SAGD WELL-PAD

PROJ 396 - CAPSTONE PROJECT

SOUTHERN ALBERTA INSTITUE OF TECHNOLOGY

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1. EXECUTIVE SUMMARY

A Steam Assisted Gravity Drainage (SAGD) operation well-pad is designed, simulated and sized. The design parameters are followed, and objectives are met. The bitumen flowrate is specified at 30 m^3/d and gas flow rate at 150 m^3/d, for a single well. A total of six well at the well-pad transport 786m^3/d of emulsion and 12,965 m^3/d of gas to the Central Processing Facility (CPF). At the well-pad, three kinds of separation are taking place. The test separation is testing the quality and content of the bitumen produced, the group separation is separating the gases from the liquid to be sent to the CPF and the produced gas separation is removing the water from the gas before sending it to the CPF.

The simulation of the well-pad is performed on *AspenHYSYS* and an iterative design process is employed. Athabasca Bitumen assay is used to define the extracted bitumen stream properties and composition[1]. A pure gas system was adopted where the produced gas is pre-separated from the emulsion by the virtue of the well design. A manifold is designed that makes the testing of individual wells possible without the need for multiple Test Separators. Each well is tested on a rotational basis as the flow from the remaining wells is directed into the Group Separator. The Group Separator uses a 2-phase separator and the Test Separator uses a 3-phase separator. 3-Phase separation required an injection of diluent to achieve desired separation. 1,470 kg/hr of CFT Fort Saskatchewan Condensate is required.

The Group Separator has dimensions of 6.08 m in length and 2.03 m diameter. The vessel has horizontal orientation and an L/D (length-diameter) ratio of 3. The vessel is designed for a liquid volumetric inlet flowrate of 27.15 m^3/h with a residence time of 20 minutes. The methodology is adapted from the GPSA (11th and 14th editions). The design and simulation are successful. The design parameters are observed, and the product is sent to the CPF. Two pipelines, one for gas and one for emulsion carry the material to the battery. The emulsion travels a mass flowrate of 34,000 kg/hr and the gas at 1,302 kg/hr. The emulsion sent to the CPF is approximately 77% water and the remaining is bitumen. The gas composition is composition is mostly n-butane, i-pentane, n-pentane, i-butane, and methane.

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[1] Appendix K

2. INTRODUCTION

Steam Assisted Gravity Drainage (SAGD) technology is used to produce bitumen from the oil sands by injecting steam into the reservoir. The steam heats the bitumen to reduce its viscosity, allowing easier flow and is collected with the condensed steam. The bitumen is then pumped to the surface for testing and separating. The recovered water is treated and recycled. The produced gas, and bitumen-water mixture are sent to the CPF in separate emulsion and vapor pipelines.

This project is intended to design a SAGD well pad with six wells using a process simulation software called Aspen *HYSYS*. The simulation requires mimicking the well conditions, testing, separation and delivery of the produced fluids to the CPF. The well-pad operation includes equipment such as Test Separators and Group Separators, Produced Gas Separators, Pumps, Compressors and Coolers. All production is directed through a Group Separator for bulk separation of gas from the liquids. A Three-Phase Test Separator is used to verify wells individually for efficiency and provides detailed information concerning the well being tested such as water, oil and vapor flow. The produced products are sent to the CPF for further processing, such as oil treating, produced water de-oiling, water treatment, and steam generation.

A process flow diagram of the operation is generated using an AutoCAD software to indicate the general flow of plant processes and equipment. The PFD shows a generalized process flow of the well pad design with major equipment and processes. The report will also show the sizing calculation of the equipment of the separators, pumps and exchangers.

3. INPUT DATA

The objective of this project is to design and simulate a Steam Assisted Gravity Drainage operation well pad. Design parameters[2] are provided with the intention of guiding us but not limiting our ability to experiment with other options. The scope of the project is limited to the well pad and the battery limit conditions served as our target. The inlet conditions for the well pad are designed to mimic bitumen conditions extracted from the well. Two components that are produced from bitumen production in a SAGD process are oil & gas, and water is recovered. The bitumen volume flow rate per well is 30 m^3/d and a series of six wells.

Temperature (°C)	Viscosity (cSt)
@4.40°C	4250000
@15.5 °C	600000
@37.8 °C	27000
@50.0 °C	7500
@ 98.8 °C	-
@ 135 °C	50

Table 2. Viscosity Curve Data

Corresponding gas-oil-ratio (GOR) and steam-oil-ratio (SOR) were specified at 5 m of non-condensable gas per cubic meter of bitumen and 3.5 m^3 of cold-water equivalent per cubic meter of bitumen, respectively. The volume of the steam is expressed in cold-water equivalency (CWE) to simplify the volume measurement as steam volume changes with pressure and temperature. CWE volumetric flow is specified at 4.30 m^3/h and the gas the flow rate at 6.25m^3/h. The inlet composition of the gas is 80% methane, 19.5% carbon dioxide and 0.5% hydrogen sulfide, in mole percent. A series of initial boiling points with their corresponding percent bitumen content (Table 1) and viscosities (Table 2) for the bitumen characterization are detailed as well.

Distilled (% vol)	Temperature (°C)
IBP	217
5%	320
10%	350
15%	370
20%	405
25%	422
30%	448
35%	475
40%	498
45%	525
Residue	55 % vol

Table 1. Distillation Curve Data

The casing gas well head pressure is given at 1,000 kPag with the well-pad limit pressure of 400 kPag. The emulsion well-pad limit[3] pressure and temperature are specified at 500 kPag and 200°C, respectively.

[2] Appendix A
[3] Appendix A

4. METHODOLOGY

4.1 Iterative Designing

Iterative designing is carried out in the execution of this project. The project was progressively refined with the help of the project sponsor and followed the methodology illustrated in Figure 1. After the initial discussion with the sponsor,

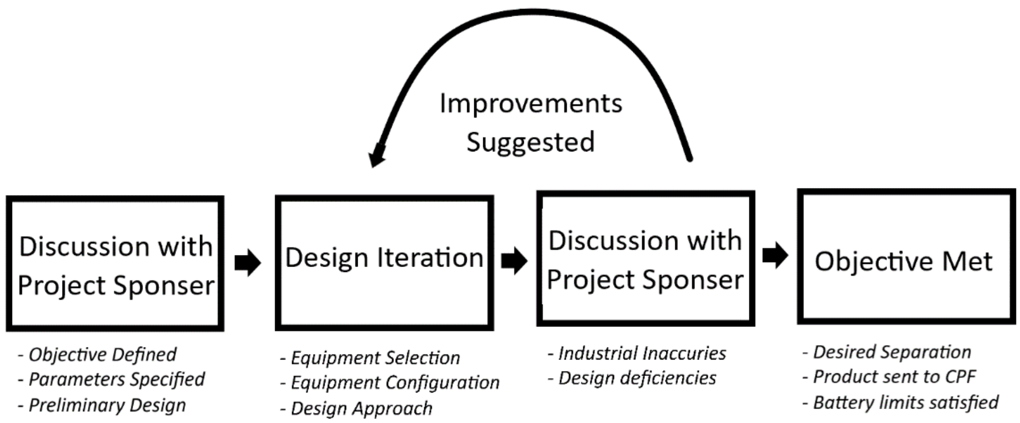

Figure 1. Methodology Flow Path

objectives are defined, parameters specified, and a preliminary design is discussed. Next, a design is built utilizing *AspenHYSYS* where the approach is selected, inlet streams are defined, and the equipment is configured and simulated. Steps taken to simulate the well-pad are as follows:

1. Defining streams
2. Imitating wells
3. Creating a manifold
4. Group Separation
5. Test Separation
6. Produced Gas Separation
7. Pressurization of fluids
8. Delivery to Central Processing Facilities

The simulation of the process is then followed by consultation with the project sponsor where process flaws are discussed; such as industrial accuracy, industry conventions and rules, inefficiencies and operational problems (i.e. cavitation). The suggested improvements are implemented, and the cycle is followed until the objective is met. The process simulator is at the heart of this project, its calculative power and functionality, combined with the iterative design process that is implemented, resulted in the successful completion of the project. The desired separation takes place, the battery limits are satisfied, and the product is sent to the Central Processing Facility in an effective manner.

Seven major iterative designs are built for the well-pad. The iterative design methodology is illustrated best in Table 1. It describes the design features that are unique to that iteration, the issue with that element and the solution implemented.

Design Iteration	Design Feature	Design Problem	Solution
1	*Distillation Curve data used for the characterization of bitumen*	*Did not mimic industrially accurate bitumen properties*	*Athabasca Bitumen is used from HYSYS predefined assays.*
2	*Test Separator designed for combined emulsion from well*	*Test Separator are meant for individual well analysis*	*Manifold designed where testing is done on rotational basis*
3	*3-phase separation*	*Desired separation is unachievable*	*Diluent is added*
4	*Three pipelines to CPF*	*Uneconomical, not required*	*System designed for two pipelines: emulsion and gas.*
5	*Mixing of emulsion and water streams for single pipeline*	*Hot emulsion causes thermal flashing causing cavitation*	*Relocation of Pumps and cooling of emulsion*
6	*3-phase separator for group separation*	*3-phase separation only required for test separation*	*Converted to 2-phase separation*
7	*Combined system*	*Industrially Inaccurate*	*Pure gas system adopted*

Table 3. Design Iteration Description

4.2 Group Separator Sizing

The GPSA (14th Edition, Section 7) [1] is used in understanding and sizing[4] of the Group Separator. Orientation determination and the internals are selected with its aid. Residence time and L/D ratios are based on industry experience. Design equations[5] for verification of the effectivity of the selected Horizontal Separator are adapted from the (GPSA 11th Edition, Section 7) [2]. Horizontal liquid droplet velocities and vertical liquid droplet velocities are compared to verify whether the length of the separator is sufficient for the liquid droplets to fall to the liquid surface before leaving the vessel. The segmental areas of the vessel for liquid droplet velocity calculation are acquired through the *Koch-Glitsch Tray Manual 4900*.

[4] Appendix L
[5] Appendix M

5. DISCUSSION

5.1 Bitumen Characterization

The process simulator, *AspenHYSYS*, enables us to design the SAGD well-pad based on the given parameters[6]. After the preliminary process design, the characterization of bitumen is performed. *HYSYS* is unable to characterize the provided distillation and viscosity curves with desirable accuracy. Several attempts made using the *Oil Manager* feature in *HYSYS* (using the densities and viscosities to create pseudo components) resulted in failure. After an investigation of the problem, the evidence suggested that specifying a bulk density for the bitumen would resolve the issue and result in a suitable blend. The generated blend did not mimic true industry conditions. *HYSYS* Athabasca bitumen[7] is used instead to stay true to actual process conditions and properties. This decision allows us to design the well-pad with industrial accuracy.

5.2 Design Approach

The imitation of the well-heads in the well-pad can be approached with three distinct designs. The purpose of this section is to mimic well-head effluent. The first option is the combined system (Figure 2); where the oil, gas and water are combined. The second is the pure gas system (Figure 3) where the gas is kept separated from oil-water mix. The third is using *HYSYS*'s Oil and Gas Feed when defining feed conditions and compositions for a material stream. Here GOR and SOR can be defined along with density and viscosity data. This approach is not employed as the other two (pure gas and combined) methods are more intuitive. These systems dictate the outlet well-head feed for our simulation. The combined system where

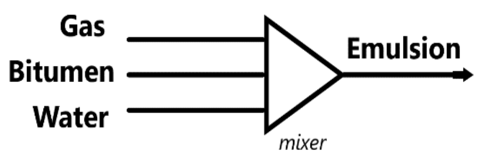

Figure 2. Combined System Process Flow Diagram

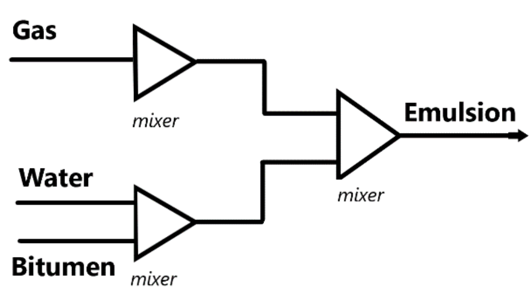

Figure 3. Pure Gas System Process Flow Diagram

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[6] Appendix A
[7] Appendix K

all gas, water and oil are emulsified is employed in the initial iteration. Three inlet streams were created and defined based on the given parameters[8]. To mimic well-head outlet conditions, all three streams are combined with the use of the mixer function, and is repeated six times, once for every well. It is later discovered, upon research, the pure gas system is industrially accurate compared to the combined gas system. The pure gas system describes the produces gas as a separate stream. This is because the gas is drawn out from the casing resulting in a degree of pre-separation.

5.3 Manifold

The emulsion is sent to the Group Separator and the Test Separator. According to Schlumberger *[3]*, Test Separator is required to "diagnose well problems, evaluate production performance of individual wells and manage reserves properly." A Test Separator is meant for an individual well, and since it is uneconomical to equip six wells with six Test Separators, a manifold is designed where each well is tested on a rotational basis, therefore only requiring one Test Separator. A simple manifold design[9] was implemented where emulsion from each well is spilt into two streams, one intended for the Test Separator and other for the Group Separator, using *HYSYS*'s Split function. All the streams for the Test Separator are combined using a mixer and similar is done for the Group Separator. To make this flow pattern work, deliberate split ratios are defined. To test individual well-head effluent the split-ratio of just one Test Separator stream is required to be set to *1.00*; signifying all

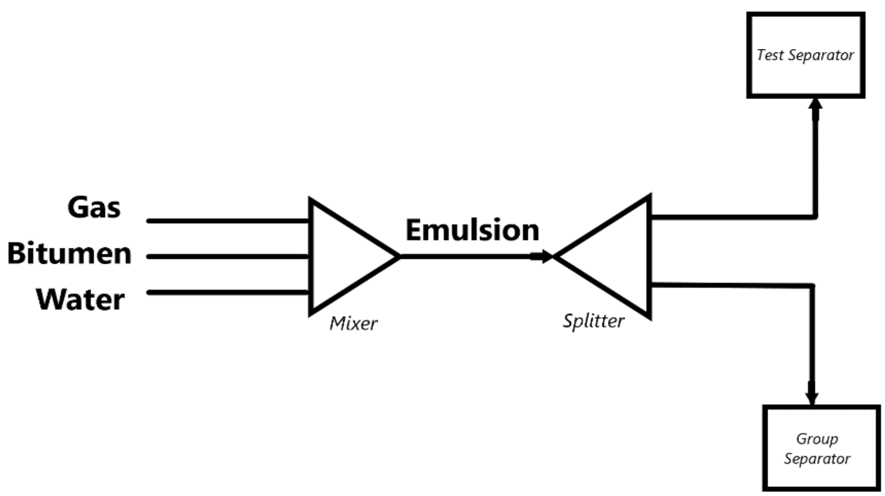

Figure 4. Simplified Manifold Design for 1 Well

[8] Appendix A
[9] Appendix E

effluent from the given well is diverted into the Test Separator stream. The split ratios are reversed for all the other well-heads. At any given time, all the flow from one well-head is being sent to the Test Separator and the emulsion flow from the remaining five wells is being sent to the Group Separator. This straightforward design eliminates the need for multiple Test Separators (Figure 4).

5.4 Group Separation

The 2-phase separator[10] is intended to separate the liquid components from the gas components. An earlier design iteration employed a 3-phase separator where gas, oil and water separation took place. This is redundant as this degree of separation is not required on the well pad. The reason to this is well-pads are mostly kilometers away from the Central Processing Facilities (CPF) and a 3-phase separation will result in three effluent streams demanding three pipelines to transport the fluid. To economize the process only gases and liquids are separated at the well-pad, requiring only two pipelines for the consequent separation to be taken place in the CPF. The vapor effluent from the Group Separator, vapor effluent from the Test Separator and the gas from the well-head are all cooled. This is to condense the water vapor and avoid it from entering the gas pipeline.

5.5 Test Separation and Diluent Injection

Unlike the group separation, which requires only 2-phase separation, the test separation, by definition, demands a 3-phase separation. Though the Test Separator[11] separates the three phases, the water and oil are recombined for economical transport as described above. Since the water and bitumen density are so close, at 1015kg/m^3 and 1016 kg/m^3, respectively, an unaided separation is impossible attain. Addition of diluent to the emulsion is necessary to facilitate the separation. The diluent is usually a natural gas condensate with a relatively low density ranging from 658-759 kg/m3. The diluent of choice is CFT Fort Saskatchewan Condensate[12]. Its compositional data is retrieved from crudemonitor.ca *[4]* and facilitates the desired dilution. Ideally a 50 kg/m^3 density differential between bitumen and water is required for effective separation. The amount of diluent added is controlled by the Adjust function. The target variable is the liquid mass density of the bitumen which is set at 965kg/m^3 and the object variable is the mass flow rate of the inlet diluent which is calculated by *HYSYS* to be

[10] Appendix G
[11] Appendix F
[12] Appendix B

at 1470 kg/hr. The diluent is mixed[13] with the bitumen before entering the Test Separator. A control valve reduces the pressure of the dilbit (diluent-bitumen mixture) from 1090 kPa to 700 kPa. The oil and water are recombined and pumped to the CPF. The vapor stream on the other hand is combined with the vapor stream from the Group Separator and the produced gas stream from the well-head, for delivery to the CPF.

5.6 Pure Gas System

In the final design iteration[14], a pure gas system[15] is adopted – a slightly complex but industrially accurate design. The distinction lies in the imitation of the well-head. In the previous design the gas, oil and water were mixed into one stream. This, in fact, is not an accurate description of actual well-head effluent. The gas is collected from a different compartment of the wellhead – the annular space called the casing. This results in pre-separation of the gas from the emulsion components. Thus, the design is adjusted for independent gas wellhead streams. In this scenario, the high-pressure casing gas is combined with the Group Separator gas outlet and Test Separator gas outlet it is then depressurized, cooled and flows into a water knockout drum[16]. The goal is to remove all the water and collect the non-condensable gases. An Aerial Cooler is used which decreases the gas temperature from 140°C to 65°C condensing more of the water in the stream. The gas and water are then separated. The produced gas is sent to the CPF, the water is combined with emulsion streams and pumped to the CPF.

5.7 Utilities

Pump location determination is precarious as locating it in the final outlet stream[17] exposes it to cavitation. The reason for the cavitation is discovered to be thermal flashing caused by the mixing of water from the gas water knockout drum (at 65°C) and hot emulsion from the Group Separator (at 140°C). This creates tiny gas bubbles in the stream and deteriorates the functionality of the pump. Locating the pump on the streams before the flashing takes place and equalizing the pressure on the other streams before mixing can mitigate the cavitation. Unfortunately, equalizing the

[13] Appendix F
[14] Appendix D
[15] Appendix I
[16] Appendix H
[17] Appendix J

pressures meant, either, increasing the vessel pressures to 2,000 kPa or equipping all outlet streams with pumps; the former is ineffective, and latter is uneconomical. The implementation of a Cooler on the hot emulsion stream solves the problem in a cost-effective manner. The hot emulsion is now cooled to 80°C which eliminates thermal flashing – thus cavitation. Furthermore, this approach only warrants one pump whereas multiple or a minimum of two were required in the previous iterations.

6. RESULTS

6.1 Material Balance

The lack of constraints such as equipment configurations and rigid specifications gave the creative freedom to design various simulations, assess their industrial accuracy, cost effectiveness and equipment longevity (i.e. cavitation elimination). As evident from the Material Balance (Table 4) at steady state conditions the input mass flow rate of 35320 kg/hr equals the output mass flow.

IN		OUT	
Stream Name	**Mass Flow (kg/h)**	**Stream Name**	**Mass Flow (kg/h)**
Water	4366	*Emulsion to CPF*	34000
athabasca bitumen-3	1270	*Pressurized Gas to CPF*	1302
Water-2	4366		
athabasca bitumen-4	1270		
Water-3	4366		
athabasca bitumen-2	1270		
Water-4	4366		
athabasca bitumen-5	1270		
Water-5	4366		
athabasca bitumen-6	1270		
Water-6	4366		
athabasca bitumen	1270		
Gas-6	5.706		
Gas-3	5.706		
Gas	5.706		
Gas-2	5.706		
Gas-4	5.706		
Gas-5	5.706		
CFT DILUENT	1470		
TOTAL	**35320**	**TOTAL**	**35302**

Table 4. Well-Pad Material Balance

The well pad produces 1302 kilograms of gas per hour with much of the composition[18] being n-butane, i-pentane, n-pentane, i-butane, methane, carbon dioxide, and water vapor. The remaining 34000 kg/hr mass output is the emulsion where 26158 kg/hr is water the rest is a mixture[19] of pseudo components as characterized by Athabasca Bitumen. It is important to note there is some sulfur content at approximately 105 kg/hr. The exact composition analysis of the output

[18] Appendix O
[19] Appendix N

flows is not required at the well-pad as it is to be processed at the CPF. The Test Separator tests a 1365 kg/hr of oil, 4065 kg/hr of water and 1573 kg/hr of gas. The vapor outlet composition is mostly n-butane, i-pentane, n-pentane, i-butane and water vapor. The composition of the gas from the well-head is mostly methane, these of the above mentioned gaseous hydrocarbons is a result diluent vaporization. To achieve the desired separation, CFT Diluent[20] is required with a density of 644.9 kg/m^3 and an inlet flowrate of 1470 kg/hr.

6.2 Energy Balance

As described by Table 5, the total input and output energy almost equalize with a slight discrepancy; which can be explained by calculative inconsistencies. Energy in the system is -4.12E+08 and energy out is -4.13E+08. There are four energy streams that are consuming energy, namely, the two Coolers, the Pump and the Compressor, hence the positive energy. The negative energies are describing the heat flow derived from the molar enthalpy and molar flow.

IN		OUT	
Stream Name	**Energy Flow (kJ/h)**	**Stream Name**	**Energy Flow (kJ/h)**
Water	-6.59E+07	*Q-100*	5.86E+06
athabasca bitumen-3	-2.35E+06	*KewlE*	8.57E+06
Water-2	-6.59E+07	*Emulsion to CPF*	-4.24E+08
athabasca bitumen-4	-2.35E+06	*Pressurized Gas to CPF*	-3.10E+06
Water-3	-6.59E+07		
athabasca bitumen-2	-2.35E+06		
Water-4	-6.59E+07		
athabasca bitumen-5	-2.35E+06		
Water-5	-6.59E+07		
athabasca bitumen-6	-2.35E+06		
Water-6	-6.59E+07		
athabasca bitumen	-2.35E+06		
Gas-6	-3.43E+04		
Gas-3	-3.43E+04		
Gas	-3.43E+04		
Gas-2	-3.43E+04		
Gas-4	-3.43E+04		
Gas-5	-3.43E+04		
CFT DILUENT	-2.53E+06		
pumpEE	8.23E+04		
CompE	1.67E+05		
TOTAL	**-4.12E+08**	**TOTAL**	**-4.13E+08**

Table 5. Well-Pad Energy Balance

[20] Appendix B

6.3 Group Separator Sizing

A horizontal orientation is chosen for the Group Separator, as it can accommodate high liquid and gas flowrates, the larger gas-liquid interface allows for more gas to evolve out of the liquid phase, is effective at higher gas velocities, and is economical. After the selection of the orientation, the sizing methodology from the *GPSA (14th edition)* is followed. The Group Separator requires 2-phase separation where the non-condensable gases and the emulsion are to be separated. Some design parameters are suggested by the project sponsor, such as residence times and liquid level heights.

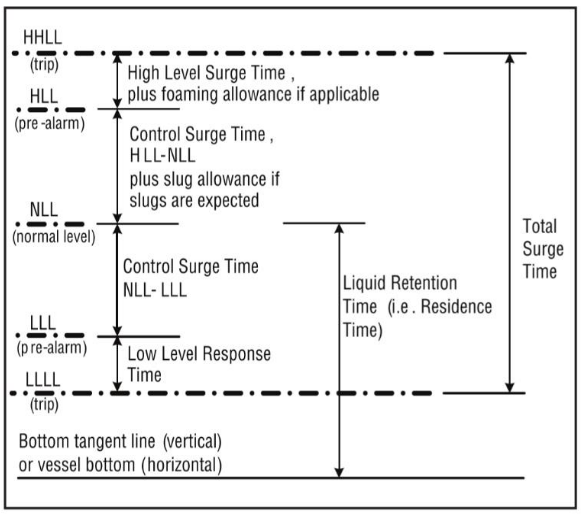

Figure 5. Level Heights and Surge Volumes (GPSA 14th Edition)

Vessels are divided several sections (Figure 5) to maintain control in the vessel. Based on industry experience, the minimum height from the bottom of the vessel to the LLLL (low low liquid level) is 6” (152mm) and from LLLL to LLL (low liquid level) is 12” (305mm). These parameters need to be accounted for when sizing the vessel. The suggested residence time for the emulsion is 20 min, this occurs between the LLL and HLL and allows for sufficient gravity separation. The L/D ratio (Length to Diameter) of the vessel is 3. With an inlet volumetric flowrate of 27.15 m^3/h, a residence time of 20 mins, an L/D ratio of 3, accounting for the low-level height constraints; a vessel with a volume of 19.69m^3 is calculated[21] (ignoring the volumes in the cylinder heads). The corresponding length and diameter are 6.08 m and 2.03 m, respectively. To verify the effectiveness of the design a vertical and horizontal liquid droplet travel time analysis[22] is done. Using the terminal velocity, cross-sectional area, and vessel parameters, it is confirmed that the liquid droplets entrained in the gas will not travel up into the gas outlet. The time for the liquid droplet to travel horizontally to the gas nozzle outlet, when the liquid level is at HLL, is 38 seconds. The time it takes for the liquid droplets to fall to the liquid level, at HLL, is 0.66 seconds. The liquid droplets fall on

[21] Appendix L
[22] Appendix M

the liquid-gas interface before they can reach the gas-outlet; thus, proving the effectivity of the design.

7. CONCLUSIONS

With the simulation of the design, achieving desired separation and satisfaction of battery limits, the objectives of this project are successfully met. This is made possible by equipping three separators; 2-phase separator for group separation, 3-phase separator test separation and a 2-phase separator for water removal from the produced gas. All the vessels are in the horizontal orientation, where only the 2-phase group separator was sized. The wells are imitated using the pure gas system, wherein the casing gas remains separated from the emulsion upon extraction.

A manifold is designed, and each well is tested on a rotational basis. The addition of diluent is required due to a lack of density differential between the bitumen and water. The diluent of choice is CFT Fort Saskatchewan Condensate. There are six wells and nineteen inlet streams; a gas stream, a bitumen stream and a water stream for each well plus a diluent stream for the test separator. The bitumen is characterized using Athabasca Bitumen assay information. There are only two exit streams from the well pad extending to the CPF, a produced gas pipe-line and an emulsion pipeline.

8. Bibliography

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[4] Crude Quality Inc. , "Fort Saskatchewan Condensate," [Online]. Available: http://www.crudemonitor.ca/condensates/index.php?acr=CFT. [Accessed 02 04 2018].

9. APPENDICES

9.1 Appendix A

Table 6: Design Parameters of the SAGD Well Pad

Bitumen	*per well*		30	m3/d
	wells per pad		6	
Emulsion	*Pad battery limit*		200	°C
			500	kPag
Produced gas	*GOR*		5	Sm3 NCG/m3 of bitumen
Casing gas	*wellhead*		1000	kPag
	Water		saturated	
	Pad battery limit		400	kPag
Steam	*SOR*		3.5	m3 steam CWE/m3 bitumen
	steam quality @ pad		0.95	
	Operating pressure		10000	kPag

9.2 Appendix B

Table 7: CFT Fort Saskatchewan Condensate Compositions

COMPONENT	VOLUME %
C1	-
C2	-
C3	0.09
C4	3.49
C5	52.43
C6	18.77
C7	11.17
C8	6
C9	2.22
C10	1.97
C11	1.8
C12	0.65
C13	0.27
C14	0.19
C15	0.14
C16	0.1
C17	0.12
C18	0.1
C19	0.07
C20	0.07
C21	0.05
C22	0.05
C23	0.03
C24	0.03
C25	0.02
C26	0.01
C27	0.01
C28	0.01
C29	0.01
C30+	0.13
Total	100

9.3 Appendix C

Table 8: Stream Conditions

Name	Temperature [C]	Pressure [kPa]	Mass Flow [kg/h]	Liquid Volume Flow [m3/h]
Water	200.0	1590	4366.2	4.38
Gas	200.0	1090	5.7	0.01
Emulsion	183.6	1090	5636.5	5.62
Water-2	200.0	1590	4366.2	4.38
Gas-2	200.0	1090	5.7	0.01
Emulsion-2	183.6	1090	5636.5	5.62
Water-3	200.0	1590	4366.2	4.38
Gas-3	200.0	1090	5.7	0.01
Emulsion-3	183.6	1090	5636.5	5.62
Water-4	200.0	1590	4366.2	4.38
Gas-4	200.0	1090	5.7	0.01
Emulsion-4	183.6	1090	5636.5	5.62
Water-5	200.0	1590	4366.2	4.38
Gas-5	200.0	1090	5.7	0.01
Emulsion-5	183.6	1090	5636.5	5.62
Water-6	200.0	1590	4366.2	4.38
Gas-6	200.0	1090	5.7	0.01
Emulsion-6	183.6	1090	5636.5	5.62
Group Gas	164.8	700	2020.7	2.03
Group Liquids	164.8	700	26161.7	26.07
Test Gas	135.9	700	1573.0	2.40
SepWater2	135.9	700	4168.8	4.12
SepOil1	135.9	700	1365.1	1.39
Mixed Emulsion	88.0	260	34022.1	33.95
Mixed Gases	158.4	700	3628.0	4.52
Athabasca bitumen	200.0	1090	1270.3	1.25
Athabasca bitumen-2	200.0	1090	1270.3	1.25
Athabasca bitumen-3	200.0	1090	1270.3	1.25
Athabasca bitumen-5	200.0	1090	1270.3	1.25
Athabasca bitumen-4	200.0	1090	1270.3	1.25
Athabasca bitumen-6	200.0	1090	1270.3	1.25
group1	183.6	1090	5636.5	5.62
group2	183.6	1090	5636.5	5.62
group3	183.6	1090	5636.5	5.62
group4	183.6	1090	5636.5	5.62
group5	183.6	1090	5636.5	5.62

group6	183.6	1090	0.0	0.00
Group Separator Emulsion	183.6	1090	28182.4	28.10
test1	183.6	1090	0.0	0.00
test2	183.6	1090	0.0	0.00
test3	183.6	1090	0.0	0.00
test4	183.6	1090	0.0	0.00
test5	183.6	1090	0.0	0.00
test6	183.6	1090	5636.5	5.62
TEST SEPARATOR EMULSION	183.6	1090	5636.5	5.62
Combined Casing Gas	200.0	1090	34.2	0.08
Cooled Mixed Gas	65.0	260	3628.0	4.52
Depressurized Mixed Gas	146.5	300	3628.0	4.52
PG Liquid	65.0	260	2326.4	2.37
Produced Gas CPF	65.0	260	1301.5	2.16
Depressurized GSE	164.8	700	28182.4	28.10
CFT DILUENT	4.0	1090	1470.5	2.29
DILBIT	144.8	1090	7107.0	7.91
DEPRESSURIZED DILBIT	135.9	700	7107.0	7.91
Test Emulsion	135.9	700	5534.0	5.51
PG Liquid Mix	78.7	260	28488.1	28.43
CooledLiquid	80.0	660	26161.7	26.07
Emulsion to CPF	88.2	2000	34022.1	33.95
Pressurized Gas to CPF	146.3	2000	1301.5	2.16

9.4 Appendix D

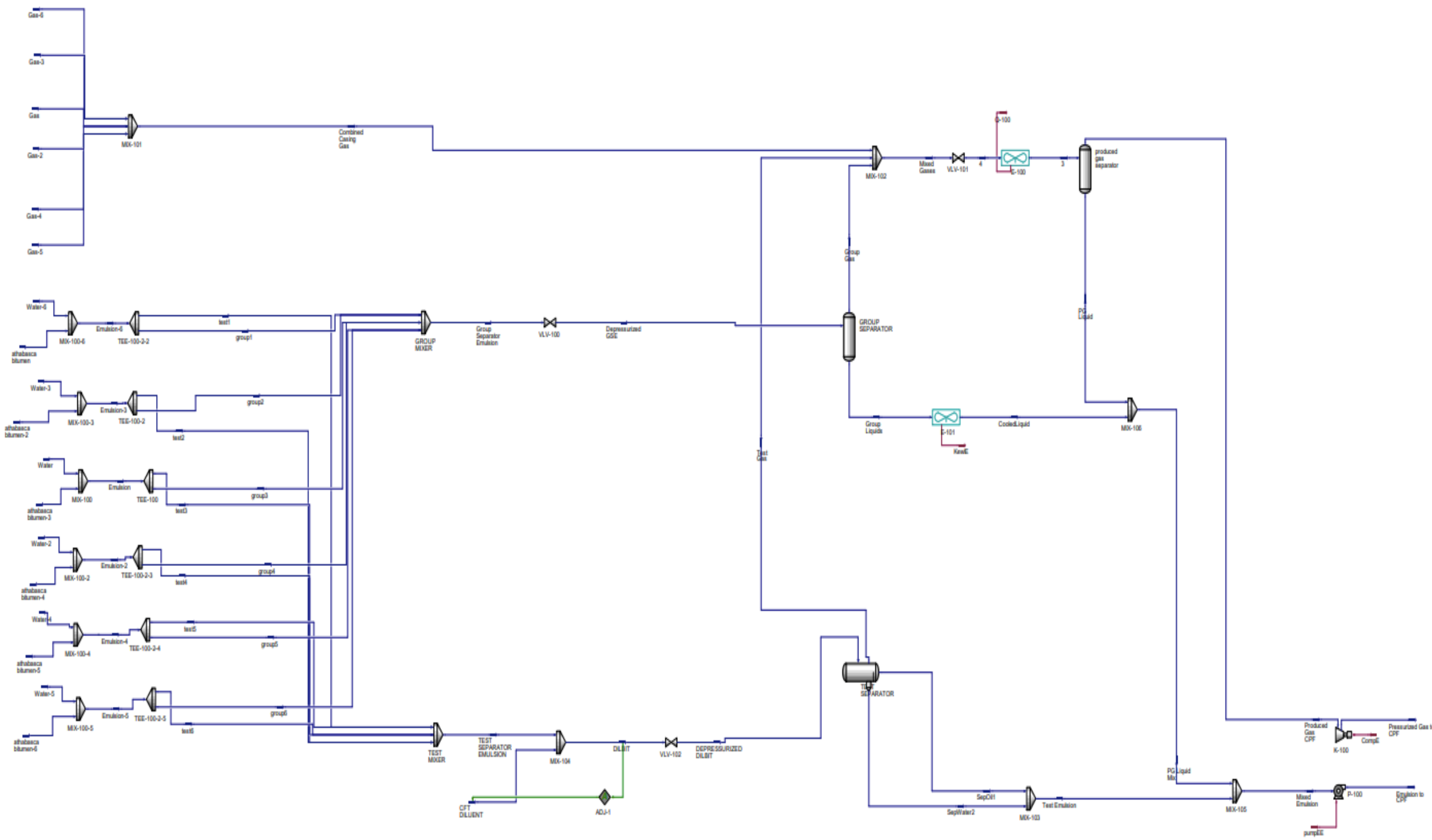

Figure 6. ***HYSYS*** **Well-Pad Simulation**

9.5 Appendix E

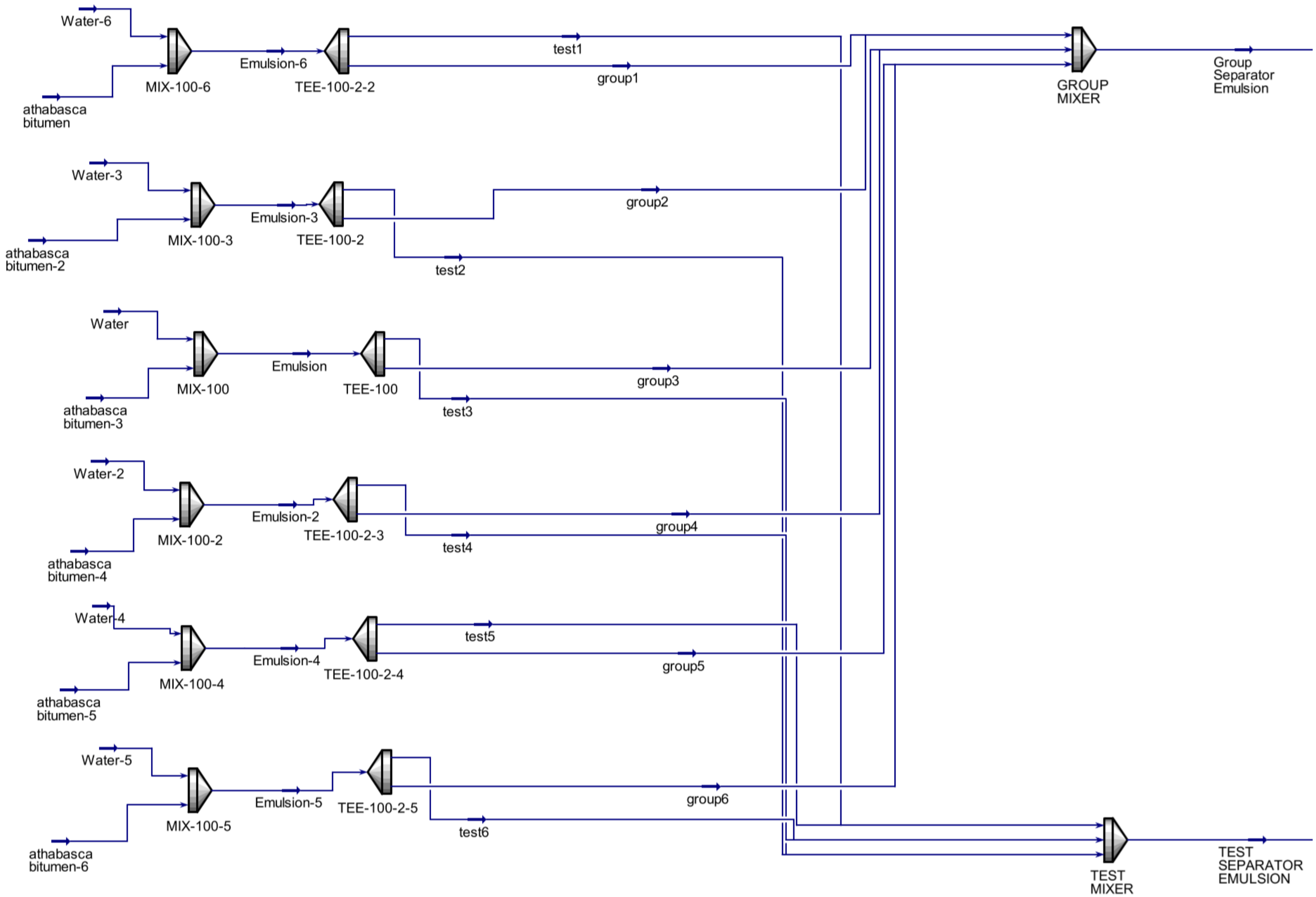

Figure 7. Well and Manifold Simulation

9.6 Appendix F

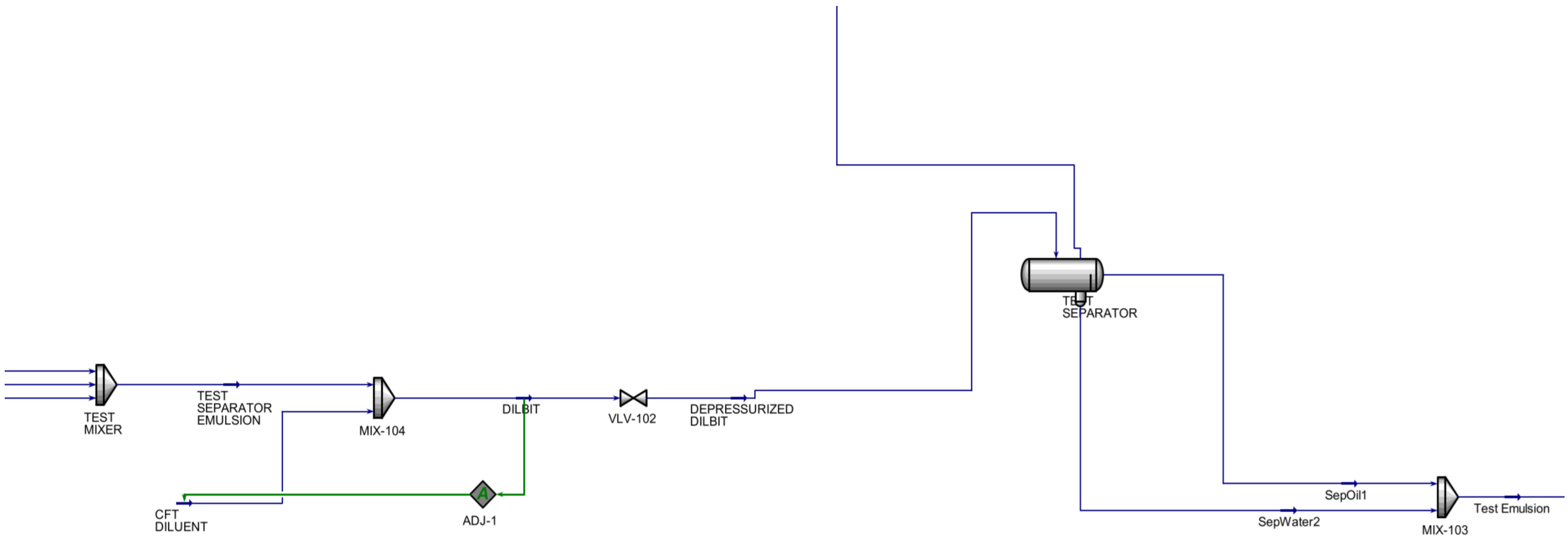

Figure 8. Test Separator and Diluent Injection Simulation

9.7 Appendix G

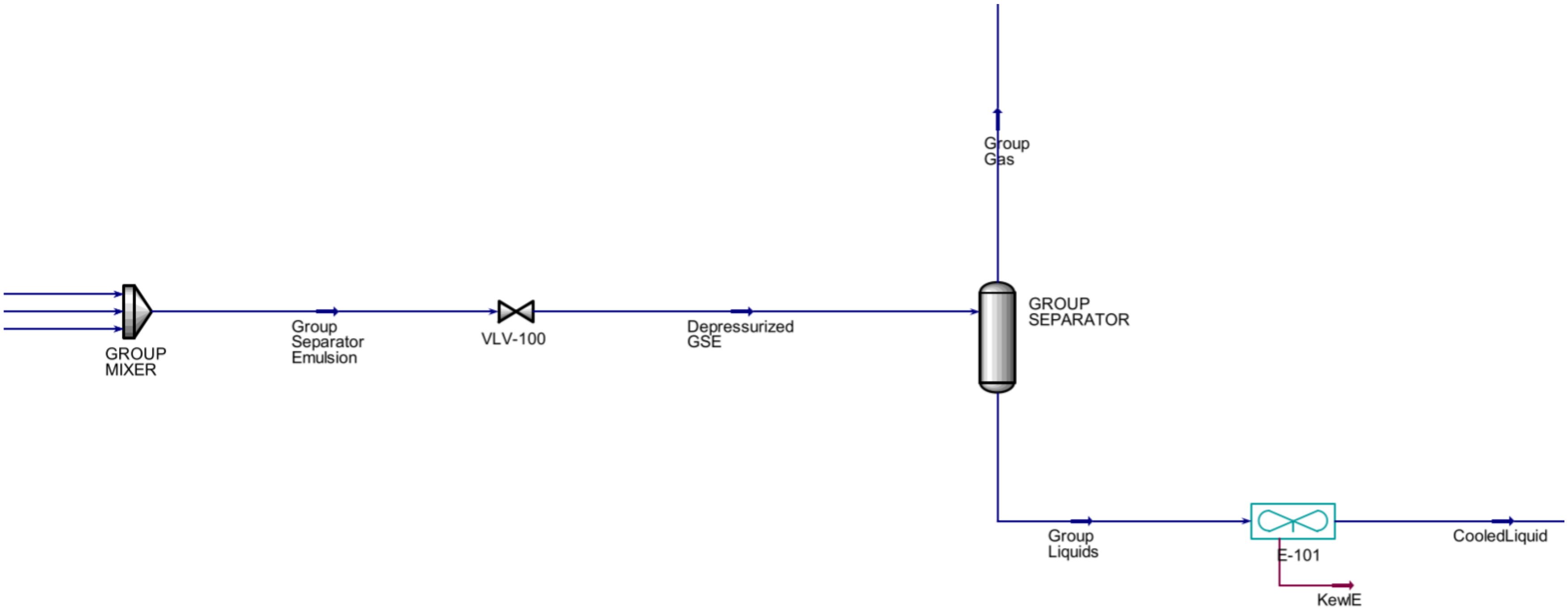

Figure 9. Group Separator Simulation

9.8 Appendix H

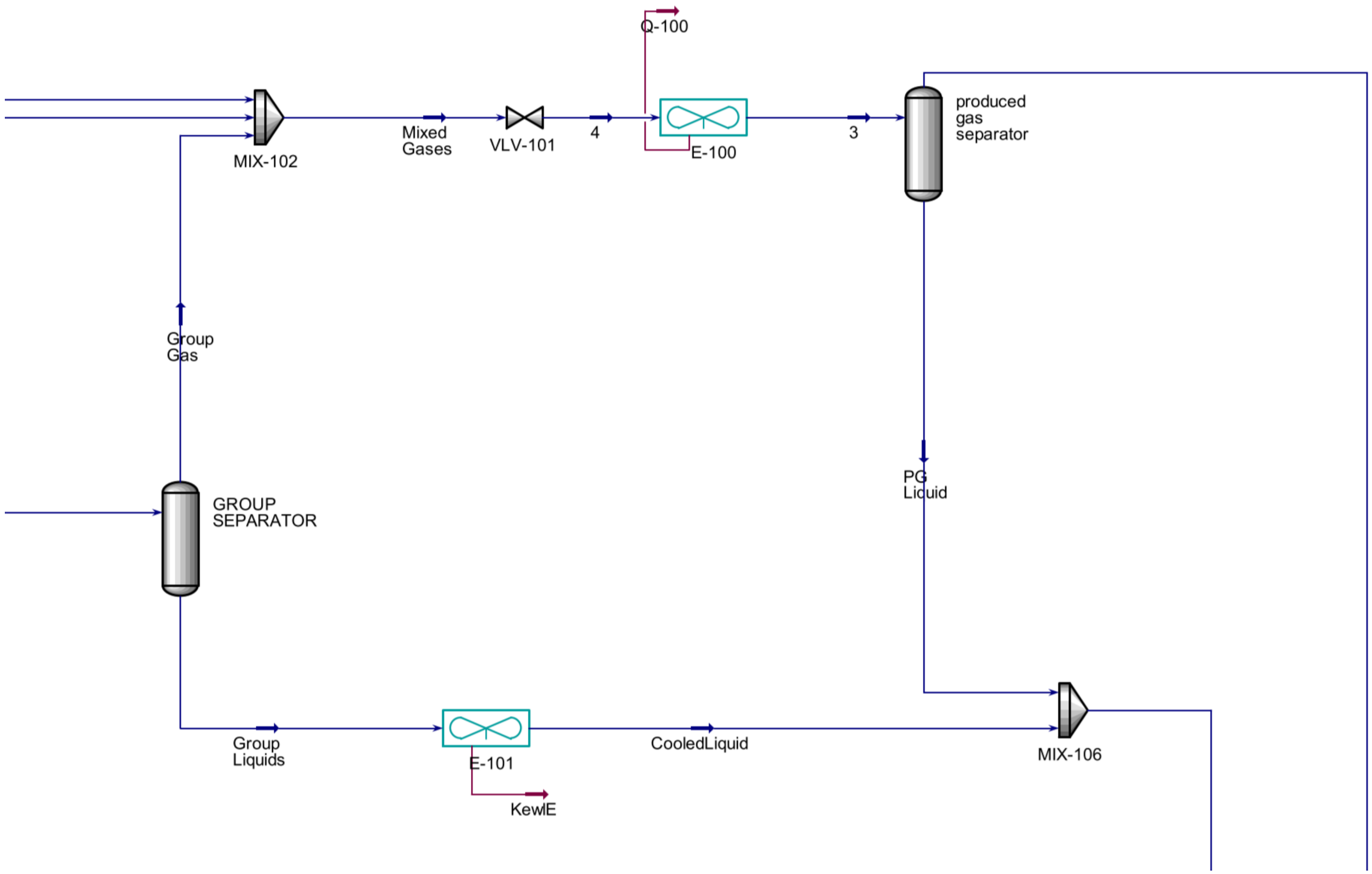

Figure 10. Produced Gas Separator and Group Separator Simulation

9.9 Appendix I

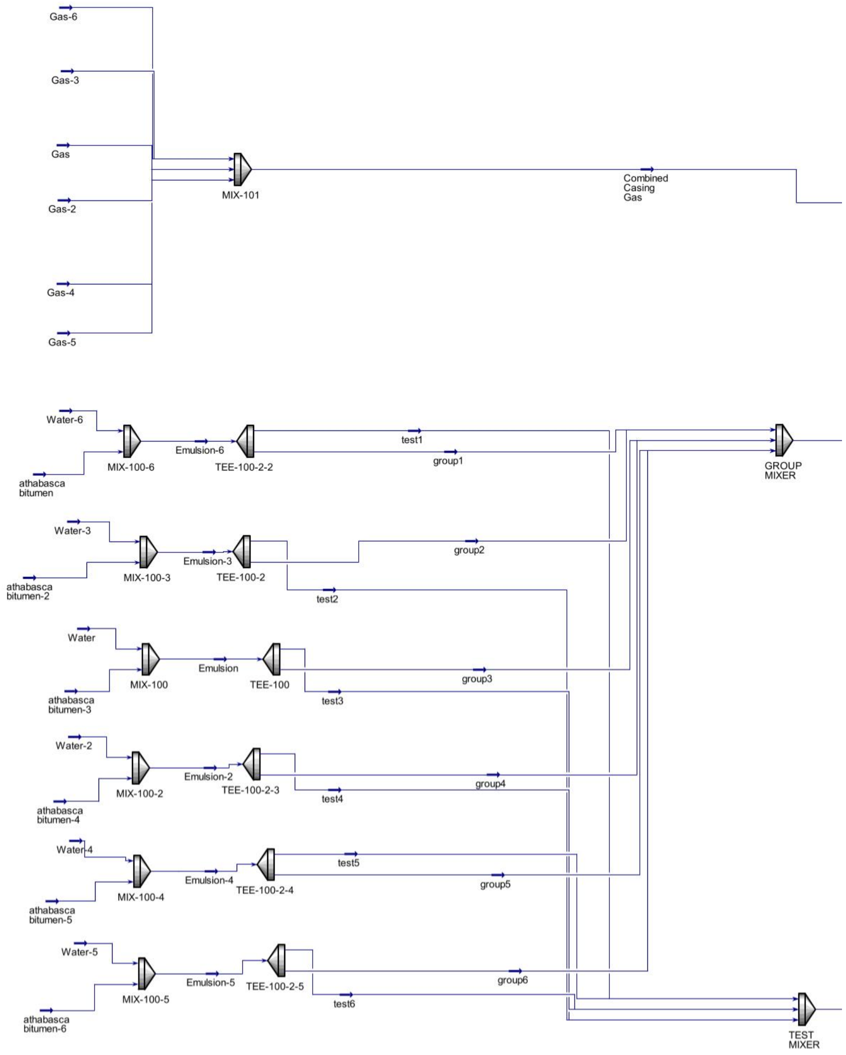

Figure 11. Pure Gas System

9.10 Appendix J

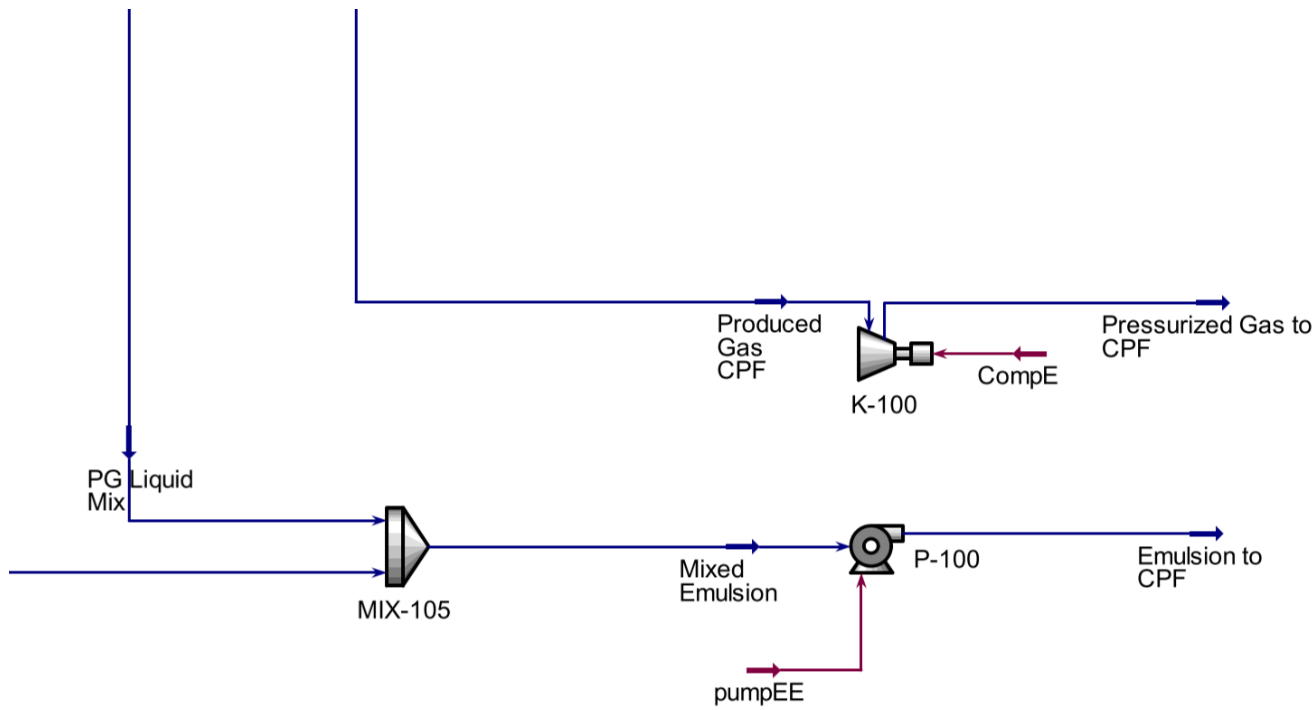

Figure 12. Well-Pad Outlet

9.11 Appendix K

13 14	COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
15	Methane	0.0010	0.0003	0.0164	0.0000	0.0001	0.0000
16	CO2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
17	H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
18	H2O	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
19	NBP[1]30*	0.0037	0.0009	0.2066	0.0002	0.0004	0.0003
20	NBP[1]40*	0.0010	0.0002	0.0585	0.0000	0.0001	0.0001
21	NBP[1]50*	0.0027	0.0007	0.1748	0.0001	0.0002	0.0002
22	NBP[1]60*	0.0031	0.0008	0.2141	0.0002	0.0002	0.0002
23	NBP[1]70*	0.0033	0.0008	0.2416	0.0002	0.0003	0.0002
24	NBP[1]80*	0.0032	0.0008	0.2535	0.0002	0.0003	0.0002
25	NBP[1]90*	0.0036	0.0009	0.2962	0.0002	0.0003	0.0003
26	NBP[1]100*	0.0039	0.0010	0.3440	0.0003	0.0004	0.0003
27	NBP[1]110*	0.0043	0.0011	0.3978	0.0003	0.0005	0.0004
28	NBP[1]120*	0.0046	0.0012	0.4587	0.0004	0.0005	0.0004
29	NBP[1]130*	0.0051	0.0013	0.5277	0.0004	0.0006	0.0005
30	NBP[1]140*	0.0055	0.0014	0.6057	0.0005	0.0007	0.0006
31	NBP[1]150*	0.0061	0.0015	0.6937	0.0005	0.0008	0.0006
32	NBP[1]160*	0.0066	0.0017	0.7927	0.0006	0.0009	0.0007
33	NBP[1]170*	0.0072	0.0018	0.9037	0.0007	0.0010	0.0008
34	NBP[1]180*	0.0078	0.0020	1.0276	0.0008	0.0012	0.0009
35	NBP[1]190*	0.0084	0.0021	1.1655	0.0009	0.0013	0.0011
36	NBP[1]200*	0.0091	0.0023	1.3184	0.0010	0.0015	0.0012
37	NBP[1]210*	0.0098	0.0025	1.4871	0.0012	0.0017	0.0014
38	NBP[1]220*	0.0106	0.0027	1.6871	0.0013	0.0019	0.0015
39	NBP[1]230*	0.0113	0.0029	1.8815	0.0015	0.0021	0.0017
40	NBP[1]240*	0.0253	0.0064	4.4025	0.0035	0.0050	0.0040
41	NBP[1]250*	0.0306	0.0077	5.5723	0.0044	0.0063	0.0051
42	NBP[1]260*	0.0366	0.0093	6.9870	0.0055	0.0079	0.0064
43	NBP[1]270*	0.0434	0.0110	8.6742	0.0068	0.0098	0.0079
44	NBP[1]280*	0.0514	0.0130	10.6574	0.0084	0.0120	0.0096
45	NBP[1]290*	0.0603	0.0153	12.9523	0.0102	0.0144	0.0116
46	NBP[1]300*	0.0700	0.0177	15.5646	0.0123	0.0172	0.0138
47	NBP[1]310*	0.0780	0.0197	17.9484	0.0141	0.0197	0.0158
48	NBP[1]320*	0.0876	0.0222	20.8436	0.0164	0.0227	0.0182
49	NBP[1]330*	0.0974	0.0246	23.9368	0.0188	0.0258	0.0207
50	NBP[1]340*	0.1072	0.0271	27.1842	0.0214	0.0290	0.0233
51	NBP[1]350*	0.1169	0.0296	30.5305	0.0240	0.0323	0.0260
52	NBP[1]360*	0.1262	0.0319	33.9101	0.0267	0.0356	0.0286
53	NBP[1]370*	0.1350	0.0341	37.2486	0.0293	0.0388	0.0312
54	NBP[1]380*	0.1430	0.0362	40.4655	0.0319	0.0418	0.0336
55	NBP[1]390*	0.1501	0.0380	43.4773	0.0342	0.0446	0.0358
56	NBP[1]400*	0.1560	0.0395	46.2009	0.0364	0.0470	0.0377
57	NBP[1]410*	0.1569	0.0397	48.5574	0.0382	0.0490	0.0393
58	NBP[1]420*	0.1588	0.0402	50.4760	0.0397	0.0505	0.0406
59	NBP[1]430*	0.1593	0.0403	51.8973	0.0409	0.0518	0.0416
60	NBP[1]440*	0.1583	0.0401	52.7766	0.0415	0.0521	0.0419
61	NBP[1]450*	0.1553	0.0393	53.0861	0.0418	0.0519	0.0417
62	NBP[1]460*	0.1508	0.0382	52.8159	0.0416	0.0512	0.0411

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
NBP[1]470*	0.1423	0.0360	51.2848	0.0404	0.0490	0.0393
NBP[1]480*	0.1423	0.0360	51.2847	0.0404	0.0490	0.0393
NBP[1]490*	0.1264	0.0320	47.5536	0.0374	0.0448	0.0359
NBP[1]500*	0.1264	0.0320	47.5535	0.0374	0.0448	0.0359
NBP[1]510*	0.1077	0.0272	42.2167	0.0332	0.0392	0.0314
NBP[1]520*	0.1077	0.0272	42.2166	0.0332	0.0392	0.0314
NBP[1]530*	0.0879	0.0222	35.8847	0.0282	0.0328	0.0263
NBP[1]540*	0.0879	0.0222	35.8846	0.0282	0.0328	0.0263
NBP[1]550*	0.0688	0.0174	29.2059	0.0230	0.0263	0.0211
NBP[1]560*	0.0688	0.0174	29.2058	0.0230	0.0263	0.0211
NBP[1]570*	0.0515	0.0130	22.7629	0.0179	0.0202	0.0162
NBP[1]580*	0.0515	0.0130	22.7629	0.0179	0.0202	0.0162
NBP[1]590*	0.0369	0.0093	16.9806	0.0134	0.0149	0.0119
NBP[1]600*	0.0369	0.0093	16.9806	0.0134	0.0149	0.0119
NBP[1]610*	0.0241	0.0061	11.6189	0.0091	0.0100	0.0080
NBP[1]620*	0.0241	0.0061	11.6189	0.0091	0.0100	0.0080
NBP[1]630*	0.0191	0.0048	9.3732	0.0074	0.0080	0.0064
NBP[1]640*	0.0140	0.0035	7.1276	0.0056	0.0060	0.0048
NBP[1]650*	0.0140	0.0035	7.1276	0.0056	0.0060	0.0048
NBP[1]660*	0.0141	0.0036	7.6053	0.0060	0.0063	0.0051
NBP[1]670*	0.0141	0.0036	7.6053	0.0060	0.0063	0.0051
NBP[1]680*	0.0076	0.0019	4.1460	0.0033	0.0034	0.0028
NBP[1]690*	0.0012	0.0003	0.6867	0.0005	0.0006	0.0005
NBP[1]700*	0.0012	0.0003	0.6867	0.0005	0.0006	0.0005
NBP[1]710*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NBP[1]720*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NBP[1]730*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NBP[1]740*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NBP[1]750*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NBP[1]760*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NBP[1]770*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NBP[1]780*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NBP[1]790*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NBP[1]800*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NBP[1]810*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NBP[1]820*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NBP[1]830*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NBP[1]840*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NBP[1]850*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NBP[1]860*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NBP[1]870*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NBP[1]880*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NBP[1]890*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NBP[1]900*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NBP[1]910*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NBP[1]920*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NBP[1]930*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NBP[1]940*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

13/14	COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
15	NBP[1]950*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
16	NBP[1]960*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
17	NBP[1]970*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
18	Ethane	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
19	Propane	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
20	i-Butane	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
21	n-Butane	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
22	i-Pentane	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
23	n-Pentane	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
24	n-Hexane	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
25	S_Rhombic	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
26	n-Decane	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
27	n-Heptane	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
28	n-Octane	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
29	n-Nonane	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
30	n-C11	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
31	n-C12	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
32	n-C13	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
33	n-C14	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
34	n-C15	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
35	n-C16	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
36	n-C17	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
37	n-C18	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
38	n-C19	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
39	n-C20	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
40	n-C21	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
41	n-C22	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
42	n-C23	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
43	n-C24	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
44	n-C25	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
45	n-C26	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
46	n-C27	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
47	n-C28	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
48	n-C29	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
49	n-C30	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
50	Total	3.9528	1.0000	1270.2927	1.0000	1.2453	1.0000

Table 9. Athabasca Bitumen Pseudo-Component Composition

9.12 Appendix L

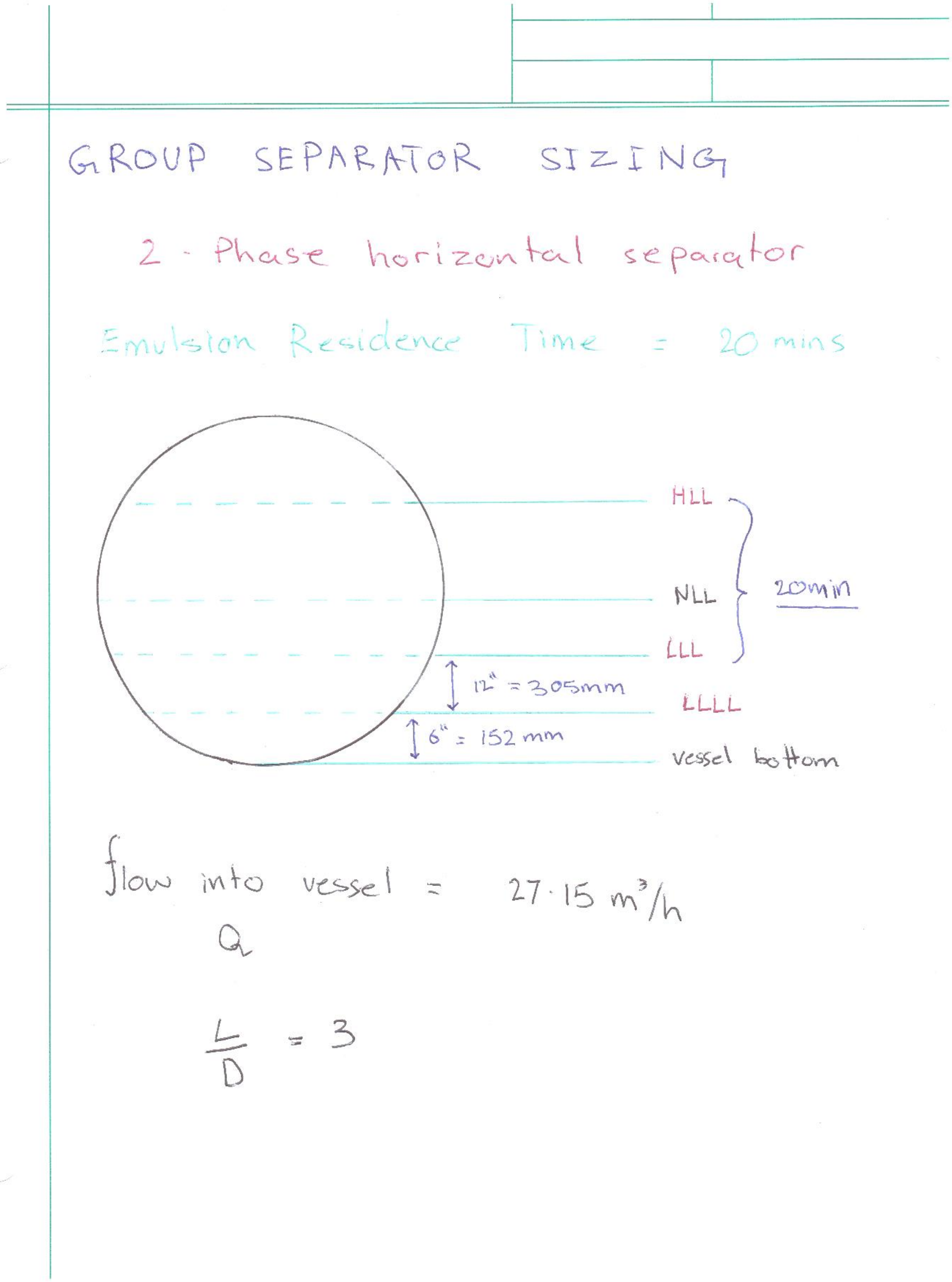

Figure 13. 2-Phase Horizontal Separator Design Parameters

$$V = 27.15\,\frac{m^3}{h} \times 0.333\,h = 9.05\,m$$

$$V = \frac{\pi}{4} d^2 \ell = \frac{3\pi}{4} d^3 \qquad {}^{*}\ \frac{L}{D} = 3$$

$$d = \sqrt[3]{\frac{4V}{3\pi}} = \sqrt[3]{\frac{4\,(9.05\,m^3)}{3\pi}}$$

$$= 1.57\,m + 0.305\,m + 0.152\,m$$

$$d = 2.03\,m$$

$$L = 3d$$

$$L = 3\,(2.03\,m) = 6.08\,m$$

$$V = \frac{\pi}{4} d^2 \ell = \frac{\pi}{4}(2.03\,m)^2(6.08\,m)$$

$$= 19.69\,m^3$$

Vessel Volume = $19.69\ m^3$

Vessel Diameter = $2.03\ m$

Vessel Lenght = $6.08\ m$

Figure 14. 2-Phase Horizontal Separator Sizing based on 20min Residence Time

9.13 Appendix M

$$t_h \geq t_v$$

$$V_t = K\sqrt{\frac{\rho_L - \rho_g}{\rho_g}} \cdot \frac{L}{3.05} \cdot 0.56$$

$$= 0.06\sqrt{\left[\frac{914 - 3.7}{3.7}\right]\frac{kg}{m^3}} \cdot \frac{6.08}{3.05} \cdot 0.56$$

$$= 1.05\ m/s$$

$$V_h = \frac{\text{Actual Gas Flow-rate}}{\text{Gas X-Section Area}} = \frac{546.4\ m^3/h}{0.97\ m^2}$$

$$= 0.16\ m/s$$

$$t_h = \frac{6.08\ m}{0.16\ \frac{m}{s}} = 38\ s \qquad t_h = \frac{L}{V_h}$$

$$t_v = \frac{0.69\ m}{1.05\ \frac{m}{s}} = 0.66\ s \qquad t_v = \frac{H_g}{V_t}$$

$$38\ s > 0.66\ s$$

∴ liquid droplets will will not be entrained in gas

Figure 15. Liquid Droplet entrainment verification calculation

9.14 Appendix N

COMPOSITION

Overall Phase Vapour Fraction 0.0000

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Methane	0.0006	0.0000	0.0089	0.0000	0.0000	0.0000
CO2	0.0013	0.0000	0.0582	0.0000	0.0001	0.0000
H2S	0.0001	0.0000	0.0037	0.0000	0.0000	0.0000
H2O	1452.0113	0.9807	26158.1303	0.7689	26.2109	0.7721
NBP[1]30*	0.0006	0.0000	0.0330	0.0000	0.0001	0.0000
NBP[1]40*	0.0004	0.0000	0.0250	0.0000	0.0000	0.0000
NBP[1]50*	0.0017	0.0000	0.1112	0.0000	0.0001	0.0000
NBP[1]60*	0.0025	0.0000	0.1712	0.0000	0.0002	0.0000
NBP[1]70*	0.0033	0.0000	0.2423	0.0000	0.0003	0.0000
NBP[1]80*	0.0040	0.0000	0.3175	0.0000	0.0004	0.0000
NBP[1]90*	0.0055	0.0000	0.4606	0.0000	0.0005	0.0000
NBP[1]100*	0.0075	0.0000	0.6591	0.0000	0.0008	0.0000
NBP[1]110*	0.0099	0.0000	0.9292	0.0000	0.0011	0.0000
NBP[1]120*	0.0130	0.0000	1.2880	0.0000	0.0015	0.0000
NBP[1]130*	0.0168	0.0000	1.7498	0.0001	0.0020	0.0001
NBP[1]140*	0.0213	0.0000	2.3230	0.0001	0.0027	0.0001
NBP[1]150*	0.0262	0.0000	3.0065	0.0001	0.0035	0.0001
NBP[1]160*	0.0315	0.0000	3.7898	0.0001	0.0043	0.0001
NBP[1]170*	0.0369	0.0000	4.6568	0.0001	0.0053	0.0002
NBP[1]180*	0.0423	0.0000	5.5915	0.0002	0.0064	0.0002
NBP[1]190*	0.0476	0.0000	6.5838	0.0002	0.0075	0.0002
NBP[1]200*	0.0526	0.0000	7.6319	0.0002	0.0087	0.0003
NBP[1]210*	0.0575	0.0000	8.7416	0.0003	0.0100	0.0003
NBP[1]220*	0.0629	0.0000	10.0083	0.0003	0.0114	0.0003
NBP[1]230*	0.0674	0.0000	11.2202	0.0003	0.0128	0.0004
NBP[1]240*	0.1511	0.0001	26.3308	0.0008	0.0299	0.0009
NBP[1]250*	0.1830	0.0001	33.3794	0.0010	0.0379	0.0011
NBP[1]260*	0.2196	0.0001	41.8892	0.0012	0.0475	0.0014
NBP[1]270*	0.2606	0.0002	52.0260	0.0015	0.0590	0.0017
NBP[1]280*	0.3085	0.0002	63.9331	0.0019	0.0719	0.0021
NBP[1]290*	0.3618	0.0002	77.7075	0.0023	0.0867	0.0026
NBP[1]300*	0.4198	0.0003	93.3841	0.0027	0.1033	0.0030
NBP[1]310*	0.4679	0.0003	107.6886	0.0032	0.1180	0.0035
NBP[1]320*	0.5256	0.0004	125.0605	0.0037	0.1359	0.0040
NBP[1]330*	0.5845	0.0004	143.6202	0.0042	0.1547	0.0046
NBP[1]340*	0.6435	0.0004	163.1049	0.0048	0.1743	0.0051
NBP[1]350*	0.7015	0.0005	183.1831	0.0054	0.1941	0.0057
NBP[1]360*	0.7573	0.0005	203.4606	0.0060	0.2138	0.0063
NBP[1]370*	0.8099	0.0005	223.4915	0.0066	0.2329	0.0069
NBP[1]380*	0.8581	0.0006	242.7929	0.0071	0.2509	0.0074
NBP[1]390*	0.9009	0.0006	260.8636	0.0077	0.2674	0.0079
NBP[1]400*	0.9357	0.0006	277.2053	0.0081	0.2819	0.0083
NBP[1]410*	0.9414	0.0006	291.3445	0.0086	0.2939	0.0087
NBP[1]420*	0.9526	0.0006	302.8561	0.0089	0.3031	0.0089
NBP[1]430*	0.9555	0.0006	311.3838	0.0092	0.3111	0.0092
NBP[1]440*	0.9499	0.0006	316.6593	0.0093	0.3127	0.0092
NBP[1]450*	0.9319	0.0006	318.5166	0.0094	0.3114	0.0092
NBP[1]460*	0.9049	0.0006	316.8956	0.0093	0.3074	0.0091
NBP[1]470*	0.8540	0.0006	307.7090	0.0090	0.2940	0.0087
NBP[1]480*	0.8540	0.0006	307.7083	0.0090	0.2940	0.0087
NBP[1]490*	0.7582	0.0005	285.3218	0.0084	0.2686	0.0079
NBP[1]500*	0.7582	0.0005	285.3211	0.0084	0.2686	0.0079
NBP[1]510*	0.6460	0.0004	253.3002	0.0074	0.2349	0.0069
NBP[1]520*	0.6460	0.0004	253.2996	0.0074	0.2349	0.0069

13 14	COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
15	NBP[1]530*	0.5276	0.0004	215.3083	0.0063	0.1968	0.0058
16	NBP[1]540*	0.5276	0.0004	215.3078	0.0063	0.1968	0.0058
17	NBP[1]550*	0.4128	0.0003	175.2354	0.0052	0.1579	0.0047
18	NBP[1]560*	0.4128	0.0003	175.2350	0.0052	0.1579	0.0047
19	NBP[1]570*	0.3092	0.0002	136.5775	0.0040	0.1213	0.0036
20	NBP[1]580*	0.3092	0.0002	136.5772	0.0040	0.1213	0.0036
21	NBP[1]590*	0.2215	0.0001	101.8838	0.0030	0.0893	0.0026
22	NBP[1]600*	0.2215	0.0001	101.8836	0.0030	0.0893	0.0026
23	NBP[1]610*	0.1449	0.0001	69.7133	0.0020	0.0600	0.0018
24	NBP[1]620*	0.1449	0.0001	69.7133	0.0020	0.0600	0.0018
25	NBP[1]630*	0.1145	0.0001	56.2395	0.0017	0.0481	0.0014
26	NBP[1]640*	0.0840	0.0001	42.7658	0.0013	0.0362	0.0011
27	NBP[1]650*	0.0840	0.0001	42.7657	0.0013	0.0362	0.0011
28	NBP[1]660*	0.0845	0.0001	45.6318	0.0013	0.0380	0.0011
29	NBP[1]670*	0.0845	0.0001	45.6318	0.0013	0.0380	0.0011
30	NBP[1]680*	0.0458	0.0000	24.8760	0.0007	0.0207	0.0006
31	NBP[1]690*	0.0072	0.0000	4.1205	0.0001	0.0034	0.0001
32	NBP[1]700*	0.0072	0.0000	4.1204	0.0001	0.0034	0.0001
33	NBP[1]710*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
34	NBP[1]720*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
35	NBP[1]730*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
36	NBP[1]740*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
37	NBP[1]750*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
38	NBP[1]760*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
39	NBP[1]770*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
40	NBP[1]780*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
41	NBP[1]790*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
42	NBP[1]800*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
43	NBP[1]810*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
44	NBP[1]820*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
45	NBP[1]830*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
46	NBP[1]840*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
47	NBP[1]850*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
48	NBP[1]860*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
49	NBP[1]870*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
50	NBP[1]880*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
51	NBP[1]890*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
52	NBP[1]900*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
53	NBP[1]910*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
54	NBP[1]920*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
55	NBP[1]930*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
56	NBP[1]940*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
57	NBP[1]950*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
58	NBP[1]960*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
59	NBP[1]970*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
60	Ethane	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
61	Propane	0.0004	0.0000	0.0191	0.0000	0.0000	0.0000
62	i-Butane	0.0259	0.0000	1.5051	0.0000	0.0027	0.0001

	COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
15	n-Butane	0.5156	0.0003	29.9703	0.0009	0.0514	0.0015
16	i-Pentane	0.2921	0.0002	21.0738	0.0006	0.0338	0.0010
17	n-Pentane	0.2101	0.0001	15.1574	0.0004	0.0241	0.0007
18	n-Hexane	0.2062	0.0001	17.7712	0.0005	0.0268	0.0008
19	S_Rhombic	3.2873	0.0022	105.4095	0.0031	0.0509	0.0015
20	n-Decane	0.2132	0.0001	30.3398	0.0009	0.0414	0.0012
21	n-Heptane	0.1027	0.0001	10.2919	0.0003	0.0150	0.0004
22	n-Octane	0.0542	0.0000	6.1875	0.0002	0.0088	0.0003
23	n-Nonane	0.0276	0.0000	3.5354	0.0001	0.0049	0.0001
24	n-C11	0.0202	0.0000	3.1513	0.0001	0.0042	0.0001
25	n-C12	0.0140	0.0000	2.3908	0.0001	0.0032	0.0001
26	n-C13	0.0094	0.0000	1.7371	0.0001	0.0023	0.0001
27	n-C14	0.0106	0.0000	2.0992	0.0001	0.0028	0.0001
28	n-C15	0.0083	0.0000	1.7669	0.0001	0.0023	0.0001
29	n-C16	0.0055	0.0000	1.2451	0.0000	0.0016	0.0000
30	n-C17	0.0052	0.0000	1.2527	0.0000	0.0016	0.0000
31	n-C18	0.0035	0.0000	0.8993	0.0000	0.0011	0.0000
32	n-C19	0.0034	0.0000	0.9033	0.0000	0.0011	0.0000
33	n-C20	0.0019	0.0000	0.5441	0.0000	0.0007	0.0000
34	n-C21	0.0018	0.0000	0.5466	0.0000	0.0007	0.0000
35	n-C22	0.0012	0.0000	0.3655	0.0000	0.0005	0.0000
36	n-C23	0.0006	0.0000	0.1835	0.0000	0.0002	0.0000
37	n-C24	0.0005	0.0000	0.1838	0.0000	0.0002	0.0000
38	n-C25	0.0005	0.0000	0.1843	0.0000	0.0002	0.0000
39	n-C26	0.0005	0.0000	0.1847	0.0000	0.0002	0.0000
40	n-C27	0.0063	0.0000	2.4069	0.0001	0.0030	0.0001
41	n-C28	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
42	n-C29	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
43	n-C30	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
44	Total	1480.5392	1.0000	34022.0722	1.0000	33.9456	1.0000

Table 10. Emulsion to CPF composition

9.15 Appendix O

COMPOSITION

Overall Phase Vapour Fraction 1.0000

COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
Methane	1.2744	0.0558	20.4445	0.0157	0.0683	0.0317
CO2	0.3079	0.0135	13.5527	0.0104	0.0164	0.0076
H2S	0.0078	0.0003	0.2666	0.0002	0.0003	0.0002
H2O	2.1650	0.0948	39.0028	0.0300	0.0391	0.0181
NBP[1]30*	0.0217	0.0009	1.2064	0.0009	0.0022	0.0010
NBP[1]40*	0.0054	0.0002	0.3261	0.0003	0.0004	0.0002
NBP[1]50*	0.0143	0.0006	0.9377	0.0007	0.0011	0.0005
NBP[1]60*	0.0160	0.0007	1.1133	0.0009	0.0013	0.0006
NBP[1]70*	0.0163	0.0007	1.2072	0.0009	0.0014	0.0006
NBP[1]80*	0.0153	0.0007	1.2036	0.0009	0.0014	0.0006
NBP[1]90*	0.0158	0.0007	1.3165	0.0010	0.0015	0.0007
NBP[1]100*	0.0159	0.0007	1.4047	0.0011	0.0016	0.0008
NBP[1]110*	0.0156	0.0007	1.4577	0.0011	0.0017	0.0008
NBP[1]120*	0.0148	0.0006	1.4644	0.0011	0.0017	0.0008
NBP[1]130*	0.0136	0.0006	1.4163	0.0011	0.0016	0.0008
NBP[1]140*	0.0120	0.0005	1.3111	0.0010	0.0015	0.0007
NBP[1]150*	0.0101	0.0004	1.1557	0.0009	0.0013	0.0006
NBP[1]160*	0.0080	0.0004	0.9664	0.0007	0.0011	0.0005
NBP[1]170*	0.0061	0.0003	0.7654	0.0006	0.0009	0.0004
NBP[1]180*	0.0043	0.0002	0.5744	0.0004	0.0007	0.0003
NBP[1]190*	0.0030	0.0001	0.4095	0.0003	0.0005	0.0002
NBP[1]200*	0.0019	0.0001	0.2783	0.0002	0.0003	0.0001
NBP[1]210*	0.0012	0.0001	0.1811	0.0001	0.0002	0.0001
NBP[1]220*	0.0007	0.0000	0.1143	0.0001	0.0001	0.0001
NBP[1]230*	0.0004	0.0000	0.0687	0.0001	0.0001	0.0000
NBP[1]240*	0.0005	0.0000	0.0841	0.0001	0.0001	0.0000
NBP[1]250*	0.0003	0.0000	0.0544	0.0000	0.0001	0.0000
NBP[1]260*	0.0002	0.0000	0.0326	0.0000	0.0000	0.0000
NBP[1]270*	0.0001	0.0000	0.0195	0.0000	0.0000	0.0000
NBP[1]280*	0.0001	0.0000	0.0112	0.0000	0.0000	0.0000
NBP[1]290*	0.0000	0.0000	0.0062	0.0000	0.0000	0.0000
NBP[1]300*	0.0000	0.0000	0.0033	0.0000	0.0000	0.0000
NBP[1]310*	0.0000	0.0000	0.0017	0.0000	0.0000	0.0000
NBP[1]320*	0.0000	0.0000	0.0008	0.0000	0.0000	0.0000
NBP[1]330*	0.0000	0.0000	0.0004	0.0000	0.0000	0.0000
NBP[1]340*	0.0000	0.0000	0.0002	0.0000	0.0000	0.0000
NBP[1]350*	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000
NBP[1]360*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NBP[1]370*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NBP[1]380*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NBP[1]390*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NBP[1]400*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NBP[1]410*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NBP[1]420*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NBP[1]430*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NBP[1]440*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NBP[1]450*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NBP[1]460*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NBP[1]470*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NBP[1]480*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NBP[1]490*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NBP[1]500*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NBP[1]510*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NBP[1]520*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NBP[1]530*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NBP[1]540*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NBP[1]550*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

	COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
15	NBP[1]560*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
16	NBP[1]570*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
17	NBP[1]580*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
18	NBP[1]590*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
19	NBP[1]600*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
20	NBP[1]610*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
21	NBP[1]620*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
22	NBP[1]630*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
23	NBP[1]640*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
24	NBP[1]650*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
25	NBP[1]660*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
26	NBP[1]670*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
27	NBP[1]680*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
28	NBP[1]690*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
29	NBP[1]700*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
30	NBP[1]710*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
31	NBP[1]720*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
32	NBP[1]730*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
33	NBP[1]740*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
34	NBP[1]750*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
35	NBP[1]760*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
36	NBP[1]770*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
37	NBP[1]780*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
38	NBP[1]790*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
39	NBP[1]800*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
40	NBP[1]810*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
41	NBP[1]820*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
42	NBP[1]830*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
43	NBP[1]840*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
44	NBP[1]850*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
45	NBP[1]860*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
46	NBP[1]870*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
47	NBP[1]880*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
48	NBP[1]890*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
49	NBP[1]900*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
50	NBP[1]910*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
51	NBP[1]920*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
52	NBP[1]930*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
53	NBP[1]940*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
54	NBP[1]950*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
55	NBP[1]960*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
56	NBP[1]970*	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
57	Ethane	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
58	Propane	0.0233	0.0010	1.0270	0.0008	0.0020	0.0009
59	i-Butane	0.7481	0.0327	43.4839	0.0334	0.0774	0.0359
60	n-Butane	11.5522	0.5057	671.4616	0.5159	1.1513	0.5342
61	i-Pentane	3.4283	0.1501	247.3564	0.1901	0.3968	0.1841
62	n-Pentane	2.0262	0.0887	146.1959	0.1123	0.2322	0.1077

13 14	COMPONENTS	MOLAR FLOW (kgmole/h)	MOLE FRACTION	MASS FLOW (kg/h)	MASS FRACTION	LIQUID VOLUME FLOW (m3/h)	LIQUID VOLUME FRACTION
15	n-Hexane	0.8521	0.0373	73.4331	0.0564	0.1108	0.0514
16	S_Rhombic	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
17	n-Decane	0.0195	0.0009	2.7714	0.0021	0.0038	0.0018
18	n-Heptane	0.1803	0.0079	18.0666	0.0139	0.0263	0.0122
19	n-Octane	0.0379	0.0017	4.3298	0.0033	0.0061	0.0028
20	n-Nonane	0.0072	0.0003	0.9254	0.0007	0.0013	0.0006
21	n-C11	0.0006	0.0000	0.0863	0.0001	0.0001	0.0001
22	n-C12	0.0001	0.0000	0.0215	0.0000	0.0000	0.0000
23	n-C13	0.0000	0.0000	0.0036	0.0000	0.0000	0.0000
24	n-C14	0.0000	0.0000	0.0009	0.0000	0.0000	0.0000
25	n-C15	0.0000	0.0000	0.0003	0.0000	0.0000	0.0000
26	n-C16	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000
27	n-C17	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
28	n-C18	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
29	n-C19	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
30	n-C20	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
31	n-C21	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
32	n-C22	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
33	n-C23	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
34	n-C24	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
35	n-C25	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
36	n-C26	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
37	n-C27	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
38	n-C28	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
39	n-C29	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
40	n-C30	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
41	Total	22.8447	1.0000	1301.5236	1.0000	2.1551	1.0000

Table 11. Gas to CPF composition

9.16 Appendix P

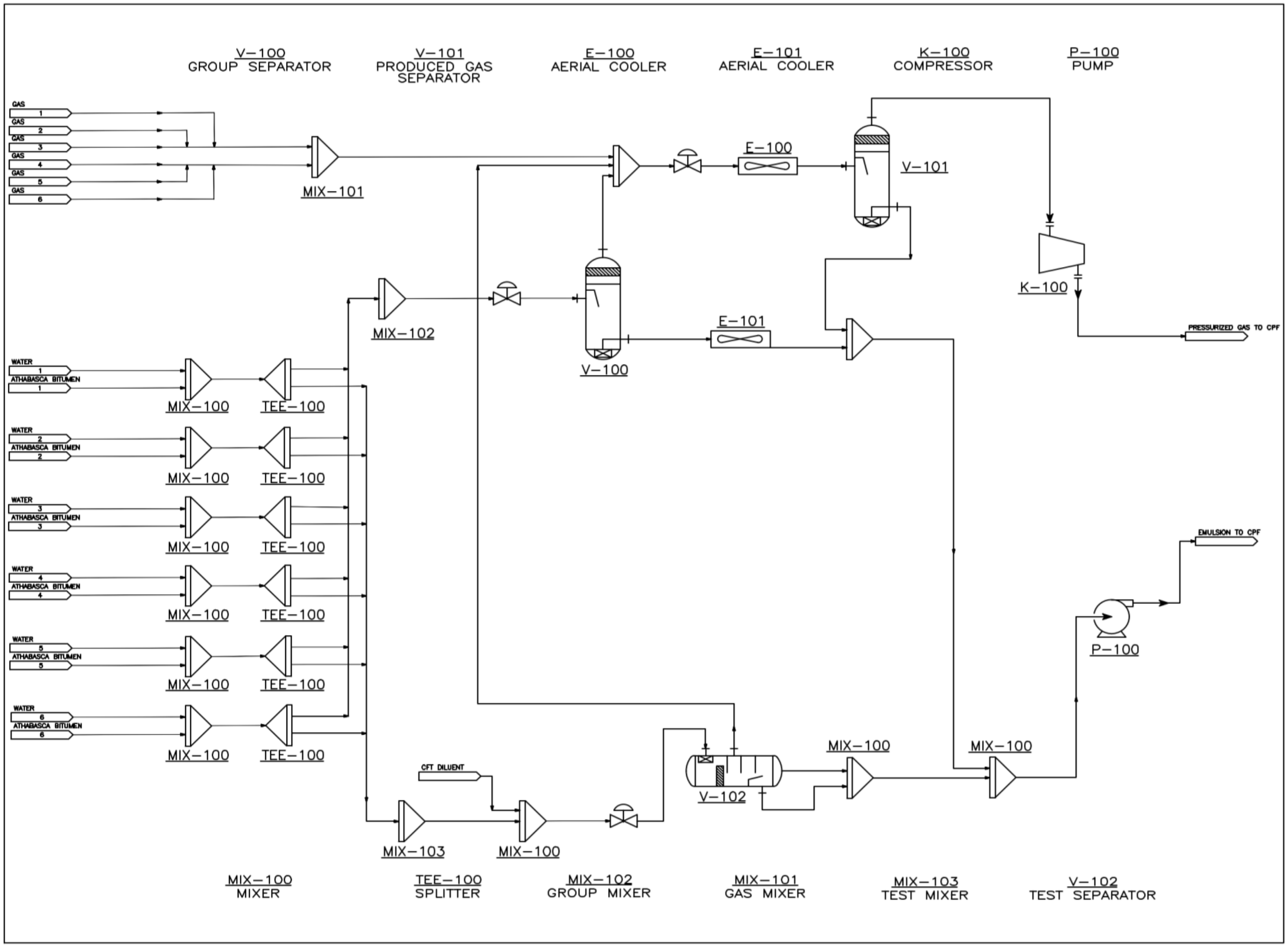

Figure 16. Well-Pad Process Flow Diagram