CHAPTER IV

RESERVOIR AND ECONOMICS MODEL

The reservoir model was constructed in ECLIPSE 300 in order to simulate its performance to find the result of the different compositions. Economic tools described in Chapter 3 are used to evaluate different recovery mechanisms on reservoirs with different fluid compositions.

4.1 Description of Reservoir Model

The reservoir model for the compositional simulation study was constructed as folows:

1. Describe the general reservoir model data in case definition such as type of simulator, structure/dimensions, PVT data, geometry and grid type, number of components, and pressure saturation solution type.
2. Define grid properties which are active grid blocks, porosity, permeability, net thickness, and reservoir geometry features.
3. Define PVT data for reservoirs gas-condensate, water PVT properties, fluid densities at surface conditions, and rock properties. The fluid compositional data are also identified in this step: component names and component properties such as critical properties, molecular weight, and acentric factor.
4. Describe fluid saturation function and reservoir initial equilibration: initial composition, initial water saturation, initial gas saturation, initial pressure, and initial dew point.
5. Select an appropriate type of simulation. Reservoir simulation is classified into different types based on the following characteristics:
    a) Fluid description
        (a) Black oil
        (b) Equation of state (EOS) –compositional
        (c) Chemical

b) Temperature
   (a) Isothermal
   (b) Thermal
c) Simulation solution method
   (a) IMPES
   (b) Fully implicit
   (c) AIM
d) Coordinates systems
   (a) Cartesian
   (b) Radial
   (c) Spherical

The reservoir simulator ECLIPSE 300 specializing in compositional modeling was used. ECLIPSE 300 is a compositional and isothermal simulator. The adaptive implicit (AIM) mode which makes implicit calculation when necessary was selected as simulation solution method. The selected grid system is Cartesian coordinate.

The changes of the fluid phase according to hydrocarbon compositions and the flow behavior of fluid in porous media are the application which this simulation considers. This chapter discusses the detail of reservoir simulation for injection and production scenarios. The simple reservoir and wellbore model are the same as the ones previous studies by Jamsutee [1].

4.1.1 Reservoir Model

A simple reservoir model with plane geometry and homogeneous reservoir properties was used. The gas-condensate reservoir is approximately 490,000 ft^2 in area and 8,000 ft TVD (depth of top-face) below the surface. The reservoir thickness is 100 ft. The five-spot injection pattern was selected. The reservoir defined in this study is a quarter five-spot with an injector at one of the corners, and a producer at the opposite corner. A schematic drawing of injection well and production well of the five-spot pattern is shown in Figure 4.1.

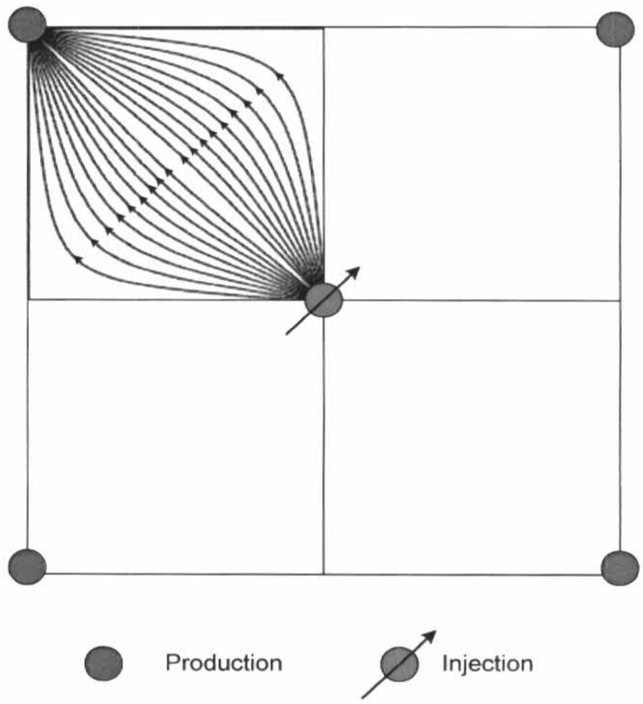

Figure 4.1: Injection well and production well of the five-spot pattern.

4.1.2 Wellbore Model

The production and injection wells have a wellbore diameter of 3-1/2 inches with an inside diameter of 2.992 inches. The well is perforated from 8,000 ft. to 8,100 ft. The perforation interval is from the top to the bottom of the reservoir. The schematic of wellbore and configuration is shown in Figure 4.2.

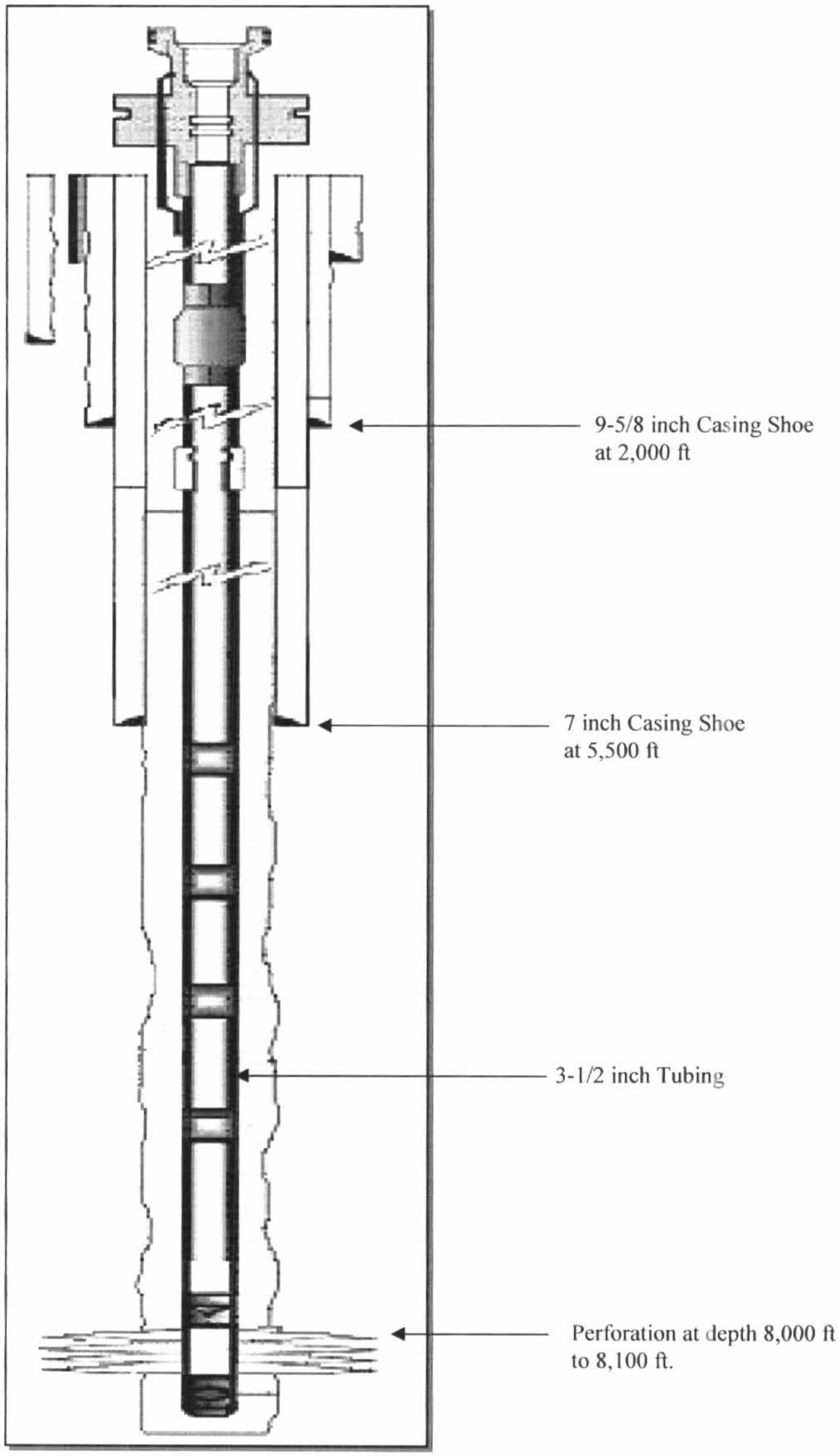

Figure 4.2: Casing and tubing flow model used in this study.

4.1.3 Input Data for Reservoir Simulation

Required data for the compositional simulation are physical characteristics of the reservoir and wells, phase equilibrium data, reservoir and fluid properties, and injection/production scenario. The PVT properties, and rock properties are tabulated in Table 4.1. Details of initial data for compositional simulation are described in Appendix A, B, and C.

a) Case Definition

Simulator:	Compositional	
Model Dimensions:	Number of cells in the x direction	35
	Number of cells in the y direction	35
	Number of cells in the z direction	8
Grid type:	Cartesian	
Geometry type:	Block Centered	
Oil-Gas-Water Options:	Water, Gas Condensate (ISGAS)	
Number of Components:	10	

Pressure Saturation Options (Solution Type): AIM

b) Grid

Properties:	Porosity		=	0.165	
	Permeability	k-x	=	10.85	mD
		k-y	=	10.85	mD
		k-z	=	1.27	mD
	Net thickness	100	feet (12.5 x 8)		
Geometry:	Grid data units				
	X Grid block sizes		=	20 ft	
	Y Grid block sizes		=	20 ft	
	Z Grid block sizes		=	12.5 ft	
Depth of Top face			=	8,000 ft	

Table 4.1: PVT properties of reservoir fluids and rock properties.

Water PVT Properties	Reference pressure(Pref)	3000	psia
	Water FVF at Pref	1.060897	rb/stb
	Water viscosity at Pref	0.1892652	cp
	Water viscosibility	5.376165E-6	/psi
Fluid Densities at Surface Conditions	Oil density	49.99914	lb/ft^3
	Water density	62.42797	lb/ft^3
	Gas density	0.04947417	lb/ft^3
Rock Properties	Reference Pressure	3000	psia
	Rock Compressibility	2.403571E-6	/psi
Fluid property	Dew Point Pressure	2,150	psia

c) SCAL (Special Core Analysis)

Initial reservoir properties

Initial Water Saturation (SWAT)	:	0.11
Initial Gas Saturation (SGAS)	:	0.89
Initial Pressure	:	3,000 psia

The initial water/gas saturation used in this study is an average value from one gas field in the Gulf of Thailand. The dew point pressure of gas condensate is obtained from the PVT data of each set of hydrocarbon compositions. The oil saturation and relative permeability relation is tabulated in Table 4.2 and shown in Figure 4.3. Both types of relative permeability, K_{row} and K_{rowg}, are presented where K_{row} is the oil relative permeability for a system with oil and water only and K_{rowg} is the oil relative permeability for a system with oil, water and gas.

Table 4.2: Oil saturation and oil relative permeabilities.

So	K_{row}	K_{rowg}
0	0	0
0.2	0	0
0.32	0.00463	0.015625
0.44	0.037037	0.125
0.56	0.125	0.421875
0.68	0.296296	1
0.95	1	1

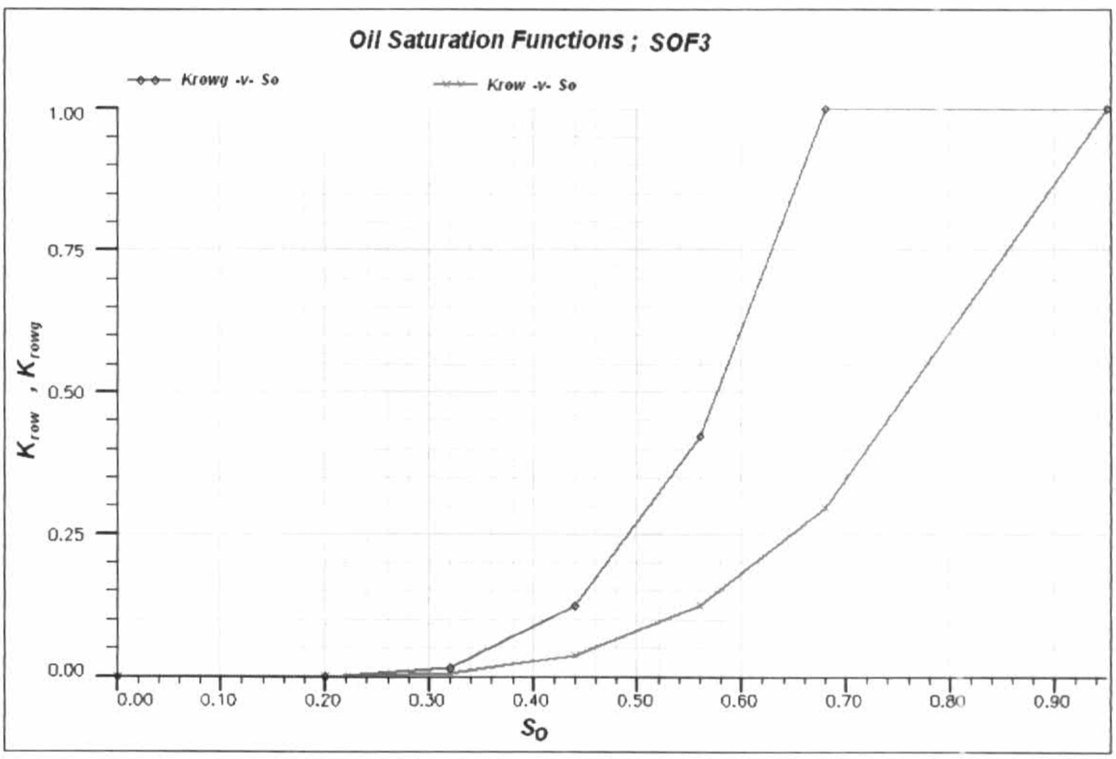

Figure 4.3: Relative permeability function.

Table 4.3: Water saturation and water relative permeability.

Sw	Krw
0.11	0
0.157	0
0.216	0
0.313	0.02
0.44	0.06
0.56	0.10
0.68	0.15
0.80	0.30
0.90	0.65

The water saturation and water relative permeability relation is tabulated in Table 4.3 and shown in Figure 4.4.

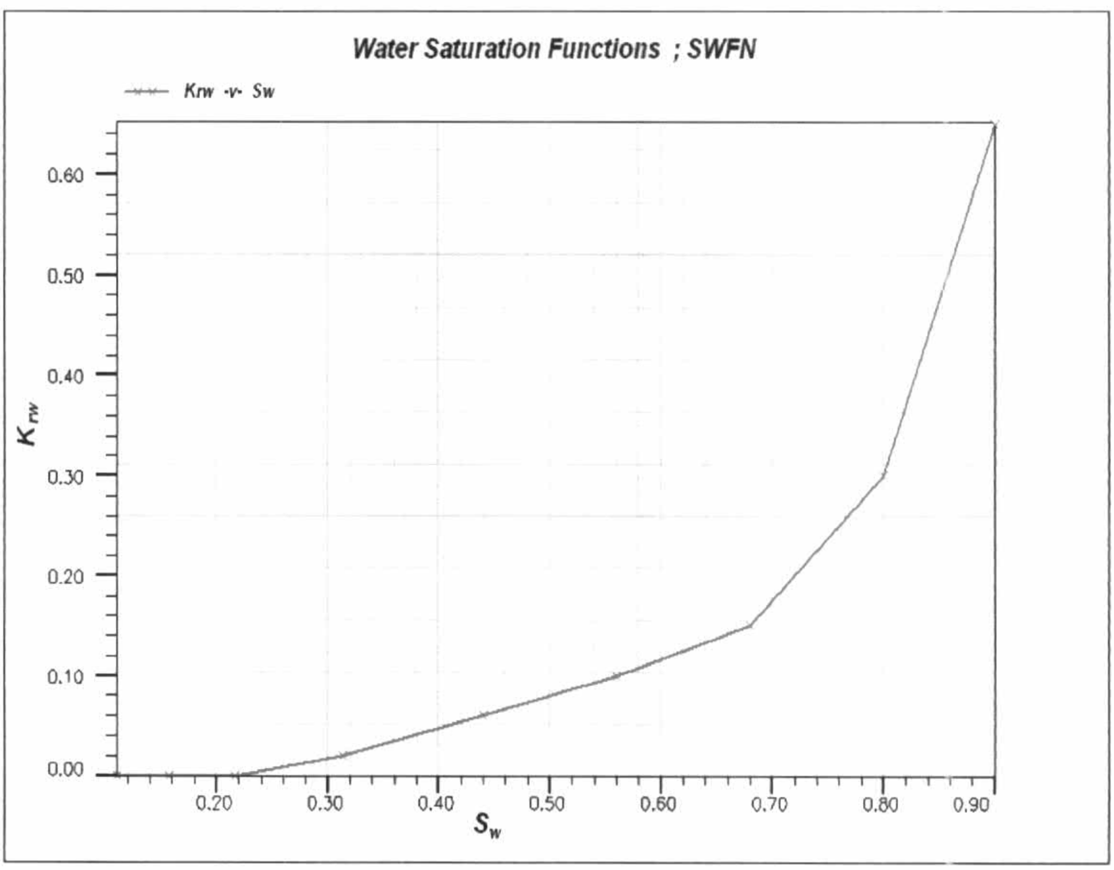

Figure 4.4: Water relative permeability as a function of water saturation.

The gas saturation and gas relative permeability relation is tabulated in Table 4.4 and shown in Figure 4.5.

Table 4.4: Gas saturation function and relative gas permeability.

Sg	Krg
0	0
0.1	0
0.2	0
0.3	0.2
0.4	0.4
0.6	0.85
0.7	0.90
0.8	0.92
0.9	0.95
0.95	0.95

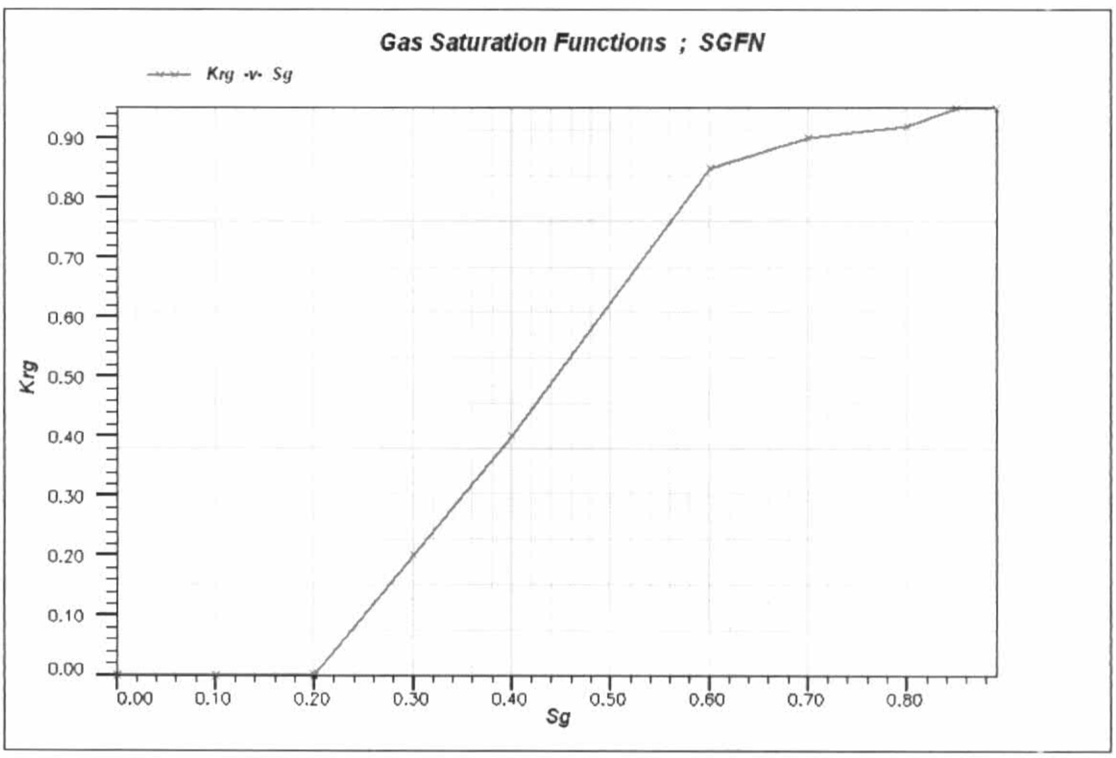

Figure 4.5: Gas relative permeability as a function of gas saturation.

The water saturation and capillary pressure is tabulated in Table 4.5, and their relation curve is shown in Figure 4.6.

Table 4.5: Water saturation and capillary pressure.

Sw	Pc (psia)
0.11	250
0.157	53
0.216	13
0.313	1
0.44	0
0.56	0
0.68	0
0.80	0
0.90	0

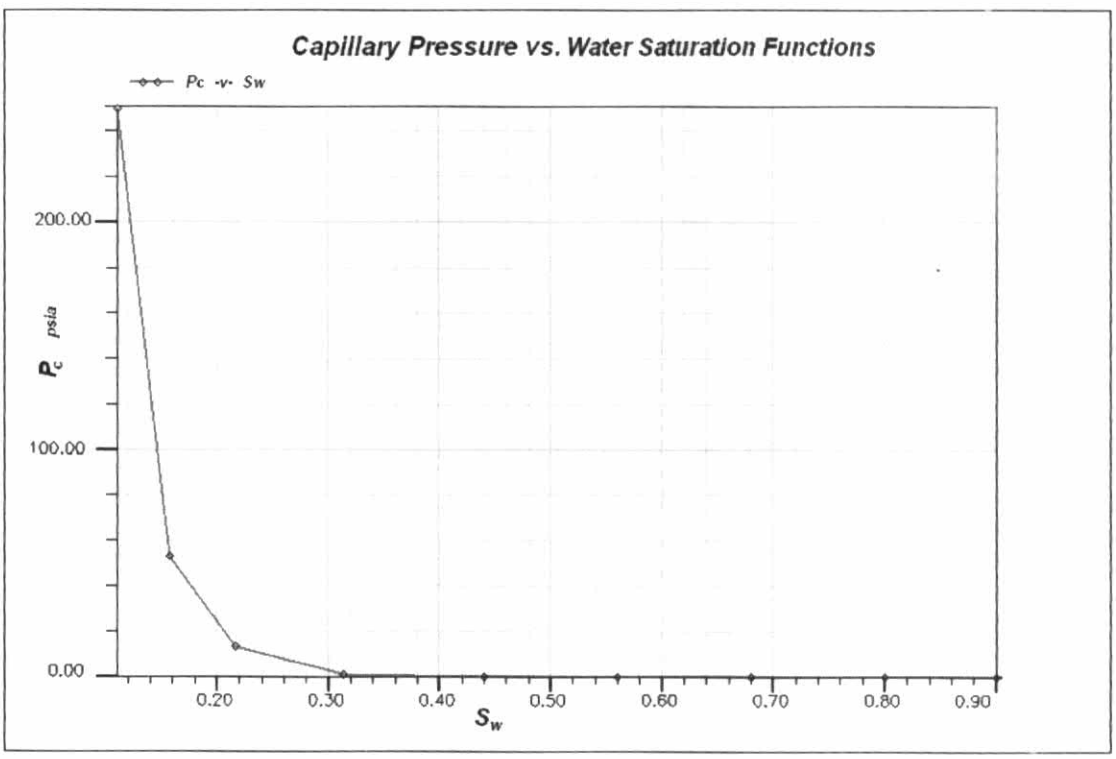

Figure 4.6: Capillary pressure as a function of water saturation.

Gas-condensate reservoir properties in this compositional simulation were obtained from average values of special core analysis data of samples collected from one of the gas fields in the Gulf of Thailand.

d) Initialization

The initial fluid compositions in gas-condensate reservoir are the actual field data from Society of Petroleum Engineering papers. They are entered in the NEI section of the simulation program. The NEI (Non-Equilibrium Initialisation) is used to generate consistent oil and gas compositions for each cell. All ten initial compositions for this study are specified and tabulated in Table 3.8.

Table 4.6: Initial fluid composition of reservoir fluid.

	NEI (Non-Equilibrium Initialisation)									
Component	**Fraction Case 1**	**Fraction Case 2**	**Fraction Case 3**	**Fraction Case 4**	**Fraction Case 5**	**Fraction Case 6**	**Fraction Case 7**	**Fraction Case 8**	**Fraction Case 9**	**Fraction Case 10**
Methane	0.59991	0.6481	0.7426	0.8358	0.832	0.834	0.7351	0.7104	0.6072	0.6372
Ethane	0.084326	0.0527	0.0818	0.0595	0.074	0.072	0.0623	0.0757	0.081	0.0575
Propane	0.063988	0.0623	0.0395	0.0291	0.028	0.0274	0.0301	0.0348	0.0637	0.0437
Isobutane	0.034127	0.0167	0.0104	0.0045	0.0063	0.0054	0.0289	0.0064	0.0398	0.0498
Normal butane	0.038989	0.0309	0.0158	0.0111	0.0094	0.009	0.0365	0.0143	0.0445	0.0315
Isopentane	0.014286	0.0137	0.0074	0.0036	0.0048	0.0042	0.024	0.005	0.0291	0.0341
Normal pentane	0.013988	0.0131	0.0087	0.0048	0.004	0.003	0.0111	0.0056	0.0252	0.0302
Hexane	0.072718	0.0159	0.0098	0.006	0.0064	0.0058	0.0174	0.0075	0.0179	0.0109
Hepthane	0.065366	0.1339	0.0656	0.008	0.0074	0.0049	0.0138	0.0107	0.0885	0.104

Table 4.6: Initial fluid composition of reservoir fluid (con't).

NEI (Non-Equilibrium Initialisation)										
Component	**Fraction Case 1**	**Fraction Case 2**	**Fraction Case 3**	**Fraction Case 4**	**Fraction Case 5**	**Fraction Case 6**	**Fraction Case 7**	**Fraction Case 8**	**Fraction Case 9**	**Fraction Case 10**
Octane	-	-	-	0.0076	0.0048	0.0054	0.0097	0.0136	-	-
Nonane	-	-	-	0.0047	0.0036	0.0043	0.0077	0.0086	-	-
Decane	-	-	-	0.0103	0.0026	0.0033	0.0048	0.0061	-	-
Undecane	-	-	-	-	0.0099	0.0147	0.0143	0.0041	-	-
Dodecane	-	-	-	-	-	-	-	0.0202	-	-
Carbon dioxide	0.012302	0.0106	0.004	0.0065	0.002	0.0019	0.0021	0.0708	0.0018	0.0008
Nitrogen	-	0.0021	0.0144	0.0085	0.0048	0.0047	0.0022	0.0062	0.0013	0.0003

4.2 Description of Economic Model

In this study, the financial aspect of each production profile of condensate reservoirs are evaluated using economic decision tools mentioned in the previous chapter: NPV, IRR, and Payback Period will be based on the previous work's assumption. The assumptions for this economic evaluation base on Jamsutee's study which are:

a) Each production profile represents an independent project.
b) Oil price equal to 62.5 US$/bbl
c) Gas price equal to 3.5 US$/MMBTU
d) Constant interest rate at 10 %
e) Total fixed cost/investment cost of production well and injection well equal to 1,200,000 US$.
f) Total cost of compressor is 2,725,000 US$
g) Apply linear depreciation for salvage cost of compressor, and compressor life time is defined at 5 years.
h) Operating cost varies only on electricity consumption.
i) The gas processing cost is not accounted in the economic evaluation.
j) The existing production facility can handle all the produced gas and condensate. Therefore, the cost of production facility is not considered.
k) The economic limit for minimum gas production rate is 100 MSCF/D
l) The economic limit for minimum oil production rate is 5 STB/D for production by natural depletion. And in case of gas cycling the economic for minimum oil production rate will be varied for each composition.

In this study, additional cost, or investment is not considered during the production period. The capital cost is invested when starting the project; so, net present value (NPV) is used as the most important economical criteria of each production profile. In addition, internal rate of return (IRR) may be used for making decision. The payback period is calculated using discounted net cash flow. The details of operation cost and the calculation of Btu for produced gas are described in appendix D.