCOSITY	INLET PRESSURE	INLET TEMP.	MOL. WEIGHT	C factor	PIPE SCHEDULE	PIPE MATERIAL	INTERNAL DIAMETER	ROUGHNESS	ACTUAL VOLUME FLOWRATE	MASS FLOWRATE	REYNOLDS NUMBER	FRICTION FACTOR CALCULATION				ACTUAL VELOCITY	ACTUAL ΔP_{100}	EROSIONAL VELOCITY LIMIT	NOISE VELOCITY LIMIT
	inch	-	-	-	-	Units	kg/m³	cP	barg	°C	kg/kmol	-	-	-	mm	mm	m³/h	kg/h	-	f	As	Bs	Cs	m/s	bar/100m	m/s	m/s
			IP SEPARATOR										-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NOTE1													-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IP sep	12	PG	T711004	AD3A	8.7	MMscfd	8.7	0.012	6.6	88.5	32.94	300	10S	Duplex	314.7	0.03	1,629.7	14,193.3	1,329,440	0.013068	8.917	8.741	8.748	5.82	0.006	101.66	60.00
PCV Inlet	8	PG	T711004	AD3A	8.7	MMscfd	8.7	0.012	6.6	88.5	32.94	300	10S	Duplex	211.6	0.03	1,629.7	14,193.3	1,977,132	0.013474	8.705	8.613	8.615	12.88	0.046	101.66	60.00
PCV Outlet	8	BL	T711004	AD3A	8.7	MMscfd	2.3	0.012	1.0	84.6	33.61	300	10S	Duplex	211.6	0.03	6,296.5	14,482.0	2,017,347	0.013462	8.708	8.617	8.619	49.75	0.181	197.81	60.00
CASE A													-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
													-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IP sep	12	PG	T711004	AD3A	8.8	MMscfd	8.6	0.012	6.6	88.5	32.66	300	10S	Duplex	314.7	0.03	1,657.0	14,316.7	1,340,998	0.013060	8.919	8.744	8.751	5.92	0.006	102.06	60.00
PCV Inlet	8	PG	T711004	AD3A	8.8	MMscfd	8.6	0.012	6.6	88.5	32.66	300	10S	Duplex	211.6	0.03	1,657.0	14,316.7	1,994,320	0.013469	8.706	8.615	8.617	13.09	0.047	102.06	60.00
PCV Outlet	8	BL	T711004	AD3A	8.8	MMscfd	2.3	0.012	1.0	84.6	33.61	300	10S	Duplex	211.6	0.03	6,405.7	14,733.1	2,052,330	0.013452	8.710	8.620	8.622	50.61	0.187	197.81	60.00
CASE B													-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
													-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IP sep	12	PG	T711004	AD3A	6.7	MMscfd	8.6	0.012	6.6	88.7	32.85	300	10S	Duplex	314.7	0.03	1,274.8	10,963.6	1,026,926	0.013343	8.853	8.648	8.658	4.55	0.004	102.30	60.00
PCV Inlet	8	PG	T711004	AD3A	6.7	MMscfd	8.6	0.012	6.6	88.7	32.85	300	10S	Duplex	211.6	0.03	1,274.8	10,963.6	1,527,236	0.013643	8.671	8.558	8.562	10.07	0.028	102.30	60.00
PCV Outlet	8	BL	T711004	AD3A	6.7	MMscfd	2.3	0.012	1.0	84.6	33.61	300	10S	Duplex	211.6	0.03	4,877.1	11,217.3	1,562,570	0.013626	8.674	8.564	8.567	38.53	0.110	197.81	60.00
CASE C													-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
													-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IP sep	12	PG	T711004	AD3A	10.1	MMscfd	8.8	0.012	6.6	88.5	33.48	300	10S	Duplex	314.7	0.03	1,912.2	16,827.6	1,576,180	0.012911	8.953	8.795	8.801	6.83	0.008	101.13	60.00
PCV Inlet	8	PG	T711004	AD3A	10.1	MMscfd	8.8	0.012	6.6	88.5	33.48	300	10S	Duplex	211.6	0.03	1,912.2	16,827.6	2,344,081	0.013380	8.724	8.644	8.645	15.11	0.064	101.13	60.00
PCV Outlet	8	BL	T711004	AD3A	10.1	MMscfd	2.3	0.012	1.0	84.6	33.61	300	10S	Duplex	211.6	0.03	7,344.7	16,892.9	2,353,183	0.013378	8.725	8.644	8.646	58.03	0.245	197.81	60.00
CASE D													-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
													-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IP sep	12	PG	T711004	AD3A	10.2	MMscfd	8.8	0.012	6.6	88.5	33.24	300	10S	Duplex	314.7	0.03	1,924.9	16,938.7	1,586,594	0.012906	8.954	8.797	8.803	6.88	0.009	101.13	60.00
PCV Inlet	8	PG	T711004	AD3A	10.2	MMscfd	8.8	0.012	6.6	88.5	33.24	300	10S	Duplex	211.6	0.03	1,924.9	16,938.7	2,359,569	0.013377	8.725	8.645	8.646	15.21	0.064	101.13	60.00
PCV Outlet	8	BL	T711004	AD3A	10.2	MMscfd	2.3	0.012	1.0	84.6	33.61	300	10S	Duplex	211.6	0.03	7,446.6	17,127.3	2,385,834	0.013371	8.726	8.647	8.648	58.83	0.252	197.81	60.00
CASE E													-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
													-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IP sep	12	PG	T711004	AD3A	7.9	MMscfd	8.8	0.012	6.6	88.8	33.52	300	10S	Duplex	314.7	0.03	1,499.0	13,190.9	1,235,550	0.013141	8.900	8.716	8.724	5.35	0.005	101.13	60.00
PCV Inlet	8	PG	T711004	AD3A	7.9	MMscfd	8.8	0.012	6.6	88.8	33.52	300	10S	Duplex	211.6	0.03	1,499.0	13,190.9	1,837,499	0.013518	8.696	8.599	8.601	11.84	0.039	101.13	60.00
PCV Outlet	8	BL	T711004	AD3A	7.9	MMscfd	2.3	0.012	1.0	84.6	33.61	300	10S	Duplex	211.6	0.03	5,750.6	13,226.3	1,842,433	0.013517	8.697	8.599	8.601	45.43	0.152	197.81	60.00
CASE F													-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
													-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
			LP SEPARATOR										-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
													-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LP sep	12	PG	T711007	AD3A	8.2	MMscfd	2.9	0.010	0.9	82.4	45.51	300	10S	Duplex	314.7	0.03	6,366.2	18,589.4	2,132,087	0.012676	9.006	8.879	8.882	22.74	0.030	175.56	60.00
PCV Inlet	8	PG	T711007	AD3A	8.2	MMscfd	2.9	0.010	0.9	82.4	45.51	300	10S	Duplex	211.6	0.03	6,366.2	18,589.4	3,170,822	0.013243	8.751	8.689	8.690	50.30	0.231	175.56	60.00
PCV Outlet	16	BL	T711007	AD3A	8.2	MMscfd	2.3	0.012	1.0	84.6	33.61	300	10S	Duplex	396.8	0.03	5,969.0	13,728.6	1,019,618	0.013050	8.984	8.742	8.754	13.41	0.007	197.81	60.00
CASE A													-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
													-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LP sep	12	PG	T711007	AD3A	8.2	MMscfd	2.9	0.010	0.9	82.3	45.46	300	10S	Duplex	314.7	0.03	6,403.1	18,569.0	2,087,150	0.012691	9.003	8.873	8.877	22.87	0.031	176.17	60.00
PCV Inlet	8	PG	T711007	AD3A	8.2	MMscfd	2.9	0.010	0.9	82.3	45.46	300	10S	Duplex	211.6	0.03	6,403.1	18,569.0	3,103,992	0.013252	8.750	8.686	8.687	50.59	0.232	176.17	60.00
PCV Outlet	16	BL	T711007	AD3A	8.2	MMscfd	2.3	0.012	1.0	84.6	33.61	300	10S	Duplex	396.8	0.03	5,969.0	13,728.6	1,019,618	0.013050	8.984	8.742	8.754	13.41	0.007	197.81	60.00
CASE B													-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
													-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LP sep	12	PG	T711007	AD3A	5.9	MMscfd	2.8	0.010	0.9	70.9	43.50	300	10S	Duplex	314.7	0.03	4,565.9	12,784.6	1,436,983	0.012994	8.934	8.767	8.773	16.31	0.015	179.28	60.00
PCV Inlet	8	PG	T711007	AD3A	5.9	MMscfd	2.8	0.010	0.9	70.9	43.50	300	10S	Duplex	211.6	0.03	4,565.9	12,784.6	2,137,069	0.013429	8.714	8.628	8.629	36.07	0.116	179.28	60.00
PCV Outlet	16	BL	T711007	AD3A	5.9	MMscfd	2.3	0.012	1.0	84.6	33.61	300	10S	Duplex	396.8	0.03	4,294.7	9,877.9	733,628	0.013507	8.869	8.589	8.605	9.65	0.004	197.81	60.00
CASE C													-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
													-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LP sep	12	PG	T711007	AD3A	8.6	MMscfd	2.9	0.010	0.9	82.1	45.81	300	10S	Duplex	314.7	0.03	6,767.1	19,624.7	2,205,815	0.012653	9.011	8.887	8.890	24.17	0.034	176.17	60.00
PCV Inlet	8	PG	T711007	AD3A	8.6	MMscfd	2.9	0.010	0.9	82.1	45.81	300	10S	Duplex	211.6	0.03	6,767.1	19,624.7	3,280,470	0.013230	8.754	8.693	8.694	53.46	0.259	176.17	60.00
PCV Outlet	16	BL	T711007	AD3A	8.6	MMscfd	2.3	0.010	1.0	84.6	33.61	300	10S	Duplex	396.8	0.03	6,260.1	14,398.3	1,283,227	0.012778	9.052	8.837	8.847	14.06	0.007	197.81	60.00
CASE D													-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
													-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LP sep	12	PG	T711007	AD3A	8.6	MMscfd	2.9	0.010	0.9	82.1	45.76	300	10S	Duplex	314.7	0.03	6,759.8	19,603.3	2,203,408	0.012653	9.011	8.887	8.890	24.15	0.034	176.17	60.00
PCV Inlet	8	PG	T711007	AD3A	8.6	MMscfd	2.9	0.010	0.9	82.1	45.76	300	10S	Duplex	211.6	0.03	6,759.8	19,603.3	3,276,889	0.013230	8.754	8.693	8.694	53.41	0.259	176.17	60.00
PCV Outlet	16	BL	T711007	AD3A	8.6	MMscfd	2.3	0.010	1.0	84.6	33.61	300	10S	Duplex	396.8	0.03	6,260.1	14,398.3	1,283,227	0.012778	9.052	8.837	8.847	14.06	0.007	197.81	60.00
CASE E													-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
													-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LP sep	12	PG	T711007	AD3A	6.2	MMscfd	2.9	0.010	0.9	70.8	43.87	300	10S	Duplex	314.7	0.03	4,672.0	13,548.9	1,522,894	0.012942	8.946	8.785	8.791	16.69	0.017	176.17	60.00
PCV Inlet	8	PG	T711007	AD3A	6.2	MMscfd	2.9	0.010	0.9	70.8	43.87	300	10S	Duplex	211.6	0.03	4,672.0	13,548.9	2,254,835	0.013398	8.721	8.638	8.639	36.91	0.125	176.17	60.00
PCV Outlet	16	BL	T711007	AD3A	6.2	MMscfd	2.3	0.012	1.0	84.6	33.61	300	10S	Duplex	396.8	0.03	4,513.1	10,380.2	770,931	0.013433	8.887	8.613	8.629	10.14	0.004	197.81	60.00
CASE F													-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Table D.1 (continued): Line sizing validation analysis results

REV.	LINE SPECIFICATION				PROCESS DATA				LINE DEFINITION					
	NOMINAL DIAMETER	SERVICE CODE	NUMBER	PIPE MATERIAL CLASS	ACTUAL VOLUME FLOWRATE		ACTUAL DENSITY	VISCOSITY	PUMP TYPE	LINE LOCATION	ROTATIONAL SPEED	FLUID STATE	OPERATION MODE	FLUID TYPE
	Inch	-	-	-	-	Units	kg/m³	cP	-	-	rpm	-	-	-
E A&B oil outl	12	PL	T621029	AC31	111,400.0	bpd	794.0	2.22						Liquids
u/s of LCV-007														
d/s of LCV-00	18	PL	T621030	AC31	111,400.0	bpd	794.0	2.22						Liquids
CASE C	12	PL	T621029	AC31	589.9	bpd	788.4	2.19						Liquids
u/s of LCV-007														
d/s of LCV-00	18	PL	T621030	AC31	589.9	bpd	788.4	2.19						Liquids
CASE D& E	12	PL	T621029	AC31	111,700.0	bpd	787.0	2.19						Liquids
/S OF LCV-007														
/S OF LCV-00	18	PL	T621030	AC31	111,700.0	bpd	787.0	2.19						Liquids
CASE F	12	PL	T621029	AC31	87,350.0	bpd	787.0	1.95						Liquids
/S OF LCV-007														
/S OF LCV-00	18	PL	T621030	AC31	87,350.0	bpd	787.0	1.95						Liquids

REV.	LINE DATA				CALCULATION								CRITERIA	
	PIPE SCHEDULE	PIPE MATERIAL	INTERNAL DIAMETER	ROUGHNESS	ACTUAL VOLUME FLOWRATE	REYNOLDS NUMBER	FRICTION FACTOR CALCULATION				ACTUAL VELOCITY	ACTUAL ΔP_{100}	MATERIAL VELOCITY LIMIT	PUMP VELOCITY LIMIT
	-	-	mm	mm	m³/h	-	f	As	Bs	Cs	m/s	bar/100m	m/s	m/s
E A&B oil outl	STD	CS	304.7	0.05	738.0	306,462	0.015929	8.157	7.908	7.924	2.81	0.164	6.00	-
u/s of LCV-007	-	-	-	-	-	-	-	-	-	-	-	-	-	-
d/s of LCV-00	STD	CS	437.9	0.05	738.0	213,155	0.016350	8.119	7.796	7.823	1.36	0.027	6.00	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CASE C	STD	CS	304.7	0.05	3.9	1,635	0.039145	-	-	-	0.01	0.000	6.00	-
u/s of LCV-007	-	-	-	-	-	-	-	-	-	-	-	-	-	-
d/s of LCV-00	STD	CS	437.9	0.05	3.9	1,138	0.056255	-	-	-	0.01	0.000	6.00	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CASE D& E	STD	CS	304.7	0.05	740.0	309,034	0.015913	8.160	7.912	7.928	2.82	0.163	6.00	-
/S OF LCV-007	-	-	-	-	-	-	-	-	-	-	-	-	-	-
/S OF LCV-00	STD	CS	437.9	0.05	740.0	215,041	0.016328	8.124	7.801	7.828	1.36	0.027	6.00	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CASE F	STD	CS	304.7	0.05	578.6	271,038	0.016176	8.105	7.846	7.864	2.20	0.101	6.00	-
/S OF LCV-007	-	-	-	-	-	-	-	-	-	-	-	-	-	-
/S OF LCV-00	STD	CS	437.9	0.05	578.6	188,602	0.016666	8.049	7.720	7.748	1.07	0.017	6.00	-

APPENDIX E: OIL TRAIN PROCESS FLOW DIAGRAM

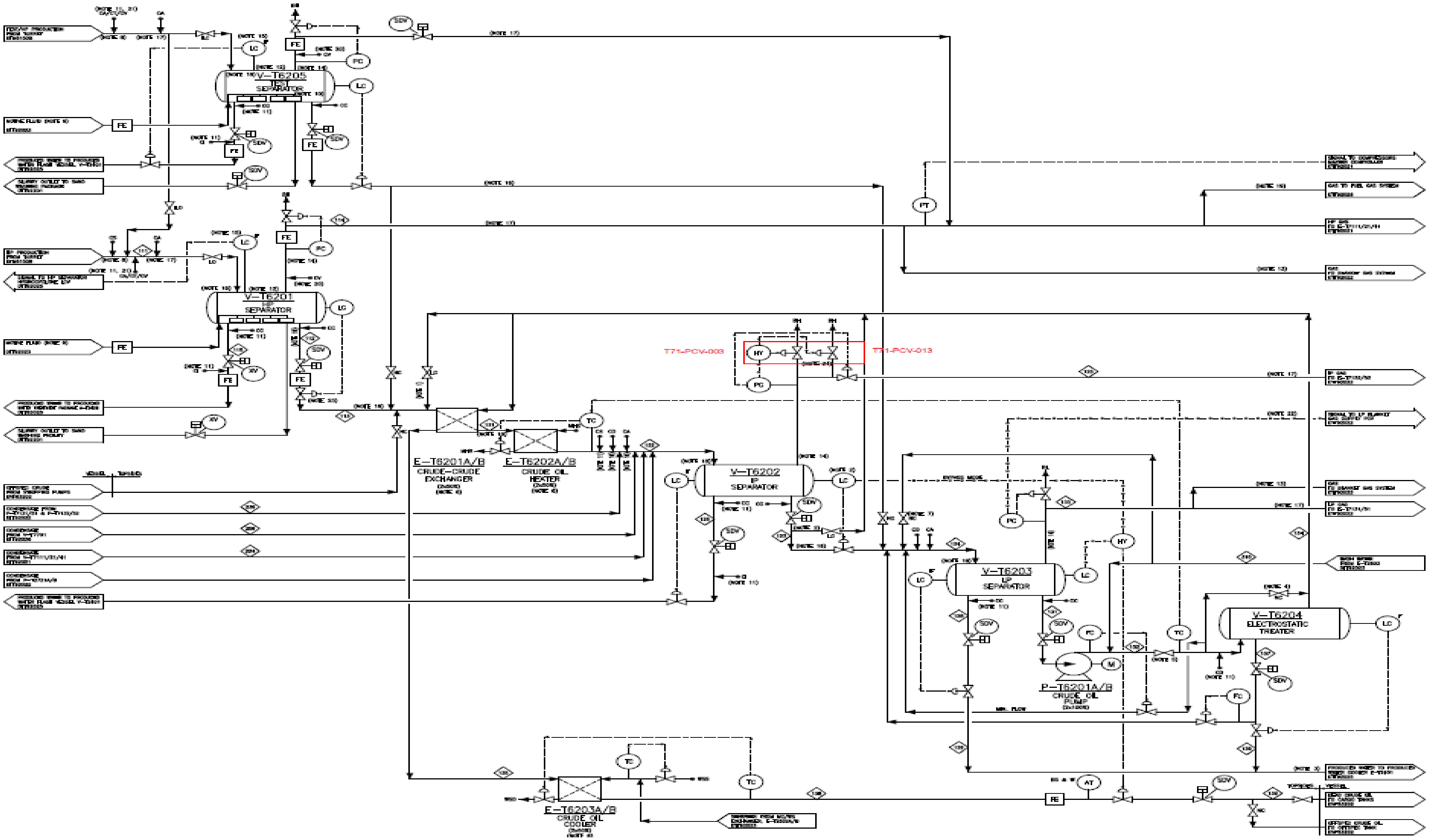


Figure E.1: Oil process train flow diagram

APPENDIX F: SELECTED EQUIPMENT DATASHEET

Table F.1: HP separator datasheet

Operating Conditions			
Case	**-**	***1***	***2***
Pressure	bar(g)	19	19
Temperature	°C	62	63
Gas flowrate	kg/h	112875	86740
	(a)m^3/h	7099	5525
Gas density @P,T	kg/m^3	15.9	15.7
Gas viscosity @P,T	cP	0.013	0.013
Gas compressibilty	-	0.9550	0.9557
Oil flowrate	(a)m^3/h	710.2	175
Oil density @P,T	kg/m^3	859.7	839.8
Oil viscosity @P,T	cP	24	24
Oil surface tension	dyne/cm	22	20
Total water flowrate	(a)m^3/h	171.5	687
Water density @P,T	kg/m^3	1092	1078
Water viscosity @P,T	cP	0.9	0.6
Water surface tension	dyne/cm	74	70
Foaming tendency	-	Yes	
Waxing tendency	-	Yes	

Table F.2: IP separator datasheet

Operating Conditions			
Case	**-**	***1***	***2***
Pressure	bar(g)	7	7
Temperature	°C	90	89
Gas flowrate	kg/h	13663	10107
	(a)m^3/h	1366.3	1217.7
Gas density @P,T	kg/m^3	10.0	8.3
Gas viscosity @P,T	cP	0.012	0.013
Gas compressibilty	-	0.9510	0.9686
Oil flowrate	(a)m^3/h	729.3	722.4
Oil density @P,T	kg/m^3	822.1	819.5
Oil viscosity @P,T	cP	6.3	7.1
Oil surface tension	dyne/cm	19	19
Total water flowrate	(a)m^3/h	2	82
Water density @P,T	kg/m^3	1061	1064
Water viscosity @P,T	cP	0.4	0.4
Water surface tension	dyne/cm	64	64
Foaming tendency	-	Yes	
Waxing tendency	-	Yes	

Table F.3: LP separator datasheet

Operating Conditions			
Case	**-**	***1***	***2***
Pressure	bar(g)	1	1
Temperature	°C	82	85
Gas flowrate	kg/h	15262	11091
	(a)m^3/h	4923	3824.5
Gas density @P,T	kg/m^3	3.1	2.9
Gas viscosity @P,T	cP	0.010	0.010
Gas compressibilty	-	0.9793	0.9819
Oil flowrate	(a)m^3/h	702.3	701
Oil density @P,T	kg/m^3	834.7	828.9
Oil viscosity @P,T	cP	7.4	6.9
Oil surface tension	dyne/cm	21.3	20.7
Total water flowrate	(a)m^3/h	69	106
Water density @P,T	kg/m^3	1065.2	1065.2
Water viscosity @P,T	cP	0.4	0.4
Water surface tension	dyne/cm	66	66
Foaming tendency	-	Yes	
Waxing tendency	-	Yes	

Table F.4: Electrostatic treater datasheet

Operating Conditions			
Case	-	***1***	***2***
Pressure	bar(g)	4	4
Temperature	°C	83	85
Gas flowrate	kg/h	-	-
	(a)m^3/h	-	-
Gas density @P,T	kg/m^3	-	-
Gas viscosity @P,T	cP	-	-
Gas compressibilty	-	-	-
Oil flowrate	(a)m^3/h	702	701
Oil density @P,T	kg/m^3	834.8	828.9
Oil viscosity @P,T	cP	6.5	7.0
Oil surface tension	dyne/cm	21	21
Total water flowrate	(a)m^3/h	70	83
Water density @P,T	kg/m^3	1065	1065
Water viscosity @P,T	cP	0.4	0.4
Water surface tension	dyne/cm	65	66
Foaming tendency	-	No*	
Waxing tendency	-	Yes	

Table F.5: Test separator datasheet

Operating Conditions					
Case	-	***1***	***2***	***3***	***4***
Pressure	bar(g)	19	19	3	3
Temperature	°C	62	63	58	60
Gas flowrate	kg/h	30241	16920	33239	17615
	(a)m^3/h	1902	1078	9776	5505
Gas density @P,T	kg/m^3	15.9	15.7	3.4	3.2
Gas viscosity @P,T	cP	0.013	0.013	0.012	0.012
Gas compressibilty	-	0.9551	0.9559	0.9882	0.9897
Oil flowrate	(a)m^3/h	173	17	172	17
Oil density @P,T	kg/m^3	859.7	839.8	877.1	856.9
Oil viscosity @P,T	cP	24	24	24	24
Oil surface tension	dyne/cm	22	20	25	23
Total water flowrate	(a)m^3/h	-	155	-	154
Water density @P,T	kg/m^3	-	1078	-	1080
Water viscosity @P,T	cP	-	0.6	-	0.6
Water surface tension	dyne/cm	-	70	-	70
Foaming tendency	-	Yes			
Waxing tendency	-	Yes			

Table F.6: 100 plates crude oil heater datasheet

Fluid		**Heating medium**	**Crude**
Mass flow rate	kg/h	128089	336228
Fluid Condensed/Vapourized	kg/h	0.000	2442
Inlet temperature	°C	130.0	63.6
Outlet temperature (vapor/liquid)	°C	89.7	90.0
Operating pressure (In/Out)	bara	/	10.3/8.13
Pressure drop (Perm/Calculate)	kPa	/13.3	/222
Velocity Connection (In/Out)	m/s	0.775/0.751	3.73/5.64
Heat Exchanged	kW	6077	
Heat transfer area	m²	147.0	
O.H.T.C service	W/(m²*K)	1276	
O.H.T.C clean	W/(m²*K)	1604	
Duty Margin	%	25.7	
MTD	K	32.4	
Relative directions of fluids		Countercurrent	
No. of plates		100	
No. of effective plates		98	
Number of passes		1	1
Extension capacity		28	
Plate material/ Thickness		TI / 0.85 mm	
Sealing material		HNBR GLUED	HNBR GLUED
Connection material		Titanium	Titanium
Connection standard		10"	10"
Nozzle orientation		S1 -> S2	S4 <- S3

Table F.7: 128 plates crude oil heater datasheet

		Hot side	**Cold side**
Fluid		Heating Medium	Crude Oil 2
Density	kg/m³	944.4	359 (average)
Specific heat capacity	kJ/(kg*K)	4.24	Pro Forma
Thermal conductivity	W/(m*K)	0.688	0.072 (average)
Viscosity inlet	cP	0.214	4.30
Viscosity outlet	cP	0.265	1.23
Mass flow rate	kg/h	250000	240300
Inlet temperature	°C	130.0	64.4
Outlet temperature	°C	106.0	105.0
Pressure drop	kPa	28.8	112
Heat Exchanged	kW	7080 ***(Please check)***	
L.M.T.D.	K	32.6	

Due to the higher heat load and the higher crude outlet temperature the plate pack must be extended from 100 plates to 128 plates. (full capacity for current frame size)

Also the capacity of Heating Medium is increased from 128.000 to 250.000 kg/h.

Relative directions of fluids	Countercurrent	
Number of plates	128	
Number of passes	1	1
Extension capacity	0	
Plate material / thickness	TI / 0.85 mm	

Table F.8: 1st stage injection gas compressor datasheet

SIEMENS

Siemens Nederland N.V.

CENTRIFUGAL AND AXIAL COMPRESSOR
DATA SHEET (API 617-7TH Chapter 2)
SI UNITS (1-1.6.5)

JOB NO. VC5708/9; HE2824248/9 ITEM NO. A-T7110; A-T7120; A-T7140
PURCHASE ORDER NO. 01.39510.0018 / 0019
INQUIRY NO.
REVISION NO. 05 DATE 20-02-2014
PAGE 1a OF 7 BY GP/PM

1	APPLICABLE TO: ◯ PROPOSAL ◉ Purchase ◯ As built			
2	FOR	SBM Offshore/ENI	UNIT	K-T7111,2,3; K-T7121,2,3; K-T7141,2,3
3	SITE	N'goma FPSO	SERIAL NO.	VC5708 / VC5709 / VC5710 /VC5756/VC5757/VC5758
4	SERVICE	Associated gas	NO. REQUIRED	3 off 50% trains
5	MANUFACTURER	Siemens Nederland N.V.	DRIVER TYPE (1-3.1.1)	GT (SGT400)
6	MODEL	STC-SV (06-8-B) / (06-6-A)	DRIVER ITEM NO.	KT-T7110/20/40
7				
8	INFORMATION TO BE COMPLETED: ○ BY PURCHASER ☐ BY MANUFACTURER △ MUTUAL AGREEMENT (PRIOR TO PURCHASE)			

No.	Item	Unit	Max 1			Max 2		
9	OPERATING CONDITIONS							
10	(ALL DATA ON PER UNIT BASIS)							
11	SPECIFIED OPERATING CASE		Max 1			Max 2		
11a	CASING TYPE		Barrel		Barrel	Barrel		Barrel
11b	SECTION		1st stage	2nd stage	3rd stage	1st stage	2nd stage	3rd stage
12	○ GAS HANDLED (ALSO SEE PAGE ______)							
13	△ GAS PROPERTIES (1-2.1.1.4)							
14	● Standard flow (1.01325 BAR & 15.6°C WET)	[Sm³/h@15.6C]	67723	67695	58852	67677	67684	58675
14	● WEIGHT FLOW, (WET)	[kg/h]	58387	58231	50516	61355	61199	52955
15	BYPASS FLOW, (WET)	[%]	0	0	0	0	0	0
16	**INLET CONDITIONS**							
17	● PRESSURE	[barg] (note 6)	17,80	54,70	142,20	17,80	54,34	141,26
18	● TEMPERATURE	[°C]	43,8	44,8	47,8	43,8	44,8	47,8
19	● RELATIVE HUMIDITY (NOTE 8)	[%]	100,0	100,0	0,0	100,0	100,0	0,0
20	● MOLECULAR WEIGHT	[]	20,32	20,33	20,33	21,36	21,38	21,38
21	■ Cp/Cv (K1) (NOTE 1,7)	[-]	1.297	1.441	1.836	1.300	1.445	1.854
22	■ COMPRESSIBILITY (Z1) (NOTE 1,7)	[-]	0,956	0,877	0,797	0,955	0,876	0,790
23	■ INLET VOLUME, (WET)	[m³/h]	3849	1192	369	3844	1197	367
24	**DISCHARGE CONDITIONS**							
25	● PRESSURE	[barg] (note 6)	56,04	144,40	293,01	55,68	143,46	293,00
26	■ TEMPERATURE	[°C]	144	141	130	144	141	130,4
27	■ Cp/Cv (K2) (NOTE 1,7)	[-]	1,271	1,391	1,556	1,273	1,394	1,565
28	■ COMPRESSIBILITY (Z2) (NOTE 1,7)	[-]	0,962	0,951	1,036	0,961	0,948	1,030
29	■ GAS kW REQUIRED	[kW]	3464	3387	2551	3463	3381	2554
30	■ TRAIN BRAKE kW REQUIRED	[kW]	6933		2613	6923		2615
31	■ BRAKE kW REQUIRED AT DRIVER INCL 2,6 % GEAR LOSSES	[kW]	9794			9786		
32	■ SPEED	[rpm]	13740			13482		
33	■ TURNDOWN	[%]	See performance curves					
34	■ POLYTROPIC HEAD	[kJ/kg]	158,8	129,4	96,3	150,2	122,9	91,8
35	■ POLYTROPIC EFFICIENCY	[%]	74,3	61,8	53,0	73,9	61,8	52,9
36	● CERTIFIED POINT		YES	YES	YES	NO	NO	NO
37	○ EXPECTED OPERATION AT EACH CONDITION (%)							

Table F.9: 2nd stage injection gas compressor datasheet

SIEMENS

Siemens Nederland N.V.

CENTRIFUGAL AND AXIAL COMPRESSOR
DATA SHEET (API 617-7TH Chapter 2)
SI UNITS (1-1.6.5)

JOB NO.	VC5708/9; HE2824248/9
ITEM NO.	A-T7110; A-T7120; A-T7140
PURCHASE ORDER NO.	01.39510.0018 / 0019
INQUIRY NO.	
REVISION NO.	05
DATE	20-02-2014
PAGE	1b OF 7
BY	GP/PM

1	APPLICABLE TO: ○ PROPOSAL ● Purchase ○ As built			
2	FOR	SBM Offshore/ENI	UNIT	K-T7111,2,3; K-T7121,2,3; K-T7141,2,3
3	SITE	N'goma FPSO	SERIAL NO.	VC5708 / VC5709 / VC5710 /VC5756/VC5757/VC5758
4	SERVICE	Associated gas	NO. REQUIRED	3 off 50% trains
5	MANUFACTURER	Siemens Nederland N.V.	DRIVER TYPE (1-3.1.1)	GT (SGT400)
6	MODEL	STC-SV (06-8-B) / (06-6-A)	DRIVER ITEM NO.	KT-T7110/20/40
7				
8	INFORMATION TO BE COMPLETED: ○ BY PURCHASER ☐ BY MANUFACTURER △ MUTUAL AGREEMENT (PRIOR TO PURCHASE)			
9	OPERATING CONDITIONS			

No.	(ALL DATA ON PER UNIT BASIS)	Unit	L MW Case1			L MW Case2		
10								
11	SPECIFIED OPERATING CASE		L MW Case1			L MW Case2		
11a	CASING TYPE		Barrel		Barrel	Barrel		Barrel
11b	SECTION		1st stage	2nd stage	3rd stage	1st stage	2nd stage	3rd stage
12	○ GAS HANDLED (ALSO SEE PAGE)							
13	△ GAS PROPERTIES (1-2.1.1.4)							
14	● Standard flow (1.01325 BAR & 15.6°C WET)	[Sm³/h@15.6C]	58196	58225	40462	63305	63310	54438
15	● WEIGHT FLOW, (WET)	[kg/h]	43592	43545	30209	50282	50228	43110
16	BYPASS FLOW, (WET)	[%]	0	0	0	0	0	0
16	**INLET CONDITIONS**							
17	● PRESSURE	[barg] (note 6)	17,80	57,03	143,96	17,80	57,17	146,00
18	● TEMPERATURE	[°C]	34,7	44,9	47,8	34,9	44,9	47,8
19	● RELATIVE HUMIDITY (NOTE 8)	[%]	100,0	100,0	0,0	100,0	100,0	0,0
20	● MOLECULAR WEIGHT	[]	17,69	17,69	17,68	18,76	18,75	18,76
21	■ Cp/Cv (K1) (NOTE 1,7)	[-]	1.340	1.448	1,734	1,319	1,444	1,786
22	■ COMPRESSIBILITY (Z1) (NOTE 1,7)	[-]	0,966	0,916	0,868	0,959	0,894	0,833
23	■ INLET VOLUME, (WET)	[m³/h]	3242	1028	273	3502	1089	347
24	**DISCHARGE CONDITIONS**							
25	● PRESSURE	[barg] (note 6)	58,37	146,16	293,00	58,51	148,20	293,00
26	■ TEMPERATURE	[°C]	154	153	152	143	145	134
27	■ Cp/Cv (K2) (NOTE 1,7)	[-]	1,299	1,387	1,497	1,286	1,389	1,536
28	■ COMPRESSIBILITY (Z2) (NOTE 1,7)	[-]	0,980	0,987	1,073	0,969	0,970	1,053
29	■ GAS kW REQUIRED	[kW]	3137	3037	2009	3303	3211	2368
30	■ TRAIN BRAKE kW REQUIRED	[kW]	6261		2076	6598		2432
31	■ BRAKE kW REQUIRED AT DRIVER INCL 2,6 % GEAR LOSSES	[kW]	8554			9264		
32	■ SPEED	[rpm]	14384			14020		
33	■ TURNDOWN	[%]	See performance curves					
34	■ POLYTROPIC HEAD	[kJ/kg]	191,6	153,1	118,9	177,0	141,5	104,2
35	■ POLYTROPIC EFFICIENCY	[%]	74,0	61,0	49,6	74,8	61,5	52,7
36	● CERTIFIED POINT		NO	NO	NO	NO	NO	NO
37	○ EXPECTED OPERATION AT EACH CONDITION (%)							

Table F.10: 3rd stage injection gas compressor datasheet

SIEMENS
Siemens Nederland N.V.

CENTRIFUGAL AND AXIAL COMPRESSOR
DATA SHEET (API 617-7TH Chapter 2)
SI UNITS (1-1.6.5)

JOB NO.	VC5708/9; HE2824248/9
ITEM NO.	A-T7110; A-T7120; A-T7140
PURCHASE ORDER NO.	01.39510.0018 / 0019
INQUIRY NO.	
REVISION NO.	05
DATE	20-02-2014
PAGE	1c OF 7
BY	GP/PM

1 APPLICABLE TO: ○ PROPOSAL ◉ Purchase ○ As built

No.				
2	FOR	SBM Offshore/ENI	UNIT	K-T7111,2,3; K-T7121,2,3; K-T7141,2,3
3	SITE	N'goma FPSO	SERIAL NO.	VC5708 / VC5709 / VC5710 /VC5756/VC5757/VC5758
4	SERVICE	Associated gas	NO. REQUIRED	3 off 50% trains
5	MANUFACTURER	Siemens Nederland N.V.	DRIVER TYPE (1-3.1.1)	GT (SGT400)
6	MODEL	STC-SV (06-8-B) / (06-6-A)	DRIVER ITEM NO.	KT-T7110/20/40
7				

8 INFORMATION TO BE COMPLETED: ○ BY PURCHASER ☐ BY MANUFACTURER △ MUTUAL AGREEMENT (PRIOR TO PURCHASE)

9 **OPERATING CONDITIONS**

10 (ALL DATA ON PER UNIT BASIS)

No.	Item	Unit	TD			SRC1		
11	SPECIFIED OPERATING CASE		TD			SRC1		
11a	CASING TYPE		Barrel		Barrel	Barrel		Barrel
11b	SECTION		1st stage	2nd stage	3rd stage	1st stage	2nd stage	3rd stage
12	○ GAS HANDLED (ALSO SEE PAGE ____)							
13	△ GAS PROPERTIES (1-2.1.1.4)							
14	● Standard flow (1.01325 BAR & 15.6°C WET)	[Sm³/h@15.6C]	55043	53801	35080	49294	48890	33575
15	● WEIGHT FLOW, (WET)	[kg/h]	43867	42812	27863.1	51267.4	48874.5	33509.9
16	BYPASS FLOW, (WET)	[%]	44	40	19	20	23	9
16	**INLET CONDITIONS**							
17	● PRESSURE	[barg] (note 6)	17,80	56,14	142,82	17,80	54,65	139,91
18	● TEMPERATURE	[°C]	36,4	44,9	47.80	40.30	44.80	47.80
19	● RELATIVE HUMIDITY (NOTE 8)	[%]	100,0	100,0	0,0	100.0	100.0	0,0
20	● MOLECULAR WEIGHT	[]	18,81	18,81	18.81	24.53	23.63	23.64
21	■ Cp/Cv (K1) (NOTE 1,7)	[-]	1,320	1,441	1.771	1.279	1.490	2.064
22	■ COMPRESSIBILITY (Z1) (NOTE 1,7)	[-]	0,960	0,898	0,836	0,929	0,818	0,706
23	■ INLET VOLUME, (WET)	[m³/h]	3065	946	230	2690	803	189
24	**DISCHARGE CONDITIONS**							
25	● PRESSURE	[barg] (note 6)	57,48	145,02	293,00	55,99	142,11	293,00
26	■ TEMPERATURE	[°C]	146	147	149	127	128	126,7
27	■ Cp/Cv (K2) (NOTE 1,7)	[-]	1,286	1,385	1,495	1,273	1,439	1,604
28	■ COMPRESSIBILITY (Z2) (NOTE 1,7)	[-]	0,971	0,971	1,064	0,922	0,892	0,999
29	■ GAS kW REQUIRED	[kW]	2883	2772	1783	2369	2256	1523
30	■ TRAIN BRAKE kW REQUIRED	[kW]	5736		1845	4687		1571
31	■ BRAKE kW REQUIRED AT DRIVER INCL 2,6 % GEAR LOSSES	[kW]	7778			6421		
32	■ SPEED	[rpm]	13708			11545		
33	■ TURNDOWN	[%]	See performance curves					
34	■ POLYTROPIC HEAD	[kJ/kg]	175,0	141,2	110,1	123,3	100,6	78,2
35	■ POLYTROPIC EFFICIENCY	[%]	74,0	60,6	47,8	74,2	60,5	47,8
36	● CERTIFIED POINT		NO	NO	NO	NO	NO	NO
37	○ EXPECTED OPERATION AT EACH CONDITION (%)							

Table F.11: Injection gas compressor gas generator datasheet

1	CONSTRUCTION FEATURES (Gas Generator)	
2	■ SPEEDS: Gas Generator	MATERIALS OF CONSTRUCTION (4.10)
3	MAX. CONT. 14300 RPM TRIP 15000 RPM	COMPRESSOR ROTOR BLADES 17-4 PH & FV 448E
4	■ LATERAL CRITICAL SPEEDS (DAMPED)	COMPRESSOR STATOR VANES 17-4 PH & BS970 410DP
5	FIRST CRITICAL 4773 RPM 1st Bounce MODE	SHAFT BS970 820 M40 BLADE/VANE COATING Sermetal 5380 DP
6	SECOND CRITICAL 6072 RPM 2nd Bounce MODE	TURBINE STAGE / NOZZLES / BLADES / WHEELS OR DISCS
7	THIRD CRITICAL 18272 RPM 1st Bending MODE	
8	FOURTH CRITICAL RPM MODE	1: INCO 939 / CM 186 LC / INCO 718
9	□ PROTOTYPE OR MODIFIED ROTOR SUPPORT (4.7.3.5)	2: INCO 939 / CM 186 LC / INCO 718
10	○ TRAIN LATERAL ANALYSIS REQUIRED (D1.3)	3
11	○ TRAIN TORSIONAL ANALYSIS REQUIRED (2.7.4.5)	4
12	□ TORSIONAL CRITICAL SPEEDS:	
13	FIRST CRITICAL RPM	
14	SECOND CRITICAL RPM	
15	THIRD CRITICAL RPM	
16	FOURTH CRITICAL RPM	COMBUSTORS Haynes 230
17	VIBRATION: (4.7.4.5) (7.2.3o)	COMPRESSOR CASING BS 2789 Gr420/12
18	■ ALLOWABLE TEST LEVEL: SHAFT 41.0 MICRONS P/P	COMBUSTOR CASING BS 2789 Gr420/12
19	CASE 9 mm/SEC	TURBINE CASING BS 2789 Gr420/12
20	□ ROTATION, VIEWED FROM DRIVE END ○ CW ■ CCW	GAUGE BOARDS AND CONTROL PANELS
21	AIR COMPRESSOR:	
22	STAGES 11 MAX. TIP SPEED 427 m/s	GAUGE BOARDS
23	TYPE Axial RATIO 16.7:1	■ LOCATION None, all indication on VDU
24	CASING SPLIT (2.2.3) ● AXIAL ○ RADIAL	CONTROL CONSOLES (5.4.5.1.1) ○ ON-SKID ○ OFF SKID LOCAL
25	ROTOR □ SOLID ■ BUILT UP	● OFF SKID REMOTE
26	TURBINE:	WEATHER PROTECTION REQUIRED ○ YES ● NO
27	STAGES 2 MAX. TIP SPEED 496 m/s	● SPECIFICATION JB 72 IP66 (on skid), UCP IP54 (control room)
28	CASING SPLIT (4.2.3) ○ AXIAL ● RADIAL	○ ANNUNCIATOR REQUIRED (5.4.4.8.5)
29	ROTOR □ SOLID ■ BUILT UP	■ VISUAL DISPLAY UNIT (VDU) ■ KEYBOARD
30	COMBUSTORS: (4.3.2)	
31	□ SINGLE ■ MULTIPLE, NUMBER 6	
32	■ GAS □ LIQUID □ DUAL FUEL	
33	MAX. ALLOW TEMP. VARIATION 90 °C	CONTROL SYSTEMS
34	APPLICABLE PLANE	TYPE (5.4.1.5)
35	FUEL NOZZLES PER COMBUSTOR 1 Pilot + 1 Main	○ MECH ○ PNEU ○ HYDRA ○ ELECTRIC ○ ELECTRONIC
36	● WOBBE INDEX NO. REQD (4.3.7) ■ MIN/MAX 37 - 49 MJ/m^3	● MICROPROCESSOR BASED ○ COMBINED

Table F.12: 1st and 2nd stage flash gas compressors datasheet

[logo]	PROCESS DATA SHEET ROTARY SCREW COMPRESSOR	DOC. NO.	STT71003	
		TAG NO.	K-T7131/32 (TRAIN A) K-T7151/52 (TRAIN B)	
		SHEET	03 of 07	
		QUANTITY	2 x 100%	

PROJECT	ANGOLA BLOCK 15/06 West Hub Development Project	PREPARED	CMY	CMY	PSG	
LOCATION	Offshore Angola	CHECKED	WLL	WLL	WLL	
FACILITY	381203-XIKOMBA-FPSO	APPROVED	WLL	GWE	GWE	
CLIENT	Eni Angola S.p.A.	DATE	10-Mar-11	18-Jul-11	24-Nov-11	
PROJECT NO.	HI39510	REVISION	C1	A1	A2	

REV.		GENERAL DATA		UNITS						
	1	Name		-	Flash Gas Compressor (Train A & B)					
A2	2	P&ID No.		-	DTT71011/12/74/79					
	3	Fluid Handled		-	Hydrocarbon gas					
	4	Operation	(continuous / intermittent)	-	Continuous					
	5	Type		-	Two (2)-stage variable speed dry screw compressor (Note 1, 2)					
	6	Driver		-	Electric Motor (2100 kW)					
	7	Liquid Entrainment	(yes / no)	-	No (Note 3)					
	8	Hazardous Service	(yes / no)	-	Yes					
	9	Corrosive Service	(yes - type of corrosive agent / no)	-	Yes - CO_2					
	10									
	11	DESIGN DATA								
	12	Compressor Stage		barg	1st Stage			2nd Stage		
	13	Design Pressure		barg	10			30 *2		
	14	Design Temperature	(min. / max.)	°C	-15 / 200			-15 / 200		
	15	Settle-out Pressure	(per stage)	barg	3.9 (Hold 1)			5.8 (Hold 1)		
	16	Settle-out Pressure	(overall)	barg	5.7 (Hold 1)					
	17	Design Margin		%	(Note 4)					
	18	Design Life		years	15					
	19									
A2	20	OPERATING DATA			Max. Gas Case 1 (Note 5, 6, 7)		Max. Gas Case 2 (High CO2) (Note 5, 6, 7)		Turndown Case (Note 5)	
	21	Compressor Stage		-	1st Stage	2nd Stage	1st Stage	2nd Stage	1st Stage	2nd Stage
A2	22	Vapor Flowrate	(@ inlet)	MMscfd	6.7	12.5	5.3	10.5	0.3	0.6
A2	23	Vapor Mass Flow	(@ inlet)	kg/h	16,410	22,796	12,613	19,294	404	694
	24	Recycle Flow		MMscfd	0	0	0.44	0	4.15	7.67
	25	SUCTION CONDITIONS								
	26	Operating Pressure	(@ compressor flange)	barg	0.45	5.36	0.45	5.36	0.45	5.36
A2	27	Operating Temperature	(@ compressor flange)	°C	44.9	44.6	44.9	44.7	44.9	44.6
A2	28	Actual Volume Flow	(vapor)	Am^3/h	5,937	2,427	4,713	2,142	262	124
A2	29	Molecular Weight	(vapor)	kg/kgmole	45.76	36.65	47.32	35.45	27.72	22.89
A2	30	Mass Density	(vapor)	kg/m^3	2.8	9.4	2.7	9.0	1.5	5.6
A2	31	Cp / (Cp-R)	(vapor)	-	1.106	1.135	1.111	1.146	1.204	1.236
A2	32	Compressibility Factor	(vapor)	-	0.9763	0.9404	0.9787	0.9491	0.9935	0.9812
	33									
	34	DISCHARGE CONDITIONS (Note 8)								
A2	35	Operating Pressure	(@ compressor flange)	barg	6.0	19.3	6.0	19.3	6.0	19.3
A2	36	Operating Temperature	(@ compressor flange)	°C	123 ~~119.5*~~	113 ~~116.9*~~	128 ~~122.9*~~	121 ~~121.4*~~	185 ~~178.8*~~	170 ~~159.3*~~
A2	37	Mass Density	(vapor)	kg/m^3	11.2 *	25.6 *	10.7 *	23.9 *	5.2 *	13.2 *
A2	38	Cp / (Cp-R)	(vapor)	-	1.087 *	1.111 *	1.091 *	1.120 *	1.159 *	1.193 *
A2	39	Compressibility Factor	(vapor)	-	0.9371 *	0.8986 *	0.9455 *	0.9183 *	0.9909 *	0.9816 *
	40	Compressor Speed *1		rpm	4615	6262	4042	5485	3483	4726
	41	PERFORMANCE			(100.7%)	(100.7%)	(88.2%)	(88.2%)	(76%)	(76%)
A2	42	Estimated Gas Power		kW	615 *	803 *	491 *	718 *	29 *	44 *
	43	Adiabatic Efficiency		%	61 ~~65*~~	64 ~~68*~~	60 ~~65*~~	62 ~~68*~~	57 ~~65*~~	59 ~~66*~~
	44	Certified Point	(yes / no)	-	Yes	Yes	No	No	No	No
	45	BHP required		kW	720	935	612	802	512	671
	46	NOTES / HOLD								
A2	47	Refer to Sheet 07 of 07								
	48	*1 Compressor rated speed will not be changed from original process gas certified condition as follows.								
	49	1st stage compressor speed : 4583 rpm @ 100 % Rated speed.								
	50	4615 rpm @ 100.7% Normal speed for revised process gas certified condition.								
	51	2nd stage compressor speed : 6219 rpm @ 100 % Rated speed.								
	52	6262 rpm @ 100.7% Normal speed for revised process gas certified condition.								
	53									
	54	*2 Design pressure is compressor casing design pressure. It is not a design pressure of operating condition for								
	55	Main motor driving.								
	56	* To be completed / confirmed by VENDOR								

Table F.13: Injection and flash gas compressors scrubber's datasheet

Operating Conditions						
Vessel Tag No.	-	***V-T7141***	***V-T7142***	***V-T7143***	***V-T7151***	
Case	-	***1***	***1***	***1***	***1***	***2***
Pressure	bar(g)	18	57	138	0.55	0.55
Temperature	°C	44	45	48	45	45
Gas flowrate	kg/h	61037	61630	54221	16410	12595
	(a)m^3/h	3745	1113	359	5551	5236
Gas density @P,T	kg/m^3	16.3	55.4	151.1	3.0	2.4
Gas viscosity @P,T	cP	0.01	0.01	0.02	0.01	0.01
Gas compressibilty	-	0.94	0.84	0.73	0.97	0.98
Oil flowrate	(a)m^3/h	1.1	2.6	-	2.78	-
Oil density @P,T	kg/m^3	669	555	-	696	-
Oil viscosity @P,T	cP	0.28	0.14	-	0.34	-
Heavy Liquid flowrate	(a)m^3/h	0.6	0.2	0.13	1.69	-
Heavy Liquid density	kg/m^3	994	994	1100	992	-
Heavy Liquid viscosity	cP	0.6	0.6	20.0	0.6	-
Foaming tendency	-	Yes	Yes	No	Yes	-
Waxing tendency	-	No	No	No	No	-

Vessel Tag No.	-	***V-T7152***	***V-T2701***	
Case	-	***1***	***1***	***2***
Pressure	bar(g)	5.7	0.14-0.25	0.14-0.25
Temperature	°C	45	50	50
Gas flowrate	kg/h	22798	17530$^{(1)}$	10661$^{(1)}$
	(a)m^3/h	2297	9226$^{(1)}$	8884$^{(1)}$
Gas density @P,T	kg/m^3	9.9	1.9	1.2
Gas viscosity @P,T	cP	0.01	0.01	0.01
Gas compressibilty	-	0.94	0.99	1.00
Oil flowrate	(a)m^3/h	8.71	0.2$^{(1)}$	0
Oil density @P,T	kg/m^3	627	741	795
Oil viscosity @P,T	cP	0.21	0.55	1.73
Heavy Liquid flowrate	(a)m^3/h	0.8	0.93$^{(1)}$	-
Heavy Liquid density	kg/m^3	992	988	-
Heavy Liquid viscosity	cP	0.6	0.5	-
Foaming tendency	-	Yes	No	No
Waxing tendency	-	No	No	No

Table F.14: 1st stage flash gas compressors coolers' datasheet

8	Service of Unit	FGC Suction Cooler Train B		Item No.	E-T7151	
9	Size	675.000 x 4699.94 mm	Type BFU Horz.	Connected In	1 Parallel	1 Series
10	Surf/Unit (Gross/Eff) 181.93 / 179.89 m2		Shell/Unit 1	Surf/Shell (Gross/Eff) 181.93 / 179.89 m2		
11	PERFORMANCE OF ONE UNIT					
12	Fluid Allocation		Shell Side		Tube Side	
13	Fluid Name		Water		Liquid Hydrocarbon	
14	Fluid Quantity, Total	kg/hr	46720.3		14745.1	
15	Vapor (In/Out)				14745.1	11469.0
16	Liquid		46720.3	46720.3		1763.1
17	Steam					
18	Water		46720.3	46720.3		1513
19	Noncondensables					
20	Temperature (In/Out)	C	35.00	62.20	84.70	45.00
21	Specific Gravity		0.9947	0.9827		0.8072
22	Viscosity	mN-s/m2	0.7192	0.4514	0.0100	0.0090 V/L 0.4376
23	Molecular Weight, Vapor					
24	Molecular Weight, Noncondensables					
25	Specific Heat	kJ/kg-C	4.1776	4.1826	1.9100	1.7600 V/L 3.147
26	Thermal Conductivity	W/m-C	0.6225	0.6533	0.0200	0.0200 V/L 0.260
27	Latent Heat	kJ/kg			2336.90	692.742
28	Inlet Pressure	kPa	651.340		186.333	
29	Velocity	m/s	0.27		21.84	
30	Pressure Drop, Allow/Calc	kPa	50.001	23.963	30.000	20.593
31	Fouling Resistance (min)	m2-K/W	0.000250		0.000150	
32	Heat Exchanged W	1476581		MTD (Corrected)	16.3 C	
33	Transfer Rate, Service	502.47 W/m2-K	Clean	762.76 W/m2-K	Actual	573.89 W/m2-K
34	CONSTRUCTION OF ONE SHELL				Sketch (Bundle/Nozzle Orientation)	
35			Shell Side	Tube Side		
36	Design/Test Pressure	kPaG	1000.02 / FV	1000.02 / FV		
37	Design Temperature	C	-20 / 200.00	-20 / 200.00		
38	No Passes per Shell		2	2		
39	Corrosion Allowance	mm	1.5	0		
40	Connections	In mm	1 @ 202.718 150# RF	1 @ 254.509 150# RF		
41	Size &	Out mm	1 @ 202.718 150# RF	1 @ 254.509 150# RF		
42	Rating	Intermediate	@	@		
43	Tube No. 309U	OD 19.050 mm	Thk(Avg) 1.651 mm	Length 4.700 m	Pitch 23.812 mm	Layout 60
44	Tube Type	Plain		Material 316 STAINLESS STEEL (17 CR, 12 NI)		
45	Shell	ID 675.000 mm	OD mm	Shell Cover		
46	Channel or Bonnet			Channel Cover		
47	Tubesheet-Stationary			Tubesheet-Floating		
48	Floating Head Cover			Impingement Plate	None	
49	Baffles-Cross	Type SINGLE-SEG.	%Cut (Diam) 20.00	Spacing(c/c) 298.000	Inlet 450.000 mm	
50	Baffles-Long		Seal Type			
51	Supports-Tube		U-Bend		Type	
52	Bypass Seal Arrangement		Tube-Tubesheet Joint			
53	Expansion Joint		Type			
54	Rho-V2-Inlet Nozzle	162.61 kg/m-s2	Bundle Entrance 267.24		Bundle Exit 270.50 kg/m-s2	
55	Gaskets-Shell Side		Tube Side			
56	-Floating Head					
57	Code Requirements ASME VIII Div.1				TEMA Class R	
58	Weight/Shell 4471.14		Filled with Water 6546.01		Bundle 2375.16 kg	
59	Remarks: 1. 2 nos. 2" 150# WNRF vent and drain nozzles on shellside.					

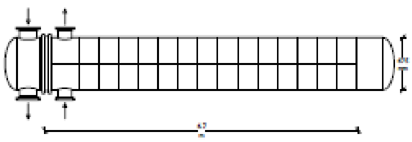


Table F.15: 2nd stage flash gas compressors coolers' datasheet

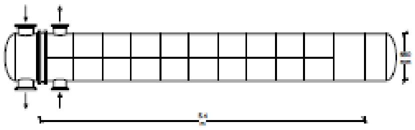
8	Service of Unit	FGC Interstage Cooler Train B			Item No.	E-T7152
9	Size	680.000 x 5399.93 mm	Type BFU	Horz.	Connected In	1 Parallel 1 Series
10	Surf/Unit (Gross/Eff)	245.07 / 242.44 m2	Shell/Unit	1	Surf/Shell (Gross/Eff)	245.07 / 242.44 m2
11			PERFORMANCE OF ONE UNIT			
12	Fluid Allocation		Shell Side		Tube Side	
13	Fluid Name		Water		Blend 1	
14	Fluid Quantity, Total	kg/hr	65241.3		28495.2	
15	Vapor (In/Out)				28495.2	20336.1
16	Liquid		65241.3	65241.3		7364
17	Steam					
18	Water					795
19	Noncondensables					
20	Temperature (In/Out)	C	35.00	63.90	107.60	45.00
21	Specific Gravity		0.9935	0.9809		0.6319
22	Viscosity	mN-s/m2	0.7192	0.4403	0.0110	0.0100 V/L 0.2067
23	Molecular Weight, Vapor					
24	Molecular Weight, Noncondensables					
25	Specific Heat	kJ/kg-C	4.1801	4.1901	2.1200	1.9100 V/L 2.542
26	Thermal Conductivity	W/m-C	0.6237	0.6585	0.0300	0.0200 V/L 0.119
27	Latent Heat	kJ/kg			1549.05	391.144
28	Inlet Pressure	kPa	651.340		701.340	
29	Velocity	m/s	0.41		11.88	
30	Pressure Drop, Allow/Calc	kPa	100.002	36.748	30.000	29.089
31	Fouling Resistance (min)	m2-K/W	0.000250		0.000150	
32	Heat Exchanged W	2201321		MTD (Corrected)	16.8 C	
33	Transfer Rate, Service	540.67 W/m2-K	Clean	817.04 W/m2-K	Actual	601.21 W/m2-K
34		CONSTRUCTION OF ONE SHELL			Sketch (Bundle/Nozzle Orientation)	
35			Shell Side	Tube Side		
36	Design/Test Pressure	kPaG	1000.02 / FV	1000.02 / FV		
37	Design Temperature	C	-20 / 200.00	-20 / 200.00		
38	No Passes per Shell		2	2		
39	Corrosion Allowance	mm	1.5	0		
40	Connections	In mm	1 @ 202.718 150# RF	1 @ 254.509 150# RF		
41	Size &	Out mm	1 @ 202.718 150# RF	1 @ 254.509 150# RF		
42	Rating	Intermediate	@	@		
43	Tube No. 455U	OD 15.875 mm	Thk(Avg) 1.651 mm		Length 5.400 m	Pitch 19.850 mm Layout 30
44	Tube Type	Plain			Material	316 STAINLESS STEEL (17 CR, 12 NI)
45	Shell	ID 680.000 mm	OD	mm	Shell Cover	
46	Channel or Bonnet				Channel Cover	
47	Tubesheet-Stationary				Tubesheet-Floating	
48	Floating Head Cover				Impingement Plate	None
49	Baffles-Cross	Type SINGLE-SEG.	%Cut (Diam) 24.84	Spacing(c/c) 482.000		Inlet 482.000 mm
50	Baffles-Long		Seal Type			
51	Supports-Tube		U-Bend		Type	
52	Bypass Seal Arrangement		Tube-Tubesheet Joint			
53	Expansion Joint		Type			
54	Rho-V2-Inlet Nozzle	317.49 kg/m-s2	Bundle Entrance	401.66	Bundle Exit	406.79 kg/m-s2
55	Gaskets-Shell Side		Tube Side			
56	-Floating Head					
57	Code Requirements	ASME VIII Div.1			TEMA Class	R
58	Weight/Shell	5568.56	Filled with Water	7825.41	Bundle	3238.53 kg
59	Remarks:	1. 2 nos. 2" 150# WNRF vent and drain nozzles on shell side				

Table F.16: Pressure control valve T71-PCV-003's datasheet

ontrol Valve Specification	Customer : SBM 2012	Project : ENI Blk15/06-West Hub R4	Valve Tag # : T71-PCV-003
repared By :	PO # : 001.39510.000525 REV 0	Proj Num :	Page # : 47
JOLAC Engineering Sdn Bhd	Serial # : 718880.047	Quote ID : CHTan_WJVZ9689_2823	P&ID :
Shah Alam, Malaysia	Rev/By : 0.0/CHTan	Alternate :	Line :
	Application :		Date / Ver : 2012-11-26 /12.6292

Section	No.	Item	Units	Min	Cond 2	Max	Cond 4
Process Data For Control Valve Selection	1	Pipe Size, Up/Down		6.000 / 6.000			
	2	Pipe Sch, Up/Down		10S / 10S			
	3	Allow Noise/Add Attn/Type		85 / 0 /			
	4	Process Fluid		Process Gas			
	5	Design Press./Temp.		0.00 / 10.00 bar (g) / -10.00 / 110.00 °C			
	6			Min	Cond 2	Max	Cond 4
	7	Temperature	(°C)	90.000		90.000	
	8	Inlet Press	(bar (g))	7.000		7.000	
	9	Outlet Press	(bar (g))	1.500		1.500	
	10	Liq. Flow Rate	(m^3/h)	0		0	
	11	Gas Flow Rate	(Sm^3/h)	898.600		8986.000	
	12	Viscosity	(cP)	0.014		0.012	
	13	Vapor Press	(bar (a))	0.000		0.000	
	14	SG-MW		35.920		35.920	
	15	Max Shutoff / Shutoff Class		10.000 bar / Class IV			
	16	Available Air Supply		5.500 bar (g)			
	17	Valve Function		Throttling			
Calculated Data	18			Min	Cond 2	Max	Cond 4
	19	Flow Coeff.	(Cv)	12.173		113.857	
	20	Est Stroke	(Percent)	14.000		80.000	
	21	Pressure Drop	(bar)	5.500		5.500	
	22	Choke Drop	(bar)	3.928		4.531	
	23	Noise	[[c-IEC]] (dBA)	80.000		87.000	
	24	Valve Vel	(mach#)	0.050		0.495	
	25	Pipe Vel	(mach#)	0.197			
Valve Body Assembly	26	Valve Model / Body Type		Mark One / Globe / MegaStream			
	27	Size/Pressure Class/Body Form		4.00 / CL 150 / Cast			
	28	Trim # - Cv / Characteristic		3.50B Cv:141 / Equal Percent			
	29	Stages/Pass Size/Ret Guiding		1 Stage / D / / Guided			
	30	Flow Direction		Flow Under			
	31	Body Matl / Bonnet Matl		Duplex SS 22% Cr / Duplex SS 22% Cr			
	32	End Conn/Sch/Face to Face		Integral Flange / / ISA S75.08.01			
	33	Flange Finish		125 - 250 Ra			
	34	Bonnet Type		Standard /			
	35	Trim Type		P/B PTFE /			
	36	Plug Matl / Facing		Duplex SS 22% Cr / /			
	37	Plug Stem Facing/Pilot Spring		/ /			
	38	Seat Ring Matl / Facing		Duplex SS 22% Cr /			
	39	Soft Seat/Pilot Plug					
	40	Retainer Matl		Duplex SS 22% Cr			
	41	PB Design/Sleeve Mtl		Duplex SS 22% Cr			
	42	Guides Upper/Lower		Duplex 22% & GL PTFE/Duplex 22% & GL PTFE			
	43	Packing Matl / Style / Vac / Fire		PTFE V-Ring / Single / /			
	44	Packing - Live-Loaded					
	45	Bonnet Port / Body Drain		/			
	46	Bellows Type / Material		/			
	47	Body Bolting/Bonnet Flange Matl		Duplex SS 22% Cr / Duplex SS 22% Cr			
	48	Gaskets		PTFE			
	49	Gland Flange Material		Stainless Steel			
	50	Gland Flange Bolting		Stainless Steel			

Section	No.	Item	Value
Actuator	51	Act. Type/Matl	VL Cylinder / Aluminum
	52	Act. Size	50
	53	Stroke/Spring	2.50 / Dual
	54	Fail/Air-To	Close / Open
	55	Vol. Tank/Orient	/
	56	Tubing Size/Mtl	1/4" / 316 SS
	57	Fitting Mfg/Mtl	Swagelok / 316 SS
	58	Handwheel	
	59	Actuator O-Rings	Buna-N
	60		
	61		
Positioner	62	Model	Logix 3000 Series / MD
	63	Model #	3211MD-28-D6-M-04-40-0S-00
	64	Diagnostic	Advanced
	65	Comm/Signal	HART / 4 - 20 mA
	66	Housing/Conn	Stainless Steel / M20
	67	Piezo Temperature	Extended Piezo temp
	68	Shaft	Linear-D Shaft
	69	Action	4-Way
	70	Feedback	None
	71	Gauges	2 SS-SS PSI/BAR/KPA
	72	Pos Tag/Mounting	T71-PY-003 /
Pos Ind Sw	73	Model	
	74		
	75		
	76		
	77		
	78		
	79		
	80		
	81		
Solenoid	82	Model/Qty	
	83	Cv-Kv/De-en	
	84	Volt/Watt	
	85	Body/Housing Mtl	
	86	Body/Elect Conn	
	87	Port Size/Mtg	
	88	Tag/Reset-Override	
Others	89	Air Filter/Mnting	/
	90	Filter-Reg/Mnting	ASCO 342A8205GMB / Bracket
	91	Flow Booster	/
	92	Booster Config	
	93	Quick Exhaust	/
	94	SupTube/Jctn Box	/
	95	Lockup	
	96	Plate ID	
	97	Plate Type	
	98	Packaging	Standard
	99	Pwr. Sup.	
	00	Wiring Conn. Type	

Table F.17: Pressure control valve T71-PCV-013's datasheet

Control Valve Specification	Customer : SBM 2012	Project : ENI Blk15/06-West Hub R4	Valve Tag # : T71-PCV-013
Prepared By :	PO # : 001.39510.000525 REV 0	Proj Num :	Page # : 50
JOLAC Engineering Sdn Bhd	Serial # : 718880.050	Quote ID : CHTan_WJVZ9689_2826	P&ID :
Shah Alam, Malaysia	Rev/By : 0.0/CHTan	Alternate :	Line :
	Application :		Date / Ver : 2012-11-26 /12.6292

Section	No.	Item	Unit	Min	Cond 2	Max	Cond 4
Process Data For Control Valve Selection	1	Pipe Size, Up/Down		12.000 / 12.000			
	2	Pipe Sch, Up/Down		10S / 10S			
	3	Allow Noise/Add Attn/Type		85 / 0 /			
	4	Process Fluid		Process Gas			
	5	Design Press./Temp.		0.00 / 10.00 bar (g) / -10.00 / 110.00 °C			
	6			Min	Cond 2	Max	Cond 4
	7	Temperature	(°C)	90.000		90.000	
	8	Inlet Press	(bar (g))	2.000		2.000	
	9	Outlet Press	(bar (g))	0.500		0.500	
	10	Liq. Flow Rate	(m^3/h)	0		0	
	11	Gas Flow Rate	(Sm^3/h)	1770.000		17697.000	
	12	Viscosity	(cP)	0.011		0.011	
	13	Vapor Press	(bar (a))	0.000		0.000	
	14	SG-MW		43.030		43.030	
	15	Max Shutoff / Shutoff Class		10.000 bar / Class IV			
	16	Available Air Supply		5.500 bar (g)			
	17	Valve Function		Throttling			
Calculated Data	18			Min	Cond 2	Max	Cond 4
	19	Flow Coeff.	(Cv)	78.734		703.179	
	20	Est Stroke	(Percent)	13.000		68.000	
	21	Pressure Drop	(bar)	1.500		1.500	
	22	Choke Drop	(bar)	1.144		1.475	
	23	Noise	[[c-IEC]] (dBA)	74.000		85.000	
	24	Valve Vel	(mach#)	0.029		0.287	
	25	Pipe Vel	(mach#)	0.187			
Valve Body Assembly	26	Valve Model / Body Type		Mark One / Globe / MegaStream			
	27	Size/Pressure Class/Body Form		10.00 / CL 150 / Cast			
	28	Trim # - Cv / Characteristic		8.00A Cv:962 / Equal Percent			
	29	Stages/Pass Size/Ret Guiding		1 Stage / A / / Guided			
	30	Flow Direction		Flow Under			
	31	Body Matl / Bonnet Matl		Duplex SS 22% Cr / Duplex SS 22% Cr			
	32	End Conn/Sch/Face to Face		Integral Flange / / ISA S75.08.01			
	33	Flange Finish		125 - 250 Ra			
	34	Bonnet Type		Standard /			
	35	Trim Type		P/B PTFE /			
	36	Plug Matl / Facing		Duplex SS 22% Cr / /			
	37	Plug Stem Facing/Pilot Spring		/ /			
	38	Seat Ring Matl / Facing		Duplex SS 22% Cr /			
	39	Soft Seat/Pilot Plug					
	40	Retainer Matl		Duplex SS 22% Cr			
	41	PB Design/Sleeve Mtl		Duplex SS 22% Cr			
	42	Guides Upper/Lower		Duplex 22% & GL PTFE/Duplex 22% & GL PTFE			
	43	Packing Matl / Style / Vac / Fire		PTFE V-Ring / Single / /			
	44	Packing - Live-Loaded					
	45	Bonnet Port / Body Drain		/			
	46	Bellows Type / Material		/			
	47	Body Bolting/Bonnet Flange Matl		Duplex SS 22% Cr / Duplex SS 22% Cr			
	48	Gaskets		PTFE			
	49	Gland Flange Material		Stainless Steel			
	50	Gland Flange Bolting		Stainless Steel			

Section	No.	Item	Value
Actuator	51	Act. Type/Matl	VL-ES Cylinder / Carbon Steel
	52	Act. Size	150ES
	53	Stroke/Spring	6.00 / Heavy Duty
	54	Fail/Air-To	Close / Open
	55	Vol. Tank/Orient	/
	56	Tubing Size/Mtl	3/8" / 316 SS
	57	Fitting Mfg/Mtl	Swagelok / 316 SS
	58	Handwheel	
	59	Actuator O-Rings	Buna-N
	60		
	61		
Positioner	62	Model	Logix 3000 Series / MD
	63	Model #	3211MD-28-D6-M-04-40-0S-00
	64	Diagnostic	Advanced
	65	Comm/Signal	HART / 4 - 20 mA
	66	Housing/Conn	Stainless Steel / M20
	67	Piezo Temperature	Extended Piezo temp
	68	Shaft	Linear-D Shaft
	69	Action	4-Way
	70	Feedback	None
	71	Gauges	2 SS-SS PSI/BAR/KPA
	72	Pos Tag/Mounting	T71-PY-013 /
Pos Ind Sw	73	Model	
	74		
	75		
	76		
	77		
	78		
	79		
	80		
	81		
Solenoid	82	Model/Qty	
	83	Cv-Kv/De-en	
	84	Volt/Watt	
	85	Body/Housing Mtl	
	86	Body/Elect Conn	
	87	Port Size/Mtg	
	88	Tag/Reset-Override	
Others	89	Air Filter/Mnting	/
	90	Filter-Reg/Mnting	ASCO 342A8205GMB / Bracket
	91	Flow Booster	Bifold VBP-12-11-V-02 / Bracket
	92	Booster Config	1 Top 1 Bottom
	93	Quick Exhaust	/
	94	SupTube/Jctn Box	3/4" By Others /
	95	Lockup	
	96	Plate ID	
	97	Plate Type	
	98	Packaging	Standard
	99	Pwr. Sup.	
	00	Wiring Conn. Type	

Table F.18: Pressure control valve T71-PCV-010's datasheet

ontrol Valve Specification	Customer : SBM 2012	Project : ENI Blk15/06-West Hub R4	Valve Tag # : T71-PCV-010
repared By :	PO # : 001.39510.000525 REV 0	Proj Num :	Page # : 49
JOLAC Engineering Sdn Bhd	Serial # : 718880.049	Quote ID : CHTan_WJVZ9689_2825	P&ID :
Shah Alam, Malaysia	Rev/By : 0.0/CHTan	Alternate :	Line :
	Application :		Date / Ver : 2012-11-26 /12.6292

Section	No.	Item	Unit	Min	Cond 2	Cond 3	Cond 4
Process Data For Control Valve Selection	1	Pipe Size, Up/Down		8.000 / 8.000			
	2	Pipe Sch, Up/Down		10S / 10S			
	3	Allow Noise/Add Attn/Type		85 / 0 /			
	4	Process Fluid		Process Gas			
	5	Design Press./Temp.		0.00 / 10.00 bar (g) / -10.00 / 110.00 °C			
	6			Min	Cond 2	Cond 3	Cond 4
	7	Temperature	(°C)	90.000		90.000	
	8	Inlet Press	(bar (g))	7.000		7.000	
	9	Outlet Press	(bar (g))	6.500		6.500	
	10	Liq. Flow Rate	(m^3/h)	0		0	
	11	Gas Flow Rate	(Sm^3/h)	297.000		8986.000	
	12	Viscosity	(cP)	0.014		0.012	
	13	Vapor Press	(bar (a))	0.000		0.000	
	14	SG-MW		35.920		35.920	
	15	Max Shutoff / Shutoff Class		10.000 bar / Class IV			
	16	Available Air Supply		5.500 bar (g)			
	17	Valve Function		Throttling			
Calculated Data	18			Min	Cond 2	Cond 3	Cond 4
	19	Flow Coeff.	(Cv)	7.778		233.684	
	20	Est Stroke	(Percent)	16.000		90.000	
	21	Pressure Drop	(bar)	0.500		0.500	
	22	Choke Drop	(bar)	4.957		4.508	
	23	Noise [IEC]	(dBA)	<70		<70	
	24	Valve Vel	(mach#)	0.002		0.074	
	25	Pipe Vel	(mach#)	0.038			
Valve Body Assembly	26	Valve Model / Body Type		Mark One / Globe / Standard			
	27	Size/Pressure Class/Body Form		6.00 / CL 150 / Cast			
	28	Trim # - Cv / Characteristic		5.00 Cv:355.0 / Equal Percent			
	29	Stages / Design		/ / /			
	30	Flow Direction		Flow Over			
	31	Body Matl / Bonnet Matl		Duplex SS 22% Cr / Duplex SS 22% Cr			
	32	End Conn/Sch/Face to Face		Integral Flange / / ISA S75.08.01			
	33	Flange Finish		125 - 250 Ra			
	34	Bonnet Type		Standard /			
	35	Trim Type / P/B Seal Matl.		Unbalanced /			
	36	Plug Matl / Facing / Stem cover		Duplex SS 22% Cr / /			
	37	Stem Facing / Pilot Plug/Spring		/ /			
	38	Seat Ring Matl / Facing		Duplex SS 22% Cr /			
	39	Seat Style / Soft Material					
	40	Retainer Matl		Duplex SS 22% Cr			
	41	Sleeve Material					
	42	Guides Upper/Lower		Duplex 22% & GL PTFE/Duplex 22% & GL PTFE			
	43	Packing Matl / Style / Vac / Fire		PTFE V-Ring / Single / /			
	44	Packing - Live-Loaded					
	45	Bonnet Port / Body Drain		/			
	46	Bellows Type / Material		/			
	47	Body Bolting/Bonnet Flange Matl		Duplex SS 22% Cr / Duplex SS 22% Cr			
	48	Gaskets		PTFE			
	49	Gland Flange Material		Stainless Steel			
	50	Gland Flange Bolting		Stainless Steel			

Section	No.	Item	Value
Actuator	51	Act. Type/Matl	VL Cylinder / Aluminum
	52	Act. Size	100
	53	Stroke/Spring	3.00 / Standard
	54	Fail/Air-To	Close / Open
	55	Vol. Tank/Orient	/
	56	Tubing Size/Mtl	1/4" / 316 SS
	57	Fitting Mfg/Mtl	Swagelok / 316 SS
	58	Handwheel	
	59	Actuator O-Rings	Buna-N
	60		
	61		
Positioner	62	Model	Logix 3000 Series / MD
	63	Model #	3211MD-28-D6-M-04-40-0S-00
	64	Diagnostic	Advanced
	65	Comm/Signal	HART / 4 - 20 mA
	66	Housing/Conn	Stainless Steel / M20
	67	Piezo Temperature	Extended Piezo temp
	68	Shaft	Linear-D Shaft
	69	Action	4-Way
	70	Feedback	None
	71	Gauges	2 SS-SS PSI/BAR/KPA
	72	Pos Tag/Mounting	T71-PY-010 /
Pos Ind Sw	73	Model	
	74		
	75		
	76		
	77		
	78		
	79		
	80		
	81		
Solenoid	82	Model/Qty	
	83	Cv-Kv/De-en	
	84	Volt/Watt	
	85	Body/Housing Mtl	
	86	Body/Elect Conn	
	87	Port Size/Mtg	
	88	Tag/Reset-Override	
Others	89	Air Filter/Mnting	/
	90	Filter-Reg/Mnting	ASCO 342A8205GMB / Bracket
	91	Flow Booster	/
	92	Booster Config	
	93	Quick Exhaust	/
	94	SupTube/Jctn Box	/
	95	Lockup	
	96	Plate ID	
	97	Plate Type	
	98	Packaging	Standard
	99	Pwr. Sup.	
	00	Wiring Conn. Type	

Table F.19: Pressure control valve T62-LCV-005's datasheet

Control Valve Specification	Customer : SBM 2012	Project : ENI Blk15/06-West Hub R4	Valve Tag # : T62-LCV-005
Prepared By :	PO # : 001.39510.000525 REV 0	Proj Num :	Page # : 31
JOLAC Engineering Sdn Bhd	Serial # : 718880.031	Quote ID : CHTan_WJVZ9689_2807	P&ID :
Shah Alam, Malaysia	Rev/By : 0.0/CHTan	Alternate :	Line :
	Application :		Date / Ver : 2012-11-26 /12.6292

Section	No.	Item	Unit	Min	Nor	Max	Cond 4
Process Data For Control Valve Selection	1	Pipe Size, Up/Down		4.000 / 4.000			
	2	Pipe Sch, Up/Down		40 / 40			
	3	Allow Noise/Add Attn/Type		85 / 0 /			
	4	Process Fluid		Produced Water			
	5	Design Press./Temp.		0.00 / 10.00 bar (g) / 0.00 / 110.00 °C			
	6			Min	Nor	Max	Cond 4
	7	Temperature	(°C)	80.000	80.000	84.000	
	8	Inlet Press	(bar (g))	7.100	2.000	7.100	
	9	Outlet Press	(bar (g))	1.100	1.100	1.100	
	10	Liq Flow Rate	(m^3/h)	16.600	60.000	80.000	
	11	Gas Flow Rate	(Sm^3/h)	0	0	0	
	12	Viscosity	(cP)	0.400	0.400	0.400	
	13	Vapor Press	(bar (a))	0.450	0.450	0.450	
	14	SG-MW		0.940	0.940	0.940	
	15	Max Shutoff / Shutoff Class		19.800 bar / Class IV			
	16	Available Air Supply		5.500 bar (g)			
	17	Valve Function		Throttling			
Calculated Data	18			Min	Nor	Max	Cond 4
	19	Flow Coeff.	(Cv)	7.597	70.898	36.534	
	20	Est Stroke	(Percent)	13.000	81.000	56.000	
	21	Pressure Drop	(bar)	6.000	0.900	6.000	
	22	Choke Drop	(bar)	6.226	2.264	6.444	
	23	Noise [IEC]	(dBA)	<70	<70	<70	
	24	Valve Vel	(m/s)	0.569	2.057	2.743	
	25	Pipe Vel	(m/s)	2.707			
Valve Body Assembly	26	Valve Model / Body Type		Mark One / Globe / CavControl			
	27	Size/Pressure Class/Body Form		4.00 / CL 150 / Cast			
	28	Trim # - Cv / Characteristic		3.00A Cv:95 / Equal Percent			
	29	Stage		1 Stage / / /			
	30	Flow Direction		Flow Over			
	31	Body Matl / Bonnet Matl		Carbon Steel (WCB) / Carbon Steel			
	32	End Conn/Sch/Face to Face		Integral Flange / / ISA S75.08.01			
	33	Flange Finish		125 - 250 Ra			
	34	Bonnet Type		Standard /			
	35	Trim Type		Unbalanced /			
	36	Plug Matl / Facing		316 SS / Full Cont. Alloy 6 /			
	37	Plug Stem Facing		Alloy 6, LGA / /			
	38	Seat Ring Matl / Facing		316 SS / Full Bore Alloy 6			
	39	Soft Seat Material					
	40	Retainer Matl		316 SS			
	41	PB Design/Sleeve Mtl					
	42	Guides Upper/Lower		316 SS & GL PTFE/Alloy 6			
	43	Packing Matl / Style / Vac / Fire		PTFE V-Ring / Single / /			
	44	Packing - Live-Loaded					
	45	Bonnet Port / Body Drain		/			
	46	Bellows Type / Material		/			
	47	Body Bolting/Bonnet Flange Matl		B7-2H PTFE(Xylan) Coated / Carbon Steel (WCB)			
	48	Gaskets		PTFE			
	49	Gland Flange Material		Stainless Steel			
	50	Gland Flange Bolting		Carbon Steel, Zinc Plated			

Section	No.	Item	Value
Actuator	51	Act. Type/Matl	VL Cylinder / Aluminum
	52	Act. Size	50
	53	Stroke/Spring	2.00 / Standard
	54	Fail/Air-To	Close / Open
	55	Vol. Tank/Orient	/
	56	Tubing Size/Mtl	1/4" / 316 SS
	57	Fitting Mfg/Mtl	Swagelok / 316 SS
	58	Handwheel	Side Mnt/Cont Connect
	59	Actuator O-Rings	Buna-N
	60		
	61		
Positioner	62	Model	Logix 3000 Series / MD
	63	Model #	3211MD-28-D6-M-04-40-0S-00
	64	Diagnostic	Advanced
	65	Comm/Signal	HART / 4 - 20 mA
	66	Housing/Conn	Stainless Steel / M20
	67	Piezo Temperature	Extended Piezo temp
	68	Shaft	Linear-D Shaft
	69	Action	4-Way
	70	Feedback	None
	71	Gauges	2 SS-SS PSI/BAR/KPA
	72	Pos Tag/Mounting	T62-LY-005 /
Pos Ind Sw	73	Model	
	74		
	75		
	76		
	77		
	78		
	79		
	80		
	81		
Solenoid	82	Model/Qty	
	83	Cv-Kv/De-en	
	84	Volt/Watt	
	85	Body/Housing Mtl	
	86	Body/Elect Conn	
	87	Port Size/Mtg	
	88	Tag/Reset-Override	
Others	89	Air Filter/Mnting	/
	90	Filter-Reg/Mnting	ASCO 342A8205GMB / Bracket
	91	Flow Booster	/
	92	Booster Config	
	93	Quick Exhaust	/
	94	SupTube/Jctn Box	/
	95	Lockup	
	96	Plate ID	
	97	Plate Type	
	98	Packaging	Standard
	99	Pwr. Sup.	
	00	Wiring Conn. Type	

Table F.20: Pressure control valve T62-LCV-007's datasheet

Control Valve Specification	Customer : SBM 2012	Project : ENI Blk15/06-West Hub R4	Valve Tag # : T62-LCV-007
Prepared By :	PO # : 001.39510.000525 REV 0	Proj Num :	Page # : 32
JOLAC Engineering Sdn Bhd	Serial # : 718880.032	Quote ID : CHTan_WJVZ9689_2808	P&ID :
Shah Alam, Malaysia	Rev/By : 0.0/CHTan	Alternate :	Line :
	Application :		Date / Ver : 2012-11-26 /12.6292

Section	No.	Item	Units	Min	Cond 2	Max	Cond 4
Process Data For Control Valve Selection	1	Pipe Size, Up/Down		12.000 / 12.000			
	2	Pipe Sch, Up/Down		20 / 20			
	3	Allow Noise/Add Attn/Type		85 / 0 /			
	4	Process Fluid		Crude Oil			
	5	Design Press./Temp.		0.00 / 10.00 bar (g) / -10.00 / 110.00 °C			
	6			Min	Cond 2	Max	Cond 4
	7	Temperature	(°C)	87.000		89.000	
	8	Inlet Press	(bar (g))	7.000		7.000	
	9	Outlet Press	(bar (g))	1.000		1.000	
	10	Liq. Flow Rate	(m³/h)	72.100		759.700	
	11	Gas Flow Rate	(Sm³/h)	0		0	
	12	Viscosity	(cP)	14.600		16.200	
	13	Vapor Press	(bar (a))	7.970		7.980	
	14	SG-MW		0.820		0.820	
	15	Max Shutoff / Shutoff Class		10.000 bar / Class IV			
	16	Available Air Supply		5.500 bar (g)			
	17	Valve Function		Throttling			
Calculated Data	18			Min	Cond 2	Max	Cond 4
	19	Flow Coeff.	(Cv)	129.147		838.663	
	20	Est Stroke	(Percent)	24.000		66.000	
	21	Pressure Drop	(bar)	6.000		6.000	
	22	Choke Drop	(bar)	0.343		0.904	
	23	Noise [IEC]	(dBA)	---		---	
	24	Valve Vel	(m/s)	Flashing		Flashing	
	25	Pipe Vel	(m/s)	Flashing			
Valve Body Assembly	26	Valve Model / Body Type		Mark One / Globe / Standard			
	27	Size/Pressure Class/Body Form		12.00 / CL 150 / Cast			
	28	Trim # - Cv / Characteristic		9.50 Cv:1310 / Equal Percent			
	29	Stages / Design		/ / /			
	30	Flow Direction		Flow Over			
	31	Body Matl / Bonnet Matl		Carbon Steel (WCB) / Carbon Steel			
	32	End Conn/Sch/Face to Face		Integral Flange / / ISA S75.08.01			
	33	Flange Finish		125 - 250 Ra			
	34	Bonnet Type		Standard /			
	35	Trim Type / P/B Seal Matl.		Unbalanced /			
	36	Plug Matl / Facing / Stem cover		316 SS / Full Cont. Alloy 6 /			
	37	Stem Facing / Pilot Plug/Spring		Alloy 6, LGA / /			
	38	Seat Ring Matl / Facing		316 SS / Full Bore Alloy 6			
	39	Seat Style / Soft Material					
	40	Retainer Matl		316 SS			
	41	Sleeve Material					
	42	Guides Upper/Lower		316 SS & GL PTFE/Alloy 6			
	43	Packing Matl / Style / Vac / Fire		PTFE V-Ring / Single / /			
	44	Packing - Live-Loaded					
	45	Bonnet Port / Body Drain		/			
	46	Bellows Type / Material		/			
	47	Body Bolting/Bonnet Flange Matl		B7-2H PTFE(Xylan) Coated / Carbon Steel (WCB)			
	48	Gaskets		PTFE			
	49	Gland Flange Material		Carbon Steel			
	50	Gland Flange Bolting		Carbon Steel, Zinc Plated			

Section	No.	Item	Value
Actuator	51	Act. Type/Matl	VL Cylinder / Aluminum
	52	Act. Size	200
	53	Stroke/Spring	4.00 / Standard
	54	Fail/Air-To	Close / Open
	55	Vol. Tank/Orient	/
	56	Tubing Size/Mtl	3/8" / 316 SS
	57	Fitting Mfg/Mtl	Swagelok / 316 SS
	58	Handwheel	Side Mnt/Cont Connect
	59	Actuator O-Rings	Buna-N
	60		
	61		
Positioner	62	Model	Logix 3000 Series / MD
	63	Model #	3211MD-28-D6-M-04-40-0S-00
	64	Diagnostic	Advanced
	65	Comm/Signal	HART / 4 - 20 mA
	66	Housing/Conn	Stainless Steel / M20
	67	Piezo Temperature	Extended Piezo temp
	68	Shaft	Linear-D Shaft
	69	Action	4-Way
	70	Feedback	None
	71	Gauges	2 SS-SS PSI/BAR/KPA
	72	Pos Tag/Mounting	T62-LY-007 /
Pos Ind Sw	73	Model	
	74		
	75		
	76		
	77		
	78		
	79		
	80		
	81		
Solenoid	82	Model/Qty	
	83	Cv-Kv/De-en	
	84	Volt/Watt	
	85	Body/Housing Mtl	
	86	Body/Elect Conn	
	87	Port Size/Mtg	
	88	Tag/Reset-Override	
Others	89	Air Filter/Mnting	/
	90	Filter-Reg/Mnting	ASCO 342A8205GMB / Bracket
	91	Flow Booster	/
	92	Booster Config	
	93	Quick Exhaust	/
	94	SupTube/Jctn Box	/
	95	Lockup	
	96	Plate ID	
	97	Plate Type	
	98	Packaging	Standard
	99	Pwr. Sup.	
	00	Wiring Conn. Type	

Table F.21: Pressure control valve T71-PCV-004's datasheet

Control Valve Specification	Customer : SBM 2012	Project : ENI Blk15/06-West Hub R4	Valve Tag # : T71-PCV-004
Prepared By :	PO # : 001.39510.000525 REV 0	Proj Num :	Page # : 48
JOLAC Engineering Sdn Bhd	Serial # : 718880.048	Quote ID : CHTan_WJVZ9689_2824	P&ID :
Shah Alam, Malaysia	Rev/By : 0.0/CHTan	Alternate :	Line :
	Application :		Date / Ver : 2012-11-26 /12.6292

Section	#	Item	Units	Min	Cond 2	Max	Cond 4
Process Data For Control Valve Selection	1	Pipe Size, Up/Down		8.000 / 16.000			
	2	Pipe Sch, Up/Down		20 / 20			
	3	Allow Noise/Add Attn/Type		85 / 0 /			
	4	Process Fluid		Process Gas			
	5	Design Press./Temp.		0.00 / 10.00 bar (g) / -10.00 / 110.00 °C			
	6			Min	Cond 2	Max	Cond 4
	7	Temperature	(°C)	95.000		82.000	
	8	Inlet Press	(bar (g))	1.000		1.000	
	9	Outlet Press	(bar (g))	0.200		0.200	
	10	Liq. Flow Rate	(m³/h)	0		0	
	11	Gas Flow Rate	(Sm³/h)	213.700		8182.000	
	12	Viscosity	(cP)	0.012		0.010	
	13	Vapor Press	(bar (a))	0.000		0.000	
	14	SG-MW		44.100		44.100	
	15	Max Shutoff / Shutoff Class		10.000 bar / Class IV			
	16	Available Air Supply		5.500 bar (g)			
	17	Valve Function		Throttling			
Calculated Data	18			Min	Cond 2	Max	Cond 4
	19	Flow Coeff.	(Cv)	11.758		453.151	
	20	Est Stroke	(Percent)	13.000		92.000	
	21	Pressure Drop	(bar)	0.800		0.800	
	22	Choke Drop	(bar)	1.413		1.227	
	23	Noise	[[c-IEC] (dBA)	<70		86.000	
	24	Valve Vel	(mach#)	0.007		0.259	
	25	Pipe Vel	(mach#)	0.070			
Valve Body Assembly	26	Valve Model / Body Type		Mark One / Globe / MegaStream			
	27	Size/Pressure Class/Body Form		8.00 / CL 150 / Cast			
	28	Trim # - Cv / Characteristic		6.25 Cv:615.0 / Equal Percent			
	29	Stages/Pass Size/Ret Guiding		1 Stage / B / / Standard			
	30	Flow Direction		Flow Under			
	31	Body Matl / Bonnet Matl		316 SS / 316 SS			
	32	End Conn/Sch/Face to Face		Integral Flange / / ISA S75.08.01			
	33	Flange Finish		125 - 250 Ra			
	34	Bonnet Type		Standard /			
	35	Trim Type		P/B PTFE /			
	36	Plug Matl / Facing		316 SS / /			
	37	Plug Stem Facing/Pilot Spring		/ /			
	38	Seat Ring Matl / Facing		316 SS /			
	39	Soft Seat/Pilot Plug					
	40	Retainer Matl		316 SS			
	41	PB Design/Sleeve Mtl		316 SS			
	42	Guides Upper/Lower		316 SS & GL PTFE/316 SS & GL PTFE			
	43	Packing Matl / Style / Vac / Fire		PTFE V-Ring / Single / /			
	44	Packing - Live-Loaded					
	45	Bonnet Port / Body Drain		/			
	46	Bellows Type / Material		/			
	47	Body Bolting/Bonnet Flange Matl		B8M-8MA / 316 SS			
	48	Gaskets		PTFE			
	49	Gland Flange Material		Stainless Steel			
	50	Gland Flange Bolting		Stainless Steel			

Section	#	Item	Value
Actuator	51	Act. Type/Matl	VL-ES Cylinder / Carbon Steel
	52	Act. Size	100ES
	53	Stroke/Spring	4.00 / Standard
	54	Fail/Air-To	Open / Close
	55	Vol. Tank/Orient	/
	56	Tubing Size/Mtl	3/8" / 316 SS
	57	Fitting Mfg/Mtl	Swagelok / 316 SS
	58	Handwheel	
	59	Actuator O-Rings	Buna-N
	60		
	61		
Positioner	62	Model	Logix 3000 Series / MD
	63	Model #	3211MD-28-D6-M-04-40-0S-00
	64	Diagnostic	Advanced
	65	Comm/Signal	HART / 4 - 20 mA
	66	Housing/Conn	Stainless Steel / M20
	67	Piezo Temperature	Extended Piezo temp
	68	Shaft	Linear-D Shaft
	69	Action	4-Way
	70	Feedback	None
	71	Gauges	2 SS-SS PSI/BAR/KPA
	72	Pos Tag/Mounting	T71-PY-004 /
Pos Ind Sw	73	Model	
	74		
	75		
	76		
	77		
	78		
	79		
	80		
	81		
Solenoid	82	Model/Qty	
	83	Cv-Kv/De-en	
	84	Volt/Watt	
	85	Body/Housing Mtl	
	86	Body/Elect Conn	
	87	Port Size/Mtg	
	88	Tag/Reset-Override	
Others	89	Air Filter/Mnting	/
	90	Filter-Reg/Mnting	ASCO 342A8205GMB / Bracket
	91	Flow Booster	/
	92	Booster Config	
	93	Quick Exhaust	/
	94	SupTube/Jctn Box	/
	95	Lockup	
	96	Plate ID	
	97	Plate Type	
	98	Packaging	Standard
	99	Pwr. Sup.	
	00	Wiring Conn. Type	

Table F.22: Pressure control valve T71-LCV-511's datasheet

Control Valve Specification	Customer : SBM 2012	Project : ENI Blk15/06-West Hub R4	Valve Tag # : T71-LCV-511
Prepared By :	PO # : 001.39510.000525 REV 0	Proj Num :	Page # : 42
JOLAC Engineering Sdn Bhd	Serial # : 718880.042	Quote ID : CHTan_WJVZ9689_2818	P&ID :
Shah Alam, Malaysia	Rev/By : 0.0/CHTan	Alternate :	Line :
	Application :		Date / Ver : 2012-11-26 /12.6292

Section	No.	Item	Units	Min	Cond 2	Max	Cond 4
Process Data For Control Valve Selection	1	Pipe Size, Up/Down		2.000 / 2.000			
	2	Pipe Sch, Up/Down		160 / 160			
	3	Allow Noise/Add Attn/Type		85 / 0 /			
	4	Process Fluid		Condensate			
	5	Design Press./Temp.		0.00 / 115.00 bar (g) / -15.00 / 180.00 °C			
	6			Min	Cond 2	Max	Cond 4
	7	Temperature	(°C)	45.000		45.000	
	8	Inlet Press	(bar (g))	57.000		57.000	
	9	Outlet Press	(bar (g))	18.000		18.000	
	10	Liq. Flow Rate	(m^3/h)	0.500		5.000	
	11	Gas Flow Rate	(Sm^3/h)	0		0	
	12	Viscosity	(cP)	0.106		0.106	
	13	Vapor Press	(bar (a))	58.010		58.010	
	14	SG-MW		0.490		0.490	
	15	Max Shutoff / Shutoff Class		115.000 bar / Class IV			
	16	Available Air Supply		5.500 bar (g)			
	17	Valve Function		Throttling			
Calculated Data	18			Min	Cond 2	Max	Cond 4
	19	Flow Coeff.	(Cv)	0.188		1.207	
	20	Est Stroke	(Percent)	29.000		77.000	
	21	Pressure Drop	(bar)	39.000		39.000	
	22	Choke Drop	(bar)	4.685		11.339	
	23	Noise [IEC]	(dBA)	---		---	
	24	Valve Vel	(m/s)	Flashing		Flashing	
	25	Pipe Vel	(m/s)	Flashing			
Valve Body Assembly	26	Valve Model / Body Type		Mark One / Angle / Standard			
	27	Size/Pressure Class/Body Form		1.00 / CL 1500 / Cast			
	28	Trim # - Cv / Characteristic		.31 Cv:2.9 / Equal Percent			
	29	Stages / Design		/ / /			
	30	Flow Direction		Flow Over			
	31	Body Matl / Bonnet Matl		316 SS / 316 SS			
	32	End Conn/Sch/Face to Face		RTJ / / Valtek Standard			
	33	Flange Finish					
	34	Bonnet Type		Standard /			
	35	Trim Type / P/B Seal Matl.		Unbalanced /			
	36	Plug Matl / Facing / Stem cover		440C SS HT / /			
	37	Stem Facing / Pilot Plug/Spring		/ /			
	38	Seat Ring Matl / Facing		440C SS HT /			
	39	Seat Style / Soft Material					
	40	Retainer Matl		410 SS HT Nitrided			
	41	Sleeve Material					
	42	Guides Upper/Lower		316 SS & Graphite/Alloy 6			
	43	Packing Matl / Style / Vac / Fire		Graphite Rib-Braid / Single / /			
	44	Packing - Live-Loaded					
	45	Bonnet Port / Body Drain		/			
	46	Bellows Type / Material		/			
	47	Body Bolting/Bonnet Flange Matl		B8M-8MA / 316 SS			
	48	Gaskets		Spiral Graphite			
	49	Gland Flange Material		Stainless Steel			
	50	Gland Flange Bolting		Stainless Steel			

Section	No.	Item	Value
Actuator	51	Act. Type/Matl	VL Cylinder / Aluminum
	52	Act. Size	50
	53	Stroke/Spring	.75 / Dual
	54	Fail/Air-To	Close / Open
	55	Vol. Tank/Orient	/
	56	Tubing Size/Mtl	1/4" / 316 SS
	57	Fitting Mfg/Mtl	Swagelok / 316 SS
	58	Handwheel	
	59	Actuator O-Rings	Buna-N
	60		
	61		
Positioner	62	Model	Logix 3000 Series / MD
	63	Model #	3211MD-28-D6-M-04-40-0S-00
	64	Diagnostic	Advanced
	65	Comm/Signal	HART / 4 - 20 mA
	66	Housing/Conn	Stainless Steel / M20
	67	Piezo Temperature	Extended Piezo temp
	68	Shaft	Linear-D Shaft
	69	Action	4-Way
	70	Feedback	None
	71	Gauges	2 SS-SS PSI/BAR/KPA
	72	Pos Tag/Mounting	T71-LY-511 /
Pos Ind Sw	73	Model	
	74		
	75		
	76		
	77		
	78		
	79		
	80		
	81		
Solenoid	82	Model/Qty	
	83	Cv-Kv/De-en	
	84	Volt/Watt	
	85	Body/Housing Mtl	
	86	Body/Elect Conn	
	87	Port Size/Mtg	
	88	Tag/Reset-Override	
Others	89	Air Filter/Mnting	/
	90	Filter-Reg/Mnting	ASCO 342A8205GMB / Bracket
	91	Flow Booster	Bifold VBP-12-11-V-02 / Bracket
	92	Booster Config	1 Bottom
	93	Quick Exhaust	/
	94	SupTube/Jctn Box	3/4" By Others /
	95	Lockup	
	96	Plate ID	
	97	Plate Type	
	98	Packaging	Standard
	99	Pwr. Sup.	
	00	Wiring Conn. Type	

APPENDIX G: RAW RESULTS FROM HYSYS

Table G.1: HP separator simulations vs. design

HP Separator Inlet (Stream 111)								
Phase	**Parameters**	**Case_A**	**Case_B**	**Case_C**	**Case_D**	**Case_E**	**Case_F**	**Design**
Vapour	Mass Flow [kg/h]	76345.6	84681.0	76217.5	71906.2	80163.9	71706.6	**112875.0**
Vapour	Std Gas Flow [MMscfd]	71.6	79.0	71.4	69.5	76.9	69.3	**107**
Vapour	Actual Gas Flow [m^3/h]	4523.3	4999.3	4510.9	4181.5	4634.0	4169.1	**7099.1**
Vapour	Mol. Weight [kg/kmol]	21.4	21.5	21.4	20.7	20.9	20.7	**21.5**
Vapour	Mass Density [kg/m^3]	16.9	16.9	16.9	17.2	17.3	17.2	**15.9**
Vapour	Viscosity [cP]	0.012	0.013	0.012	0.012	0.012	0.012	**0.013**
Light Liquid	Mass Flow [kg/h]	468111.7	474052.8	468407.4	472106.6	478022.5	472475.2	**610599.0**
Light Liquid	Actual Volume Flow [m^3/h]	574.6	571	575.2	573.4	569.8	574.2	**710.2**
Light Liquid	Mass Density [kg/m^3]	814.7	830.3	814.3	823.3	839.0	822.8	**859.7**
Light Liquid	Viscosity [cP]	3.4	4.2	3.4	4.3	5.3	4.2	**24.0**
Heavy Liquid	Mass Flow [kg/h]	239856.8	327266.5	239842.8	242740.3	331147.2	242726.0	**740130.0**
Heavy Liquid	Actual Volume Flow [m^3/h]	242.5	330.8	242.4	242.7	331.2	242.7	**686.6**
Heavy Liquid	Mass Density [kg/m^3]	989.3	989.2	989.3	1000	1000	1000	**1078.0**

Table G.2: IP separator simulations vs. design

IP Separator Inlet (Stream 122)								
Phase	**Parameters**	**Case_A**	**Case_B**	**Case_C**	**Case_D**	**Case_E**	**Case_F**	**Design**
Vapour	Mass Flow [kg/h]	14213.6	14363.4	10581.4	16854.9	16970.1	13220	**13663.0**
Vapour	Std Gas Flow [MMscfd]	8.6	8.8	6.5	10.1	10.2	7.9	**7.6**
Vapour	Actual Gas Flow [m^3/h]	1560.1	1590.0	1164.5	1817.7	1843.4	1423.7	**1363.3**
Vapour	Mol. Weight [kg/kmol]	32.9	32.7	32.8	33.5	33.2	33.5	**35.9**
Vapour	Mass Density [kg/m^3]	9.1	9.0	9.1	9.3	9.2	9.3	**10.0**
Vapour	Viscosity [cP]	0.012	0.012	0.012	0.012	0.012	0.012	**0.013**
Vapour	Mass Flow [kg/h]	585938.9	585929.8	465114.4	587305.4	587216.6	466201.5	**599569.0**
Light Liquid	Actual Volume Flow [m^3/h]	737.8	738.0	589.9	740.3	740.2	591.9	**729.3**
Light Liquid	Mass Density [kg/m^3]	794.1	794.0	788.4	740.3	793.3	787.6	**822.1**
Light Liquid	Viscosity [cP]	2.2	2.2	2.0	2.2	2.2	1.9	**7.1**

Table G.2 (continued): IP separator simulations vs. design

IP Separator Inlet (Stream 122)								
Phase	**Parameters**	**Case_A**	**Case_B**	**Case_C**	**Case_D**	**Case_E**	**Case_F**	**Design**
Light Liquid	Mass Flow [kg/h]	64817.6	64562.5	63902.3	65481.8	65169.8	64543.5	**86971.0**
Heavy Liquid	Actual Volume Flow [m^3/h]	67.7	67.4	66.7	68.4	68.1	67.4	**81.7**
Heavy Liquid	Mass Density [kg/m^3]	957.6	957.6	957.4	957.6	957.6	957.4	**1064.0**

Table G.3: LP separator simulations vs. design

LP Separator Inlet (Stream 124)								
Phase	**Parameters**	**Case_A**	**Case_B**	**Case_C**	**Case_D**	**Case_E**	**Case_F**	**Design**
Vapour	Mass Flow [kg/h]	18706.0	18691.3	12883.7	19679.5	19679.5	13584.8	**15262.0**
Vapour	Std Gas Flow [MMscfd]	8.2	8.2	5.9	8.6	8.6	6.2	**6.9**
Vapour	Actual Gas Flow [m^3/h]	5907.5	5907.7	4123.3	6173.6	6173.6	4307.7	**4923.2**
Vapour	Mol. Weight [kg/kmol]	45.5	45.5	43.5	45.8	45.8	43.9	**44.1**
Vapour	Mass Density [kg/m^3]	3.2	3.2	3.1	3.2	3.2	3.2	**3.1**
Vapour	Viscosity [cP]	0.010	0.010	0.010	0.010	0.010	0.010	**0.010**
Light Liquid	Mass Flow [kg/h]	569086.3	569088.4	572035.7	569478.6	569451.4	572393.1	**586242.0**
Light Liquid	Actual Volume Flow [m^3/h]	704.4	704.4	701.9	704.9	704.9	702.4	**702.3**
Light Liquid	Mass Density [kg/m^3]	807.9	807.9	815.0	807.9	807.9	814.9	**834.7**
Light Liquid	Viscosity [cP]	3.0	3.0	3.6	3.0	3.0	3.6	**7.4**
Heavy Liquid	Mass Flow [kg/h]	101862.3	101869.9	95622.6	101917.7	101919.1	95689.5	**112464.0**
Heavy Liquid	Actual Volume Flow [m^3/h]	105.8	105.8	98.4	105.9	105.9	98.5	**105.6**
Heavy Liquid	Mass Density [kg/m^3]	962.4	962.5	971.7	962.7	962.7	971.7	**1065.2**

Table G.4: Electrostatic treater simulations vs. design

Electrostatic Treater Inlet (Stream 132A)								
Phase	**Parameters**	**Case_A**	**Case_B**	**Case_C**	**Case_D**	**Case_E**	**Case_F**	**Design**
Light Liquid	Mass Flow [kg/h]	569085.3	569087.7	572033.8	569477.6	569450.7	572391.2	**586242.0**
Light Liquid	Actual Volume Flow [m^3/h]	704.3	704.3	701.7	704.7	704.7	702.3	**702.3**
Light Liquid	Mass Density [kg/m^3]	808.0	808.0	815.2	808.1	808.0	815.1	**834.8**
Light Liquid	Viscosity [cP]	3.0	3.0	3.6	3.0	3.0	3.6	**6.5**

Table G.4 (continued): Electrostatic treater simulations vs. design

Electrostatic Treater Inlet (Stream 132A)								
Phase	**Parameters**	**Case_A**	**Case_B**	**Case_C**	**Case_D**	**Case_E**	**Case_F**	**Design**
Heavy Liquid	Mass Flow [kg/h]	79469.9	79469.9	79565.4	79481.6	79480.9	79576.6	**87942.0**
Heavy Liquid	Actual Volume Flow [m^3/h]	82.6	82.6	81.9	82.6	82.6	81.9	**82.6**
Heavy Liquid	Mass Density [kg/m^3]	962.4	962.4	971.6	962.6	962.6	971.7	**1065.0**

Table G.5: Test separator simulations vs. design

Test Separator Inlet (Stream Test Sep Inlet)								
Phase	**Parameters**	**Case_A**	**Case_B**	**Case_C**	**Case_D**	**Case_E**	**Case_F**	**Design**
Vapour	Mass Flow [kg/h]	15997.5	7789.0	18325.7	16016.6	7789.0	18330.6	**30241.0**
Vapour	Std Gas Flow [MMscfd]	16.2	8.6	17.6	16.2	8.6	17.6	**29.0**
Vapour	Actual Gas Flow [m^3/h]	865.5	439.4	2457.9	866.6	439.4	2460.9	**1902.0**
Vapour	Mol. Weight [kg/kmol]	19.8	18.1	20.8	19.8	18.1	20.8	**21.1**
Vapour	Mass Density [kg/m^3]	18.5	17.7	7.5	18.5	17.7	7.4	**15.9**
Vapour	Viscosity [cP]	0.011	0.011	0.011	0.011	0.011	0.011	**0.013**
Light Liquid	Mass Flow [kg/h]	121162.6	115192.1	119032.0	121101.1	115192.1	118971.3	**148728.1**
Light Liquid	Actual Volume Flow [m^3/h]	137.9	139.8	134.8	137.8	139.8	134.8	**173.0**
Light Liquid	Mass Density [kg/m^3]	878.8	824.0	882.7	878.9	824.0	882.9	**859.7**
Light Liquid	Viscosity [cP]	14.0	7.3	17.9	14.1	7.3	18.0	**24.0**
Heavy Liquid	Mass Flow [kg/h]	90529.3	-	90397.3	90529.9	-	90397.2	**167090.0**
Heavy Liquid	Actual Volume Flow [m^3/h]	88.5	-	88.4	88.5	-	88.4	**155.0**
Heavy Liquid	Mass Density [kg/m^3]	1023.2	-	1022.6	1023.2	-	1022.6	**1078.0**

Table G.6: Crude oil pumps simulations vs. design

Crude Oil Pumps							
Parameter	**Case_A**	**Case_B**	**Case_C**	**Case_D**	**Case_E**	**Case_F**	**Design**
Flow Rate [m^3/h]	717.1	717.1	714.5	717.5	717.5	715.0	**730**
Head [m]	62.9	62.9	62.3	62.9	62.9	62.4	**71.2**
Power [kW]	132.8	132.8	132.3	132.9	132.9	132.4	**151**
Density [kg/m^3]	810.6	810.6	817.8	810.6	810.6	817.7	**845**

Table G.7: Oil train heat exchangers simulations vs. design

Oil Train Heat Exchangers' Duties			
Duty [kW]	**Crude/Crude Exchanger**	**Crude Oil Heater**	**Crude Oil Cooler**
Design Case	**11860**	**12154**	**6380**
Case_A	9673	11281	1272
Case_B	10206	11693	729
Case_C	4990	10030	2100
Case_D	12355	13742	0
Case_E	12873	14124	0
Case_F	8105	12075	0

Table G.8: Injection gas compressor coolers simulations vs. design

IGC Suction Coolers' Duties				
Duty [kW]	**1st Stage Cooler**	**2nd Stage Cooler**	**3rd Stage Cooler**	**IGC Discharge Cooler**
Design Case	1127	4996	4986	3105
Case_A	401	4190	4235	2413
Case_B	489	4195	4235	2413
Case_C	529	3445	3471	1881
Case_D	114	4118	4219	2419
Case_E	157	4123	4219	2420
Case_F	222	3376	3454	1886

Table G.9: 1st stage injection gas compressor scrubbers' simulations vs. design

1st Stage IGC Suction Scrubbers (Stream 212)								
Phase	**Parameters**	**Case_A**	**Case_B**	**Case_C**	**Case_D**	**Case_E**	**Case_F**	**Design**
Vapour	Mass Flow [kg/h]	59107.8	59120.7	48775.1	57482.4	57685.9	47868.5	**61037.0**
Vapour	Std Gas Flow [MMSCFD]	50.6	50.6	41.3	50.0	50.1	41.0	**58.0**
Vapour	Actual Gas Flow [m^3/h]	3223.1	3224.5	2621.0	3211.5	3221.8	2605.1	**3741.0**
Vapour	Molecular Weight [kg/kmol]	23.4	23.4	23.7	23.0	23.1	23.4	**21.2**
Vapour	Mass Density [kg/m^3]	18.3	18.3	18.6	17.9	18.0	18.4	**16.3**
Vapour	Viscosity [cP]	0.012	0.012	0.012	0.012	0.012	0.012	**0.010**

Table G.9 (continued): 1st stage injection Gas Compressor scrubbers' simulations vs. design

1st Stage IGC Suction Scrubbers (Stream 212)								
Phase	**Parameters**	**Case_A**	**Case_B**	**Case_C**	**Case_D**	**Case_E**	**Case_F**	**Design**
Light Liquid	Mass Flow [kg/h]	298.9	349.7	498.0	1.7	3.9	86.3	**708.0**
Light Liquid	Actual Volume Flow [m^3/h]	0.5	0.5	0.8	0.0	0.0	0.1	**1.1**
Light Liquid	Mass Density [kg/m^3]	662.4	661.3	653.0	717.5	709.0	663.5	**669.0**
Light Liquid	Viscosity [cP]	0.3	0.27	0.25	0.50	0.45	0.27	**15.0**
Heavy Liquid	Mass Flow [kg/h]	238.0	258.7	231.0	137.5	145.6	130.3	**563.0**
Heavy Liquid	Actual Volume Flow [m^3/h]	0.2	0.3	0.2	0.1	0.1	0.1	**0.6**
Heavy Liquid	Mass Density [kg/m^3]	994.5	994.4	994.8	993.6	993.8	994.9	**994.0**

Table G.10: 2nd stage injection Gas Compressor scrubbers' simulations vs. design

2nd Stage IGC Suction Scrubbers (Stream 215)								
Phase	**Parameters**	**Case_A**	**Case_B**	**Case_C**	**Case_D**	**Case_E**	**Case_F**	**Design**
Vapour	Mass Flow [kg/h]	57511.6	57564.6	47052.8	57173.7	57207.3	46714.1	**61630.0**
Vapour	Std Gas Flow [MMSCFD]	49.9	49.9	40.6	49.8	49.8	40.5	**57.0**
Vapour	Actual Gas Flow [m^3/h]	924.7	924.7	745.9	925.3	925.4	746.3	**1112.0**
Vapour	Molecular Weight [kg/kmol]	23.1	23.1	23.2	23.0	23.0	23.1	**21.2**
Vapour	Mass Density [kg/m^3]	62.2	62.2	63.1	61.8	61.8	62.6	**55.4**
Vapour	Viscosity [cP]	0.014	0.014	0.014	0.014	0.014	0.014	**0.010**
Light Liquid	Mass Flow [kg/h]	1473.6	1431.4	1625.2	174.2	346.4	1059.0	**1431.0**
Light Liquid	Actual Volume Flow [m^3/h]	2.7	2.6	3.1	0.3	0.6	2.0	**2.6**
Light Liquid	Mass Density [kg/m^3]	543.7	543.9	530.4	554.9	553.0	538.1	**555.0**
Light Liquid	Viscosity [cP]	0.1	0.1	0.1	0.1	0.1	0.1	**0.1**
Heavy Liquid	Mass Flow [kg/h]	160.5	162.5	128.4	172.3	170.0	126.4	**194.0**
Heavy Liquid	Actual Volume Flow [m^3/h]	0.2	0.2	0.1	0.2	0.2	0.1	**0.2**
Heavy Liquid	Mass Density [kg/m^3]	994.2	994.2	994.1	994.2	994.2	994.1	**994.0**

Table G.11: 3rd stage injection Gas Compressor scrubbers' simulations vs. design

3rd Stage IGC Suction Scrubbers (Stream 223)								
Phase	**Parameters**	**Case_A**	**Case_B**	**Case_C**	**Case_D**	**Case_E**	**Case_F**	**Design**
Vapour	Mass Flow [kg/h]	51651.3	51700.0	41177.9	51337.6	51368.9	40869.2	**54221.0**
Vapour	Std Gas Flow [MMSCFD]	44.8	44.8	35.5	44.7	44.7	35.4	**50.0**
Vapour	Actual Gas Flow [m^3/h]	297.0	297.1	232.1	297.7	297.7	232.7	**359.0**
Vapour	Molecular Weight [kg/kmol]	23.1	23.1	23.2	23.0	23.0	23.1	**21.2**
Vapour	Mass Density [kg/m^3]	173.9	174.0	177.4	172.5	172.5	175.7	**151.1**
Vapour	Viscosity [cP]	0.021	0.021	0.021	0.021	0.021	0.021	**0.020**

Table G.12: 3rd stage injection Gas Compressor scrubbers' simulations vs. design

Injection Gas Compressors (Stream 214, 217 and 220)													
		DUTY [kW]				**Volumetric Flow Std [MMSCFD]**			**Molecular Weight [kg/kmol]**			**Remarks**
		1st Stage	**2nd Stage**	**3rd Stage**	**TOTAL**	**1st Stage**	**2nd Stage**	**3rd Stage**	**1st Stage**	**2nd Stage**	**3rd Stage**	
DESIGN CRITERIA	**Maximum**	3464	3387	2613	9546	57.4	57.4	49.9	20.32	20.33	20.33	0% Bypass Flow
	LMN Case 1	3181	3080	2076	8337	49.3	49.3	34.3	17.69	17.69	17.68	Only one compression train in operation 0% Bypass flow
	Turndown Case 1	2924	2812	1845	7581	46.7	45.6	29.7	18.81	18.81	18.81	44% Bypass flow stage 1 40% Bypass flow stage 2 19% Bypass flow stage 3
	Turndown Case 2	2401	2286	1571	6258	41.8	41.4	28.5	24.53	23.63	23.64	20% Bypass flow stage 1 23% Bypass flow stage 2 9% Bypass flow stage 3
Case_A		3235	2607	2204	8047	50.6	49.9	44.8	23.4	23.1	23.1	-
Case_B		3237	2608	2204	8049	50.6	49.9	44.8	23.4	23.1	23.1	-
Case_C		2623	2100	1727	6449	41.3	40.6	35.5	23.7	23.2	23.2	-
Case_D		3231	2610	2208	8049	50.0	49.8	44.7	23.0	23.0	23.0	-
Case_E		3231	2611	2208	8049	50.1	49.8	44.7	23.1	23.0	23.0	-
Case_F		2612	2102	1729	6443	41.0	40.5	35.4	23.4	23.1	23.1	-

Table G.13: 1st stage flash gas compressor coolers' simulations vs. design

1st Stage FGC Suction Coolers (Stream 20)								
Phase	**Parameters**	**Case_A**	**Case_B**	**Case_C**	**Case_D**	**Case_E**	**Case_F**	**Design**
Vapour	Mass Flow [kg/h]	20836.2	20821.4	15013.9	21876.5	21809.7	15115.0	**14745.0**
Vapour	Std Gas Flow [MMSCFD]	9.2	9.2	6.9	9.6	9.6	6.9	**6.915**
Vapour	Actual Gas Flow [m^3/h]	7171.9	7172.1	5241.3	7475.7	7459.9	5340.6	**5404.0**

Table G.14: 2nd stage flash gas compressor coolers' simulations vs. design

2nd Stage FGC Suction Coolers (Stream 233A)								
Phase	**Parameters**	**Case_A**	**Case_B**	**Case_C**	**Case_D**	**Case_E**	**Case_F**	**Design**
Vapour	Mass Flow [kg/h]	30819.1	30959.3	24178.3	34380.9	34436.1	27481.7	**28495.0**
Vapour	Std Gas Flow [MMSCFD]	15.4	15.5	12.4	17.1	17.3	13.1	**13.4**
Vapour	Actual Gas Flow [m^3/h]	3280.3	3314.8	2683.0	3645.3	3670.9	3832.4	**2843**

Table G.15: 1st and 2nd stage flash gas compressor coolers' duties simulations vs. design

1st and 2nd Stage FGC Suction Coolers' Duties		
Duty [kW]	**1st Stage Cooler**	**2nd Stage Cooler**
Design Case	1479	2193
Case_A	1837	2148
Case_B	1836	2163
Case_C	795	1685
Case_D	1896	2360
Case_E	1893	2368
Case_F	819	1878

Table G.16: 1st stage flash gas compressor scrubber's simulations vs. design

1st stage FGC Suction Scrubbers (Stream 231)								
Phase	**Parameters**	**Case_A**	**Case_B**	**Case_C**	**Case_D**	**Case_E**	**Case_F**	**Design**
Vapour	Mass Flow [kg/h]	16605.6	16595.9	13596.9	17526.0	17466.0	14261.6	**12595.0**
Vapour	Std Gas Flow [MMSCFD]	6.7	6.7	5.9	7.0	7.0	6.2	**6.3**
Vapour	Actual Gas Flow [m^3/h]	5528.3	5531.5	4904.9	5796.0	5782.7	5103.3	**5236.0**
Vapour	Molecular Weight [kg/kmol]	49.5	49.5	45.9	49.8	49.8	46.2	**40.1**
Vapour	Mass Density [kg/m^3]	3.0	3.0	2.8	3.0	3.0	2.8	**2.4**
Vapour	Viscosity [cP]	0.009	0.009	0.009	0.009	0.009	0.009	**0.010**
Light Liquid	Mass Flow [kg/h]	2424.6	2421.9	632.3	2491.9	2488.6	646.9	**1934.9**
Light Liquid	Actual Volume Flow [m^3/h]	3.5	3.5	0.9	3.6	3.6	0.9	**2.8**
Light Liquid	Mass Density [kg/m^3]	693.0	693.0	704.1	692.7	692.7	703.8	**696.0**
Light Liquid	Viscosity [cP]	0.34	0.34	0.38	0.34	0.34	0.38	**0.3**

Table G.16 (continued): 1st stage flash gas compressor scrubber's simulations vs. design

1st stage FGC Suction Scrubbers (Stream 231)								
Phase	**Parameters**	**Case_A**	**Case_B**	**Case_C**	**Case_D**	**Case_E**	**Case_F**	**Design**
Heavy Liquid	Mass Flow [kg/h]	1806.0	1803.6	784.6	1858.5	1855.1	806.4	**1532.0**
Heavy Liquid	Actual Volume Flow [m^3/h]	1.8	1.8	0.8	1.9	1.9	0.8	**1.5**
Heavy Liquid	Mass Density [kg/m^3]	992.1	992.1	992.1	992.1	992.1	992.1	**992.0**

Table G.17: 2nd stage flash gas compressor scrubber's simulations vs. design

2nd Stage FGC Suction Scrubbers (Stream 234)								
Phase	**Parameters**	**Case_A**	**Case_B**	**Case_C**	**Case_D**	**Case_E**	**Case_F**	**Design**
Vapour	Mass Flow [kg/h]	23677.7	23792.5	19280.7	26627.0	26685.3	22094.8	**22798.0**
Vapour	Std Gas Flow [MMSCFD]	12.7	12.9	10.5	14.2	14.3	12.0	**11.0**
Vapour	Actual Gas Flow [m^3/h]	2341.9	2370.5	1940.1	2618.4	2640.9	2209.8	**2302.8**
Vapour	Molecular Weight [kg/kmol]	37.4	37.1	36.8	37.6	37.3	37.0	**36.6**
Vapour	Mass Density [kg/m^3]	10.1	10.0	9.9	10.2	10.1	10.0	**9.9**
Vapour	Viscosity [cP]	0.011	0.010	0.011	0.010	0.010	0.010	**0.010**
Light Liquid	Mass Flow [kg/h]	6278.1	6293.6	4211.6	6781.7	6770.6	4593.4	**5461.2**
Light Liquid	Actual Volume Flow [m^3/h]	10.0	10.1	6.7	10.8	10.8	7.3	**8.7**
Light Liquid	Mass Density [kg/m^3]	625.5	625.3	632.1	625.4	625.4	632.2	**627.0**
Light Liquid	Viscosity [cP]	0.21	0.21	0.22	0.21	0.21	0.22	**0.2**
Heavy Liquid	Mass Flow [kg/h]	863.3	873.3	686.0	972.2	980.2	793.5	**793.6**
Heavy Liquid	Actual Volume Flow [m^3/h]	0.9	0.9	0.7	1.0	1.0	0.8	**0.8**
Heavy Liquid	Mass Density [kg/m^3]	992.3	992.3	992.3	992.3	992.3	992.3	**992.0**

Table G.18: Glycol scrubber's simulations vs. design

Glycol scrubber (Stream 218)								
Phase	**Parameters**	**Case_A**	**Case_B**	**Case_C**	**Case_D**	**Case_E**	**Case_F**	**Design**
Vapour	Mass Flow [kg/h]	57473.4	57526.8	47021.5	57135.9	57169.5	46683.4	**58186.0**
Vapour	Std Gas Flow [MMSCFD]	49.9	49.9	40.6	49.8	49.8	40.5	**57.3**
Vapour	Actual Gas Flow [m^3/h]	320.7	320.7	257.1	321.5	321.6	257.8	**402.4**
Vapour	Molecular Weight [kg/kmol]	23.1	23.1	23.2	23.0	23.0	23.1	**20.3**
Vapour	Mass Density [kg/m^3]	179.2	179.4	182.9	177.7	177.8	181.1	**144.6**
Vapour	Viscosity [cP]	0.021	0.021	0.022	0.021	0.021	0.021	**0.019**

Table G.18 (continued): Glycol scrubber's simulations vs. design

Glycol scrubber (Stream 218)								
Phase	**Parameters**	**Case_A**	**Case_B**	**Case_C**	**Case_D**	**Case_E**	**Case_F**	**Design**
Light Liquid	Mass Flow [kg/h]	-	-	-	-	-	-	**-**
Light Liquid	Actual Volume Flow [m^3/h]	-	-	-	-	-	-	**-**
Light Liquid	Mass Density [kg/m^3]	-	-	-	-	-	-	**-**
Light Liquid	Viscosity [cP]	-	-	-	-	-	-	**-**
Heavy Liquid	Mass Flow [kg/h]	37.9	37.8	30.9	37.8	37.8	30.9	**45.6**
Heavy Liquid	Actual Volume Flow [m^3/h]	0.04	0.04	0.03	0.04	0.04	0.03	**0.05**
Heavy Liquid	Mass Density [kg/m^3]	997.0	997.0	996.9	997.0	997.0	996.9	**996.7**

Table G.19: Produced water flash vessel simulations vs. design

Produced Water Flash Vessel (Stream 311)								
Phase	**Parameters**	**Case_A**	**Case_B**	**Case_C**	**Case_D**	**Case_E**	**Case_F**	**Design**
Light Liquid	Mass Flow [kg/h]	-	-	-	-	-	-	**3050.5**
Light Liquid	Actual Volume Flow [m^3/h]	-	-	-	-	-	-	**3.6**
Light Liquid	Mass Density [kg/m^3]	-	-	-	-	-	-	**845.0**
Light Liquid	Viscosity [cP]	-	-	-	-	-	-	**7.3 / 5.9**
Heavy Liquid	Mass Flow [kg/h]	118948.5	28160.6	125211.9	119491.7	28654.4	125764.0	**384104.0**
Heavy Liquid	Actual Volume Flow [m^3/h]	118.1	29.4	124.6	118.6	29.9	125.2	**361.0**
Heavy Liquid	Mass Density [kg/m^3]	1007.4	957.3	1004.8	997.0	957.2	1004.6	**1064.0**

Table G.20: Produced water cooler simulations vs. design

Produced Water Cooler' Duties	
Duty [kW]	**Value**
Design Case	6028
Case_A	360
Case_B	5183
Case_C	0
Case_D	353
Case_E	5179
Case_F	0

Table G.21: Cooling medium consumers duties simulations vs. design

Cooling Medium Consumers Duties							
Duty [kW]	**IGC 1st Stage Cooler**	**IGC 2nd Stage Cooler**	**IGC 3rd Stage Cooler**	**IGC Discharge Cooler**	**FGC 1st Stage Cooler**	**FGC 2nd Stage Cooler**	**Total Cooling Load (Design)**
Design Case	1127	4996	4986	3105	1479	2193	32100
Case_A	401	4190	4235	2413	1837	2148	26463
Case_B	489	4195	4235	2413	1836	2163	26665
Case_C	529	3445	3471	1881	795	1685	21133
Case_D	114	4118	4219	2419	1896	2360	25996
Case_E	157	4123	4219	2420	1893	2368	26099
Case_F	222	3376	3454	1886	819	1878	20573

Table G.22: Heating medium consumers duties simulations vs. design

Heating Medium Consumers Duties					
Duty [kW]	**Crude Oil Heater**	**Fuel Gas Pre-Heater**	**HP Fuel Gas Superheater**	**LP Fuel Gas Superheater**	**Total Heating Load (Design Case)**
Design Case	12142	369	157	104	12774
Case_A	11281	176	66	34	11556
Case_B	11693	176	66	34	11969
Case_C	10030	180	66	34	10311
Case_D	13742	175	66	34	14016
Case_E	14124	175	66	34	14399
Case_F	12075	179	66	34	12354

Table G.23: New blend Reid vapour pressure and true vapour pressure simulations vs. design

New Blend RVP and TVP							
Parameter	**Case_A**	**Case_B**	**Case_C**	**Case_D**	**Case_E**	**Case_F**	**Design**
RVP at 37.8°C [psia]	5.61	5.63	7.30	5.72	5.73	7.42	**≤ 10**
TVP at 50°C [psia]	14.19	14.20	19.38	14.22	14.22	19.34	**≤ 14.7**

Table G.24: Cooling duties for the major seawater heat exchangers simulations vs. design

Cooling Duties for the Major Seawater Heat Exchangers				
Duty [kW]	**Produced Water Cooler**	**Crude Oil Cooler**	**HP Separator PW Cooler**	**Total Cooling Load (Design)**
Design Case	6028	6380	10697	23105
Case_A	360	1272	0	1632
Case_B	5183	729	13	5924
Case_C	0	2100	0	2100
Case_D	353	0	0	353
Case_E	5179	0	0	5179
Case_F	0	0	0	0

Table G.25: Fuel gas scrubber simulations vs. design

Fuel Gas Scrubber (Stream 252)									
Phase	**Parameters**	**Case_A**	**Case_B**	**Case_C**	**Case_D**	**Case_E**	**Case_F**	**Design Normal Case**	**Design Start-Up Case**
Vapour	Mass Flow [kg/h]	10858.6	10874.1	10840.9	10868.9	10876.2	10839.0	**22723.0**	**18646.0**
Vapour	Std Gas Flow [MMSCFD]	9.8	9.8	9.7	9.8	9.8	9.8	**21.0**	**18.0**
Vapour	Actual Gas Flow [m^3/h]	394.1	394.1	390.9	394.4	394.5	391.5	**893.0**	**1211.0**
Vapour	Molecular Weight [kg/kmol]	22.3	22.3	22.3	22.3	22.3	22.3	**20.9**	**20.8**
Vapour	Mass Density [kg/m^3]	27.6	27.6	27.7	27.6	27.6	27.7	**25.5**	**15.4**
Vapour	Viscosity [cP]	0.012	0.012	0.012	0.012	0.012	0.012	**0.010**	**0.010**
Light Liquid	Mass Flow [kg/h]	669.0	665.2	752.6	609.7	610.1	696.0	**1107.0**	**0.3**
Light Liquid	Actual Volume Flow [m^3/h]	1.1	1.1	1.3	1.0	1.0	1.2	**1.8**	**0.0003**
Light Liquid	Mass Density [kg/m^3]	591.4	591.0	583.5	592.1	592.4	585.8	**601.0**	**860.0**
Light Liquid	Viscosity [cP]	0.18	0.18	0.17	0.18	0.18	0.17	**0.2**	**8.4**
Heavy Liquid	Mass Flow [kg/h]	-	-	-	-	-	-	**-**	**-**
Heavy Liquid	Actual Volume Flow [m^3/h]	-	-	-	-	-	-	**-**	**-**
Heavy Liquid	Mass Density [kg/m^3]	-	-	-	-	-	-	**-**	**-**

Table G.26: Fuel gas operating parameters simulations vs. design

Fuel Gas Operating Parameters (Stream 253 and 253-2)									
Fuel Gas – Normal – sourced from outlet of TEG contactor									
Parameter	**Case_A**	**Case_B**	**Case_C**	**Case_D**	**Case_E**	**Case_F**	**Design Minimum**	**Design Maximum**	**Power Generation Turbine Requirement**
Molecular Weight [kg/kmol]	22.3	22.3	22.3	22.3	22.3	22.3	**17.8**	**22.5**	
LHV [MJ/Sm^3]	41.8	41.8	42.8	41.8	42.7	42.7	**33.3**	**45.6**	
HHV [MJ/Sm^3]	46.1	46.0	47.1	46.0	47.0	47.0	-	-	
Wobbe Index (Simulation) [MJ/Sm^3]	52.5	52.4	53.6	52.4	53.5	53.5	-	-	
Gas Temperature [°C]	37.1	37.0	36.8	36.7	36.6	36.6	-	-	
Wobbe Index (Corrected at T°C) [MJ/Sm^3]	46.0	45.9	47.0	46.0	46.9	46.9	**40.90**	**49.80**	**37 - 49**
Fuel Gas – Start-Up – Sourced from Hp separator									
Molecular Weight [kg/kmol]	21.4	21.5	21.4	20.7	20.9	20.7	**20.8**	**21.8**	
LHV [MJ/Sm^3]	40.7	39.7	41.0	39.6	38.7	39.9	**35.0**	**41.6**	
HHV [MJ/Sm^3]	44.9	43.8	45.2	43.7	42.7	44.0	-	-	
Wobbe Index (Simulation) [MJ/Sm^3]	52.1	50.8	52.5	51.6	50.3	51.9	-	-	
Gas Temperature [°C]	69.4	69.5	69.4	55.4	55.5	55.4	-	-	
Wobbe Index (Corrected at T°C) [MJ/Sm^3]	43.4	42.3	43.7	43.8	42.7	44.1	**36.30**	**44.10**	**37 - 49**

Table G.27: Fuel gas heat exchangers simulation vs. design

Fuel Gas Heat Exchangers Duties			
Duty [kW]	**Fuel Gas Pre-Heater**	**HP Fuel Gas Superheater**	**LP Fuel Gas Superheater**
Design Case	369	157	106
Case_A	176	66	34
Case_B	176	66	34
Case_C	180	66	34
Case_D	175	66	34
Case_E	175	66	34
Case_F	175	66	34