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นายนิวัตร จำรูญสิน

วิทยานิพนธ์นี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรปริญญาวิศวกรรมศาสตรมหาบัณฑิต
สาขาวิชาวิศวกรรมปิโตรเลียม ภาควิชาวิศวกรรมเหมืองแร่และปิโตรเลียม
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APPLICATION OF GENETIC ALGORITHM IN WELL PLACEMENT FOR WATERFLOODING

Mr. Niwat Jamrunsin

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By	Mr. Niwat Jamrunsin
Field of Study	Petroleum Engineering
Thesis Advisor	Assistant Professor Suwat Athichanagorn, Ph.D.

Accepted by the Faculty of Engineering, Chulalongkorn University in Partial Fulfillment of the Requirements for the Master's Degree

.... Dean of the Faculty of Engineering

(Associate Professor Boonsom Lerdhirunwong, Dr.Ing.)

THESIS COMMITTEE

...................................Chairman

(Associate Professor Sarithdej Pathanasethpong)

Suwat Athichanagorn Thesis Advisor

(Assistant Professor Suwat Athichanagorn, Ph.D.)

.... Examiner

(Assistant Professor Jirawat Chewaroungroaj, Ph.D.)

Witsarut T. .... External Examiner

(Witsarut Thungsuntonkhun, Ph.D.)

นิวัตร จำรูญสิน : การประยุกต์ใช้อัลกอริทึมพันธุกรรมในการวางตำแหน่งหลุมสำหรับกระบวนการอัดน้ำแทนที่ (APPLICATION OF GENETIC ALGORITHM IN WELL PLACEMENT FOR WATERFLOODING) อ. ที่ปรึกษาวิทยานิพนธ์หลัก: ผศ. ดร. สุวัฒน์ อธิชนากร, 174 หน้า.

การวางตำแหน่งหลุมอัดน้ำในกระบวนการอัดน้ำแทนที่ให้เหมาะสม เป็นสิ่งที่จำเป็นอย่างยิ่งในการเพิ่มประสิทธิภาพการผลิตน้ำมัน การวางหลุมอัดน้ำและหลุมผลิตน้ำมันในตำแหน่งที่เหมาะสมไม่เพียงแต่เป็นการเพิ่มประสิทธิภาพการผลิตน้ำมันจากชั้นหินกักเก็บ แต่เป็นการประหยัดเวลา ในการดำเนินการผลิตน้ำมันจากแหล่งกักเก็บ ในกระบวนการผลิตน้ำมันด้วยการอัดน้ำแทนที่นี้ หลุมอัดน้ำแบบแนวดิ่งและหลุมอัดน้ำแบบแนวนอนถูกนำมาใช้ สำหรับงานวิจัยนี้เป็นการประยุกต์ใช้อัลกอริทึมพันธุกรรม (Genetic Algorithm) ในการวางตำแหน่งหลุมสำหรับกระบวนการอัดน้ำแทนที่ ซึ่งการหาตำแหน่งของหลุมจะกระทำโดยใช้อัลกอริทึมพันธุกรรม (Genetic Algorithm) ควบคู่กับโปรแกรมการจำลองการไหลในแหล่งกักเก็บ (Reservoir simulator) โดยมีการเปรียบเทียบผลผลิตน้ำมันที่ได้จากการใช้ชนิดของหลุมผลิตน้ำมันและหลุมอัดน้ำที่มีความแตกต่างกัน แต่ละกรณีจะถูกศึกษาผ่านตัวแปรอัตราการอัดน้ำและความหนาที่เปลี่ยนแปลงไปของหินกักเก็บ

จากงานวิจัยนี้พบว่าการวางตำแหน่งหลุมอัดน้ำและชนิดของหลุมอัดน้ำในกระบวนการอัดน้ำแทนที่จะมีความแตกต่างกัน ซึ่งขึ้นอยู่กับความหนาของชั้นหินกักเก็บ ในกรณีที่ชั้นหินกักเก็บน้ำมันมีความหนามากกว่า 100 ฟุต จ ะสามารถผลิตน้ำมันได้มากที่สุดเมื่อใช้หลุมผลิตแบบแนวดิ่งกับ หลุมอัดน้ำแบบแนวนอน 2 หลุม แต่สำหรับชั้นหินกักเก็บที่ความหนาน้อยกว่า 100 ฟุต ก าร ผลิตน้ำมันโดยใช้หลุมแบบแนวนอน กับการอัดน้ำโดยใช้หลุมแบบแนวนอน 2 หลุม จะให้ประสิทธิภาพที่สูงกว่า

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Well placement is very important in waterflooding process. A good arrangement of well location does not only increase oil recovery but also reduces the time required to produce the oil. Either vertical or horizontal injectors can be used in this process. This thesis studies application of genetic algorithm in well placement for waterflooding process. A reservoir simulator coupled with genetic algorithm is used to find well locations for each case. The well locations depend on several parameters such as length of well, injection rate, and reservoir thickness. These parameters are varied in order to find the most suitable location.

In this study, the scenario to obtain the highest recovery for each reservoir thickness is different. In case of a large reservoir thickness (more than 100 ft), the oil recovery is the highest when using a single vertical producer with two horizontal injectors at injection rate of 10,000 STB/D. This scenario provides high oil recovery and low water production. The production time required to produce oil is less than other scenarios. Although a single vertical producer with two horizontal injectors result in the highest oil recovery for a thick reservoir, this scenario is not suitable for a thin reservoir due to an early breakthrough. A large amount of produced water is turned out. For thin reservoirs, using one horizontal producer with two horizontal injectors with injection rate of 10,000 STB/D is the best choice.

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Contents

Page

Abstract (Thai)......iv

Abstract (English)......v

Contents......vii

List of Tables......xi

List of Figures......xiv

List of Abbreviations......xxvi

Nomenclature......xxvii

CHAPTER

I. INTRODUCTION......1

II. LITERATURE REVIEW......3

III. THEORY AND CONCEPT......10

3.1 Waterflooding......10

3.1.1 Flooding patterns and sweep efficiency......10

3.1.2 Factors constituting a waterflooding design......12

3.1.3 Injection rate......12

3.1.4 Effect of reservoir thickness......13

3.2 Horizontal and vertical well......13

3.2.1 Pressure drop through a horizontal well......13

3.2.2 Types of horizontal wells......15

3.2.3 Benefits and disadvantages of horizontal and vertical wells......16

Page

3.3 Genetic algorithm ……………………………………………………………..17

3.3.1 Population…………………………………………………………......17

3.3.2 Evaluation……………………………………………………………..18

3.3.3 Reproduction………………………………………………………….19

3.3.4 Gene and chromosome length effect…………………………………..21

3.3.5 Features of the Genetic optimization………………………………….22

3.3.6 Termination criteria…………………………………………………..23

IV. RESERVOIR MODEL BUILDING…………………………………………24

4.1 Reservoir model…………………………………………………………..24

4.1.1 Reservoir model description…………………………………………24

4.1.2 Fluid properties and SCAL…………………………………………..25

4.1.3 Initial condition model ……………………………………………...28

4.2 Well model description……………………………………………………..28

4.3 Production and injection rate………………………………………………..29

4.4 Methodology………………………………………………………………..30

V. SIMULATION RESULT AND ANALYSIS……………………………………..33

5.1 Well placement in 30-ft thick reservoir……………………………………..33

5.1.1 Well placement for one producer with two injectors…………........33

5.1.1.1 One horizontal producer with two vertical injectors………33

5.1.1.2 One horizontal producer with two horizontal injectors…....38

5.1.1.3 One vertical producer with two vertical injectors……...….43

5.1.1.4 One vertical producer with two horizontal injectors….…...47

5.1.2 Well placement for two producers with one injector……………...51

5.1.2.1 Two horizontal producers with one vertical injector….…...51

5.1.2.2 Two horizontal producers with one horizontal injector…....56

Page

5.1.2.3 Two vertical producers with one vertical injector…………...60

5.1.2.4 Two vertical producers with one horizontal injector……....65

5.1.3 Summary for well placement at 30-ft thick reservoir……………....70

5.2 Well placement in 100-ft thick reservoir…………………....……..….........73

5.2.1 Well placement for one producer with two injectors….……….......73

5.2.1.1 One horizontal producer with two vertical injectors………73

5.2.1.2 One horizontal producer with two horizontal injectors…....78

5.2.1.3 One vertical producer with two vertical injectors……........82

5.2.1.4 One vertical producer with two horizontal injectors………86

5.2.2 Well placement for two producers with one injector……………...91

5.2.2.1 Two horizontal producers with one vertical injector………91

5.2.2.2 Two horizontal producers with one horizontal injector…....97

5.2.2.3 Two vertical producers with one vertical injector……......102

5.2.2.4 Two vertical producers with one horizontal injector….......106

5.2.3 Summary for well placement at 100-ft thick reservoir…………....111

5.3 Well placement in 300-ft thick reservoir……………....…………..…......113

5.3.1 Well placement for one producer with two injectors………….....113

5.3.1.1 One horizontal producer with two vertical injectors……..113

5.3.1.2 One horizontal producer with two horizontal injectors…..118

5.3.1.3 One vertical producer with two vertical injectors……..…123

5.3.1.4 One vertical producer with two horizontal injectors…..…127

5.3.2 Well placement for two producers with one injector……………..131

5.3.2.1 Two horizontal producers with one vertical injector……..131

5.3.2.2 Two horizontal producers with one horizontal injector…..135

5.3.2.3 Two vertical producers with one vertical injector………..139

Page

5.3.2.4 Two vertical producers with one horizontal injector……..143

5.3.3 Summary for well placement at 300-ft thick reservoir…………....147

VI. CONCLUSIONS AND RECOMMENDATIONS…………………...…………..149

6.1 Conclusions……………………………………………...…………....149

6.2 Recommendations…………………………………………...………..…151

References………………………………...……………………………………...…152

Appendix…………...…………………………...……………………………………..155

Vitae…………………………………………...…………………………………….174

List of Tables

Page

Table 3.1: Maximum well lengths at different turning radii …………..…………….…15

Table 3.2: Cost ratios between horizontal and vertical well…………….…………......…13

Table 4.1: The data for Corey correlation……………………………….………….….26

Table 4.2: Reservoir properties……………………………………..………..…...27

Table 4.3: PVT data……………………………………….………………….…...28

Table 4.4: Injection rate condition……………………………….…...……...…29

Table 4.5: Production condition……………………………………………………….…..30

Table 4.6: The scenario for the study……………………...……….………..……….…31

Table 5.1: Well locations and recovery factor for each generation in the case of one horizontal producer and two vertical injectors in 30-ft thick reservoir …......36

Table 5.2: Production data for the case of one horizontal producer and two vertical injectors at injection rate of 1,000 STB/D, 2,500 STB/D, and 5,000 STB/D in 30 ft-thick reservoir…….……………………………………..…37

Table 5.3: Well locations and recovery factor for each generation in the case of one horizontal producer and two horizontal injectors in 30-ft thick reservoir ….40

Table 5.4: Production data for the case of one horizontal producer and two horizontal injectors at injection rate of 1,000 STB/D, 2,500 STB/D, and 5,000 STB/D in 30 ft-thick reservoir……………………...……...…41

Table 5.5: Well locations and recovery factor for each generation in the case of one vertical producer and two vertical injectors in 30-ft thick reservoir ……....45

Table 5.6: Production data for the case of one vertical producer and two vertical injectors at injection rate of 1,000 STB/D, 2,500 STB/D, and 5,000 STB/D in 30 ft-thick reservoir……………………………………….….…46

Table 5.7: Well locations and recovery factor for each generation in the case of one vertical producer and two horizontal injectors in 30-ft thick reservoir …....49

Page

Table 5.8: Production data for the case of one vertical producer and two horizontal injectors at injection rate of 1,000 STB/D, 2,500 STB/D, and 5,000 STB/D in 30 ft-thick reservoir…..……………………………………..…50

Table 5.9: Well locations and recovery factor for each generation in the case of two horizontal producers and one vertical injector in 30-ft thick reservoir …......53

Table 5.10: Production data for the case of two horizontal producers and one vertical injector at injection rate of 1,000 STB/D, 2,500 STB/D, and 5,000 STB/D in 30 ft-thick reservoir…………..…………………………………..…54

Table 5.11: Well locations and recovery factor for each generation in the case of two horizontal producers and one horizontal injector in 30-ft thick reservoir ……………………………………………………………………….....58

Table 5.12: Production data for the case of two horizontal producers and one horizontal injector at injection rate of 1,000 STB/D, 2,500 STB/D, and 5,000 STB/D in 30 ft-thick reservoir…………………………………..…59

Table 5.13: Well locations and recovery factor for each generation in the case of two vertical producers and one vertical injector in 30-ft thick reservoir ……......52

Table 5.14: Production data for the case of two vertical producers and one vertical injector at injection rate of 1,000 STB/D, 2,500 STB/D, and 5,000 STB/D in 30 ft-thick reservoir…..……………………………………..…63

Table 5.15: Well locations and recovery factor for each generation in the case of two vertical producers and one horizontal injector in 30-ft thick reservoir …......67

Table 5.16: Production data for the case of two vertical producers and one horizontal injector at injection rate of 1,000 STB/D, 2,500 STB/D, and 5,000 STB/D in 30 ft-thick reservoir……………………………………………..…68

Table 5.17: Well placement results for 30-ft thick reservoir at low injection rate….…..71

Table 5.18: Well placement results for 30-ft thick reservoir at medium injection rate.....71

Table 5.19: Well placement results for 30-ft thick reservoir at high injection rate……..72

Page

Table 5.20: Well locations and recovery factor for each generation in the case of one horizontal producer and two vertical injectors in 100-ft thick reservoir 75

Table 5.21: Production data for the case of one horizontal producer and two vertical injectors at injection rate of 2,500 STB/D and 5,000 STB/D in 100 ft-thick reservoir……………………………...………………...………..…76

Table 5.22: Well locations and recovery factor for each generation in the case of one horizontal producer and two horizontal injectors in 100-ft thick reservoir …..…………………………………………………………...80

Table 5.23: Production data for the case of one horizontal producer and two horizontal injectors at injection rate of 2,500 STB/D and 5,000 STB/D in 100 ft-thick reservoir……….…………………………………….....…81

Table 5.24: Well locations and recovery factor for each generation in the case of one vertical producer and two vertical injectors in 100-ft thick reservoir …......84

Table 5.25: Production data for the case of one vertical producer and two vertical injectors at injection rate of 2,500 STB/D and 5,000 STB/D in 100 ft-thick reservoir……………………..……………….....……..…85

Table 5.26: Well locations and recovery factor for each generation in the case of one vertical producer and two horizontal injectors in 100-ft thick reservoir …...89

Table 5.27: Production data for the case of one vertical producer and two horizontal injectors at injection rate of 2,500 STB/D and 5,000 STB/D in 100 ft-thick reservoir……………………………………………………..…90

Table 5.28: Well locations and recovery factor for each generation in the case of two horizontal producers and one vertical injector in 100-ft thick reservoir........94

Page

Table 5.29: Production data for the case of two horizontal producers and one vertical injector at injection rate of 2,500 STB/D and 5,000 STB/D in 100 ft-thick reservoir……………………………………..……………..…95

Table 5.30: Well locations and recovery factor for each generation in the case of two horizontal producers and one horizontal injector in 100-ft thick reservoir....99

Table 5.31: Production data for the case of two horizontal producers and one horizontal injector at injection rate of 2,500 STB/D, and 5,000 STB/D in 100 ft-thick reservoir……………..…………………………………...…..100

Table 5.32: Well locations and recovery factor for each generation in the case of two vertical producers and one vertical injector in 100-ft thick reservoir …......104

Table 5.33: Production data for the case of two vertical producers and one vertical injector at injection rate of 2,500 STB/D, and 5,000 STB/D in 100 ft-thick reservoir……………………………………………………...…105

Table 5.34: Well locations and recovery factor for each generation in the case of two vertical producers and one horizontal injector in 100-ft thick reservoir ………………………………………….……………..108

Table 5.35: Production data for the case of two vertical producers and one horizontal injector at injection rate of 2,500 STB/D, and 5,000 STB/D in 100 ft-thick reservoir………………..…………..…………..….109

Table 5.36: Well placement results for 100-ft thick reservoir at medium injection rate.111

Table 5.37: Well placement results for 100-ft thick reservoir at high injection rate…...112

Table 5.38: Well locations and recovery factor for each generation in the case of one horizontal producer and two vertical injectors in 300-ft thick reservoir ……………………………………………………..….......115

Table 5.39: Production data for the case of one horizontal producer and two vertical injectors at injection rate of 2,500 STB/D and 5,000 STB/D in 300 ft-thick reservoir……………..………………...………………………….116

Page

Table 5.40: Well locations and recovery factor for each generation in the case of one horizontal producer and two horizontal injectors in 300-ft thick reservoir 120

Table 5.41: Production data for the case of one horizontal producer and two horizontal injectors at injection rate of 2,500 STB/D and 5,000 STB/D in 300 ft-thick reservoir...121

Table 5.42: Well locations and recovery factor for each generation in the case of one vertical producer and two vertical injectors in 300-ft thick reservoir 125

Table 5.43: Production data for the case of one vertical producer and two vertical injectors at injection rate of 2,500 STB/D and 5,000 STB/D in 300 ft-thick reservoir...126

Table 5.44: Well locations and recovery factor for each generation in the case of one vertical producer and two horizontal injectors in 300-ft thick reservoir 129

Table 5.45: Production data for the case of one vertical producer and two horizontal injectors at injection rate of 2,500 STB/D and 5,000 STB/D in 300 ft-thick reservoir...130

Table 5.46: Well locations and recovery factor for each generation in the case of two horizontal producers and one vertical injector in 300-ft thick reservoir 133

Table 5.47: Production data for the case of two horizontal producers and one vertical injector at injection rate of 2,500 STB/D and 5,000 STB/D in 300 ft-thick reservoir...134

Table 5.48: Well locations and recovery factor for each generation in the case of two horizontal producers and one horizontal injector in 300-ft thick reservoir 137

Page

Table 5.49: Production data for the case of two horizontal producers and one horizontal injector at injection rate of 2,500 STB/D, and 5,000 STB/D in 300 ft-thick reservoir……………..………………………………..…....138

Table 5.50: Well locations and recovery factor for each generation in the case of two vertical producers and one vertical injector in 300-ft thick reservoir ……..141

Table 5.51: Production data for the case of two vertical producers and one vertical injector at injection rate of 2,500 STB/D, and 5,000 STB/D in 300 ft-thick reservoir………………………………………………..….142

Table 5.52: Well locations and recovery factor for each generation in the case of two vertical producers and one horizontal injector in 300-ft thick reservoir …..145

Table 5.53: Production data for the case of two vertical producers and one horizontal injector at injection rate of 2,500 STB/D, and 5,000 STB/D in 300 ft-thick reservoir…….……………………………………………..146

Table 5.54: Well placement results for 300-ft thick reservoir at low injection rate…....147

Table 5.55: Well placement results for 300-ft thick reservoir at medium injection rate.148

List of Figures

Page

Figure 3.1: Areal sweep efficiency……………………………………………………...10

Figure 3.2: Well patterns for waterflooding process ………………………….....…...11

Figure 3.3: Pressure drop alongside horizontal wellbore versus measured depth..……..13

Figure 3.4: Binary encoding for genetic algorithm……………………………………...18

Figure 3.5: Evaluation step for genetic algorithm …………………………………..…..19

Figure 3.6: Single crossover process for genetic algorithm…………….……………..…20

Figure 3.7: Multiple crossover process for genetic algorithm …………………………..20

Figure 3.8: Mutation process for genetic algorithm …………….…………………..….21

Figure 3.9: The length of gene (Individual value)……………...……………………….22

Figure 3.10: The different lengths of chromosomes……………………………………..22

Figure 4.1: Reservoir model……….……………………………….………………..…25

Figure 4.2: Water/oil relative permeability curve……………………………………..…26

Figure 4.3: Gas/oil relative permeability curve………………………………………..…27

Figure 4.4: Optimization algorithm…………………….………………………………..31

Figure 5.1: Recovery factor as a function of generation in the case of one horizontal producer and two vertical injectors in 30-ft thick reservoir……...…….…..34

Figure 5.2: Optimal well location for the case of one horizontal producer and two vertical injectors at injection rate of 5,000 STB/D in 30-ft thick reservoir....35

Figure 5.3: Recovery factor for the case of one horizontal producer and two vertical injectors at injection rate of 1,000 STB/D, 2,500 STB/D, and 5,000 STB/D in 30 ft-thick reservoir..…………..…...…………………………......38

Figure 5.4: Well placement for the case of one horizontal producer and two horizontal injectors at injection rate of 5,000 STB/D for 30-ft thick reservoir…….……………………………………………………………….38

Page

Figure 5.5: Recovery factor as a function of generation in the case of horizontal producer and two horizontal injectors in 30-ft thick reservoir…..………….…39

Figure 5.6: Recovery factor for the case of one horizontal producer and two horizontal injectors at injection rate of 2,000 STB/D, 5,000 STB/D and 10,000 STB/D in 30 ft-thick reservoir……………………………...….42

Figure 5.7: Cumulative produced water for the case of one horizontal producer and two horizontal injectors at injection rate of 2,000 STB/D, 5,000 STB/D and 10,000 STB/D in 30 ft-thick reservoir..………………..…42

Figure 5.8: Recovery factor as a function of generation in the case of one vertical producer and two vertical injectors in 30-ft thick reservoir ……………..….43

Figure 5.9: Well placement for the case of one vertical producer and two vertical injectors at injection rate of 2,500 STB/D in 30-ft thick reservoir....44

Figure 5.10: Recovery factor for the case of one vertical producer and two vertical injectors at injection rate of 1,000 STB/D, 2,500 STB/D and 5,000 STB/D in 30 ft-thick reservoir…………………………..…...….47

Figure 5.11: Recovery factor as a function of generation in the case of one vertical producer and two horizontal injectors in 30-ft thick reservoir……..……....48

Figure 5.12: Well placement for the case of one vertical producer and two horizontal injectors at injection rate of 2,000STB/D in 30-ft thick reservoir……………………………………………………………….….48

Figure 5.13: Recovery factor for the case of one vertical producer and two horizontal injectors at injection rate of 2,000 STB/D, 5,000 STB/D and 10,000 STB/D in 30-ft thick reservoir……………………………………....….51

Figure 5.14: Recovery factor as a function of generation in the case of two horizontal producers and one vertical injector in 30-ft thick reservoir…………..…....52

Figure 5.15: Well placement for the case of two horizontal producers and one vertical injector at injection rate of 5,000STB/D in 30-ft thick reservoir......52

Page

Figure 5.16: Recovery factor for the case of two horizontal producers and one vertical injector at injection rate of 1,000 STB/D, 2,500 STB/D and 5,000 STB/D in 30-ft thick reservoir……………………………….…..55

Figure 5.17: Production time for the case of two horizontal producers and one vertical injector at injection rate of 1,000 STB/D, 2,500 STB/D, and 5,000 STB/D in 30-ft thick reservoir………………………..…………...….…..55

Figure 5.18: Well placement for the case of two horizontal producers and one horizontal injector at injection rate of 10,000 STB/D in 30-ft thick reservoir…………………………………...…………………….……….56

Figure 5.19: Recovery factor as a function of generation in the case of two horizontal producers and one horizontal injector in 30-ft thick reservoir ……..…....….57

Figure 5.20: Recovery factor for the case of two horizontal producers and one horizontal injector at injection rate of 2,000 STB/D, 5,000 STB/D and 10,000 STB/D in 30-ft thick reservoir………………………………….…...60

Figure 5.21: Recovery factor as a function of generation in the case of two vertical producers and one vertical injector in 30-ft thick reservoir …………..….….61

Figure 5.22: Well placement for the case of two vertical producers and one vertical injector at injection rate of 2,500 STB/D in 30-ft thick reservoir.....61

Figure 5.23: Recovery factor for the case of two vertical producers and one vertical injector at injection rate of 1,000 STB/D, 2,500 STB/D and 5,000 STB/D in 30-ft thick reservoir……………………………………………...64

Figure 5.24: The production time for optimizing location of two vertical producers and one vertical injector in 30-ft thick reservoir ……..……………….….….64

Figure 5.25: Recovery factor as a function of generation in the case of two vertical producers with one horizontal injector in 30-ft thick reservoir……………..…65

Page

Figure 5.26: Well placement for the case of two vertical producers and one horizontal injector at injection rate of 5,000 STB/D in 30-ft thick reservoir ……………………………………………………………...…….66

Figure 5.27: Recovery factor for the case of two vertical producers and one horizontal injector at injection rate of 2,000 STB/D, 5,000 STB/D and 10,000 STB/D in 30-ft thick reservoir………………………………….69

Figure 5.28: Production times for the case of two vertical producers and one horizontal injector at injection rate of 2,000 STB/D, 5,000 STB/D and 10,000 STB/D in 30-ft thick reservoir………………..…………………69

Figure 5.29 Recovery factor as a function of generation in the case of one horizontal producer with two vertical injectors in 100-ft thick reservoir…………..….74

Figure 5.30: Well placement for the case of one horizontal producer and two vertical injectors at injection rate of 5,000 STB/D in 100-ft thick reservoir…………………………………………………………………74

Figure 5.31: Recovery factor for the case of one horizontal producer and two vertical injectors at injection rate of 2,500 STB/D and 5,000 STB/D in 100-ft thick reservoir ………………………………………………………77

Figure 5.32: Cumulative produced water for the case of one horizontal producer and two vertical injectors at injection rate of 2,500 STB/D and 5,000 STB/D in 100-ft thick reservoir………………………………...…...77

Figure 5.33: Well placement for the case of one horizontal producer and two horizontal injectors at injection rate of 10,000STB/D in 100-ft thick reservoir………………………………………………………………...…78

Figure 5.34: Recovery factor as a function of generation in the case of one horizontal producer with two horizontal injectors in 100-ft thick reservoir...………....79

Page

Figure 5.35: Recovery factor for the case of one horizontal producer and two horizontal injectors at injection rate of 5,000 STB/D and 10,000 STB/D in 100-ft thick reservoir……………………………………………..…....82

Figure 5.36: Recovery factor as a function of generation in the case of one vertical producer and two vertical injectors in 100-ft thick reservoir….……………83

Figure 5.37: Well placement for the case of one vertical producer and two vertical injectors at injection rate of 5,000 STB/D in 100-ft thick reservoir……………………………………………………….……………83

Figure 5.38: Recovery factor for the case of one vertical producer and two vertical injectors at injection rate of 2,500 STB/D and 5,000 STB/D in 100-ft thick reservoir………………………………………………..……86

Figure 5.39: Recovery factor as a function of generation in the case of one vertical producer with two horizontal injectors in 100-ft thick reservoir ………..….87

Figure 5.40: Well placement for the case of one vertical producer and two horizontal injectors at injection rate of 10,000 STB/D in 100-ft thick reservoir ……………………………………………………...………..…87

Figure 5.41: Recovery factor for the case of one vertical producer and two horizontal injectors at injection rate of 5,000 STB/D and 10,000 STB/D in 100-ft thick reservoir …………………………...…………………………….…....91

Figure 5.42: Recovery factor as a function of generation in the case of two horizontal producers with one vertical injector in 100-ft thick reservoir…...……......…92

Figure 5.43: Well placement for the case of two horizontal producers and one vertical injector at injection rate of 5,000 STB/D in 100-ft thick reservoir …………………………………...…………………......….92

Figure 5.44: Recovery factors for the case of two horizontal producers with one vertical injector at injection rate of 2,500 STB/D and 5,000 STB/D in 100-ft thick reservoir……………………………………………….….96

Page

Figure 5.45: Production times for the case of two horizontal producers and one vertical injector at injection rate of 2,500 STB/D and 5,000 STB/D in 100-ft thick reservoir…………………………………………….…………....96

Figure 5.46: Well placement for the case of two horizontal producers and one horizontal injector at injection rate of 10,000 STB/D in 100-ft thick reservoir ……………………...…………………..……………………97

Figure 5.47: Recovery factor as a function of generation in the case of two horizontal producers and one horizontal injector in 100-ft thick reservoir …….……...98

Figure 5.48: Recovery factor for the case of two horizontal producers and one horizontal injector at injection rate of 5,000 STB/D and 10,000 STB/D in 100-ft thick reservoir…………………………………….……...101

Figure 5.49: Production times for the case of two horizontal producers and one horizontal injector at injection rate of 5,000 STB/D and 10,000 STB/D in 100-ft thick reservoir…………………………….………......101

Figure 5.50: Recovery factor as a function of generation in the case two vertical producers and one vertical injector in 30-ft thick reservoir …………102

Figure 5.51: Well placement for the case of two vertical producers and one vertical injector at injection rate of 10,000 STB/D in 100-ft thick reservoir…....…103

Figure 5.52: Recovery factor for the case of two vertical producers and one vertical injector at injection rate of 2,500 STB/D and 5,000 STB/D in 100-ft thick reservoir…...…………………………………………….…………..105

Figure 5.53: Recovery factor as a function of generation in the case of two vertical producers and one horizontal injector in 100-ft thick reservoir ………….106

Page

Figure 5.54: Well placement for the case of two vertical producers and one horizontal injector at injection rate of 10,000 STB/D in 100-ft thick reservoir ……………………………………………………………..….107

Figure 5.55: Recovery factor for the case of two vertical producers with one horizontal injector at injection rate of 5,000 STB/D and 10,000 STB/D for 100-ft thick reservoir…………………………………………...…....111

Figure 5.56: Recovery factor as a function of generation in the case of one horizontal producer and two vertical injectors in 300-ft thick reservoir ….…………..114

Figure 5.57: Well placement for the case of one horizontal producer and two vertical injectors at injection rate of 5,000STB/D in 300-ft thick reservoir…………………………………………………………….....114

Figure 5.58: Recovery factor for the case of one horizontal producer and two vertical injectors at injection rate of 2,500 STB/D and 5,000 STB/D in 300-ft thick reservoir……………………………...…….….…………117

Figure 5.59: Production time for the case of one horizontal producer and two vertical injectors at injection rate of 2,500 STB/D and 5,000 STB/D in 300-ft thick reservoir ……………………………...…….….…………117

Figure 5.60: Well placement for the case of one horizontal producer and two Horizontal injectors at injection rate of 10,000 STB/D in 300-ft thick reservoir…………………………………………………...………….118

Figure 5.61: Recovery factor as a function of generation in the case of one horizontal producer and two horizontal injectors in 300-ft thick reservoir..119

Figure 5.62: Recovery factor for the case of one horizontal producer and two horizontal injectors at injection rate of 5,000 STB/D and 10,000 STB/D in 300-ft thick reservoir…………….……………………….…………..122

Page

Figure 5.63: Production time for the case of one horizontal producer and two horizontal injectors at injection rate of 5,000 STB/D 10,000 STB/D in 300-ft thick reservoir…..122

Figure 5.64: Recovery factor as a function of generation in the case one vertical producer and two vertical injectors in 300-ft thick reservoir …..…….....…..123

Figure 5.65: Well placement for the case of one vertical producer and two vertical injectors at injection rate of 5,000 STB/D in 300-ft thick reservoir ……………………………………..…………….………...124

Figure 5.66: Recovery factor for the case of one vertical producer and two vertical injectors at injection rate of 2,500 STB/D and 5,000 STB/D in 300-ft thick reservoir ………………………………………………..……..126

Figure 5.67: Recovery factor as a function of generation in the case of one vertical producer and two horizontal injectors in 300-ft thick reservoir ……..….....127

Figure 5.68: Well placement for the case of one vertical producer and two horizontal injectors at injection rate of 10,000 STB/D in 300-ft thick reservoir …………………………………...……………………...128

Figure 5.69: Recovery factor for the case of one vertical producer and two horizontal injectors at injection rate of 5,000 STB/D 10,000 STB/D in 300-ft thick reservoir …….…………………………………...………………...130

Figure 5.70: Recovery factor as a function of generation in the case of two horizontal producers and one vertical injector in 300-ft thick reservoir ……………..131

Figure 5.71: Well placement for the case of two horizontal producers and one vertical injector at injection rate of 5,000 STB/D in 300-ft thick reservoir ……………………………………………………………...132

Figure 5.72: Recovery factor for the case of two horizontal producers and one vertical injector at injection rate of 2,500 STB/D and 5,000 STB/D in 300-ft thick reservoir ….……………………………..…………...134

Page

Figure 5.73: Well placement for the case location of two horizontal producers and one horizontal injector at injection rate of 10,000 STB/D in 300-ft thick reservoir ……….………………………………………………….……135

Figure 5.74: Recovery factor as a function of generation in the case of two horizontal producers and one horizontal injector in 300-ft thick reservoir ……………………………………………………….…………..136

Figure 5.75: Recovery factor for the case of two horizontal producers and one horizontal injector at injection rate of 5,000 STB/D 10,000 STB/D in 300-ft thick reservoir……………………………………………..…...138

Figure 5.76: Recovery factor as a function of generation in the case of two vertical producers and one vertical injector in 300-ft thick reservoir…..…………139

Figure 5.77: Well placement for the case of two vertical producers and one vertical injector at injection rate of 5,000 STB/D in 300-ft thick reservoir ……………………………………...…………….………...140

Figure 5.78: Recovery factor of two vertical producers and one vertical injector at injection rate of 2,500 STB/D, and 5,000 STB/D in 300-ft thick reservoir ……………………………………………………….…………..142

Figure 5.79: Well placement for the case of two vertical producers and one horizontal injector at injection rate of 10,000 STB/D in 300-ft thick reservoir ……………………………………………………………...143

Figure 5.80: Recovery factor as a function of generation in the case of two vertical producers with one horizontal injector in 300-ft thick reservoir ………....144

Figure 5.81: Recovery factor for the case of two vertical producers and one horizontal injector at injection rate of 5,000 STB/D and 10,000 STB/D in 300-ft thick reservoir ……………………………….……..147

List of Abbreviations

API	degree (American Petroleum Institute)
ANN	artificial neural network
CMAES	covariance matrix adaptation – evolution strategy
bbl	barrel (bbl/d : barrel per day)
GA	genetic algorithm
HGA	hybrid genetic algorithm

Nomenclature

A	cross-sectional area
B_w	water formation volume factor
B_o	oil formation volume factor
c	compressibility
c_t	total compressibility
d	horizontal well diameter
dp/dL	pressure gradient
f	friction factor
h	formation thickness
k	formation permeability
k_r	relative permeability
k_{rg}	gas relative permeability
k_{ro}	oil relative permeability
p	pressure
p_i	initial reservoir pressure
q	flow rate

GREEK LETTERS

ρ	density
ϕ	porosity
μ	fluid viscosity
Δ	difference operator

CHAPTER I

INTRODUCTION

Waterflooding technique has been successfully used for many years in the recovery of oil from various reservoirs because investment cost of this technique is lower than other recovery methods. For this technique, either vertical or horizontal wells can be used in this process. Generally, using horizontal well for producing oil has a high potential of providing more amount of oil recovery. Although using horizontal well for producing oil has continued to evolve over time, it has not always been effective. Problem concerning with low permeability which limits the rate at which oil can be produced from the reservoir decreases the attractiveness of horizontal production well. In some cases, the production from certain wells may have to be limited due to surface facility constraints. Using vertical producer with horizontal injector instead of using horizontal producer and injector may be more effective in the case of limited production rate. However, the location of injector still needs to be optimized in order to increase oil recovery. A good arrangement of well location does not only increase oil recovery but also reduces the time required to produce oil and gas.

The optimal well location can be determined by using genetic algorithm (GA). The genetic algorithm (GA) is a search technique based on the principle of selecting the best fitness objective function. In this study, the ultimate oil recovery (RF) is used as the objective function. The locations of all wells are transformed in binary forms as strings. The algorithm is run together with reservoir simulator in order to optimize well locations. The use of genetic algorithm to apply with the well placement problem reduces the required number of simulations in comparison to the trial and error method. Performance of the genetic algorithm depends on length of string. A large number of simulations are required when the length of string increases.

This thesis studies application of genetic algorithm in well placement for waterflooding process. A reservoir simulator coupled with genetic algorithm (GA) is used to find optimum well location for each case. The optimal well location depends on several parameters such as length of well, injection rate, and reservoir thickness.

These parameters are varied in order to find the most suitable location of well. In this thesis, six chapters are presented:

Chapter II represents the literature review concerning optimization of well location using genetic algorithm (GA).

Chapter III describes the principle of waterflooding and well optimization by using genetic algorithm (GA).

Chapter IV describes the reservoir model used to study well placement for each case.

Chapter V represents the results of well placement for each scenario and discusses the results of each case.

Chapter VI provides the conclusions and recommendations for the future study.

CHAPTER II

LITERATURE REVIEW

Several researchers have applied different algorithms to solve the well placement problem. Genetic and hybrid genetic algorithm can be utilized in the optimization of well location because of their effectiveness. Genetic algorithm can be easily added in a tool box of commercial software.

In this chapter, the literature reviews are categorized in two sections: well location optimization and waterflooding.

2.1 Well location optimization literatures

Cullick et al.[1] tried to optimize well location by using genetic algorithm coupled with flow simulation. The objective was to optimize location of several wells by using different objective function. The objective functions used in genetic algorithm are net present value (NPV) and recovery factor. The initial guesses of well locations were necessarily used for starting a trial and error process until obtaining the optimum values. Algorithm of their well planning composed of two main loops: optimization loop and uncertainty loop. In conclusion, the use of net present value (NPV) and recovery factor as objective functions leads to different optimal well locations.

Montes and Bartolome[2] studied the placement in case of vertical wells using genetic algorithm (GA) without any hybridization. The authors performed sensitivity analysis on the internal parameters of genetic algorithm (GA) such as mutation probability, population size and the use of elitism. In this work, the authors concluded that increasing mutation probability without increasing population size may lead to loss of good result.

Guyaguler and Horne[3] also applied hybrid algorithm (HGA) comprising of genetic algoritm (GA), kriging, and artificial neural networks (ANN) to reduce the number of simulations required. This hybrid algorithm was applied to real field cases. In conclusion, using genetic algorithm with kriging was found to be superior to that with artificial neural networks (ANN).

Pan and Horne[4] applied least squares and kriging interpolation techniques as proxies to identify well configurations. The proxies were constructed from previously simulated well configurations. In this work, the authors suggested that the least squares and kriging proxies are a good method for nonlinear regression.

Cruz[5] introduced a concept of quality map to evaluate well locations in waterflooding process. The author varied the locations of wells in each run until obtaining the best locations for all wells. Although the method provides good solutions, it is complex and requires numerous simulation runs.

Centilmen et al.[6] proposed a simulation technique that comprised of a reservoir simulator and artificial neural network. The artificial neural network selected several key well scenarios for all vertical wells by either randomness or intuition. The simulated scenarios performed by this simulation were used to train the network. As a result, the simulator evaluated numerous well scenarios efficiently with little computational time. The authors concluded that their approach was reasonably accurate and faster than conventional methods, and therefore it can effectively be used for field optimization.

Nakajima and Schiozer[7] used a quality map to guide optimization of well locations in waterflooding process. Three methods of creating quality map were presented: (1) numerical simulation, (2) analytical and (3) fuzzy system. These three methods were developed to provide a fast evaluation in order to reduce time consuming and computational efforts. More areas with high production potential are obtained when using numerical simulation and fuzzy system. The well placement results of numerical simulation and fuzzy system were similar. For analytical method, the well placement result was different from numerical simulation and fuzzy system because this method provided smaller areas with good production potential.

Zarei et al.[8] used neuro fuzzy proxy to optimize well locations. In this study, the authors used a 3D black-oil hypothetical model consisting of 20 × 40 × 12 grid blocks. For this reservoir model, the water saturated region was in deeper sector (lower zone) and upper region was assumed with more than 85% of gas saturation. The authors used net present value (NPV) as the objective function. This study presented an approach using hybrid optimization technique based on genetic algorithm (GA) and neuro fuzzy system. The purpose of neuro fuzzy system was to decrease the number of time consuming simulations. The network was used to estimate the fitness function at points that simulations have not been done. This proxy was also able to get better during the optimization each time. A new point was established and updated. In conclusion, the authors showed that using neuro fuzzy systems as proxy models can save time in analysis and calculation. However, the accuracy of application of neuro fuzzy proxy has to be evaluated for each particular reservoir.

Maschio et al.[9] optimized production strategy by using genetic algorithm and quality map. The authors proposed the use of quality map constructed with two dimensions of regions and oil production potential in a reservoir. A sand stone reservoir with area of 7.4 km^2 was used and the reservoir was discretized by 50 x 50 x 46 blocks with dimensions of 80 x 60 x 2 m. The optimization algorithm used in this work was the genetic algorithm (GA). The crossover fraction was set to 0.7-0.9, and the mutation rate was set to 0.1- 0.3, depending on the case. Some operational constraints were made: 1) maximum water cut at 90% and 2) maximum liquid production of the platform at a rate of 45000 m^3/day. The results show that using quality map as criteria to locate wells was very important to minimize the random feature of genetic algorithm (GA). In addition, quality map can reduce the number of simulations.

Ding[10] studied optimization of well placement using evolutionary algorithms. The author focused on non-conventional wells (horizontal well) because this type of wells can produce with high hydrocarbon recovery. In this paper, the author proposed the covariance matrix adaptation – evolution strategy method (CMAES) which is a stochastic method combining two different points with evolution strategy method for mutation and selection. CMAES is based on evolutionary approach and has been considered as one of the best stochastic optimization method for non-linear problem. The application of CMAES to the problem of well placement optimization was presented in the paper. CMAES was compared with genetic algorithm. In most cases, CMAES provided more accurate and better solution. However, the population size in CMAES has an impact on the optimization results for well placement. The efficiency of CMAES and genetic algorithm depends on parameters such as the step size of CMAES and discretization steps in genetic algorithm.

Morales et al.[11] used modified genetic algorithm for horizontal well placement optimization in gas condensate reservoirs where condensate reservoir may occur. Condensate accumulates around the wellbore when the reservoir pressure decreases below the dew point. In this study, the authors presented a horizontal well placement optimization method based on a modified genetic algorithm. Unlike oil reservoirs, the cumulative production in gas reservoir did not significantly vary and there were several likelihoods for optimal locations. Therefore, the prospect of searching better production scenarios in subsequent optimization steps was not much higher than the poorer case scenarios, which spent a lot of time finding the best production plan. To solve this problem, the authors used a cumulative distribution function to magnify the difference between production scenarios. As a result, they were able to find the best scenario with fewer simulations. From the result, a genetic algorithm code created for condensate reservoir is different from that for oil reservoir.

Wathiq et al.[12] used optimization techniques for determining optimal locations of additional wells to be drilled in an oil field located in South Rumaila. The South Rumaila oil field was anticline reservoir. The dimensions of the field were about 38 km long and 12 km wide. The authors used a reservoir simulator called SimBest II for their study. Two methods of optimization were proposed in the study. The first one was manual optimization (trial and error) and the other method was automatic optimization. In this study, the authors focused on automatic method while the manual method was used for comparison. Genetic algorithm was used as the automatic optimization method to find the best number and locations of the wells. The genetic coupled with SimBest II was used in order to re-evaluate optimized wells at each run. For the results, the genetic algorithm provided results similar to the results obtained by the manual method but less computer time.

Chunsen[13] studied optimization of horizontal well length by using staggered line drive pattern. In this paper, three dimensionless parameters were proposed as follows:

Dimensionless length of horizontal well:

$$l_D = \frac{l^2}{ab}$$

Dimensionless productivity of horizontal well:

$$Q_D = \frac{Q_h \mu}{2\pi k h \Delta p}$$

Shape factor:

$$F = 0.024 l_D^2 + 0.261 l_D + 1.4478$$

where

l_D is dimensionless length

l is horizontal well length

ab is pattern area

Q_h is the horizontal well production

k is the permeability

μ is fluid viscosity

Δp is pressure drop

F is shape factor

The author was interested in relationship between shape factor with dimensionless length of horizontal well and dimensionless productivity. In conclusion, a dimensionless productivity and length of horizontal well increases when a shape factor is increased. However, a shape factor did not have an effect on optimal dimensionless productivity of horizontal well when they investigated these parameters for thin oil reservoirs.

2.2 Waterflooding literatures

Popa[14] studied waterflooding by using horizontal injectors and horizontal producers. A thin reservoir model was used for investigating different parameters such as water breakthrough time, oil recovery at breakthrough time, sweep efficiency, and pressure drop alongside the horizontal wells. In his study, he categorized well placement into two cases: staggered line drive pattern and L shaped pattern. From their result, staggered line drive pattern was appropriate for case of short distance between producer and injector (250 m-300 m). For the case of long distance between producer and injector (700 m), oil recovery of staggered line drive pattern was higher than oil recovery of L shape pattern. Although staggered line drive pattern was used for this case but oil recovery for this case was lower than that for the case with short distance between producer and injector.

Chun[15] presented methodology to estimate the optimum horizontal well length based on total economics and productivity index. The productivity index depends on the length of horizontal well due to frictional pressure loss in the horizontal well. The productivity index is reduced by frictional pressure loss when flow rate is very high. On the other hand, pressure loss in a short horizontal well rarely affects the productivity index.

Phade[16] used waterflooding help to maintain the reservoir pressure 150 psi above the bubble point pressure. Daily production rate was about 13,000 BBL/D while injection rate was about 15,000 BBL/D. For this case study, oil recovery was approximately 52% at 7 years (breakthrough time). The author concluded that the waterflooding process did not only increase oil production rate but also reduced the time required to produce oil.

Singhal[17] studied various waterflood rate to increase oil production. He varied the water injection rate for some period of time (weeks or months). His objective was to perturb the reservoir system by increasing and reducing production rate in a short period of time. The perturbation was repeated several times. Capillary pressure of oil in porous rock was changed in some period of time when he changed injection rate. The author concluded that oil recovery factor was higher if the water injection rate is gradually increased and reduced in a short period of variation.

Many waterflooding studies (Popa, Cullick et al., Phade) have reported only application of genetic algorithm for each particular reservoir. Reservoir thickness represented in literature is very thick. In Thailand, most reservoirs are very thin and fluid properties are different from other locations. Therefore, using genetic algorithm for well placement for various reservoir thicknesses should be considered because the result may be different from the literature review. The aim of this thesis is to use genetic algorithm for well placement for reservoir with different thicknesses and to study the effect of the thickness on well placement.

CHAPTER III
THEORY AND CONCEPT

This chapter presents the principle of waterflooding and well optimization by using genetic algorithm. The details of this chapter comprise of flooding pattern, effects of injection rate and reservoir thickness, definition of genetic algorithm, steps of well optimization and termination criteria.

3.1 Waterflooding

3.1.1 Flooding patterns and sweep efficiency

In waterflooding process, water is injected into injectors and oil is produced from producers. The amount of oil recovered depends on the percentage of oil in place that is removed by waterflooding process. In symmetrical well patterns, a straight line (black line in **Figure 3.1**) connecting the injector and producer is the shortest streamline between the injector and producer. As a result, the pressure gradient along this line is the highest. The injected water that moves along this shortest streamline arrives at the producer before water travelling along any other streamlines. Therefore, at water breakthrough time, only a portion of the reservoir area lying between these two wells is contacted by water. This contacted fraction is the areal sweep efficiency at breakthrough. **Figure 3.1** shows the sweep of a five-spot pattern as the injected water moves to breakthrough.

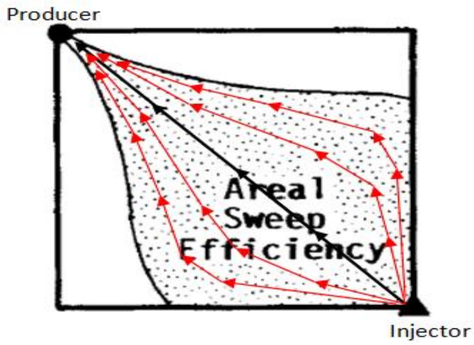

Figure 3.1: Areal sweep efficiency.

Various areal sweep efficiencies at breakthrough have been obtained for a variety of flooding patterns. For the condition that mobility ratio is 1.0 or less, there is reasonable agreement among most researchers that the five-spot flooding pattern gives the highest sweep efficiency. In the oil field, the five-spot waterflood pattern has been used more frequently than any other, but sometimes the peripheral or line drive flood pattern are used. Because of well spacing regulations, primary wells are usually drilled on a square pattern, which is easy to convert to a five-spot waterflood. The general well patterns are shown in **Figure 3.2**.

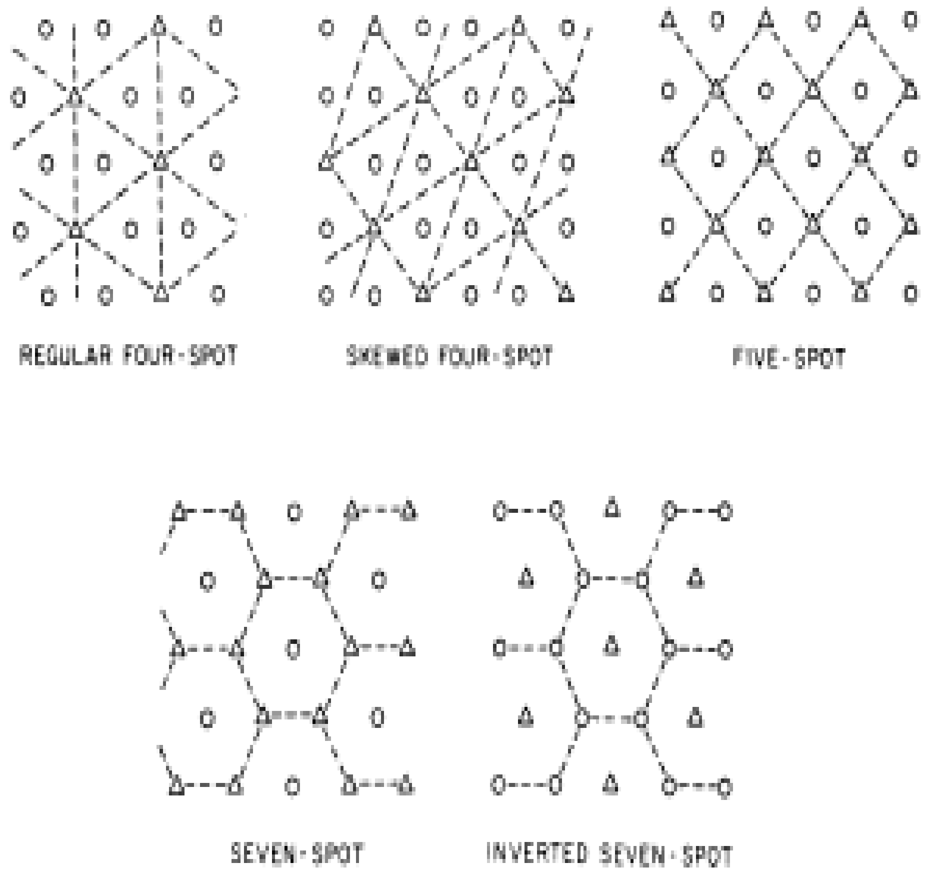

Figure 3.2: Well patterns for waterflooding process.[18]

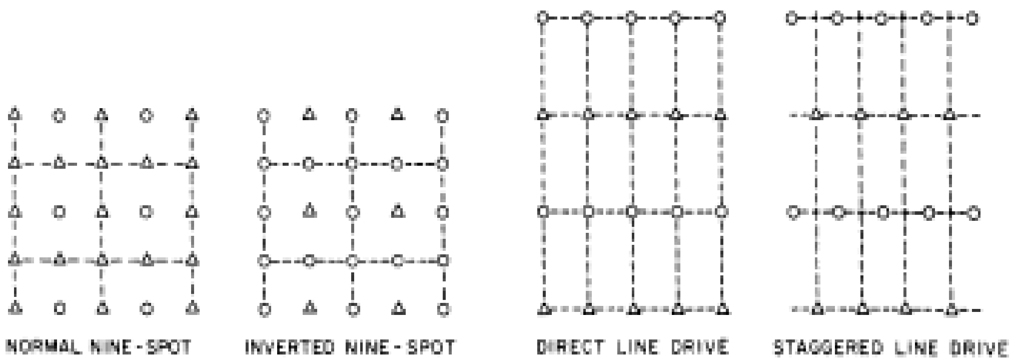

Figure 3.2: Well patterns for waterflooding process.(continued)[18]

3.1.2 Factors constituting a waterflooding design

Five important steps in the design of a waterflood are as follows:[18]

1. Evaluation of the reservoir, including primary production performance.
2. Selection of potential flooding plans.
3. Estimation of injection and production rates.
4. Projection of oil recovery over anticipated life of the project for each flooding plan.
5. Identification of variables that may cause uncertainty in technical analysis.

The analysis of waterflood is used for the estimates of volume of water and water injection rate. The estimates are used also for sizing equipment and fluid handling systems. It is necessary to identify a source of water for injection that is compatible with connate fluids as well as with rock properties. Design includes arrangement for proper disposal of produced water.

3.1.3 Injection rates

The oil recovery correlates with the cumulative volume of injection water. Injection rate is a fiscal key in the evaluation of waterflood. When a waterflood is conducted in an established area, there may be data or correlations based on operating experience. In general, injection rate are correlated with terms of injectivities as barrels per day per acre-ft. The injectiviy value depends on reservoir rock properties, interaction between fluid and rock, spacing, and available pressure drop. However, comparable values would be expected under similar reservoir and operating condition.

It is possible to estimate injection rates from reasonably simple equations. Two situations are of interest in waterflooding operation. The first case is when water injection is initiated before a mobile gas saturation builds up, In this case, the system may be treated as if it were liquid filled. Another case is the depleted reservoir where mobile gas saturation develops during production by solution gas drive. In this case, initial injection rate declines rapidly as the mobile gas is displaced.

3.1.4 Reservoir thickness

Once there is difference in fluid densities, fluid with higher density will move downward while fluid with lower density moves upward, resulting in segregation. In a thick layer, fluids can segregate because of high density difference and gravity effect. When water displaces oil in a thick layer, water tongue will be developed, causing early water breakthrough at the bottom part of the layer. After breakthrough, the water cut will increase significantly because water prefers moving at the bottom part of the layer. As a result, oil at the upper part of the layer will be bypassed and the recovery will be low.

3.2 Horizontal and vertical wells

3.2.1 Pressure drop through a horizontal well

A pressure drop along horizontal well length is generally small but sometime viscous crude or high flow rates of light oil (greater than 10,000 B/D) can cause a large pressure drop along the wellbore. The optimum well length can be calculated by accounting for the pressure drop in the horizontal well. Pressure drop of horizontal well slightly increases from heel to toe as shown in **Figure 3.3**. Basically, the pressure drop of horizontal well can be computed in the same manner as pressure drop calculation of horizontal pipe. The equation of pressure drop in pipe can be expressed as

$$\left(\frac{dp}{dL}\right)_{total} = \left(\frac{dp}{dL}\right)_{friction} + \left(\frac{dp}{dL}\right)_{acceleration} + \left(\frac{dp}{dL}\right)_{hydrostatic}$$

where $\left(\frac{dp}{dL}\right)$ is pressure drop in horizontal well.

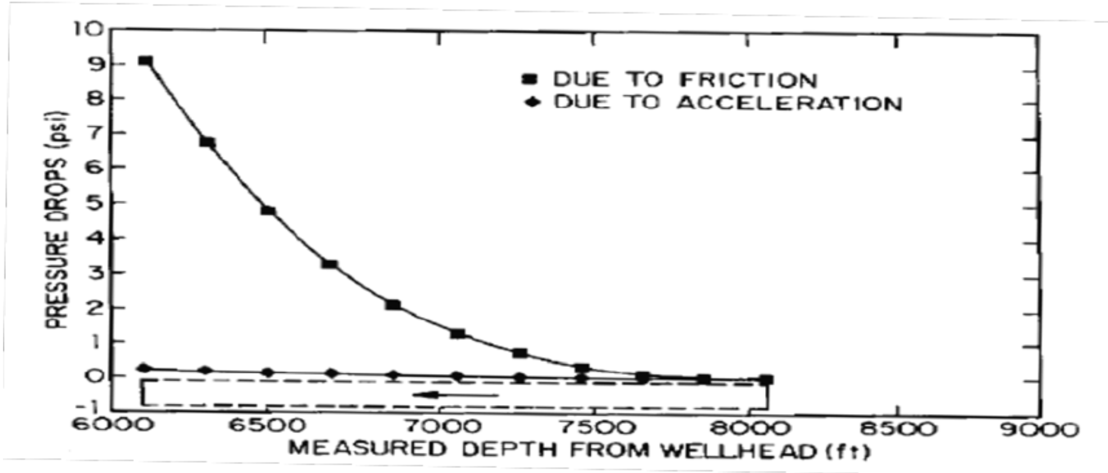

Figure 3.3: Pressure drop alongside horizontal wellbore versus measured depth.[19]

The gravity and acceleration terms are negligible for flow in a horizontal well. Thus, the equation can be reduced to

$$\left(\frac{dp}{dL}\right)_{total} = \left(\frac{dp}{dL}\right)_{friction} = \frac{f_m \rho v^2}{2g_c d}$$

or

$$\Delta p = -\frac{f_m \rho v^3 \Delta L}{2g_c d}$$

For single phase oil flowing through a horizontal well, the equation can be rewritten as follows:

$$\Delta p = 1.14644 \times 10^{-5} f_m \rho q^2 L d^5$$

where

f_m is Moody's friction factor, dimensionless

ρ is fluid density, g/cc

q is flow rate at reservoir condition, rb/d

L is horizontal well length, ft

Δp is pressure drop, psia

The example of pressure profile calculated by the above equation is shown in **Figure 3.3**. This magnitude of wellbore pressure drop would have a significant influence on well productivity. The influence of wellbore pressure loss or well productivity can be minimized by choosing appropriate hole size, horizontal length and completion geometry.

3.2.2 Types of horizontal wells

There are three types of horizontal well categorized by turning radius. Wells with arcs of 3 to 40 foot radius are defined as short radius horizontal wells. The build rate of this type is approximately 1 to 3 degrees per foot drilled. For medium radius, wells have arcs of 200 to 1,000 foot radius which build rates is about 8 to 30 degrees per 100 feet drilled. Long radius wells have arcs of 1,000 to 2,500 feet which build rate is higher than 6 degrees per 100 feet). Maximum length of horizontal well depends on radius of curvature. Examples of maximum length for each type are shown in **Table3.1**. In this thesis, the turning radius of well is assumed as long radius because long length of horizontal well is occurred from well placement by using genetic algorithm.

Table 3.1: Maximum well lengths at different turning radii.[19]

Drainage Area		**60 acre**	**80 acre**
Maximum X or Y dimension, ft		1617	1867
Maximum length or diagonal, ft		2286	2640
Drilling Method	**Turning radius, ft**	**Maximum well length, ft**	**Maximum well length, ft**
Ultrashort Radius	1-2	200	200
Short Radius	20-40	450	450
Medium Radius	300-800	1017	1267
Long Redius	1000-2500	1074	1428

Short radius horizontal wells

Short-radius horizontal wells are commonly used for thin reservoirs. Short radius drilling rapidly reaches a pay zone. The small displacement is required to reach a near horizontal attitude and this type is used with small drainage area. Drilling horizontal well with short radius also has certain economic advantages. The short radius horizontal wells have a lower capital cost due to the fact that the inlet pressure for down hole production pumps is smaller. However, the diameter size of hole can only vary up to about 6 inches and the hole cannot be logged since adequately small measurement tools are not yet available.

Medium radius horizontal wells

Medium radius horizontal wells is used for the larger hole diameters and more knowledgeable and complex completion methods. Logging the hole is possible for medium radius well. The drilling of medium radius horizontal wells requires the use of an measurement while drilling system (MWD) which drilling cost is higher than that of short radius well. Using medium radius holes are the most popular current option. They can be drilled on area as small as 20 acres.

Long radius horizontal wells

Conventional drilling tools or newer steerable systems can be used with long radius holes. The long radius is not suited to area less than 160 acres due to their low build rates. This method has a high capital cost but section of horizontal length is quite long.

3.2.3 Benefits and disadvantages of horizontal and vertical wells [19]

Benefits of horizontal wells are:

1. Higher rates and reserves as compared to vertical wells. This results in less finding cost and less operating cost per barrel of oil produced. The operating costs of vertical well are $7 to $9 per barrel of oil but the horizontal well operating costs are $3 to $4 per barrel.
2. For many horizontal well projects, the finding (developing) cost, defined as well cost divided by well reserves, is about $3 to $4/bbl. This is about 25% to 50% lower than the cost of buying proved producing reserves.
2. To produce the same amount of oil, one needs fewer horizontal wells as compared to vertical wells. This results in reduced need for surface pipelines, locations, etc.

Disadvantages of horizontal wells are:

1. High cost as compared to a vertical well. A new horizontal well drilled from the surface costs 1.5 to 2.5 times more than a vertical well. A re-entry horizontal well costs about 0.4 to 1.3 times a vertical well cost. Example of cost ratio of horizontal well to vertical well is listed in **Table 3.2**.
2. Generally only one zone at a time can be produced using a horizontal well. If the reservoir has multiple pay-zones, especially with large differences in vertical depth, or large differences in permeabilities, it is not easy to drain all the layers using a single horizontal well.

Table 3.2: Cost ratios between horizontal and vertical well.[19]

Depth, ft	Reservoir contact length, ft	Horizontal/ vertical cost	Comments
2195	330	4.3	Drill from the surface
4100	1214	3.5	Drill from the surface
4500	1988	2.1	Drilled into fractured limestone. Produced 15 times better than a vertical well. Reduced water coning.
9500	1300	2.1	Not only increased production, but reduced water coning.

3.3 Genetic algorithm

Genetic algorithm (GA) is a search technique based on the principles of natural development and selection. The genetic algorithm searches solutions by generating large population that provides possible solutions and then evaluating each solution to determine their level of fitness (i.e., recovery factor). Better solutions are evolved by applying genetic algorithm operators to previous solutions and this process continues until a termination criterion is met.

Three main steps are used in genetic algorithm: population generation, evaluation, and reproduction. All of those steps are explained below.

3.3.1 Population generation

Genetic algorithm process starts by generating a population of possible solutions. The populations are the set of various chromosomes that represent different values of objective function. The chromosomes are created by using the binary encoded form of all parameters that have the possible solutions. For case of well location optimization, the locations of horizontal and vertical wells are the variables represented by binary strings. These strings are referred to as chromosomes. **Figure 3.4** demonstrates a chromosome corresponding to the solution.

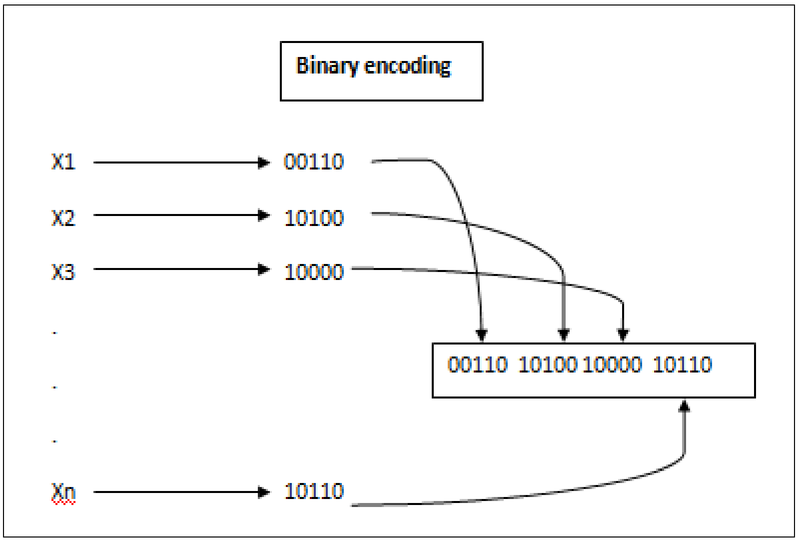

Figure 3.4: Binary encoding for genetic algorithm.

3.3.2 Evaluation

The fitness of population is evaluated in this step. **Figure 3.5** is an example showing step evaluation. The objective function (recovery factor) of each case is evaluated by reservoir simulation. The population are ranked from best to worst based on recovery factor. Two strings that have the highest oil recovery factor will be selected for the process of reproduction.

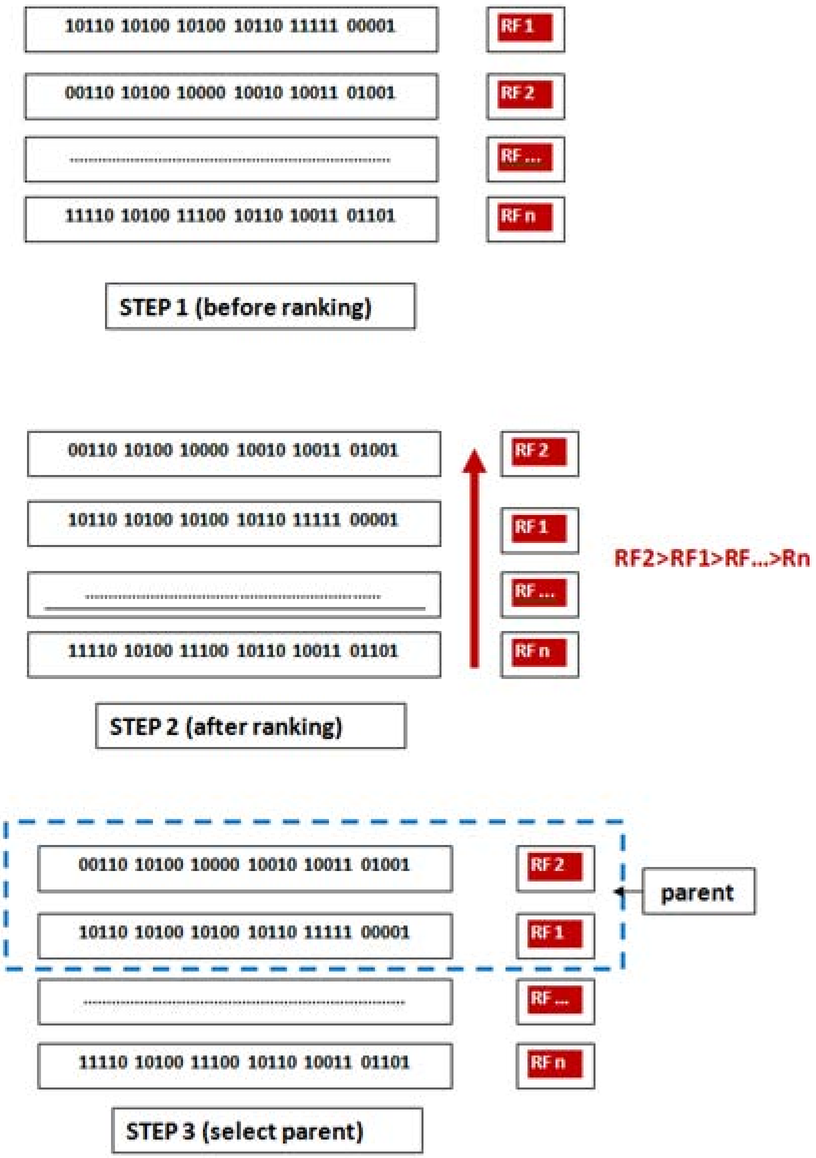

Figure 3.5: Evaluation step for genetic algorithm.

3.3.3 Reproduction

3.3.3.1 Crossover

Crossover is the genetic algorithm operator that tries to mix each pair of chromosomes selected as parents, to create the likelihood of keeping the good properties of each parent chromosome in the offspring chromosome. The crossover process in genetic algorithm is performed by cutting some part of each parent chromosome and replacing it into the other parent chromosomes. This operator is used in several works in the literature. The simplest type of crossover is single point crossover. In this method, one random point in the chromosome is selected and calculated crossover probability. The rest of the chromosome string after the selected point is swapped between two parents. The single cross over point represented in **Figure 3.6**.

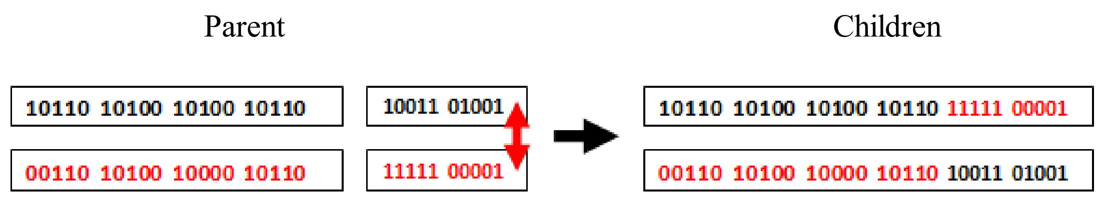

Figure 3.6: Single crossover process for genetic algorithm.

Other crossover types involve selection of two or more random crossover points within the chromosomes and swapping the strings between those points. These methods are called two-point crossover or multi-point crossover that the number of crossover point is selected over the entire chromosome length. The idea for these crossover operators has been obtained from the crossover in a standard genetic algorithm. However, the chromosomes is separated more than two pieces in multi-point crossover. For uniform crossover, it is a particular case of multi-point crossover. Both methods are illustrated in **Figure 3.7** (Initially the top parent chromosome was in black and the bottom parent chromosome was in red).

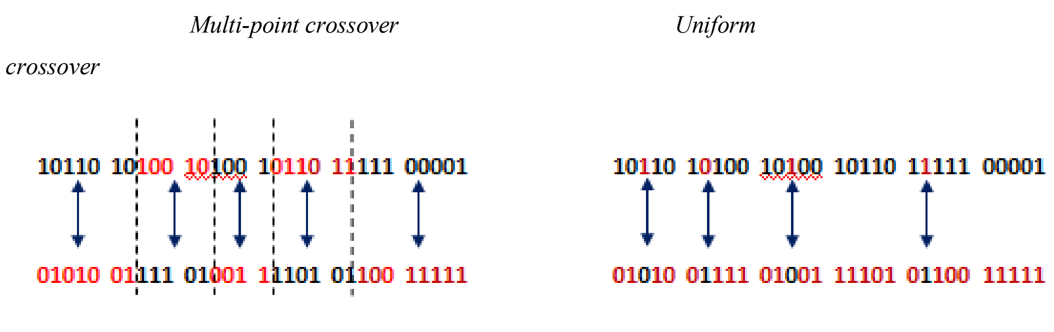

Figure 3.7: Multiple and uniform crossover process for genetic algorithm.

3.3.3.2 Mutation

The function of mutation process is to maintain the diversity of the population during the evolution process. In a binary genetic algorithm, mutation in chromosome is performed by simply changing the value of some bits. A number of changed bits in the chromosome are assigned by probability of mutation but the position of mutation depends on random process. The probability is generally selected to be small. One way to manage this operator is by distributing a random variable to each gene of the chromosome. Each random variable determines if the value of that gene is going to be changed. **Figure 3.8** shows the mutation in a binary genetic algorithm.

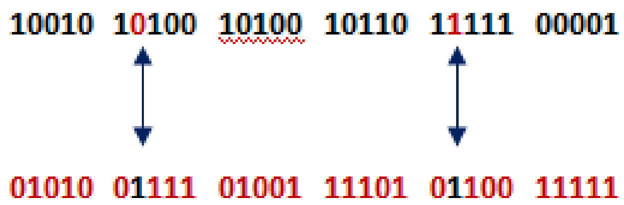

Figure 3.8: Mutation process for genetic algorithm.

3.3.4 Gene and chromosome length effect

The genes represent the individual unknowns. In this study, we use gene to identify the position horizontal and vertical wells, such as, top perforated vertical well position, toe and heel positions of horizontal well. Each unknown shows different length of gene. In order to avoid different length of genes, we fix length of gene as five digits shown in **Figure 3.9**.

The chromosome is constructed by combining all unknown (all genes). The length of the chromosome will vary with the number of unknowns (genes) as can be seen in **Figure 3.10**. Since we want to consider a number of different well types in this thesis, we need to have the ability to represent all possible well combinations on a chromosome. For example, the chromosome length in case of using 1 horizontal producer with 2 horizontal injectors is longer than that in case of using 1vertical producer and 2 vertical injectors. It is possible to use chromosomes of different lengths, but performance of the genetic algorithm depends on length of string. The short length of string rapidly converges to the solution. Moreover, a number of population will also depend on the length of chromosome. A long length string causes an increase in the number of population.

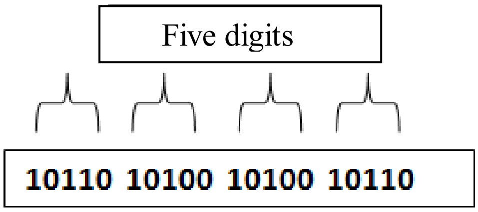

Figure 3.9: Length of gene.

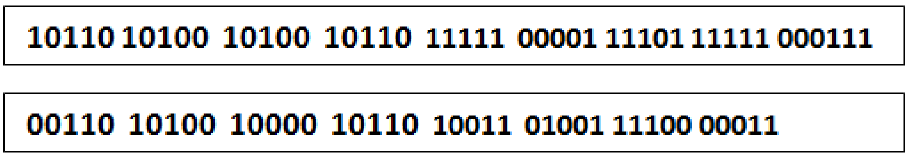

Figure 3.10: Different lengths of chromosomes.

3.3.5 Features of genetic optimization

The genetic optimization tool can interface with commercial reservoir simulation software. When a new set of wells is proposed as a possible set of optimum solutions, these wells are written to the input data file of the reservoir simulator (SCHEDULE part) and the simulator is run. After the run is completed, the fitness of individual population is evaluated. This process is repeated for all sets of wells (population) in the generation. Then, the oil recovery factors of all populations are ranked from best to worst. Two population of highest oil recovery are selected as parent and performed for next generation. Using a reservoir simulator as the objective function evaluator allows us to adjust many parameters such as abandonment oil rate, abandonment water cut and production rate. This can usually be accomplished with existing keywords in the simulator. The developed GA code can fully communicate with the simulators, and any summary keywords can be read from their output (RSM file).

3.3.6 Termination criterion

The termination criterion is mostly based on the improvement of solution. In this study, the genetic algorithm is designed to terminate in two ways: (1) solution does not improve for at least 10 generations or (2) the algorithm reaches the maximum number of generations (40 generations).

CHAPTER IV
RESERVOIR MODEL AND METHODOLOGY

The thesis studies well placement of horizontal and vertical well under different scenarios of producer and injector types in order to find the best case. A simplified reservoir model (hypothetical model) with homogeneous reservoir properties was constructed. The objective of the reservoir simulation is to calculate value of recovery factor. The hypothetical model in this study is available with several requirements such as

1. Connection with genetic algorithm optimization tool.
2. Relocating location of production and injection well.
3. Computation of friction loss along horizontal well.

This chapter describes the construction of reservoir model. The reservoir properties are based on field data obtained from a reservoir in Thailand. In this study, different well patterns are also presented.

4.1 Reservoir model description

4.1.1 Reservoir model

Reservoir simulation is a good tool for reservoir engineer to determine the best strategy of well placement in a reservoir. Simulation requires construction of a model whose rock and fluid properties are defined or assigned. The objective of the simulation in this study is to observe the behavior of oil recovery when using different injector locations. A good model should be accurate enough to study effects of changing injector location on displacement mechanism in a reservoir.

In this study, reservoir simulation is carried out with the use of commercial reservoir simulator. A reservoir with a non-uniform pattern waterflood scheme and no-flow boundaries on all sides is considered. This hypothetical model is a simple reservoir of the size 6,510×6,510 ft^2. For the base case, the reservoir is modeled using 30×30×10 grid blocks which is shown in **Figure 4.1**. The model does not have aquifer and all grid blocks are assigned as active cells. The top depth of reservoir is 5,100 ft below ground level with an initial pressure of 2,510 psi and fracture pressure of 3,700 psi. The ratio between vertical permeability to horizontal permeability is assumed to be 0.1.

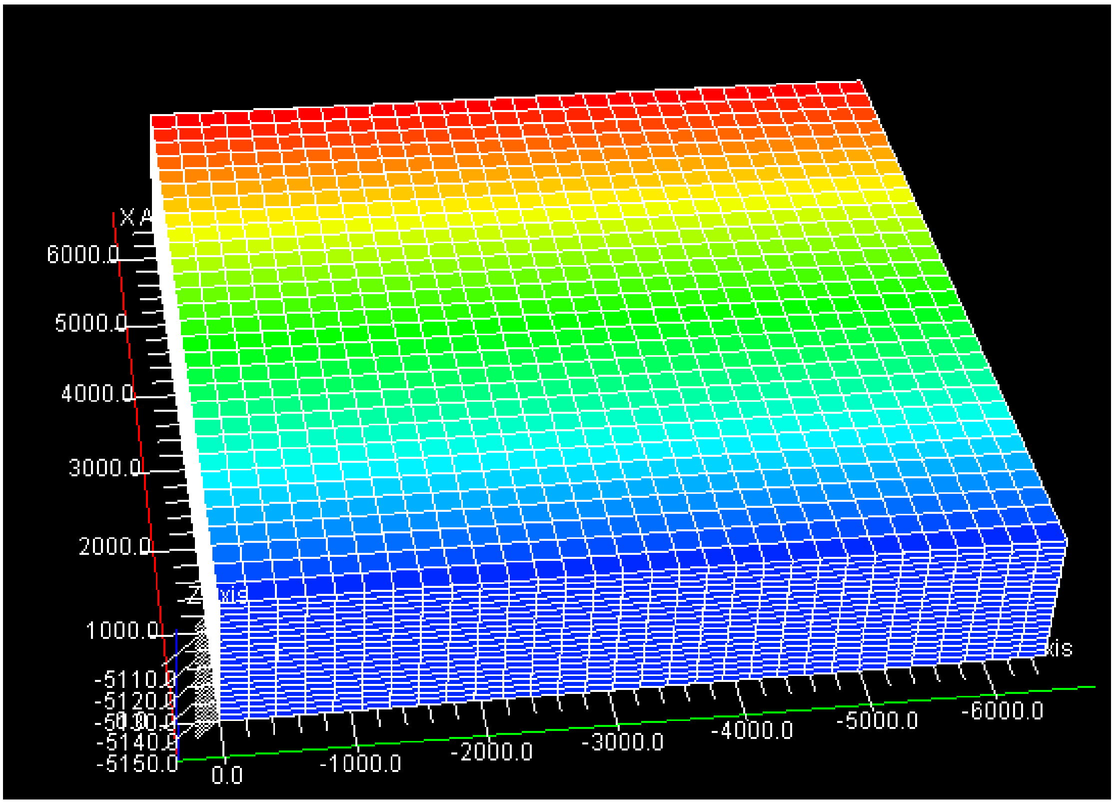

Figure 4.1: Reservoir model.

4.1.2 Fluid and SCAL properties

The initial reservoir fluids in the model comprise of oil and water. The initial water saturation of 0.35 is uniform throughout the reservoir. The type of oil used in model is live oil. The gas-oil ratio (GOR) is initially 783 SCF/STB and climbing with decreased pressure. For this study, relative permeability is calculated using Corey correlation. The parameters used in Corey correlation are listed in **Table 4.1,** and relative permeability curves are shown in **Figures 4.2** and **4.3**. Other reservoir and fluid properties obtained from a reservoir in Thailand are listed in **Tables 4.2 and 4.3**.

For surface conditions, the oil has a density of 50.78 lb/cuft while the density of water is 62.43 lb/cuft and the density of gas is 0.048 lb/cuft. Water compressibility is 3.02 x 10^{-6} psi^{-1}, water formation volume factor is 1.01 rb/stb and water viscosity is 0.352 cp at a reference pressure of 2,510 psi. The bulk compressibility of the rock is 1.2 x 10^{-5} psi^{-1}.

Table 4.1: Data for Corey correlation.

Item	Value
Irreducible water saturation (S_{wc})	0.35
Residual oil saturation (S_{or})	0.2
Initial oil gas saturation (Sg_i)	0
Water curve exponent (N_w)	2.8
Oil curve exponent (N_o)	2
Gas curve exponent (N_g)	2.8
Maximum oil relative permeability	0.9
Maximum water relative permeability	0.35
Maximum gas relative permeability	0.9
Water relative permeability at S_{or}	1
Oil relative permeability at S_{wc}	0.9

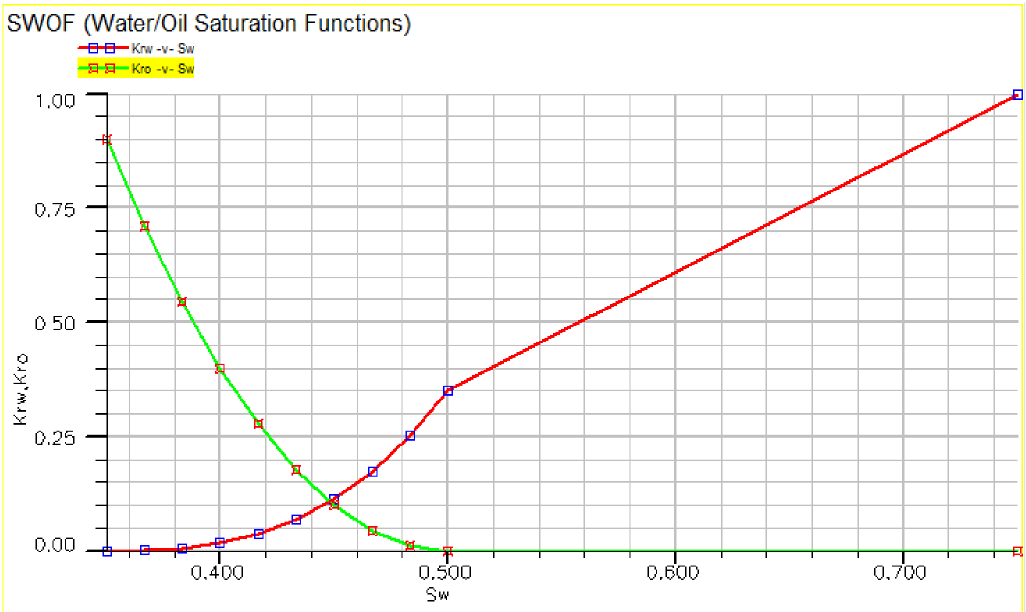

Figure 4.2: Water/oil relative permeability curve.

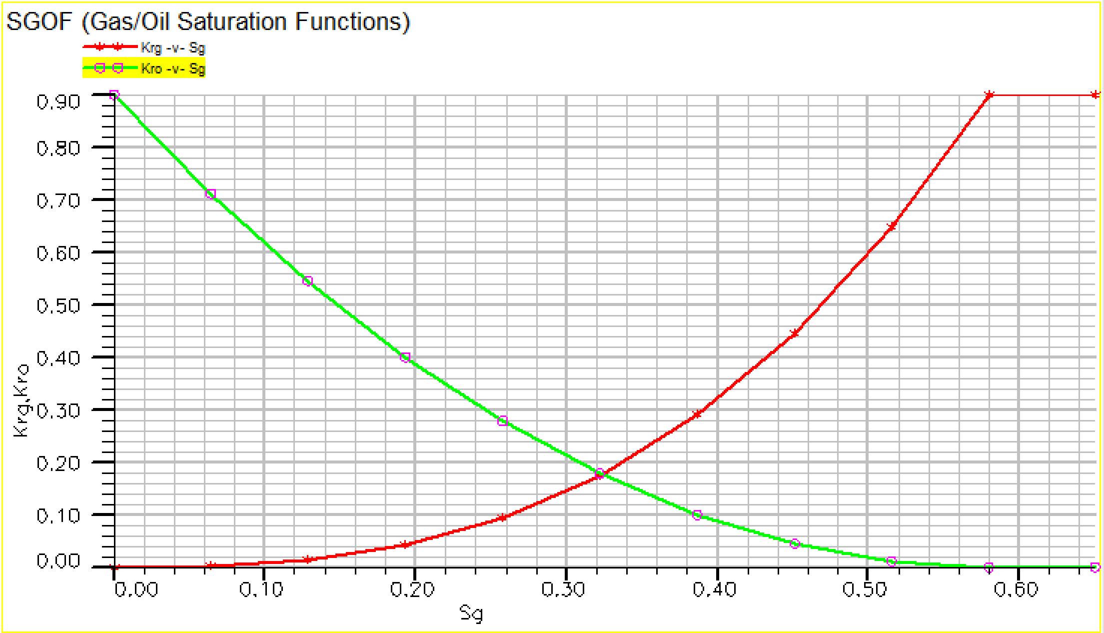

Figure 4.3: Gas/oil relative permeability curve.

Table 4.2**:** Reservoir and fluid properties.

Parameter	**Value**
Permeability *(md)*	131
Porosity *(%)*	23
Oil gravity *(˚API)*	42.3
Water viscosity *(cp)*	1
Reservoir temperature *(˚F)*	194
Gas gravity	0.776
Bubble point pressure *(psi)*	2398

Table 4.3: PVT data.

P(psi)	Rs (scf/stb)	FVF (rb/stb)	Visc (cp)
802	209	1.152	0.691
1327	384	1.239	0.534
1589	477	1.288	0.483
2114	672	1.394	0.409
2398	783	1.456	0.380
2901	783	1.443	0.399
3163	783	1.438	0.410
3688	783	1.430	0.436
3950	783	1.427	0.450
4475	783	1.421	0.480
5000	783	1.417	0.512

4.1.3 Initial condition

The initial conditions for every grid block are defined in the initialization section of reservoir simulator. The conditions used in this study consist of initial pressure, initial water saturation, initial gas saturation, and initial solution gas/oil ratio. The initial water saturation and solution gas/oil ratio have already been mentioned in the previous section. The initial pressure is assumed to be 2,510 psia. Initial gas saturation is set as zero for the assumed undersaturated oil reservoir.

4.2 Well model description

For all cases, the well bore diameter is fixed as 8.75 inches for both vertical and horizontal wells. The tubing diameter for horizontal and vertical wells is set as 4.5 inches. The injection rate is fixed for each case as shown in **Table 4.4**. The injection rate of vertical injector is a half of horizontal injection rate. The minimum allowable bottom hole pressure is set to be 200 psi which is a typical minimum intake pressure for downhole pump and the maximum injection pressure is approximately 3,700 psi. Perforation is performed throughout the entire thickness of the reservoir. The production well is set to produce oil until the minimum oil rate of 10 STB/D or maximum water cut of each case. In waterflooding process, a large amount of water is produced after breakthrough time. In case high gross production rate, the water cut is set higher than that in case of low gross production rate because high gross production rate results in high oil production for increasing each 1% of water cut. However, produced water may impact production costs. Therefore, water cut required for each case depends on gross production rate. In this study, water cut at abandonment is assumed by using typical values of onshore fields in Thailand. Water cut is set as 98% in case of high gross production rate (more than 5000 stb/day). For case of gross production rate less than 5000 stb/day, water cut is set as 95%. In this study, if the production condition exceeds one of the economic limits that have been set, the producer will automatically be shut-in.

Table 4.4: Injection rate condition.

Well type	Injection rate (STB/D/well)		
	low	medium	high
Horizontal	2000	5000	10000
Vertical	1000	2500	5000

4.3 Production and injection rate

Generally, water injection rate of vertical injection well is lower than that of horizontal well because the contact area with reservoir of vertical well is less than that of horizontal well. For this study, therefore, water injection rate for vertical injector is assumed to be half of horizontal injector. As shown in **Table 4.4**, injection rate per a well is controlled as: 1) low injection rate, 2) medium injection rate and 3) high injection rate. Total injection rate is obtained by combining injection rates of all wells. For all cases, total production rates are balanced with total injection rate. The total production rate is determined from dividing total injection rate by initial formation volume factor.

4.4 Methodology

Optimization of well location starts by using genetic algorithm optimization tool coupled with reservoir simulator. The oil recovery from reservoir simulation is used as objective function of Genetic algorithm. The procedures of study are shown below:

1. Prepare the reservoir data, rock data, and well properties.
2. Construct base case model by using reservoir simulator. The thickness is set as 30 ft for the base case.
3. Control injection rate following **Table 4.4**. For the first case, injection rate is set as LOW condition.
4. Control restrictions of production conditions for all cases as shown in **Table 4.5.**

Table 4.5: Production condition.

Parameter		**Value**
Abandonment	Minimum oil rate (stb/day)	10
	Water cut (%) [gross rate< 5000 stb/d]	95
	Water cut (%) [gross rate ≥ 5000 stb/d]	98
$P_{\text{minimum bottomhole (producer)}}$ (psi)		200
$P_{\text{max (injector)}}$ (psi)		3700
Production tubing size (in)		3.5
Injection tubing size (in)		3.5

5. Run each scenario using genetic algorithm optimization tool coupled with reservoir simulation. Each scenario is listed in **Table 4.6**. An injection well is automatically relocated in high oil recovery zone by genetic algorithm. For the genetic parameters, the number of population is set as 20. Mutation and crossover probability are controlled as 0.2 and 0.8, respectively.

   The locations of injection wells and lengths of horizontal producers are automatically changed until the oil recovery is the highest. The algorithm for well optimization is shown in **Figure 4.4**. The initial guesses of well locations are used for starting. The well locations are represented by a binary string. In this algorithm, conditions of minimum oil recovery and maximum production time are considered before evaluating the fitness (highest oil recovery) for each generation. For each binary string, oil recovery factor is compared with minimum oil recovery. The oil recovery of 20 % is set as allowable oil recovery (minimum oil recovery). If oil recovery of binary string is less than allowable oil recovery, the binary string will be replaced by a new binary string. For production time, maximum production time is set as 100 years. Then, optimization algorithm will determine the fitness and continues to the next generation until termination criteria are met.

Table 4.6: Scenarios for the study.

Scenario	Production and injection well type
1	One horizontal producer with two vertical injectors (1HP-2VI)
2	One horizontal producer with two horizontal injectors (1HP-2HI)
3	One vertical producer with two vertical injectors (1VP-2VI)
4	One vertical producer with two horizontal injectors (1VP-2HI)
5	Two horizontal producers with one vertical injector (2HP-1VI)
6	Two horizontal producers with one horizontal injector (2HP-1HI)
7	Two vertical producers with one vertical injector (2VP-1VI)
8	Two vertical producers with one horizontal injector (2VP-1HI)

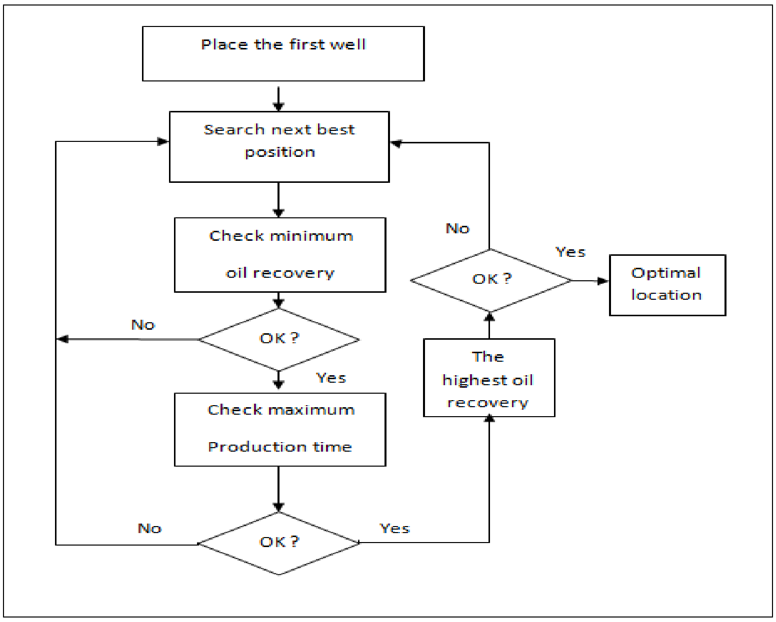

Figure 4.4: Optimization algorithm.

6. For each run, well locations, production profile, water injection profile, cumulative oil recovery, water cut profile, breakthrough time, and bottomhole pressure are recorded.
7. Repeat step 3 - 6 by changing injection rate to MEDIUM case and HIGH case, respectively (see Table 4.4.).
8. Repeat step 3 - 7 by changing reservoir thickness to 100 and 300 ft, respectively.
9. Analyze the results of all scenarios and reservoir thicknesses.

CHAPTER V
SIMULATION RESULT AND ANALYSIS

This chapter describes well placement results from using genetic optimization tool coupled with reservoir simulator. Five assumptions are used in this study:

1) In the z-direction, horizontal well is located at the middle of the reservoir (z=5).
2) There are three reservoir thicknesses performed as sensitivity analysis: 30-ft thick reservoir, 100-ft thick reservoir and 300-ft thick reservoir.
3) Frictional wellbore model for horizontal well is used in this study.
4) There are three water injection rates used as sensitivity analysis. Injection rate of 2,000, 5,000, and 10,000 STB/D is used for horizontal injector. For vertical injector, injection rate is half of horizontal injection rate (i.e., 1,000, 2,500, and 5,000 STB/D).
5) The total number of wells in this study is constrained as three.

Well placement results of all scenarios performed by genetic algorithm are categorized in three sections: 1) well placement in 30-ft thick reservoir, 2) well placement in 100-ft thick reservoir and 3) well placement in 300-ft thick reservoir. For each scenario, well placement results, recovery factor profile, production profile, cumulative water injection, cumulative produced oil and water and breakthrough time are discussed.

5.1 Well placement in 30-ft thick reservoir

For well placement by using genetic algorithm, several scenarios were executed to determine the best scenario that provides high oil recovery and short production time. The result for each scenario is described as follows:

5.1.1 Well placement of one producer with two injectors

5.1.1.1 One horizontal producer with two vertical injectors

A genetic algorithm coupled with reservoir simulator is used for well placement of one horizontal producer with two vertical injectors. Mutation and crossover helps the search escape from local maximum.

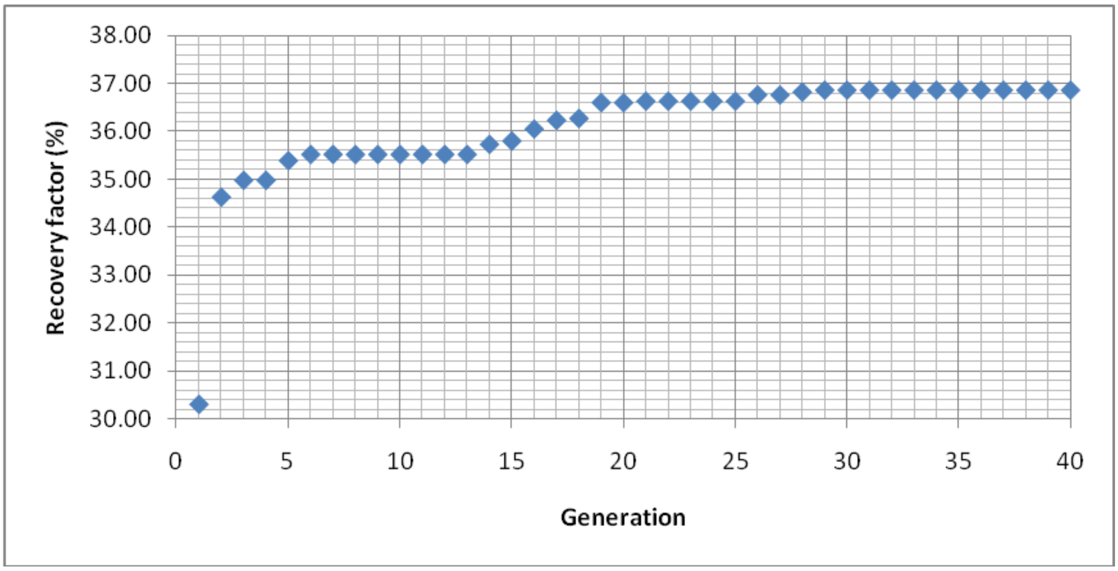

Figure 5.1: Recovery factor as a function of generation in the case of one horizontal producer and two vertical injectors in 30-ft thick reservoir.

In **Figure 5.1**, for the 1st generation the genetic algorithm tries to search region with high oil recovery in order to narrow down the search area for next generation. Oil recovery factor reaches to 34.63% in the 2nd generation and climbs to 35.39% in the 6th generation. The local maximum occurs in the 6th generation until the 13th generation. The local maximum is improved by the process of mutation and crossover in the 14th generation and oil recovery factor climbs to 36.63% in the 24th generation. The genetic algorithm provides high oil recovery factor after it reaches the 29th generation. The converged generation of the well optimization is at the 29th generation because oil recovery doesn't improve after the 29th generation.

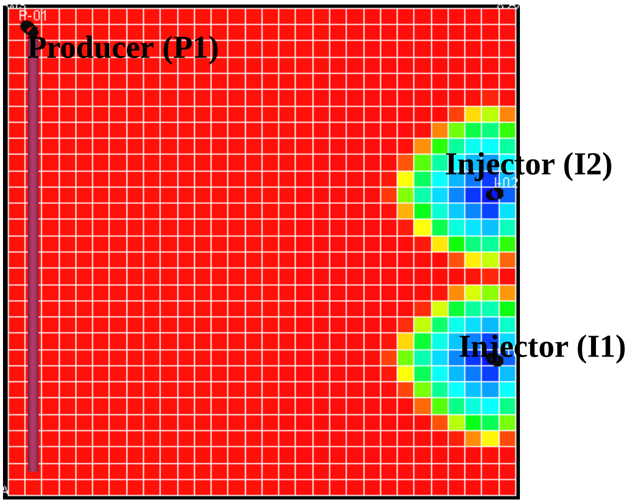

Figure 5.2: Well placement for the case of one horizontal producer and two vertical injectors at injection rate of 5,000 STB/D in 30-ft thick reservoir.

The best well placement for two vertical injectors and one horizontal producer are shown in **Figure 5.2**. These locations are at the (i,j) blocks of (29,22), (29,12), and ((2,29),(2,2)), respectively. The optimum horizontal producer length from the toe to heel is 6,076 ft. In this scenario, the injection wells I1 and I2 are not located at the upper and lower right corners due to pressure drop in horizontal well. The pressure drop is a result of wellbore friction model assigned in the horizontal production well. The pressure drop of the horizontal well slightly decreases from heel to toe as oil flows from toe to heel. Therefore, pressure at the heel is lower than that at the toe. As a result, the injection water is easy to breakthrough at the heel. To solve the early breakthrough at the heel, genetic algorithm shifts the location of injection well I2 to the (i,j) block of (29,12) and the location of injection well I1 to the (i,j) block of (29,22). The results of well locations for each generation are represented in **Table 5.1.**

Table 5.1: Well locations and recovery factor for each generation in the case of one horizontal producer and two vertical injectors in 30-ft thick reservoir.

Generations	Well I1	Well I2	Well P1		RF
			Toe	Heel	%
1	16,25	27,26	21,8	21,18	30.31
2	28,20	26,26	5,8	5,18	34.63
3	29,13	26,30	13,22	13,7	34.98
4	29,13	26,30	13,22	13,7	34.98
5	29,13	26,26	5,8	5,18	35.39
6	29,11	28,6	10,27	10,18	35.52
7	29,11	28,6	10,27	10,18	35.52
8	29,11	28,6	10,27	10,18	35.52
9	29,11	28,6	10,27	10,18	35.52
10	29,11	28,6	10,27	10,18	35.52
11	29,11	28,6	10,27	10,18	35.52
12	29,11	28,6	10,27	10,18	35.52
13	29,13	28,6	10,27	10,18	35.52
14	29,14	29,12	10,27	10,9	35.73
15	29,22	29,8	2,30	2,9	35.80
16	29,22	29,14	2,30	2,9	36.05
17	29,22	29,16	2,30	2,9	36.23
18	29,20	29,12	2,30	2,9	36.27
19	29,22	29,12	2,30	2,9	36.60
20	29,22	29,12	2,30	2,9	36.60
21	29,22	29,12	2,28	2,6	36.63
22	29,22	29,12	2,28	2,6	36.63
23	29,22	29,12	2,28	2,6	36.63
24	29,22	29,12	2,28	2,6	36.63
25	29,22	29,12	2,28	2,6	36.63
26	29,22	29,12	2,30	2,4	36.76
27	29,22	29,12	2,30	2,4	36.76
28	29,22	29,12	2,28	2,1	36.82
29-40	29,22	29,12	2,29	2,2	36.86

The highest oil recovery factor of 36.86 % represented in **Table 5.2** and **Figure 5.3** is found in this scenario with water injection rate of 5,000 STB/D. The cumulative oil recovery of 8,821 MSTB is produced at the end of 7,524 days of production. The breakthrough time for this scenario is about 899 days. The cumulative water production is 57,918 MSTB while the amount of water injection is 71,856 MSTB. Although the amount of water production at injection rate of 5,000 STB/D is approximately 1.5 times more than that at injection rate of 2,500 STB/D, but at the end of the production the oil recovery at injection rate of 5,000 STB/D is about 3% more than at injection rate of 2,500 STB/D. Therefore, producing with the injection rate of 5,000 STB/D is the best alternative for this scenario.

In this study, the oil recovery at high injection rate is higher than that at low injection rate because in the case of low injection rate water tends to move downward, resulting in segregation. As a result, water prefers moving at the bottom of the reservoir, causing low efficiency of waterflooding process. For case of high injection rate, the water injection rate can reduce the problem of segregation because the flow rate in horizontal direction is much higher than that in vertical direction.

Table 5.2: Production data for the case of one horizontal producer and two vertical injectors at injection rate of 1,000 STB/D, 2,500 STB/D and 5,000 STB/D in 30 ft-thick reservoir.

Production rate/well	Injection rate/well	Break through			Abandonment					
		Time	Cumulative oil	Recovery	Time	Recovery	Cumulative oil	Cumulative produced gas	Cumulative produced water	Cumulative water injection
STB/D	STB/D	Days	STB	%	Days	%	STB	MSCF	MSTB	MSTB
1380	1000	3182	4390872	18.35	10299	33.62	8045912	16325	6735	20750
3450	2500	1382	4768526	19.92	4894	33.04	7908418	14877	11107	23871
6900	**5000**	**899**	**5555945**	**23.21**	**7524**	**36.86**	**8821193**	**12838**	**57918**	**71856**

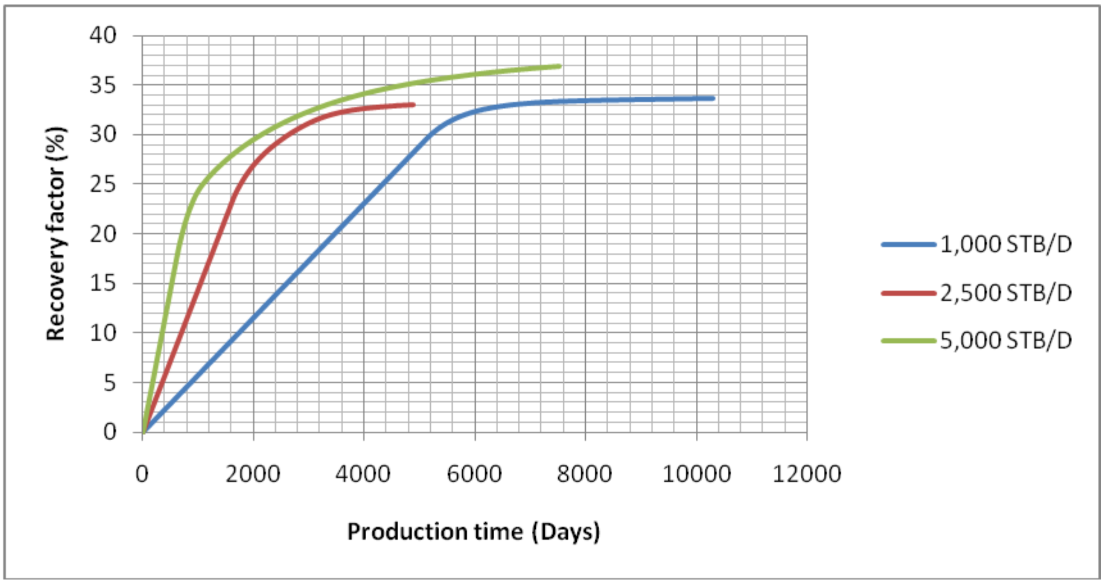

Figure 5.3: Recovery factor for the case of one horizontal producer and two vertical injectors at injection rate of 1,000 STB/D, 2,500 STB/D and 5,000 STB/D in 30 ft-thick reservoir.

5.1.1.2 One horizontal producer with two horizontal injectors

In this section, well placement for one horizontal producer and two horizontal injectors is performed by using genetic algorithm coupled with reservoir simulator.

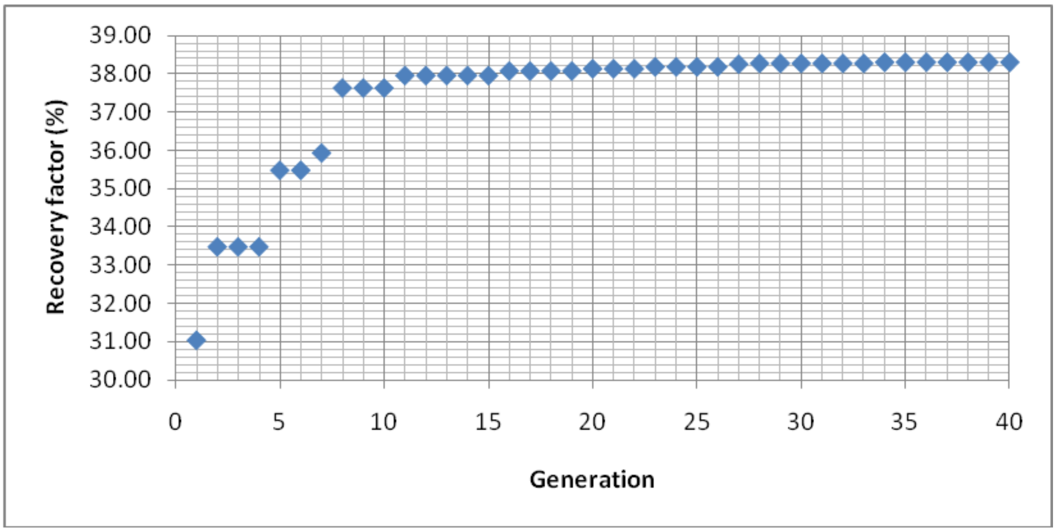

Figure 5.4: Recovery factor as a function of generation in the case of horizontal producer and two horizontal injectors in 30-ft thick reservoir.

From the 1st to the 8th generation shown in **Figure 5.4**, the genetic algorithm (GA) tries to search regions with high oil recovery in order to narrow down the search area for the next generation. Oil recovery factor climbs to 37.62% in the 8th generation. A high oil recovery factor is obtained at the 11th generation. After the 11th generation, there are 6 local maximums occurs. The last local maximum is improved by the process of mutation and crossover in the 34th generation. The genetic algorithm is continued until it reaches the terminated generation (the 40th generation) but the solution is not improved after the 34th generation. Thus, the 34th generation is the converged generation. This scenario needs more generations to reach the converged solution than the previous case because the binary string of this scenario is longer than that of one horizontal producer and two vertical injectors in previous scenario. The optimum locations of two horizontal injectors and one horizontal producer are at the (i,j) blocks of ((29,2), (29,29)), ((2,2), (2,29)) and ((15,29),(15,2)), respectively as shown in **Figure 5.5**.

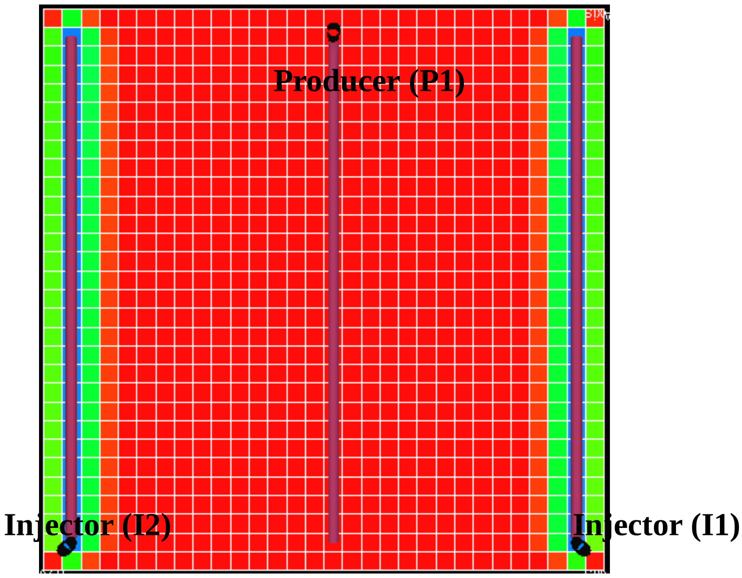

Figure 5.5: Well placement for the case of one horizontal producer and two horizontal injectors at injection rate of 5,000 STB/D for 30-ft thick reservoir.

In this scenario, the well pattern is symmetry. Genetic algorithm locates the producer between injector I1 and I2 because these injector locations help water injection breakthrough at both sides of the horizontal producer at the same time. Therefore, the areal sweep efficiency and recovery factor at breakthrough are high when genetic algorithm provides locations of wells illustrated in **Figure 5.5**. The result of well locations and oil recovery factor for each generation is shown in **Table 5.3**.

Table 5.3: Well locations and recovery factor for each generation in the case of one horizontal producer and two horizontal injectors in 30-ft thick reservoir.

Generations	Well I1		Well I2		Well P1		RF
	Toe	Heel	Toe	Heel	Toe	Heel	%
1	27,25	27,29	28,17	28,19	17,24	17,1	31.05
2	15,26	15,18	5,8	5,18	25,23	25,7	33.48
3	15,26	15,18	5,8	5,18	25,23	25,7	33.48
4	15,26	15,18	5,8	5,18	25,23	25,7	33.48
5	15,19	15,18	3,28	3,12	21,23	21,7	35.47
6	15,19	15,18	3,28	3,12	21,23	21,7	35.47
7	29,2	29,18	3,26	3,29	15,17	15,7	35.93
8	27,2	27,29	1,6	1,17	14,17	14,7	37.62
9	27,2	27,29	1,6	1,17	14,17	14,7	37.62
10	27,2	27,29	1,6	1,17	14,17	14,7	37.62
11	29,2	29,26	1,3	1,28	14,17	14,4	37.94
12	29,2	29,26	1,3	1,28	14,17	14,4	37.94
13	29,2	29,26	1,3	1,28	14,17	14,4	37.94
14	29,2	29,26	1,3	1,28	14,17	14,4	37.94
15	29,2	29,26	1,3	1,28	17,27	17,4	37.94
16	29,3	29,28	2,3	2,28	17,27	17,4	38.06
17	29,3	29,28	2,3	2,28	17,27	17,4	38.06
18	29,3	29,28	2,3	2,28	17,27	17,4	38.06
19	29,3	29,28	2,3	2,28	17,27	17,4	38.06
20	29,3	29,28	1,2	1,29	15,27	15,3	38.12
21	29,3	29,28	1,2	1,29	15,27	15,3	38.12
22	29,3	29,28	1,2	1,29	15,27	15,3	38.12
23	29,3	29,28	2,3	2,29	15,27	15,3	38.17
24	29,3	29,28	2,3	2,29	15,27	15,3	38.17
25	29,3	29,28	2,3	2,29	15,27	15,3	38.17
26	29,3	29,28	2,3	2,29	15,27	15,3	38.17
27	29,2	29,29	2,2	2,29	16,30	16,2	38.24
28	29,2	29,29	2,2	2,29	15,27	15,2	38.26
29	29,2	29,29	2,2	2,29	15,27	15,2	38.26
30	29,2	29,29	2,2	2,29	15,27	15,2	38.26
31	29,2	29,29	2,2	2,29	15,27	15,2	38.26
32	29,2	29,29	2,2	2,29	15,27	15,2	38.26
33	29,2	29,29	2,2	2,29	15,27	15,2	38.26
34-40	29,2	29,29	2,2	2,29	15,29	15,2	38.29

In **Table 5.4** and **Figure 5.6**, there are two injection rates that provide high recovery factor in the range of 36.78% to 38.29%. These two injection rates are (1) injection rate of 5,000 STB/D and (2) injection rate of 10,000 STB/D. Because the production time is not significantly different, the second injection rate seems to be the most attractive since it has the highest oil recovery although its water production shown in **Figure 5.7** is higher than that of the second injection rate. The oil recovery factor at injection rate of 10,000 STB/D is about 3 % more than that at injection rate of 5,000 STB/D. Therefore, the use of two horizontal injectors with a single horizontal producer at water injection rate of 10,000 STB/D is suitable for this scenario. With this injection rate, the cumulative oil recovery of 9,157 MSTB is produced at the end of 5,113 days of production. The breakthrough time for this case is about 223 days. The cumulative water production is 76,762 MSTB while the amount of water injection is 81,729 MSTB.

Oil recovery at high injection rate is higher than the oil recovery at low injection rate because in the case of low injection rate water tends to move downward, resulting in segregation. The problem of segregation reduces oil recovery because small areal sweep efficiency occurs in case of segregation.

Table 5.4: Production data for the case of one horizontal producer and two horizontal injectors at injection rate of 2,000 STB/D, 5,000 STB/D and 10,000 STB/D in 30 ft-thick reservoir.

Production rate/well	Injection rate/well	Break through			Abandonment					
		Time	Cumulative oil	Recovery	Time	Recovery	Cumulative oil	Cumulative produced gas	Cumulative produced water	Cumulative water injection
STB/D	STB/D	Days	STB	%	Days	%	STB	MSCF	MSTB	MSTB
2760	2000	1355	3739519	15.63	5272	34.12	8165476	16152	7969	21086
6900	5000	539	3718021	15.54	4642	36.78	8802585	14687	31825	46422
13800	**10000**	**233**	**3210657**	**13.42**	**5113**	**38.29**	**9156592**	**12519**	**76762**	**81729**

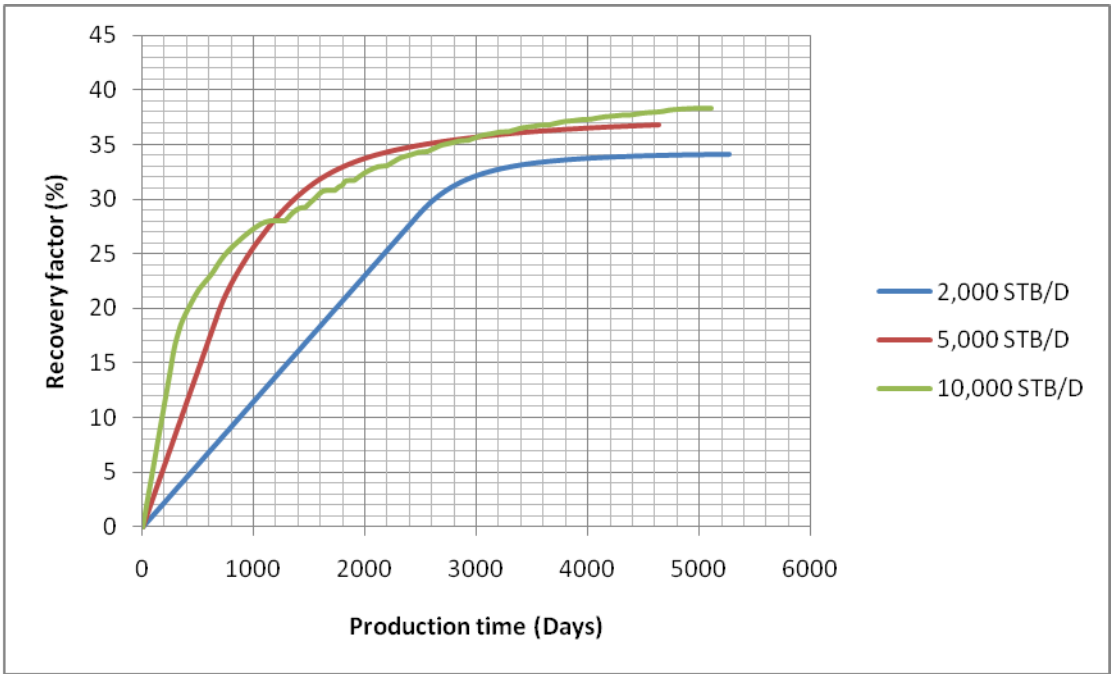

Figure 5.6: Recovery factor for the case of one horizontal producer and two horizontal injectors at injection rate of 2,000 STB/D, 5,000 STB/D and 10,000 STB/D in 30 ft-thick reservoir.

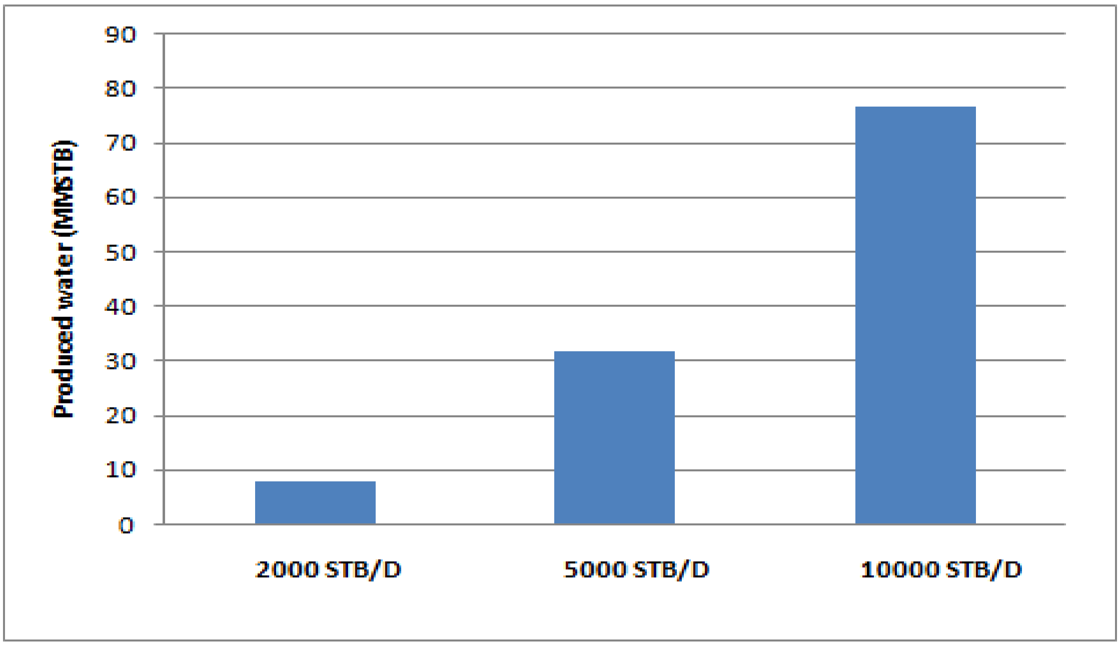

Figure 5.7: Cumulative produced water for the case of one horizontal producer and two horizontal injectors at injection rate of 2,000 STB/D, 5,000 STB/D and 10,000 STB/D in 30 ft-thick reservoir.

5.1.1.3 One vertical producer with two vertical injectors

For well placement for one vertical producer with two vertical injectors, illustrated in **Figure 5.8**, the genetic algorithm (GA) tries to search regions with high oil recovery in the 1st generation. Oil recovery factor of 28.98% is obtained in the 1st generation. From the 2nd to the 4th generation, oil recovery factor climbs from 31.15% to 34%. After the 4th generation, the local maximum occurs several times but the solution is still improved by the process of mutation and crossover. Even though the genetic algorithm is continued until it reaches the terminated generation (the 40th generation) but the solution doesn't improve after the 25th generation. Therefore, optimization of well location for one vertical producer with two vertical injectors is found at the 25th generation. The number of generation to reach the convergence in this scenario is less than that in the case of one horizontal producer with two vertical injectors because the genetic algorithm finds high oil recovery in the 4th generation.

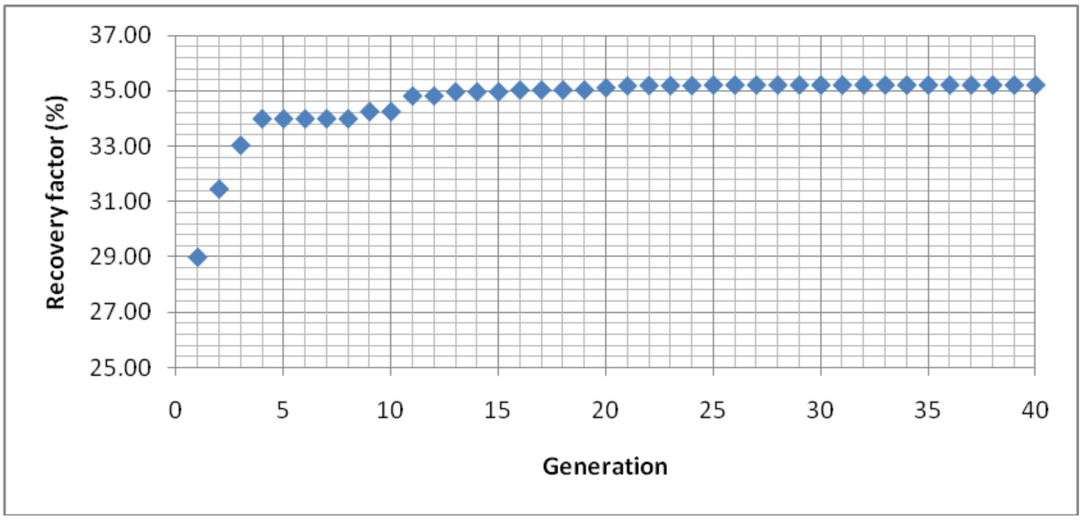

Figure 5.8: Recovery factor as a function of generation in the case of one vertical producer and two vertical injectors in 30-ft thick reservoir.

In this scenario, there is no horizontal well. The pressure drop doesn't affect location of injection well. Therefore, the injection well I1 and I2 are located at the upper and lower right corner. The optimum locations of one vertical producer and two vertical injectors obtained from the 25th generation are at the (i,j) blocks of (1,15), (30,1) and (30,30), respectively as shown in **Figure 5.9**. The results of well locations and oil recovery factor for each generation are shown in **Table 5.5**.

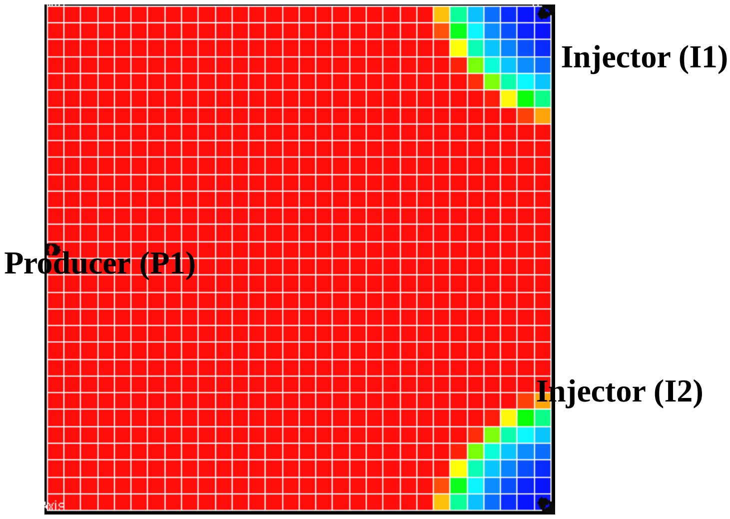

Figure 5.9: Well placement for the case of one vertical producer and two vertical injectors at injection rate of 2,500 STB/D in 30-ft thick reservoir.

Table 5.5: Well locations and recovery factor for each generation in the case of one vertical producer and two vertical injectors in 30-ft thick reservoir.

Generations	Well I1	Well I2	Well P1	RF %
1	8,8	2,30	2,12	28.98
2	11,1	13,19	25,12	31.45
3	11,30	18,4	25,22	33.04
4	30,1	7,23	14,22	34.00
5	30,1	7,23	14,22	34.00
6	30,1	7,23	14,22	34.00
7	30,1	7,23	14,22	34.00
8	30,1	7,23	14,22	34.00
9	29,8	15,8	3,12	34.26
10	29,8	15,8	3,12	34.26
11	30,4	30,25	3,17	34.83
12	30,4	30,25	3,17	34.83
13	30,4	30,25	3,17	34.98
14	30,4	30,25	3,17	34.98
15	30,4	30,25	3,17	34.98
16	30,2	29,27	1,14	35.05
17	30,2	29,27	1,14	35.05
18	30,2	29,27	1,14	35.05
19	30,2	29,27	1,14	35.05
20	30,2	30,28	2,14	35.13
21	30,2	30,28	2,16	35.20
22	30,1	30,28	1,15	35.21
23	30,1	30,28	1,15	35.21
24	30,1	30,28	1,15	35.21
25-40	30,1	30,30	1,15	35.23

The recovery factors from reservoir simulation runs for different injection rates are shown in **Table 5.6** and **Figure 5.10**. All injection flow rates result in long production time. However, water injection rate of 2,500 STB/D is the best injection rate for this scenario because the oil recovery is the highest at the end of production time. The oil recovery at injection rate of 2,500 STB/D is about 4 % more than that of other injection rates. Therefore, the use of single vertical producer with two vertical injectors at water injection rate of 2,500 STB/D is the most suitable for this scenario. The cumulative oil recovery of 8,478 MSTB is produced at the end of 10,359 days of production. The breakthrough time for this case is about 1,510 days. The cumulative water production is 37,382 MSTB while the amount of water injection is 50,210 MSTB.

At the early time, the oil recovery at high injection rate is higher than the oil recovery at low injection rate because in the case of low injection rate water tends to move downward to the bottom of the reservoir, resulting in segregation. In this scenario, at the abandonment the highest water injection rate doesn't provide the highest oil recovery because water injection rate is limited by the bottomhole pressure of injection well while production well still produces at high rate. The production rate doesn't balance with the injection rate. As a result, production rate slightly decreases because the reservoir pressure rapidly decreases.

Table 5.6: Production data for the case of one vertical producer with two vertical injectors at injection rate of 1,000 STB/D 2,500 STB/D and 5,000 STB/D in 30 ft-thick reservoir.

Production rate/well	Injection rate/well	Break through			Abandonment					
		Time	Cumulative oil	Recovery	Time	Recovery	Cumulative oil	Cumulative produced gas	Cumulative produced water	Cumulative water injection
STB/D	STB/D	Days	STB	%	Days	%	STB	MSCF	MSTB	MSTB
1380	1000	3175	4381147	18.31	9082	31.43	7521964	15449	6577	18165
3450	**2500**	**1510**	**5124744**	**21.41**	**10359**	**35.43**	**8478641**	**10310**	**37382**	**50210**
6900	5000	1433	5410582	22.61	10957	31.44	7523564	7889	50272	61310

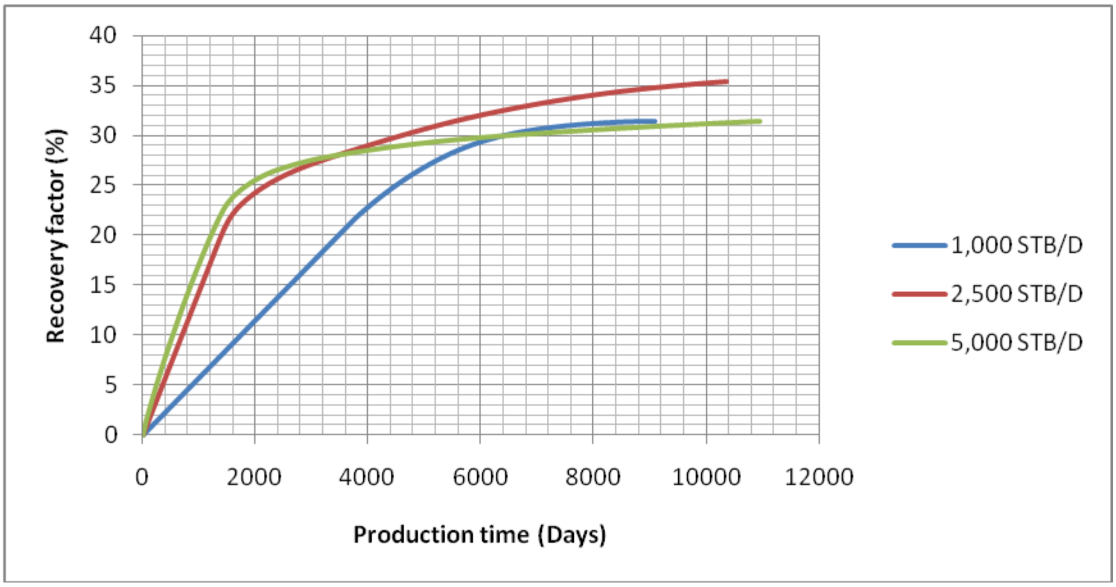

Figure 5.10: Recovery factor for the case of one vertical producer and two vertical injectors at injection rate of 1,000 STB/D, 2,500 STB/D and 5,000 STB/D in 30 ft-thick reservoir.

5.1.1.4 One vertical producer with two horizontal injectors

Well placement for one vertical producer with two horizontal producers is performed by using genetic algorithm coupled with reservoir simulation**.** In **Figure 5.11**, the 1st generation of the genetic algorithm (GA) tries to search regions with high oil recovery. From the 1st to the 8th generation, oil recovery factor increases from 29.84% to 30.08%. In the 9th generation, oil recovery factor climbs to 32.12%. After the 10th generation, local maximums occurs several times. The last local maximum is improved by the process of mutation and crossover in the 29th generation. From the 31st to the 40th generation, the mutation and crossover cannot improve the solution. Therefore, well location optimization for this scenario is obtained in the 31st generation is the converged generation.

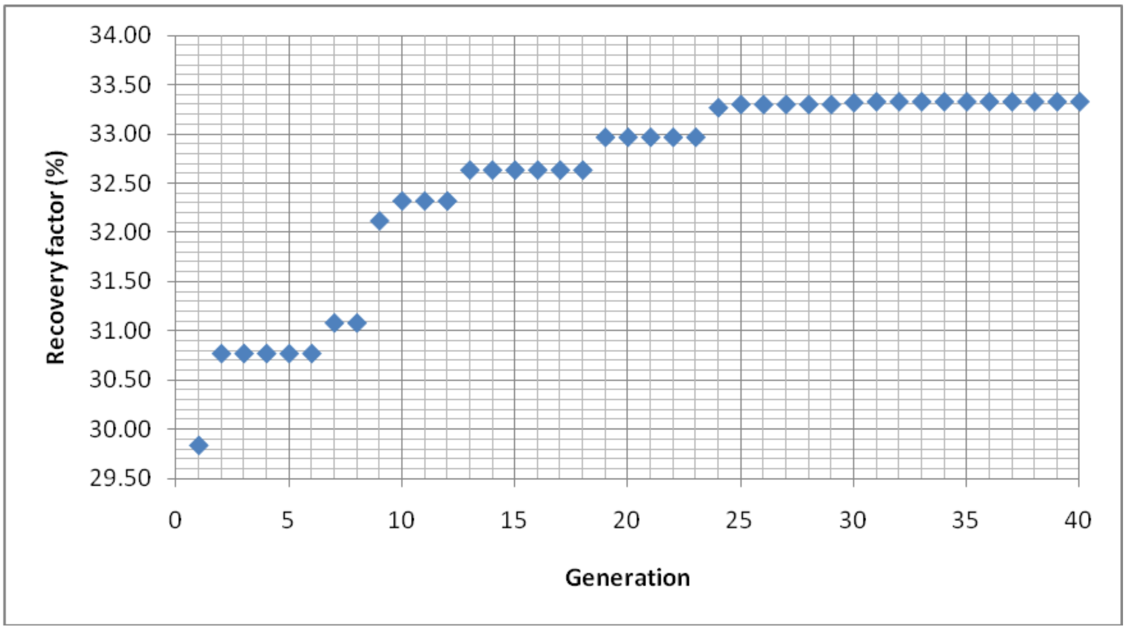

Figure 5.11: Recovery factor as a function of generation in the case of one vertical producer and two horizontal injectors in 30-ft thick reservoir.

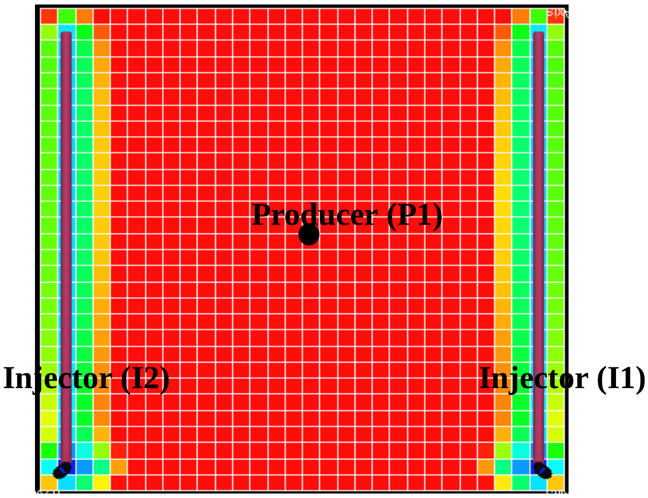

Figure 5.12: Well placement for the case of one vertical producer and two horizontal injectors at injection rate of 2,000STB/D in 30-ft thick reservoir.

Well placements of a vertical producer and two horizontal injectors are shown in **Figure 5.12**. These locations are at the (i,j) blocks of (15,18), ((29,2),(29,29)) and ((2,2),(2,29)), respectively. In this scenario, the production well is not located at the center because the frictional pressure drop in horizontal well affects the flow of injected water from the injectors to the producer. The pressure drop of horizontal injection well slightly increases from heel to toe during the injection of water. Therefore, the pressure of the horizontal injectors at the heel is higher than that at the toe. The injection water is easy to flow from the heels of horizontal injectors to the vertical producer. Therefore, the location of producer moves to the (i,j) block of (15,18) to reduce the problem of early breakthrough at the producer. **Table 5.7** shows the results of well locations and oil recovery factor for each generation in this scenario.

Table 5.7: Well locations and recovery factor for each generation in the case of one vertical producer and two horizontal injectors in 30-ft thick reservoir.

Generations	Well P1	Well I1		Well I2		RF
		Toe	Heel	Toe	Heel	%
1	20,24	1,9	1,27	10,21	10,14	29.84
2	21,13	16,12	16,24	7,18	7,23	30.77
3	21,13	16,12	16,24	7,18	7,23	30.77
4	21,13	16,12	16,24	7,18	7,23	30.77
5	21,13	16,12	16,24	7,18	7,23	30.77
6	21,13	16,12	16,24	7,18	7,23	30.77
7	19,1	28,24	28,11	6,22	6,27	31.08
8	19,1	28,24	28,11	6,22	6,27	31.08
9	19,4	29,12	29,28	4,22	4,29	32.12
10	21,4	29,12	29,28	4,3	4,29	32.32
11	21,4	29,12	29,28	4,3	4,29	32.32
12	21,4	29,12	29,28	4,3	4,29	32.32
13	20,15	30,5	30,30	1,3	1,29	32.64
14	20,15	30,5	30,30	1,2	1,29	32.64
15	22,15	30,5	30,30	1,2	1,29	32.64
16	22,17	30,5	30,30	1,2	1,29	32.64
17	22,17	30,5	30,30	1,2	1,29	32.64
18	22,17	30,5	30,30	1,2	1,29	32.64
19	20,15	29,3	29,30	2,2	2,29	32.97
20	20,15	29,3	29,30	2,2	2,29	32.97
21	20,15	29,3	29,30	2,2	2,29	32.97
22	20,15	29,3	29,30	2,2	2,29	32.97
23	20,15	29,3	29,30	2,2	2,29	32.97
24	15,17	29,1	29,30	2,2	2,29	33.27
25	15,18	29,1	29,30	2,2	2,29	33.30
26	15,18	29,1	29,30	2,2	2,29	33.30
27	15,18	29,1	29,30	2,2	2,29	33.30
28	15,18	29,1	29,30	2,2	2,29	33.30
29	15,18	29,1	29,30	2,2	2,29	33.30
30	15,17	29,2	29,29	2,2	2,29	33.32
31-40	15,18	29,2	29,29	2,2	2,29	33.33

The highest oil recovery factor of 33.33 % shown in **Table 5.8** and **Figure 5.13** is found in this scenario with water injection rate of 2,000 STB/D. The cumulative oil recovery of 7,977 MSTB is produced at the end of 6,755 days of production. The breakthrough time for this scenario is about 1,110 days. The cumulative water production is 13,768 MSTB while the amount of water injection is 27,020 MSTB.

In this scenario, at the abandonment the high water injection rate doesn't provide the highest oil recovery because water injection rate is limited by the bottomhole pressure of injection wells while production well still produces at high rate. The production rate doesn't balance with the injection rate. As a result, the production rate rapidly decreases due to low reservoir pressure.

Table 5.8: Production data for the case of one vertical producer with two horizontal injectors at injection rate of 2,000 STB/D, 5,000 STB/D and 10,000 STB/D in 30-ft thick reservoir.

Production rate/well	Injection rate/well	Break through			Abandonment					
		Time	Cumulative oil	Recovery	Time	Recovery	Cumulative oil	Cumulative produced gas	Cumulative produced water	Cumulative water injection
STB/D	STB/D	Days	STB	%	Days	%	STB	MSCF	MSTB	MSTB
2760	**2000**	**1110**	**3064467**	**12.80**	**6755**	**33.33**	**7976856**	**14290**	**13768**	**27021**
6900	5000	466	3195935	13.35	14245	30.17	7220928	6340	128535	138600
13800	10000	286	2774297	11.59	3719	21.14	5058521	3669	26114	33810

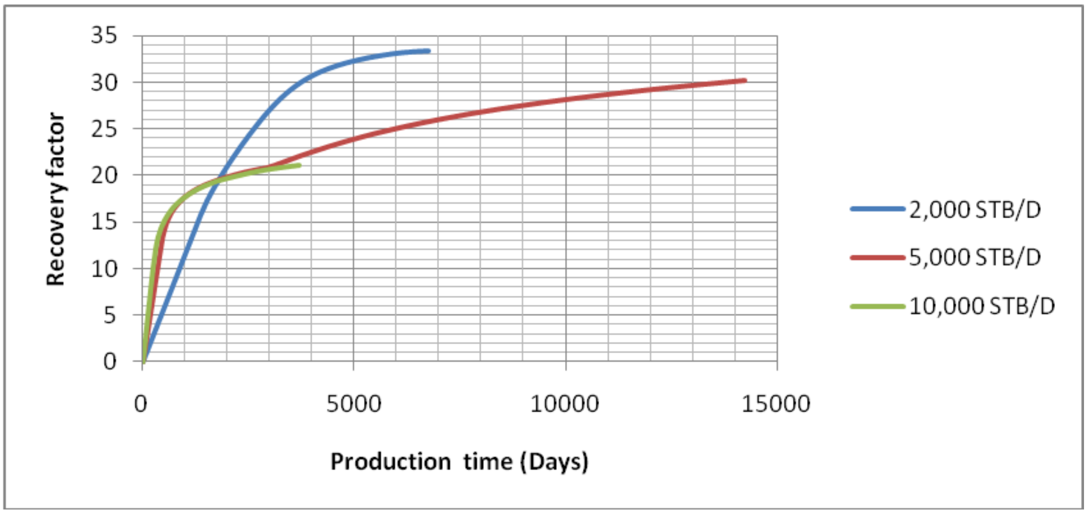

Figure 5.13: Recovery factor for the case of one vertical producer and two horizontal injectors at injection rate of 2,000 STB/D, 5,000 STB/D and 10,000 STB/D in 30-ft thick reservoir.

5.1.2 Well placement of two producers with one injector

5.1.2.1 Two horizontal producers with one vertical injector

After running genetic algorithm coupled with reservoir simulator for well placement of two horizontal producers with one vertical injector, the result of well placement is represented in **Figure 5.14**. In the 1st generation, the genetic algorithm tries to search region with high oil recovery in order to narrow down the search area for the next generation. Oil recovery factor of 31.58% is obtained in the 1st generation. Oil recovery factor reaches 33.64% in the 2nd generation and climbs to 35.07% in the13th generation. The local maximam occurs in the 6th generation to the 13th generation. After the 9th generation, the local maxima occur several times. The last local maximum is improved by the process of mutation and crossover in the 28th generation and oil recovery factor climbs to 35.87% in the 30th generation. The 30th generation provides the highest oil recovery factor. The converged generation of the well optimization is obtained in the 30th generation because oil recovery doesn't improve after the 30th generation even though genetic algorithm is run until the terminated generation (the 40th generation).

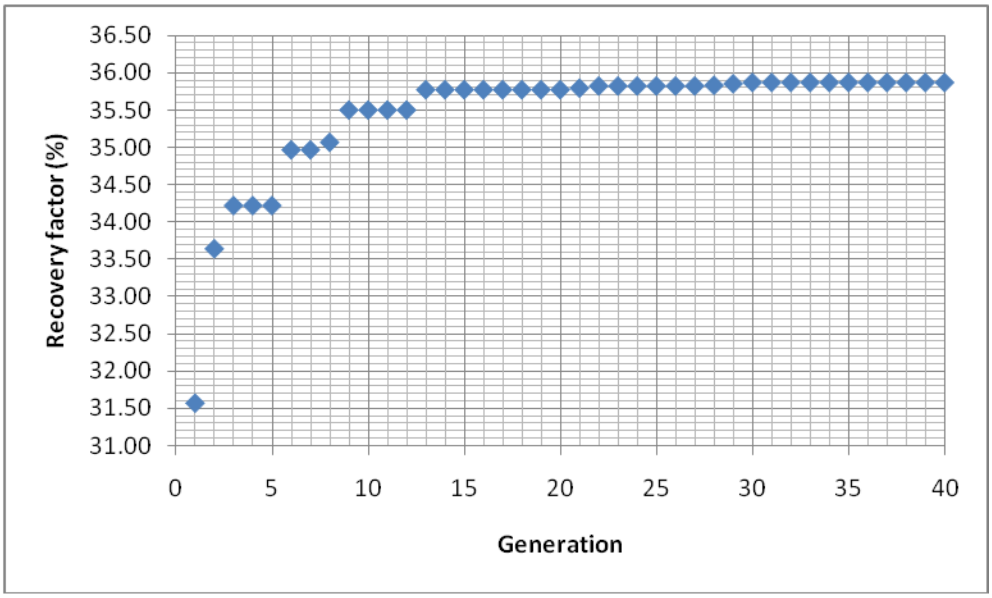

Figure 5.14: Recovery factor as a function of generation in the case of two horizontal producers and one vertical injector in 30-ft thick reservoir.

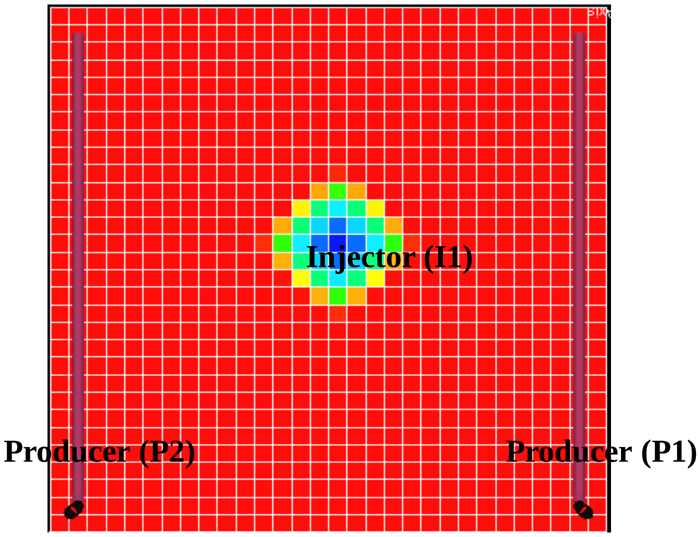

Figure 5.15: Optimal well location for the case of two horizontal producers and one vertical injector at injection rate of 5,000STB/D in 30-ft thick reservoir.

In this scenario, the injection well is optimally located as shown in **Figure 5.15** because the frictional pressure drop in horizontal production well affects the flow of water from the vertical injector to the horizontal producers. The pressure of the horizontal production well slightly decreases from the toe to the heel during oil production. Therefore, pressure of horizontal producer at the heel is lower than that at the toe. The injection water is easy to breakthrough at the heel. Therefore, the location of injector moves to the (i,j) block of (15,17) to reduce the problem of the early breakthrough. The optimum locations of two horizontal producers and one vertical injector obtained from the 30th generation are at the (i,j) blocks of ((2,2),(2,29)), ((29,2),(29,29)) and (15,17), respectively. **Table 5.9** shows the results of well locations and oil recovery factor for each generation in this scenario.

Table 5.9: Well locations and recovery factor for each generation in the case of two horizontal producers and one vertical injector in 30-ft thick reservoir.

Generations	Well I1	Well P1		Well P2		RF
		Toe	Heel	Toe	Heel	%
1	8,16	2,12	2,30	22,25	22,24	31.58
2	5,23	4,1	4,17	16,27	16,13	33.64
3	13,17	1,4	1,30	19,26	19,23	34.22
4	13,17	1,4	1,30	19,26	19,23	34.22
5	13,17	1,4	1,30	19,26	19,23	34.22
6	13,16	21,4	21,30	5,26	5,23	34.97
7	13,16	21,4	21,30	5,26	5,23	34.97
8	13,21	27,21	27,30	3,1	3,13	35.07
9	13,21	29,30	29,26	2,3	2,20	35.50
10	13,21	29,30	29,26	2,3	2,20	35.50
11	13,21	29,30	29,26	2,3	2,20	35.50
12	13,21	29,30	29,26	2,3	2,20	35.50
13	14,16	28,5	28,27	2,2	2,27	35.77
14	14,16	28,5	28,27	2,2	2,27	35.77
15	14,16	28,5	28,27	2,2	2,27	35.77
16	14,16	28,5	28,27	2,2	2,27	35.77
17	14,16	28,5	28,27	2,2	2,27	35.77
18	14,16	28,5	28,27	2,2	2,27	35.77
19	14,16	28,5	28,27	2,2	2,27	35.77
20	14,16	28,5	28,27	2,2	2,27	35.77
21	13,16	29,2	29,26	2,2	2,30	35.79
22	13,17	29,2	29,29	2,2	2,28	35.82
23	13,17	29,2	29,29	2,2	2,28	35.82
24	13,17	29,2	29,29	2,2	2,28	35.82
25	13,17	29,2	29,29	2,2	2,28	35.82
26	13,17	29,2	29,29	2,2	2,28	35.82
27	13,17	29,2	29,29	2,2	2,28	35.82
28	13,17	29,2	29,29	1,2	1,29	35.83
29	15,17	29,2	29,29	2,2	1,29	35.85
30-40	15,17	29,2	29,29	2,2	2,29	35.87

There are three injection rates that provide high recovery factor in the range of 35.01% to 35.87% as represented in **Table 5.10** and **Figure 5.16**. Even though the oil recovery of these three injection rates are significantly different, but the injection rate of 5000STB/D seems to be the most attractive since it has the shortest production time although its injection water is the highest among the three. The times required to produce oil of all three injection rates are shown in **Figure 5.17**.The production time at injection rate of 5000 STB/D is about 36 % of that at injection rate of 2500 STB/D. Therefore, the use of two horizontal producers with single vertical injector at water injection rate of 5,000 STB/D is the most suitable for this scenario. The cumulative oil recovery of 8,557 MSTB is produced at the end of 4,298 days of production. The breakthrough time for this case is about 730 days. The cumulative water production is 8,128 MSTB while the amount of water injection is 20,659 MSTB.

In this study, the oil recovery at high injection rate is higher than the oil recovery at low injection rate because in the case of low injection rate water tends to move downward, resulting in segregation. As a result, water prefers moving at the bottom part of the reservoir. The injected water bypasses the oil at the top of reservoir, causing low efficiency of waterflooding. For case of high injection rate, the water injection rate can reduce the problem of segregation because water flow rate in the horizontal direction is much higher than that in the vertical direction.

Table 5.10: Production data for the case of two horizontal producers with one vertical injector at injection rate of 1,000 STB/D, 2,500 STB/D and 5,000 STB/D in 30-ft thick reservoir.

Production rate/well	Injection rate/well	Break through			Abandonment					
		Time	Cumulative oil	Recovery	Time	Recovery	Cumulative oil	Cumulative produced gas	Cumulative produced water	Cumulative water injection
STB/D	STB/D	Days	STB	%	Days	%	STB	MSCF	MSTB	MSTB
345	1000	3773	2603140	10.88	14669	35.01	8378012	16148	6271	14669
860	2500	1272	2187331	9.14	7670	35.54	8504993	16296	7408	19175
1720	**5000**	**730**	**2511200**	**10.49**	**4298**	**35.84**	**8577864**	**16201**	**8128**	**20659**

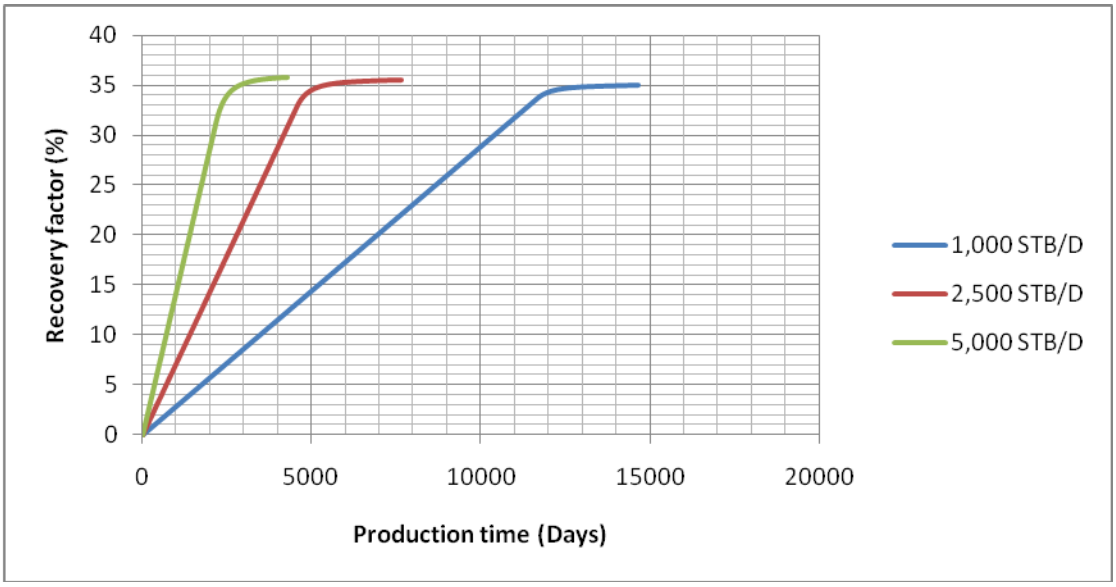

Figure 5.16: Recovery factor for the case of two horizontal producers and one vertical injector at injection rate of 1,000 STB/D, 2,500 STB/D and 5,000 STB/D in 30-ft thick reservoir.

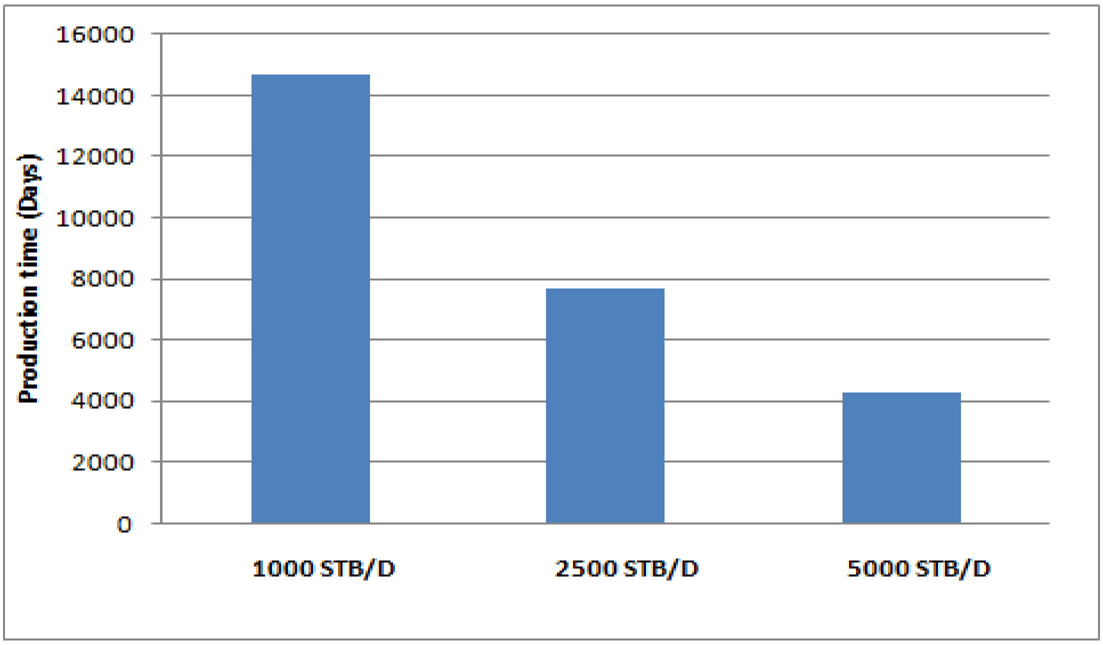

Figure 5.17: Production time for the case of two horizontal producers and one vertical injector at injection rate of 1,000 STB/D, 2,500 STB/D, and 5,000 STB/D in 30-ft thick reservoir.

5.1.2.2 Two horizontal producers with one horizontal injector

Well placement for two horizontal producers with one horizontal injector is performed by using genetic algorithm coupled with reservoir simulator. From the 1st generation in **Figure 5.18**, the genetic algorithm (GA) tries to search regions with high oil recovery in order to narrow down the search area for the next generation. Oil recovery factor climbs to 35.07% in the 5th generation. A high oil recovery factor is obtained in the 19th generation. After the 19th generation, local maxima occurs from well optimization of two horizontal producers with one horizontal injector. The last local maximum is improved by the process of mutation and crossover in the 33rd generation. Even though the genetic algorithm is continued until it reaches the terminated generation (the 40th generation) but the solution is still not improved after the 33rd generation. Thus, the 34th generation is the converged generation. The generation to reach the convergence in this scenario is more than that in the case of one horizontal producer with two vertical injectors because of a larger number of unknowns.

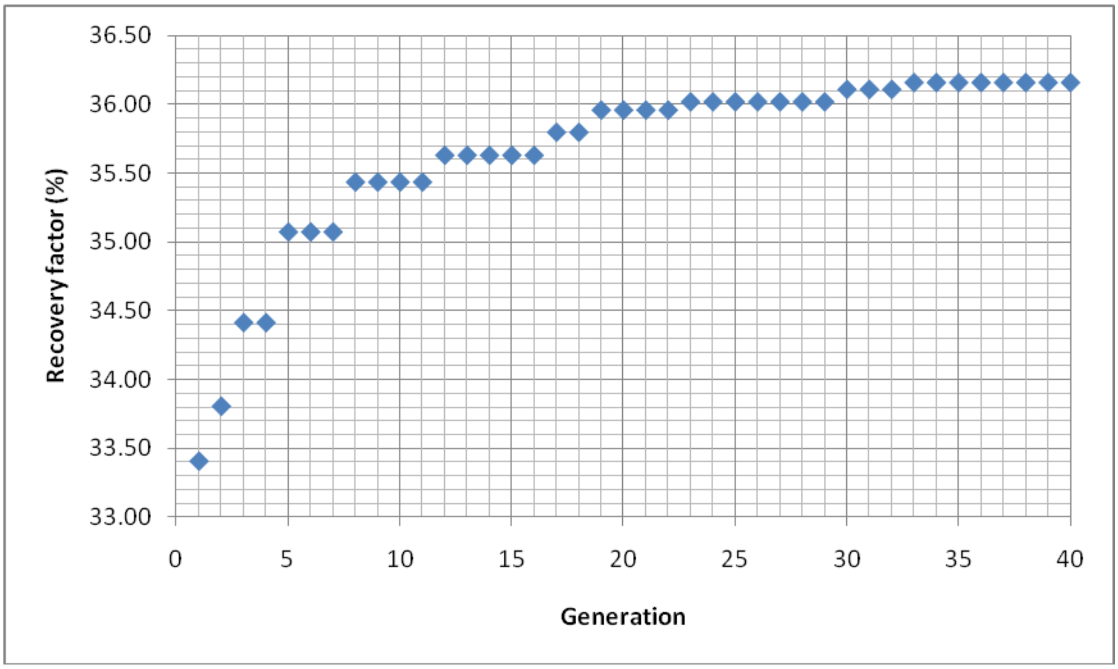

Figure 5.18: Recovery factor as a function of generation in the case of two horizontal producers and one horizontal injector in 30-ft thick reservoir.

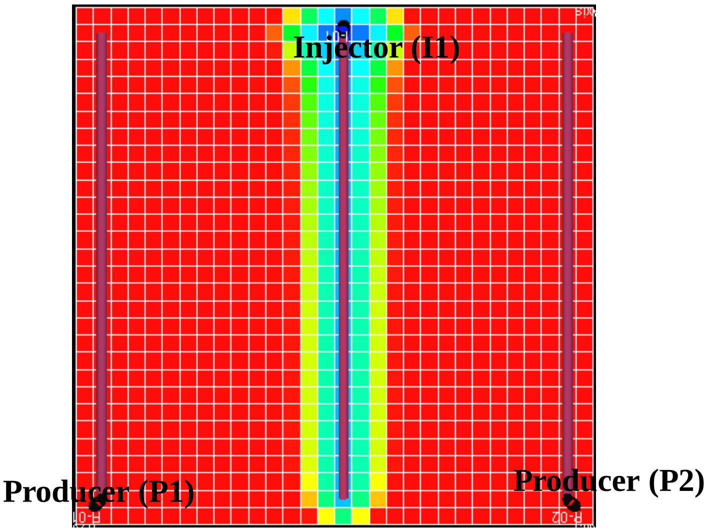

Figure 5.19: Well placement for the case of two horizontal producers and one horizontal injector at injection rate of 10,000 STB/D in 30-ft thick reservoir.

The well placement of two horizontal producers and one horizontal injector are obtained in the 33rd generation of optimization. These locations are at the (i,j) blocks of of ((29,2), (29,29)), ((2,2), (2,29)) and ((15,28),(15,2)), respectively as shown in **Figure 5.19**. In this scenario, the well pattern is symmetrical. Genetic algorithm locates the injector I1 between producers P1 and P2 because these producer locations help water injection break through at both horizontal producers at the same time. Therefore, the areal sweep efficiency and recovery factor at breakthrough are high when genetic algorithm provides locations of wells as illustrated in **Figure 5.19**. The result of well locations and oil recovery factor for each generation is shown in **Table 5.11**.

Table 5.11: Well locations and recovery factor for each generation in the case of two horizontal producer sand one horizontal injectors in 30-ft thick reservoir.

Generations	Well I1		Well P1		Well P2		RF
	Toe	Heel	Toe	Heel	Toe	Heel	%
1	25,7	25,17	15,18	15,30	21,8	21,12	33.41
2	16,20	16,30	2,8	2,30	11,2	11,12	33.81
3	25,7	25,23	7,15	7,18	18,3	18,8	34.42
4	25,7	25,23	7,15	7,18	18,3	18,8	34.42
5	15,28	15,14	29,15	29,24	4,2	4,26	35.07
6	15,28	15,14	29,15	29,24	4,2	4,26	35.07
7	15,28	15,14	29,15	29,24	4,2	4,26	35.07
8	15,26	15,22	29,9	29,27	1,3	1,26	35.44
9	15,26	15,22	29,9	29,27	1,3	1,26	35.44
10	15,26	15,22	29,9	29,27	1,3	1,26	35.44
11	15,26	15,22	29,9	29,27	1,3	1,26	35.44
12	15,26	15,23	29,2	29,30	1,3	1,26	35.63
13	15,26	15,23	29,2	29,30	1,3	1,26	35.63
14	15,26	15,23	29,2	29,30	1,3	1,26	35.63
15	15,26	15,23	29,2	29,30	1,3	1,26	35.63
16	15,26	15,23	29,2	29,30	1,3	1,26	35.63
17	15,28	15,6	28,2	28,28	2,2	2,29	35.80
18	15,28	15,6	28,2	28,28	2,2	2,29	35.80
19	15,28	15,3	28,2	28,28	2,1	2,29	35.96
20	15,28	15,3	28,2	28,28	2,1	2,29	35.96
21	15,28	15,3	28,2	28,28	2,1	2,29	35.96
22	15,28	15,3	28,2	28,28	2,1	2,29	35.96
23	15,28	15,3	29,2	29,30	2,1	2,29	36.02
24	15,28	15,3	29,2	29,30	2,1	2,29	36.02
25	15,28	15,3	29,2	29,30	2,1	2,29	36.02
26	15,28	15,3	29,2	29,30	2,1	2,29	36.02
27	15,28	15,3	29,2	29,30	2,1	2,29	36.02
28	15,28	15,3	29,2	29,30	2,1	2,29	36.02
29	15,28	15,3	29,2	29,30	2,1	2,29	36.02
30	15,28	15,2	29,2	29,30	2,2	2,29	36.11
31	15,28	15,2	29,2	29,30	2,2	2,29	36.11
32	15,28	15,2	29,2	29,30	2,2	2,29	36.11
33-40	15,28	15,2	29,2	29,29	2,2	2,29	36.16

In this scenario, all of three injection rates that provide high recovery factor, i.e., 35.77% at injection rate of 2,000 STB/D, 36.30% at injection rate of 5,000 STB/D, and 36.16 % at injection rate of 10,000 STB/D. Because the oil recovery shown in **Table 5.12** and **Figure 5.20** is not significantly different, the production time is the key for selecting the best injection rate. The production time at injection rate of 10,000 STB/D is about 50 % less than that of injection rate at 5,000 STB/D. Therefore, the use of two horizontal producers with single horizontal injector at water injection rate of 10,000 STB/D is suitable for this scenario. The cumulative oil recovery of 8,653 MSTB is produced at the end of 2,569 days of production. The breakthrough time for this case is about 513 days. The cumulative water production is 12,755 MSTB while the amount of water injection is 25,689 MSTB.

In this study, the oil recovery at high injection rate is higher than the oil recovery at low injection rate because in the case of low injection rate water tends to move downward, resulting in segregation. As a result, water prefers moving at the bottom part of reservoir, causing low efficiency of waterflooding process. For case of high injection rate, the water injection rate can reduce the problem of segregation because water flow rate in the horizontal direction is much higher than that in the vertical direction. However, using injection rate of 5,000 STB/D is better than that of 10,000 STB/D because the injection rate can reduce cumulative water injection in this scenario.

Table 5.12: Production data for the case of two horizontal producers and one horizontal injector at injection rate of 2,000 STB/D, 5,000 STB/D and 10,000 STB/D in 30-ft thick reservoir.

Production rate/well	Injection rate/well	Break through			Abandonment					
		Time	Cumulative oil	Recovery	Time	Recovery	Cumulative oil	Cumulative produced gas	Cumulative produced water	Cumulative water injection
STB/D	STB/D	Days	STB	%	Days	%	STB	MSCF	MSTB	MSTB
690	2000	2740	3780510	15.80	10592	35.77	8561612	16471	7274	21184
1720	**5000**	**970**	**3337688**	**13.95**	**4331**	**36.30**	**8686747**	**16269**	**8084**	**21657**
3450	10000	513	3541520	14.80	2569	36.16	8653223	15453	12755	25689

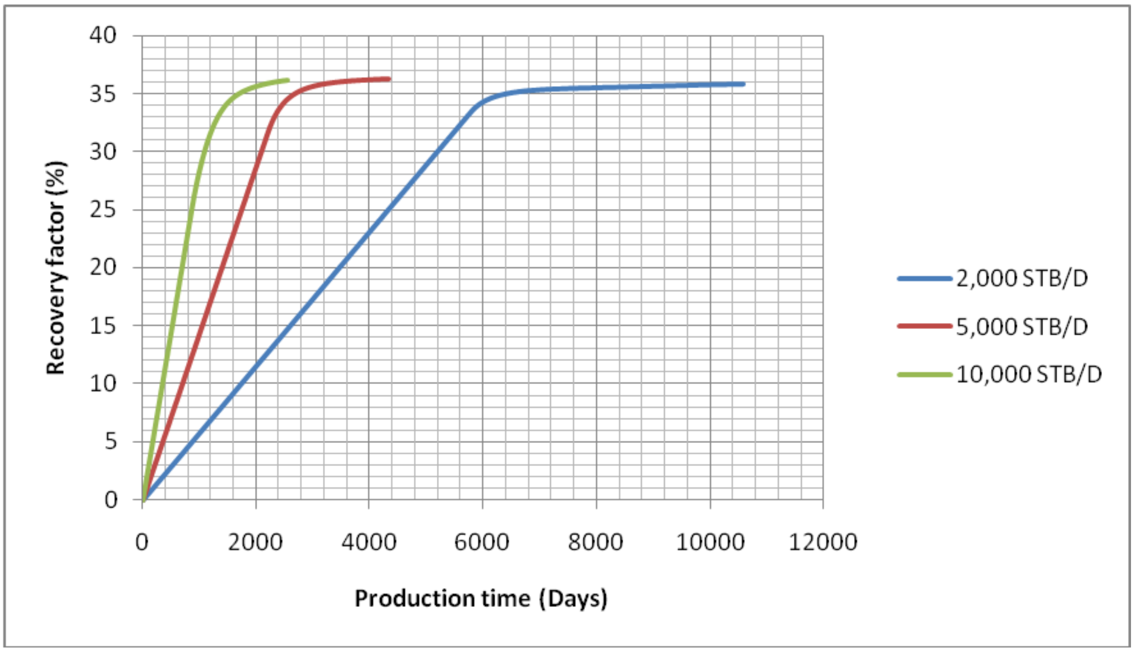

Figure 5.20: Recovery factor for the case of two horizontal producers and one horizontal injector at injection rate of 2,000 STB/D, 5,000 STB/D and 10,000 STB/D in 30-ft thick reservoir.

5.1.2.3 Two vertical producers with one vertical injector

For well placement for two vertical producers with one vertical injector, the result of well placement is shown in **Figure 5.21**. The genetic algorithm (GA) tries to search regions with high oil recovery in the 1st generation. Oil recovery factor of 22.65% is obtained in the 1st generation. From the 2nd to the 4th generation, oil recovery factor climbs from 24.40% to 27.93%. After the 4th generation, the first local maximum occurs but the solution is improved by the process of mutation and crossover in the 9th generation. A high oil recovery factor is obtained after the 13th generation. Even though the genetic algorithm is continued until it reaches the terminated generation (the 40th generation) but the solution doesn't improve after the 27th generation. Therefore, optimization of well location for two vertical producers with one vertical injector is found in the 27th generation. The number of generation to reach the convergence in this scenario is less than that in the case of one horizontal producer with two vertical injectors because the genetic algorithm finds high oil recovery in the 10th generation.

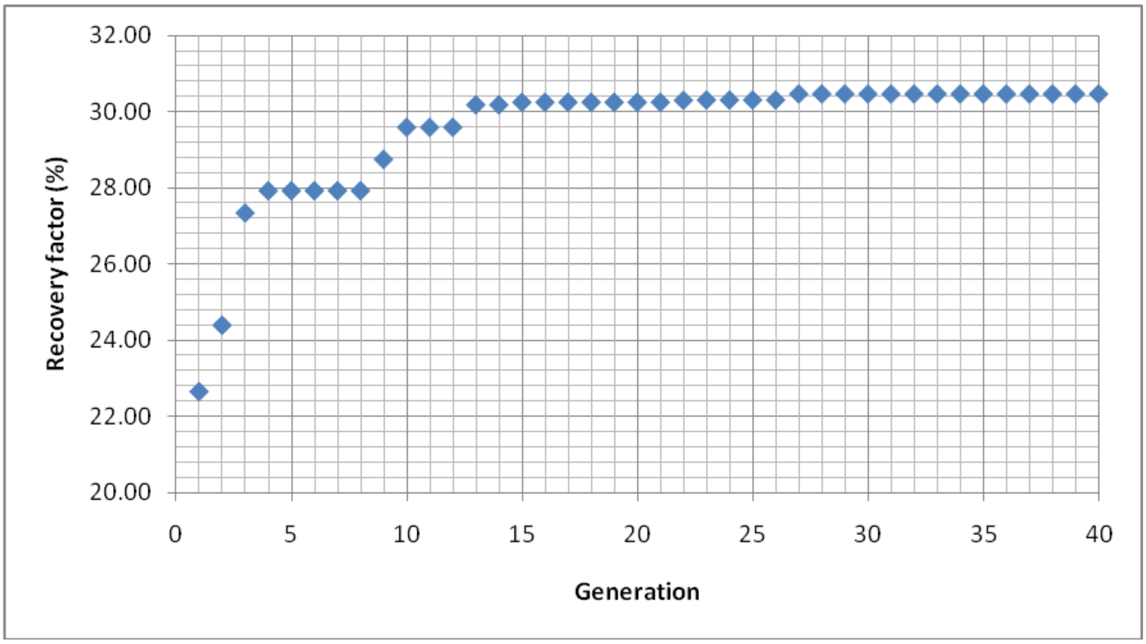

Figure 5.21: Recovery factor as a function of generation in the case of two vertical producers and one vertical injector in 30-ft thick reservoir.

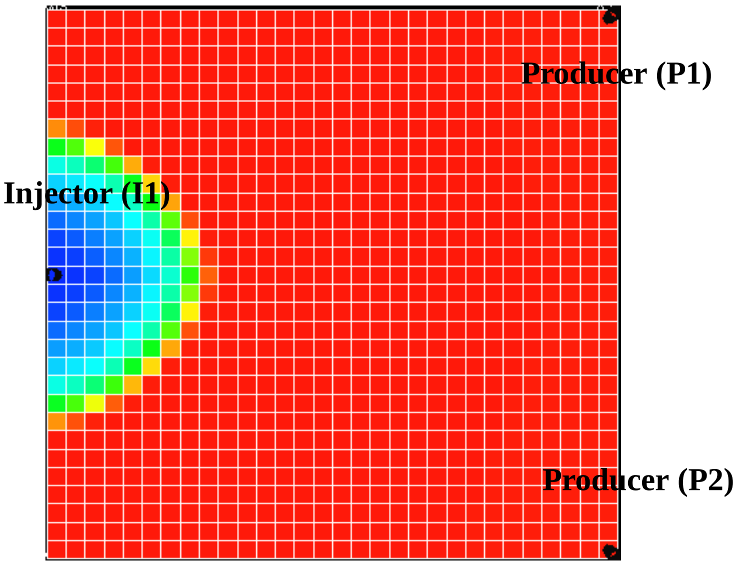

Figure 5.22: Well placement for the case of two vertical producers and one vertical injector at injection rate of 2,500 STB/D in 30-ft thick reservoir.

The best well placement of two vertical producers and one vertical injector for the best injection rate are shown in **Figure 5.22**. These locations are at the (i,j) blocks of (30,30), (30,1), and (1,15), respectively. In this scenario, there are no horizontal well. The pressure drop doesn't affect on location of injection well. Therefore, the injection wells I1 and I2 is located at the upper and lower right corners as uniform well pattern. The result of well locations and oil recovery factor for each generation is shown in **Table 5.13**.

Table 5.13: Well locations and recovery factor for each generation in the case of two vertical producers and one vertical injector in 30-ft thick reservoir.

Generations	Well I1	Well P1	Well P2	RF %
1	24,28	28,30	30,11	22.65
2	11,10	21,24	22,18	24.40
3	5,9	21,22	22,8	27.35
4	8,9	27,22	28,2	27.93
5	8,9	27,22	28,2	27.93
6	8,9	27,22	28,2	27.93
7	8,9	27,22	28,2	27.93
8	8,9	27,22	28,2	27.93
9	2,10	30,26	30,3	28.76
10	2,17	30,29	30,3	29.60
11	2,17	30,29	30,3	29.60
12	2,17	30,29	30,3	29.60
13	6,15	30,29	29,1	30.20
14	6,15	30,29	29,1	30.20
15	3,15	30,29	28,2	30.26
16	3,15	30,29	28,2	30.26
17	3,15	30,29	28,2	30.26
18	3,15	30,29	28,2	30.26
19	3,15	30,29	28,2	30.26
20	3,15	30,29	28,2	30.26
21	3,15	30,29	28,2	30.26
22	1,15	29,29	29,1	30.31
23	1,15	29,29	30,1	30.32
24	1,15	29,29	30,1	30.32
25	1,15	29,29	30,1	30.32
26	1,15	29,29	30,1	30.32
27-40	1,15	30,30	30,1	30.48

In this scenario, the highest oil recovery factor of 30.48 % is found with water injection rate of 2,500 STB/D as shown in **Table 5.14** and **Figure 5.23**. Even though oil recovery at injection rate of 1,000 STB/D closes to that at injection rate of 2,500 STB/D but in **Figure 5.24** the double production time at injection rate of 1,000 STB/D reduces attractiveness of this injection rate. The cumulative oil recovery of 7,294 MSTB is produced at the end of 6,759 days of production. The breakthrough time for this scenario is about 1,609 days. The cumulative water production is 5,717 MSTB while the amount of water injection is 15,929 MSTB.

At the early time, the oil recovery at high injection rate is higher than the oil recovery at low injection rate because in the case of low injection rate water tends to move downward to the bottom of the reservoir, resulting in segregation. In this scenario, at the abandonment the highest water injection rate doesn't provide the highest oil recovery because water injection rate is limited by the bottomhole pressure of injection well while production well still produces oil with high rate. The production rate doesn't balance with the injection rate, resulting in low reservoir pressure. The production well is produce oil with high rate in short time and then the production rate rapidly decreases.

Table 5.14: Production data for the case of two vertical producers and one vertical injector at injection rate of 1,000 STB/D, 2,500 STB/D and 5,000 STB/D in 30-ft thick reservoir.

Production rate/well	Injection rate/well	Break through			Abandonment					
		Time	Cumulative oil	Recovery	Time	Recovery	Cumulative oil	Cumulative produced gas	Cumulative produced water	Cumulative water injection
STB/D	STB/D	Days	STB	%	Days	%	STB	MSCF	MSTB	MSTB
345	1000	3652	2519880	10.53	12784	30.01	7183082	15872	5398	12784
860	**2500**	**1609**	**2767688**	**11.56**	**6759**	**30.48**	**7294090**	**15418**	**5717**	**15929**
1720	5000	1142	3926574	16.41	4347	28.44	6806692	13222	5797	17554

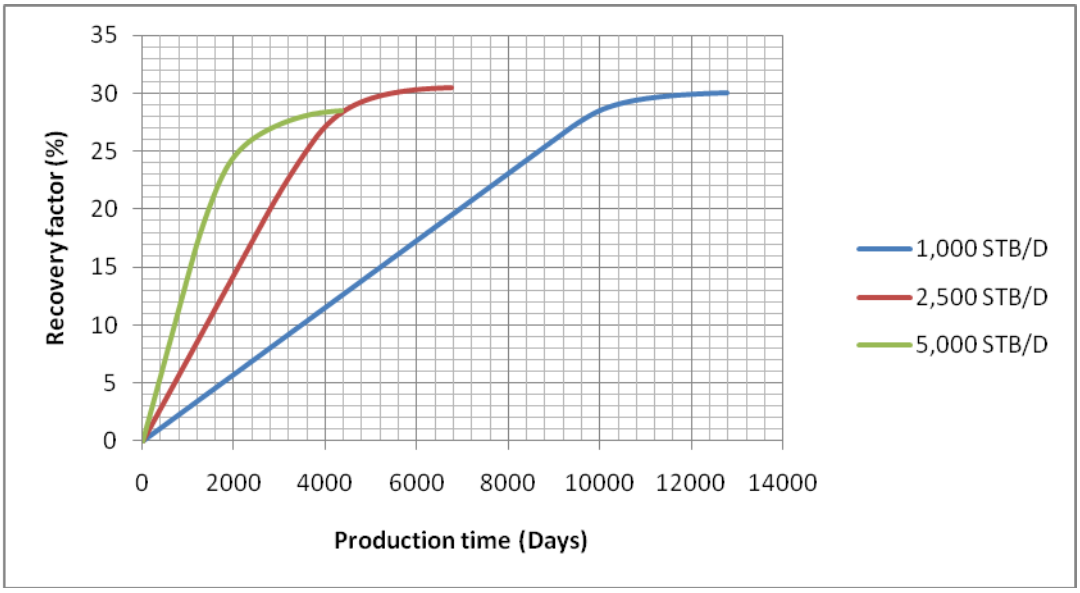

Figure 5.23: Recovery factor for the case of two vertical producers and one vertical injector at injection rate of 1,000 STB/D, 2,500 STB/D and 5,000 STB/D in 30-ft thick reservoir.

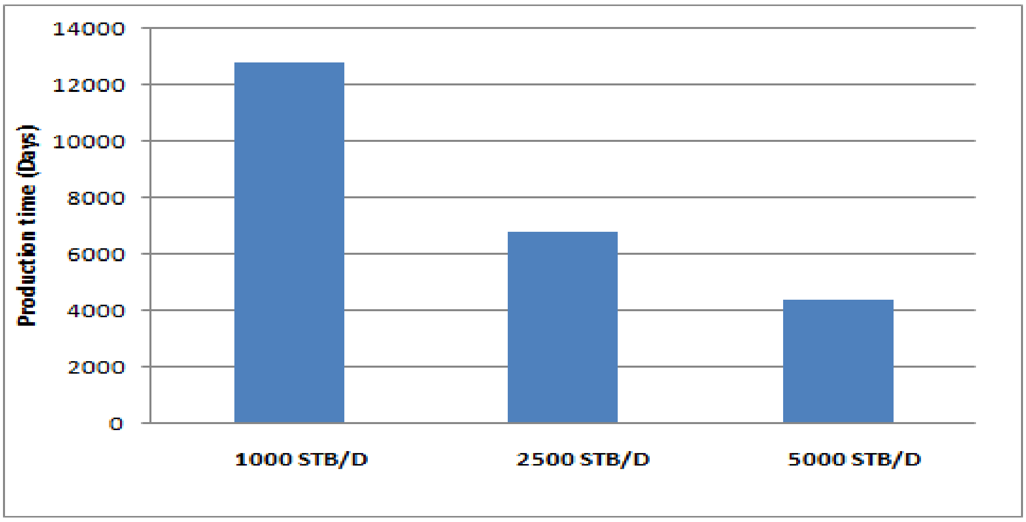

Figure 5.24: The production time for optimizing location of two vertical producers and one vertical injector in 30-ft thick reservoir.

5.1.2.4 Two vertical producers with one horizontal injector

Well placement for two vertical producers with one horizontal injector is performed by using genetic algorithm coupled with reservoir simulation**.** In **Figure 5.25**, the 1st to the 3rd generation of the genetic algorithm (GA) tries to search regions with high oil recovery. From the 3rd to the 6th generation, oil recovery factor increases from 26.35% to 33.63%. After the 6th generation, the local maxima occurs several times but the solutions are still improved by the process of mutation and crossover. In the 28th generation, oil recovery factor climbs to 34.90%. From the 28th to the 40th generation, the mutation and crossover cannot improve the solution. Therefore, well location optimization for this scenario is found in the 28th generation. The converged generation in this scenario is less than that in the case of one horizontal producer with two vertical injectors because the search closes to high oil recovery since it continues in the 6th generation.

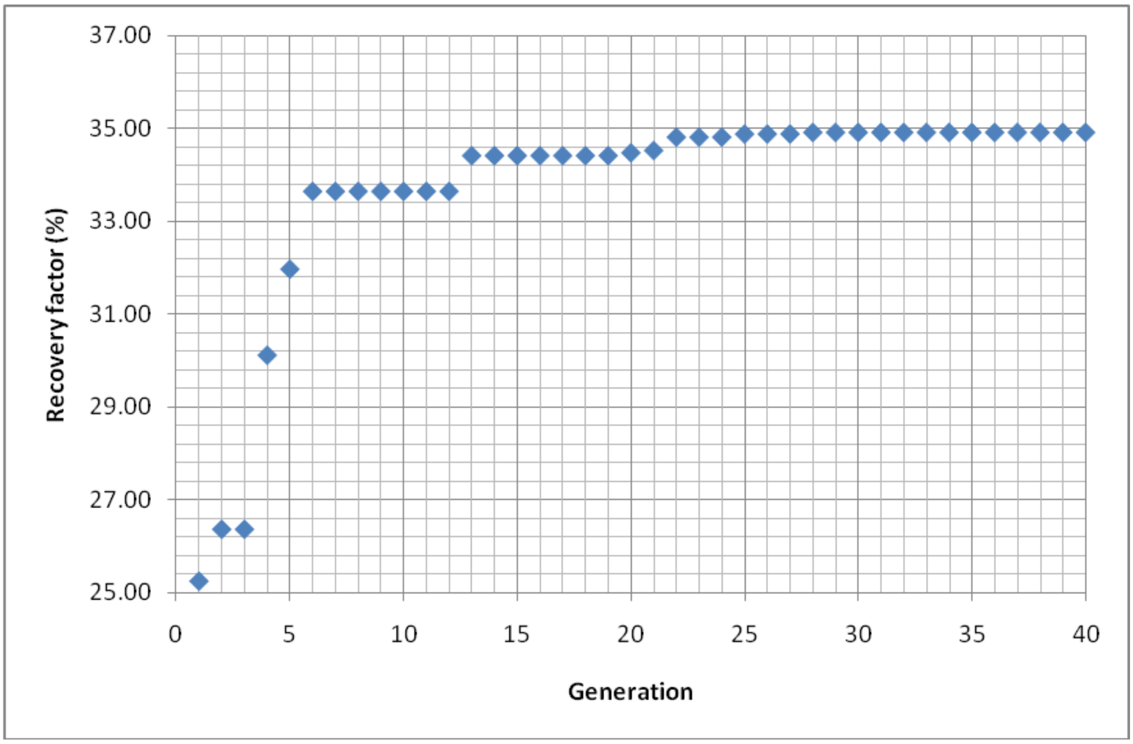

Figure 5.25: Recovery factor as a function of generation in the case of two vertical producers with one horizontal injector in 30-ft thick reservoir.

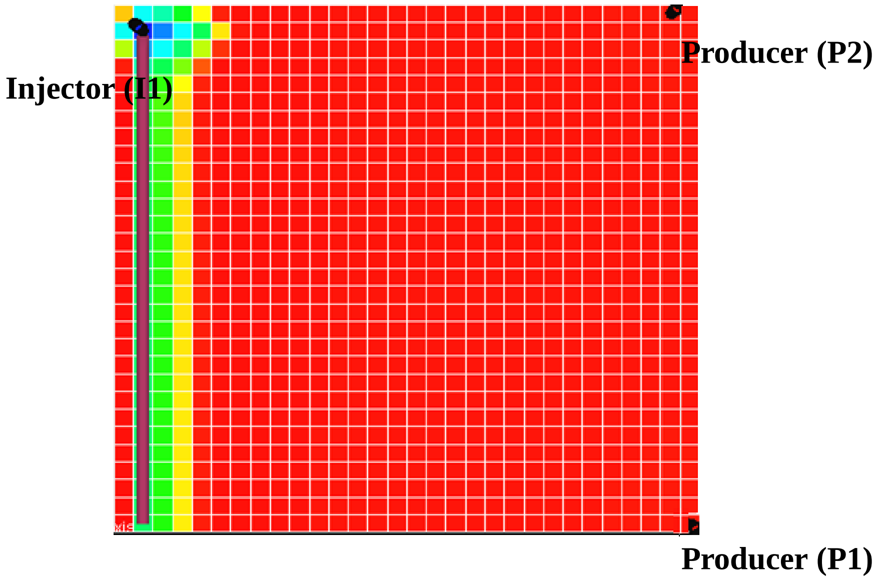

Figure 5.26: Well placement for the case of two vertical producers and one horizontal injector at injection rate of 5,000 STB/D in 30-ft thick reservoir.

The best well placement of two vertical producers and one horizontal injector are shown in **Figure 5.26**. These locations are at the (i,j) blocks of (29,1), (30,30) and ((2,29),(2,2)), respectively. In this scenario, the frictional pressure in horizontal well occurs by wellbore friction assigned in this model. The pressure of the horizontal injection well slightly decreases from heel to toe during water injection. Therefore, pressure at the heel is higher than that at the toe. The genetic algorithm tries to locate the production wells P1 and P2 at the (i,j) block of (30,30) and (29,1), respectively for reducing the problem of early water breakthrough. The result of well locations and oil recovery factor for each generation is shown in **Table 5.13**.

Table 5.15: Well locations and recovery factor for each generation in the case of two vertical producers and one horizontal producer in 30-ft thick reservoir.

Generations	Well P1	Well P2	Well I1 Toe	Well I1 Heel	RF %
1	18,1	30,1	3,30	3,25	25.24
2	18,5	8,18	2,2	3,13	26.35
3	18,5	8,18	2,2	3,13	26.35
4	26,5	26,25	2,26	2,13	30.10
5	27,3	29,25	2,26	2,13	31.96
6	27,2	28,28	2,26	2,7	33.63
7	27,2	28,28	2,26	2,7	33.63
8	27,2	28,28	2,26	2,7	33.63
9	27,2	28,28	2,26	2,7	33.63
10	27,2	28,28	2,26	2,7	33.63
11	27,2	28,28	2,26	2,7	33.63
12	27,2	28,28	2,26	2,7	33.63
13	29,1	28,30	2,30	2,3	34.40
14	29,1	28,30	2,30	2,3	34.40
15	29,1	28,30	2,30	2,3	34.40
16	29,1	28,30	2,30	2,3	34.40
17	29,1	28,30	2,30	2,3	34.40
18	29,1	28,30	2,30	2,3	34.40
19	29,1	28,30	2,30	2,3	34.40
20	29,3	29,29	1,29	1,1	34.46
21	29,1	29,29	1,29	1,1	34.51
22	29,2	29,30	1,29	1,1	34.80
23	29,2	29,30	1,29	1,1	34.80
24	29,2	29,30	1,29	1,1	34.80
25	29,1	29,30	2,29	1,2	34.87
26	29,1	29,30	2,29	1,2	34.87
27	29,1	29,30	2,29	1,2	34.87
28-40	29,1	30,30	2,29	2,2	34.90

The highest oil recovery factor of 34.90 % shown in **Table 5.16** and **Figure 5.27** is obtained in this scenario with water injection rate of 5,000 STB/D. The cumulative oil recovery of 8,353 MSTB is produced at the end of 7,305 days of production. The breakthrough time for this scenario is about 1044 days. The cumulative water production is 22,948 MSTB while the amount of water injection is 36,525 MSTB. In **Figure 5.27** and **5.28**, although the amount of production time at injection rate of 5000STB/D is 2 times more than that at injection rate of 10,000 STB/D, but the oil recovery at injection rate of 5000 STB/D is 2% more than that of injection rate at 10,000 STB/D. Therefore, producing with the injection rate of 5000STB/D is the best alternative for this scenario.

At the early time, the oil recovery at high injection rate is higher than the oil recovery at low injection rate because in the case of low injection rate water tends to move downward to the bottom of the reservoir, resulting in segregation. In this scenario, at the abandonment the highest water injection rate doesn't provide the highest oil recovery because water injection rate is limited by the bottomhole pressure of injection well while production well still produces with high rate. As a result, the production rate doesn't balance with the injection rate.

Table 5.16: Production data for the case of two vertical producers and one horizontal injector at injection rate of 2,000 STB/D, 5,000 STB/D and 10,000 STB/D in 30-ft thick reservoir.

Production rate	Injection rate	Break through			Abandonment					
		Time	Cumulative oil	Recovery	Time	Recovery	Cumulative oil	Cumulative produced gas	Produced water	Cumulative water injection
STB/D	STB/D	Days	STB	%	Days	%	STB	MSCF	MSTB	MSTB
690	2000	3036	4190284	17.51	8766	31.81	7613078	16068	6295	17532
1720	**5000**	**1044**	**3590170**	**15.00**	**7305**	**34.90**	**8353212**	**12650**	**22948**	**36525**
3450	10000	665	4438316	18.55	5844	32.70	7826972	9260	44464	56067

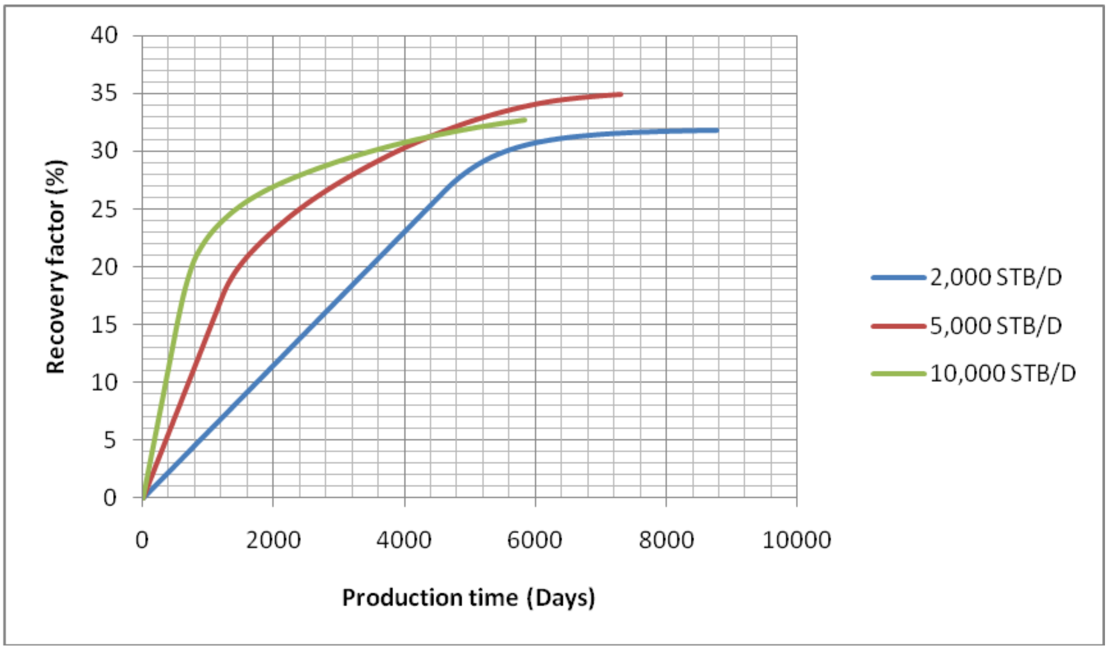

Figure 5.27: Recovery factor for the case of two vertical producers and one horizontal injector at injection rate of 2,000 STB/D, 5,000 STB/D and 10,000 STB/D in 30-ft thick reservoir.

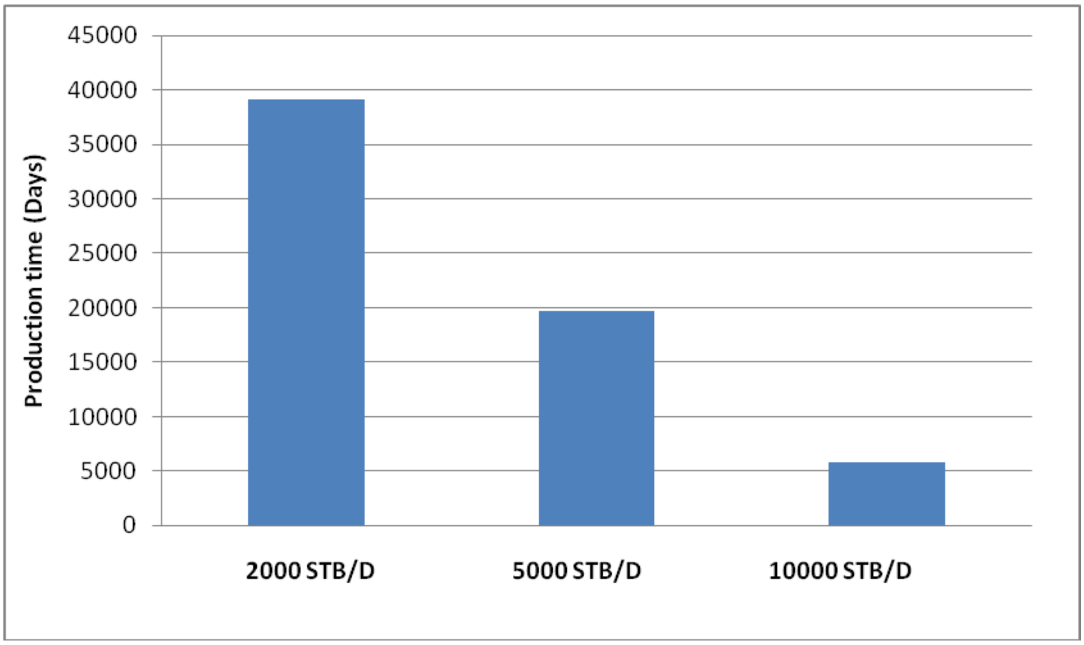

Figure 5.28: Production times for the case of two vertical producers and one horizontal injector at injection rate of 2,000 STB/D, 5,000 STB/D and 10,000 STB/D in 30-ft thick reservoir.

5.1.3 Summary for well placement in 30-ft thick reservoir

The well locations in each scenario are different because of using different combinations of well types. In the scenarios that horizontal well is used, there is a certain amount of pressure loss in the well. As a result, the production and injection rates at the toe are not the same as that at the heel. From this behavior, the genetic algorithm tries to locate the wells in locations that reduce the problem of early breakthrough. Those locations can increase oil recovery in each scenario.

In most cases, the oil recovery at high injection rate is higher than the oil recovery at low injection rate because in the case of low injection rate water tends to move downward, resulting in segregation. In some case, the highest water injection rate doesn't provide the highest oil recovery because injecting water with high rate is the cause of a large pressure drop along the horizontal wellbore. The water injection rate at the heel of the injector is much higher than that at the toe. As a result, the injected water prefers to move from the heel of injectors to the producer, causing low efficiency of waterflooding process.

The well placement results for different combinations of vertical and horizontal injectors and producers in 30-ft thick reservoir are shown in **Tables 5.17, 5.18** and **5.19**. From well location optimization of all scenarios, there are two scenarios that provide high oil recovery factor in the range of 36.86% to 38.29%. These two scenarios shown in **Table 5.19** are (1) one horizontal producer and two vertical injectors with water injection rate of 10,000 STB/D, and (2) one horizontal producer and two horizontal injectors with water injection rate of 10,000 STB/D. The first scenario seems to be the most attractive since it produces less water than the second scenario although its oil recovery is smaller than that of the second scenario. Moreover, drilling cost of the first scenario is also less than that of the second scenario. However, both scenarios need to be economically evaluated in order to determine the justification for drilling a single horizontal well and two vertical wells.

Table 5.17: Well placement results for 30-ft thick reservoir at low injection rate.

Type	Production rate/well	Break through				Abandonment					
		Injection rate/well	Time	Cumulative oil	Recovery	Time	Recovery	Cumulative oil	Cumulative produced Gas	Cumulative produced water	Cumulative water injection
Scenarios	STB/D	STB/D	Days	STB	%	Days	%	STB	MSCF	MSTB	MSTB
1HP-2VI	1380	1000	3182	4390872	18.35	10299	33.62	8045912	16324.86	6735.2	20749.9
1HP-2HI	2760	2000	1355	3739519	15.63	5272	34.12	8165476	16151.66	7968.7	21086.5
1VP-2VI	1380	1000	3175	4381147	18.31	9082	31.43	7521964	15449.38	6576.7	18164.9
1VP-2HI	2760	2000	1110	3064467	12.8	6755	33.33	7976856	14289.56	13768	27020.5
2HP-1VI	345	1000	3773	2603140	10.88	14669	35.01	8378012	16148.23	6270.6	14668.8
2HP-1HI	690	2000	2740	3780510	15.8	10592	35.77	8561612	16471.14	7273.8	21184
2VP-1VI	345	1000	3652	2519880	10.53	12784	30.01	7183082	15872.04	5398.2	12784
2VP-1HI	690	2000	3036	4190284	17.51	8766	31.81	7613078	16067.92	6295.4	17532

Table 5.18: Well placement results for 30-ft thick reservoir at medium injection rate.

Type	Production rate/well	Break through				Abandonment					
		Injection rate/well	Time	Cumulative oil	Recovery	Time	Recovery	Cumulative oil	Cumulative produced Gas	Cumulative produced water	Cumulative water injection
Scenarios	STB/D	STB/D	Days	STB	%	Days	%	STB	MSCF	MSTB	MSTB
1HP-2VI	3450	2500	1382	4768526	19.92	4894	33.04	7908418	14876.8	11107	23871
1HP-2HI	6900	5000	539	3718021	15.54	4642	36.78	8802585	14686.9	31825	46422
1VP-2VI	3450	2500	1510	5124744	21.41	10359	35.43	8478641	10309.8	37382	50210
1VP-2HI	6900	5000	466	3195935	13.35	14245	30.17	7220928	6339.8	128535	138600
2HP-1VI	860	2500	1272	2187331	9.14	7670	35.54	8504993	16296	7408	19175
2HP-1HI	1720	5000	970	3337688	13.95	4331	36.3	8686747	16269.2	8084	21657
2VP-1VI	860	2500	1609	2767688	11.56	6759	30.48	7294090	15418	5717	15929
2VP-1HI	1720	5000	1044	3590170	15	7305	34.9	8353212	12650.3	22948	36525

Table 5.19: Well placement results for 30-ft thick reservoir at high injection rate.

Type	Production rate/well	Break through				Abandonment					
		Injection rate/well	Time	Cumulative oil	Recovery factor	Time	Recovery	Cumulative oil	Cumulative produced gas	Cumulative produced water	Cumulative water injection
Scenarios	STB/D	STB/D	Days	STB	%	Days	%	STB	MSCF	MSTB	MSTB
1HP-2VI	**6900**	**5000**	**899**	**5555945**	**23.21**	**7524**	**36.86**	**8821193**	**12838**	**57918**	**71856**
1HP-2HI	**13800**	**10000**	**233**	**3210657**	**13.42**	**5113**	**38.29**	**9156592**	**12519**	**76762**	**81729**
1VP-2VI	6900	5000	1433	5410582	22.61	10957	31.44	7523564	7889	50272	61310
1VP-2HI	13800	10000	286	2774297	11.59	3719	21.14	5058521	3669	26114	33810
2HP-1VI	1720	5000	730	2511200	10.49	4298	35.84	8577864	16201	8128	20659
2HP-1HI	3450	10000	513	3541520	14.8	2569	36.16	8653223	15453	12755	25689
2VP-1VI	1720	5000	1142	3926574	16.41	4347	28.44	6806692	13222	5797	17554
2VP-1HI	3450	10000	665	4438316	18.55	5844	32.7	7826972	9260	44464	56067

5.2 Well placement in 100-ft thick reservoir

For 100-ft thick reservoir, the scenarios used for investigation are the same as those for 30-ft thick reservoir except for the case of low injection rate. This is because the well has larger injectivity due to larger reservoir thickness. The best scenario for this thickness may be different from that obtained for 30-ft thick reservoir because the productivity index of vertical well is higher. The well location optimization and oil recovery results of each scenario are explained in the following sections.

5.2.1Well placement of one producer with two injectors

5.2.1.1 One horizontal producer with two vertical injectors

A genetic algorithm coupled with reservoir simulator is used for well placement of one horizontal producer with two vertical injectors. In **Figure 5.29**, for the 1st generation the genetic algorithm tries to search region with high oil recovery in order to narrow down the search area for the next generation. Oil recovery factor reaches 35.21% in the 2nd generation and climbs to 37.63% in the 3rd generation. After the 5th generation, oil recovery factor gradually increases and the first local maximum occurs in the 9th generation to the 13th generation. The local maximum is improved by the process of mutation and crossover in the 14th generation and oil recovery factor reaches 39.77% in the 15th generation. The genetic algorithm provides high oil recovery factor since it reaches the 29th generation. The converged generation of the well optimization is found in the 29th generation because oil recovery doesn't improve after the 29th generation even though genetic algorithm reaches terminated generation (the 40th generation).

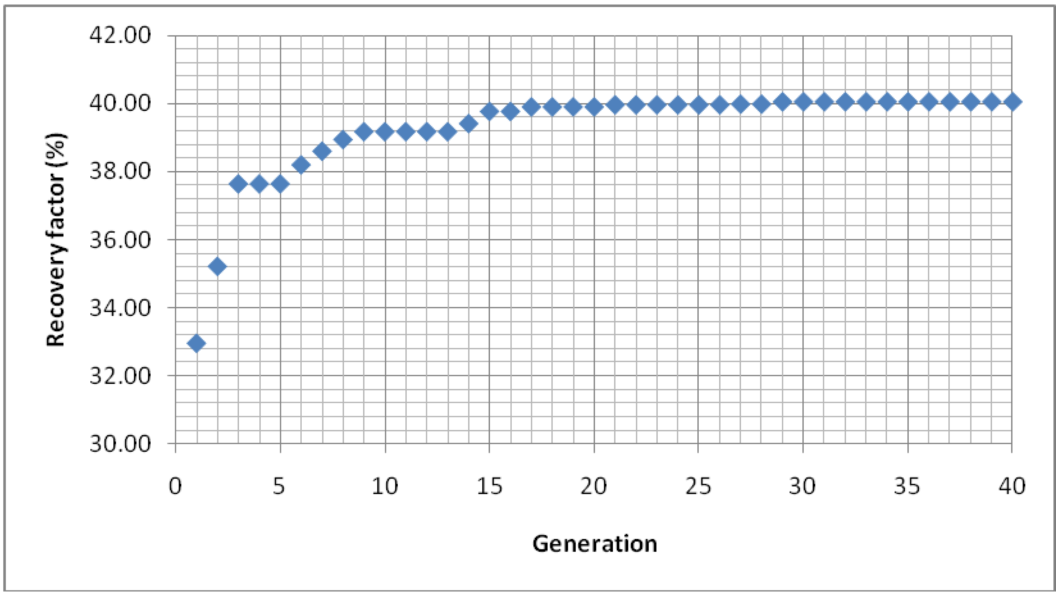

Figure 5.29: Recovery factor as a function of generation in the case of one horizontal producer with two vertical injectors in 100-ft thick reservoir.

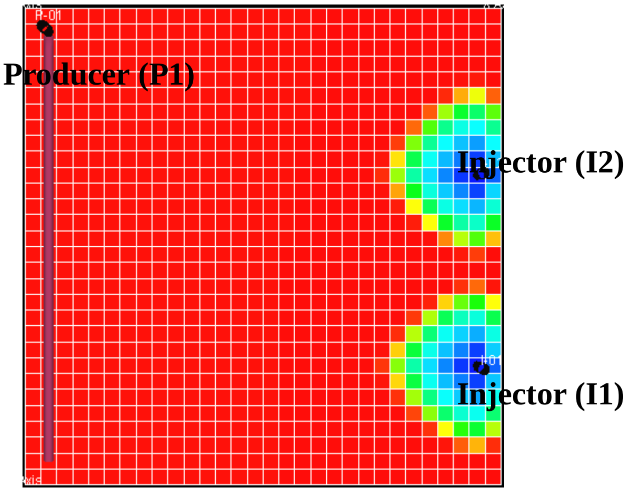

Figure 5.30: Well placement for the case of one horizontal producer and two vertical injectors at injection rate of 5,000 STB/D in 100-ft thick reservoir.

The well placement of the two vertical injectors and the horizontal producer are shown in **Figure 5.30**. These locations are at the (i,j) blocks of (29,22), (29,12), and ((2,29),(2,2)), respectively. The optimum horizontal producer length from toe to heel is 6,076 ft. In this scenario, the injection wells I1 and I2 are not located at the upper and lower right corner due to frictional pressure drop in the horizontal well. The pressure of the horizontal production well slightly decreases from toe to heel as oil flow from toe to heel. Therefore, pressure at the heel is lower than that at the toe. The injection water is easy to break through at the heel. To solve the early breakthrough at the heel, the genetic algorithm shifts the location of injection well I2 to the (i,j) block of (29,12) and the location of injection well I1 to the (i,j) block of (29,22). The results of well locations for each generation are represented in **Table 5.20.**

Table 5.20: Well locations and recovery factor for each generation in the case of one horizontal producer and two vertical injectors in 100-ft thick reservoir.

Generations	Well I1	Well I2	Well P1		RF
			Toe	Heel	%
1	14,11	12,8	2,27	2,29	32.94
2	19,11	4,8	11,24	11,14	35.21
3	19,13	2,6	13,22	13,7	37.63
4	19,13	2,6	13,22	13,7	37.63
5	19,13	2,6	13,22	13,7	37.63
6	25,13	5,6	12,28	12,7	38.19
7	25,4	5,14	9,28	9,12	38.60
8	25,4	5,14	9,28	9,12	38.94
9	27,4	3,14	10,28	10,12	39.17
10	27,4	23,14	10,28	10,12	39.17
11	27,4	23,14	10,28	10,12	39.17
12	27,4	23,14	10,28	10,12	39.17
13	27,4	23,14	20,28	10,12	39.17
14	29,28	29,12	5,28	5,12	39.41
15	29,29	25,12	5,28	5,8	39.77
16	29,29	25,12	5,28	5,8	39.77
17	29,28	27,12	2,29	2,7	39.90
18	29,28	27,12	2,29	2,7	39.90
19	29,28	27,12	2,29	2,7	39.90
20	29,29	27,12	2,29	2,7	39.90
21	29,22	29,16	2,29	2,7	39.96
22	29,22	29,16	2,29	2,7	39.96
23	29,22	29,16	2,29	2,7	39.96
24	29,22	29,16	2,29	2,7	39.96
25	29,22	29,16	2,29	2,7	39.96
26	29,22	29,16	2,29	2,7	39.96
27	29,24	29,16	2,29	2,4	39.98
28	29,24	29,16	2,29	2,4	39.98
29-40	29,22	29,12	2,29	2,2	40.00

In this scenario, the highest oil recovery factor of 40.00 % shown in **Table 5.21** and **Figure 5.31** is obtained with water injection rate of 5,000 STB/D. At this injection rate, the cumulative oil recovery of 31,903 MSTB is produced at the end of 17,167 days of production. The breakthrough time for this scenario is about 2006 days. The cumulative water production is 121,076 MSTB while the amount of water injection is 171,670 MSTB. The cumulative produced water of all injection rates is shown in **Figure 5.32**. Although the amount of water production at injection rate of 5,000 STB/D is about 3.6 times more than that at injection rate of 2,500 STB/D, but the oil recovery at injection rate of 5,000 STB/D is 2% more than that of injection rate at 2500 STB/D. Therefore, producing with the injection rate of 5,000 STB/D is the best alternative for this scenario. In this study, the oil recovery at high injection rate is higher than the oil recovery at low injection rate because of the same effect that occurs in this scenario in 30-ft thick reservoir.

Table 5.21: Production data for the case of one horizontal producer and two vertical injectors at injection rate of 2,500 STB/D and 5,000 STB/D in 100-ft thick reservoir.

Production rate/well	Injection rate/well	Break through			Abandonment					
		Time	Cumulative oil	Recovery	Time	Recovery	Cumulative oil	Cumulative produced gas	Cumulative produced water	Cumulative water injection
STB/D	STB/D	Days	STB	%	Days	%	STB	MSCF	MSTB	MSTB
3450	2500	4018	13862	17.38	15706	37.84	30188	53760	33556	78530
6900	**5000**	**2006**	**13821**	**17.32**	**17167**	**39.99**	**31903**	**51852**	**121076**	**171670**

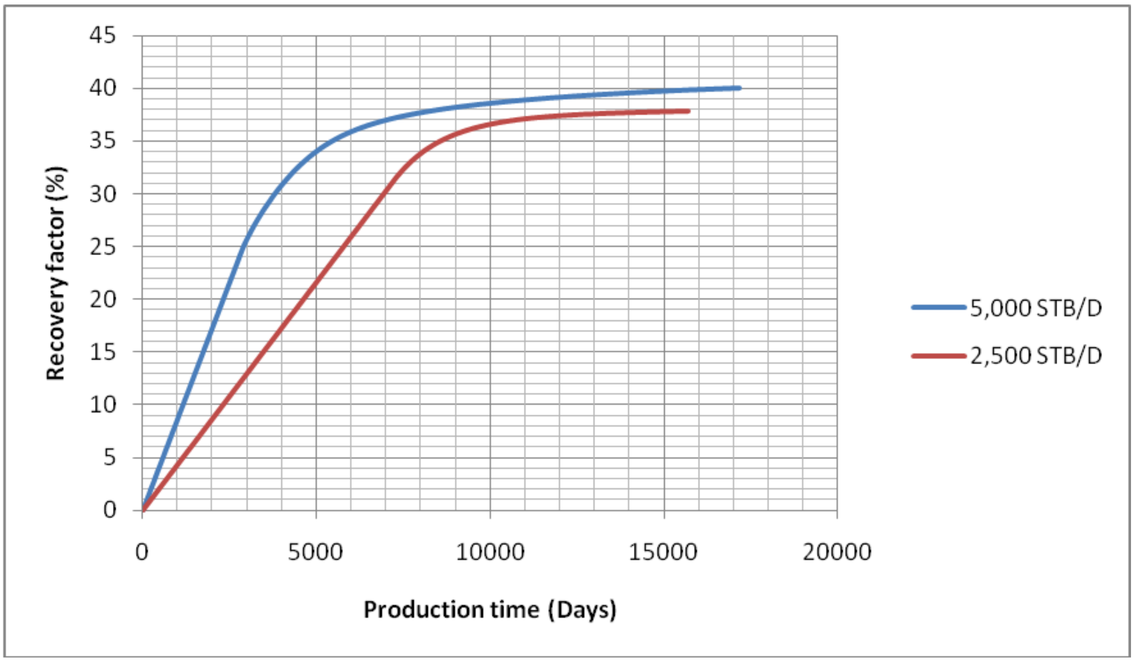

Figure 5.31: Recovery factor for the case of one horizontal producer and two vertical injectors at injection rate of 2,500 STB/D and 5,000 STB/D in 100-ft thick reservoir.

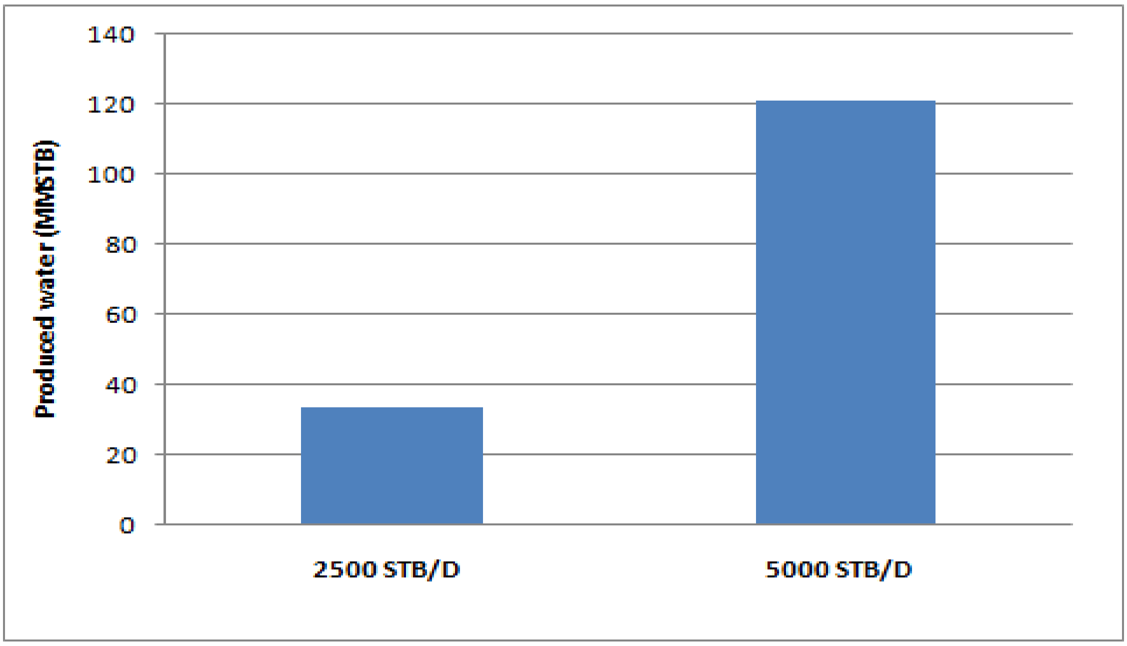

Figure 5.32: Cumulative produced water for the case of one horizontal producer and two vertical injectors at injection rate of 2,500 STB/D and 5,000 STB/D in 100-ft thick reservoir.

5.2.1.2 One horizontal producer with two horizontal injectors

Well placement for one horizontal producer with two horizontal injectors is performed by using genetic algorithm coupled with reservoir simulator. In the 1st generation in **Figure 5.33**, the genetic algorithm (GA) tries to search regions with high oil recovery in order to narrow down the search area for the next generation. Oil recovery factor climbs to 42.78% in the 2nd generation. A high oil recovery factor is obtained at the 6th generation. After the 6th generation, there are 5 local maxima occurs from well optimization of one horizontal producer with two horizontal injectors. The last local maximum is improved by the process of mutation and crossover in the 34th generation. The genetic algorithm is continued until it reaches the terminated generation (the 40th generation) but the solution is not improved after the 34th generation. Thus, the 34th generation is the converged generation. This scenario needs more generations to reach the converged solution because the binary string of this scenario is longer than that of one horizontal producer and two vertical injectors in previous scenario.

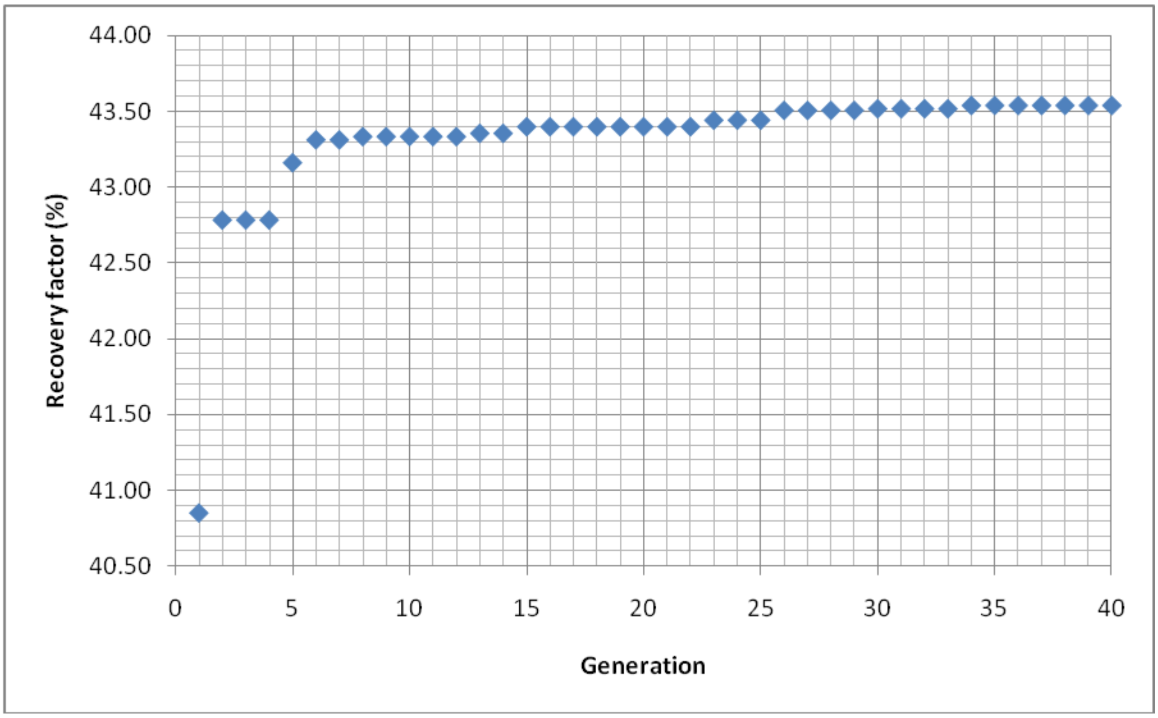

Figure 5.33: Recovery factor as a function of generation in the case of one horizontal producer with two horizontal injectors in 100-ft thick reservoir.

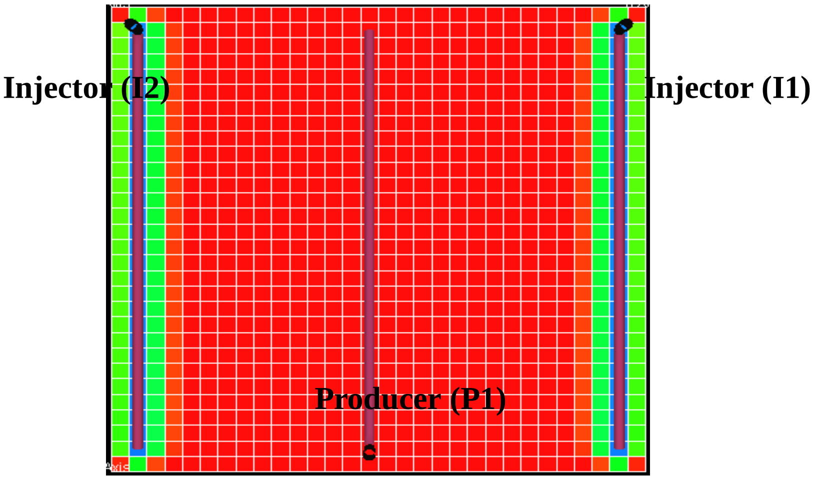

Figure 5.34: Well placement for the case of one horizontal producer and two horizontal injectors at injection rate of 10,000STB/D in 100-ft thick reservoir.

The best well placement of two horizontal injectors and one horizontal producer are obtained in the 34th generation of optimization. These locations are at the (i,j) blocks of ((2,29), (2,2)), ((29,29), (29,2)) and ((15,2),(15,29)), respectively as shown in **Figure 5.34**.In this scenario, genetic algorithm locates the producer between injector I1 and I2 because these injector locations help water injection break through at both sides of the horizontal producer at the same time. Therefore, the areal sweep efficiency and recovery factor at breakthrough are high when genetic algorithm provides locations of wells as illustrated in **Figure 5.34**. The result of well locations and oil recovery factor for each generation is shown in **Table 5.22**.

Table 5.22: Well locations and recovery factor for each generation in the case of one horizontal producer and two horizontal injectors in 100-ft thick reservoir.

	Well I1		Well I2		Well P1		RF
Generations	Toe	Heel	Toe	Heel	Toe	Heel	%
1	24,18	24,29	5,22	5,2	3,17	3,30	40.85
2	27,18	27,4	2,12	2,2	13,17	13,29	42.78
3	27,18	27,4	2,12	2,2	15,17	15,29	42.78
4	27,18	27,4	2,12	2,2	15,17	15,29	42.78
5	29,15	29,4	2,12	2,2	15,4	15,29	43.16
6	29,15	29,4	2,26	2,2	15,1	15,29	43.31
7	29,15	29,4	2,26	2,2	15,1	15,29	43.31
8	30,27	30,1	2,30	2,2	15,22	15,2	43.33
9	30,27	30,1	2,30	2,2	15,22	15,2	43.33
10	30,27	30,1	2,30	2,2	15,22	15,2	43.33
11	30,27	30,1	2,30	2,2	15,22	15,2	43.33
12	30,27	30,1	2,30	2,2	15,22	15,2	43.33
13	29,27	29,1	2,30	2,2	15,25	15,1	43.36
14	29,27	29,1	2,30	2,2	15,25	15,1	43.36
15	29,30	29,2	1,22	1,2	15,28	15,4	43.40
16	29,30	29,2	1,22	1,2	15,28	15,4	43.40
17	29,30	29,2	1,22	1,2	15,28	15,4	43.40
18	29,30	29,2	1,22	1,2	15,28	15,4	43.40
19	29,30	29,2	1,22	1,2	15,28	15,4	43.40
20	29,30	29,2	1,22	1,2	15,28	15,4	43.40
21	29,30	29,2	1,22	1,2	15,28	15,4	43.40
22	29,30	29,2	1,22	1,2	15,28	15,4	43.40
23	29,28	29,2	2,27	2,2	13,2	13,27	43.44
24	29,28	29,2	2,27	2,2	13,2	13,27	43.44
25	29,28	29,2	2,27	2,2	13,2	13,27	43.44
26	29,28	29,2	2,27	2,2	13,2	13,29	43.51
27	29,28	29,2	2,27	2,2	13,2	13,29	43.51
28	29,28	29,2	2,27	2,2	13,2	13,29	43.51
29	29,28	29,2	2,27	2,2	13,2	13,29	43.51
30	29,29	29,2	2,29	2,2	13,2	13,29	43.52
31	29,29	29,2	2,29	2,2	13,2	13,29	43.52
32	29,29	29,2	2,29	2,2	13,2	13,29	43.52
33	29,29	29,2	2,29	2,2	13,2	13,29	43.52
34-40	29,29	29,2	2,29	2,2	15,2	15,29	43.54

In **Table 5.23**, the maximum oil recovery at this scenario is approximately 43.54%. The optimum horizontal producer length is same as this scenario at 30 ft-reservoir thickness which is 6,070 ft. Injection rate of 10,000 STB/D provides the highest oil recovery as shown in **Figure 5.35**. The oil recovery factor of injection rate at 10,000 STB/D is about 4 % more than that of injection rate at 5000 STB/D. Therefore, the use of two horizontal injectors with single horizontal producer at water injection rate of 10,000 STB/D is suitable for this scenario. In this scenario, the cumulative oil recovery of 34,732 MSTB is produced at the end of 13,149 days of production. The breakthrough time for this case is about 798 days. The cumulative water production is 209,995 MSTB while the amount of water injection is 262,960 MSTB.

In this scenario, the result is not the same as the case of 30-ft thick reservoir because of thick reservoir. For case of high injection rate, the water injection rate can reduce the problem of segregation because water injection rate in the horizontal direction is much higher than that in the vertical direction. For case of low injection rate, the oil recovery is low because in the case of low injection rate water tends to move downward, resulting in segregation. As a result, water prefers moving at the bottom part of reservoir. The injected water bypasses at the bottom of reservoir to producer, causing low efficiency of waterflooding process.

Table 5.23: Production data for the case of one horizontal producer and two horizontal injectors at injection rate of 5,000 STB/D and 10,000 STB/D in 100-ft thick reservoir.

Production rate/well	Injection rate/well	Break through			Abandonment					
		Time	Cumulative oil	Recovery	Time	Recovery	Cumulative oil	Cumulative produced gas	Cumulative produced water	Cumulative water injection
STB/D	STB/D	Days	STB	%	Days	%	STB	MSCF	MSTB	MSTB
6900	5000	1795	12383	15.52	11596	39.45	31471	53266	66895	115958
13800	**10000**	**798**	**11017**	**13.81**	**13149**	**43.54**	**34732**	**50711**	**209955**	**262980**

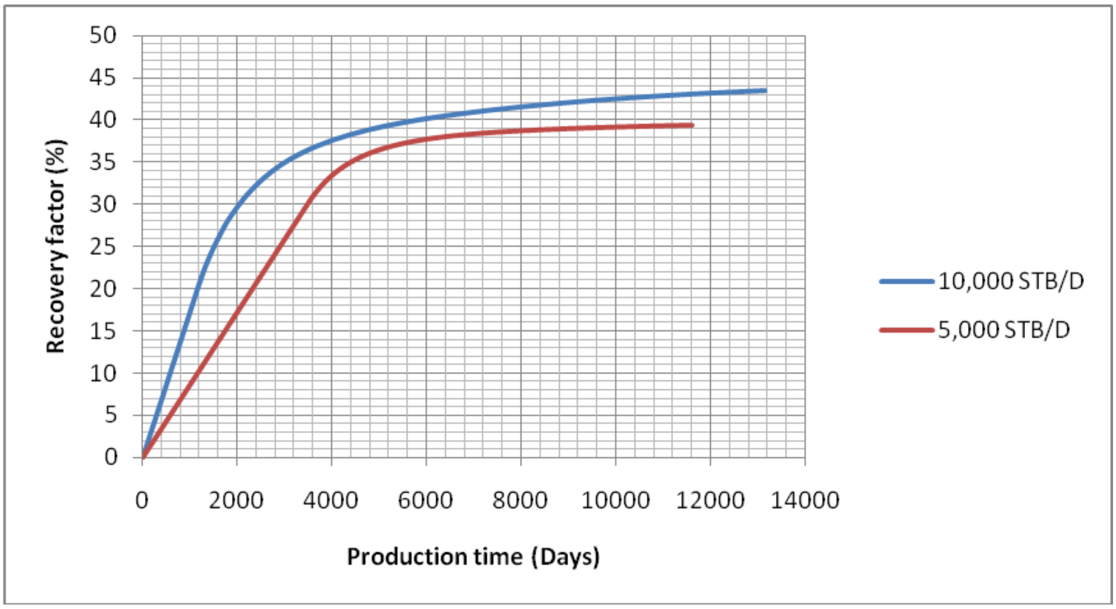

Figure 5.35: Recovery factor for the case of one horizontal producer and two horizontal injectors at injection rate of 5,000 STB/D and 10,000 STB/D in 100-ft thick reservoir.

5.2.1.3 One vertical producer with two vertical injectors

For well placement for one vertical producer with two vertical injectors, the results of each generation are shown in **Figure 5.36**. The genetic algorithm (GA) tries to search regions with high oil recovery in the 1st generation. Oil recovery factor of 35.60% is obtained in the 1st generation. In the 2nd generation, oil recovery factor climbs to 38.41%. The local maximum occurs in the 3rd to the 8th generation and in the 9th to the 11th generation. After the 11th generation, the solution is improved by the process of mutation and crossover and oil recovery climbs to 42.71% in the 15th generation. Even though the genetic algorithm is continued until it reaches the terminated generation (40th generation) but the solution doesn't improve after the 22nd generation. Therefore, optimization of well location for one vertical producer with two vertical injectors is found in the 22nd generation. The number of generation to reach the convergence in this scenario is less than that in the case of one horizontal producer with two vertical injectors because the genetic algorithm finds high oil recovery in the 4th generation.

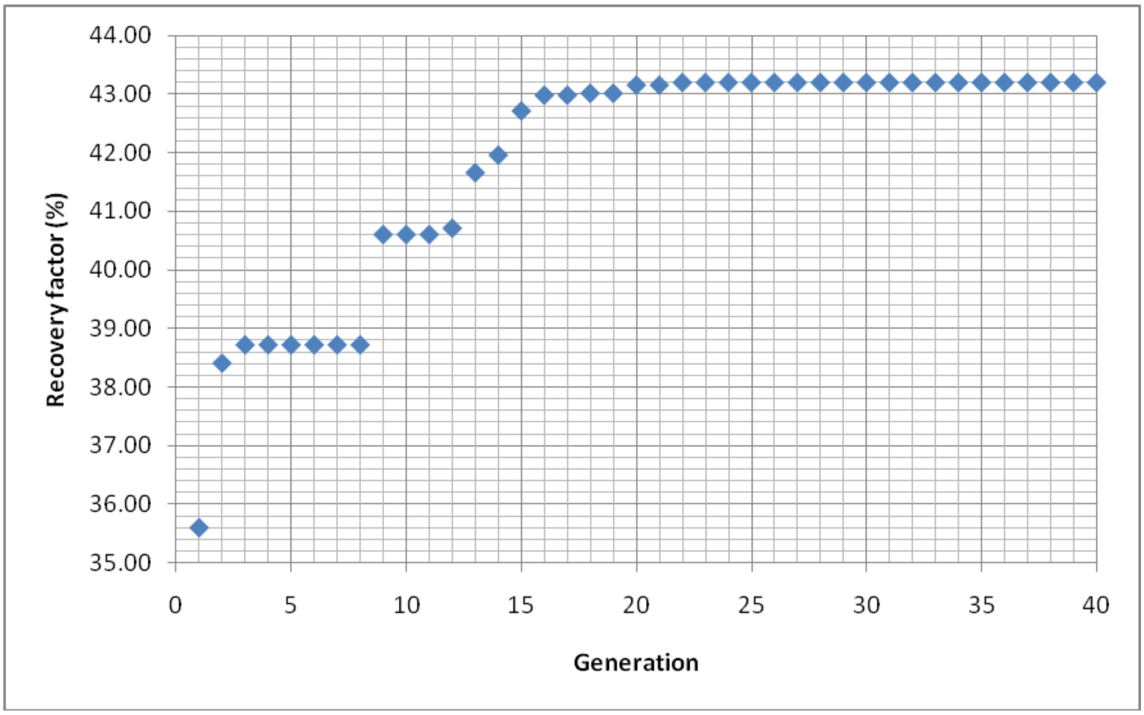

Figure 5.36: Recovery factor as a function of generation in the case of one vertical producer and two vertical injectors in 100-ft thick reservoir.

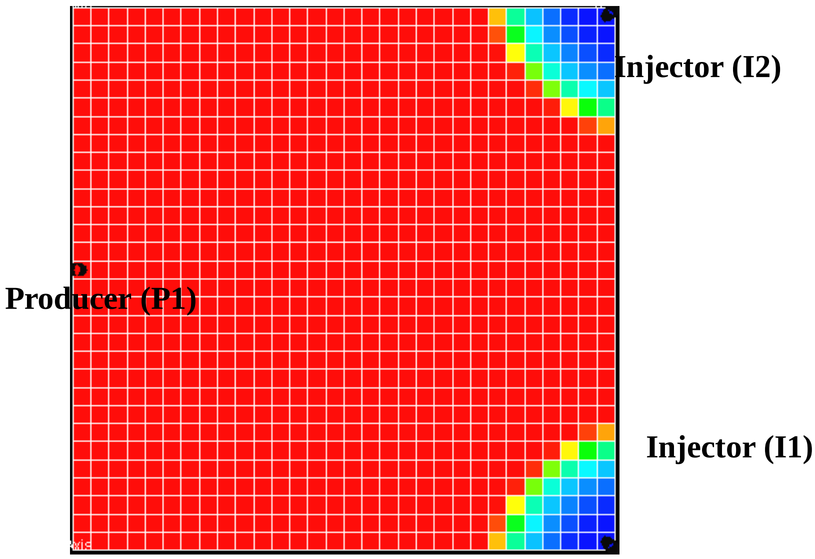

Figure 5.37: Well placement for the case of one vertical producer and two vertical injectors at injection rate of 5,000 STB/D in 100-ft thick reservoir.

The best well placement of a vertical producer and two vertical injectors obtained from the 16th generation of optimization are at the (i,j) blocks of (1,15), (30,1) and (30,30), respectively as shown in **Figure 5.37**. In this scenario, there are no horizontal well. The pressure drop doesn't affect on location of injection well. Therefore, the injection wells I1 and I2 is located at the upper and lower right corner as uniform well pattern. The result of well locations and oil recovery factor for each generation is shown in **Table 5.24**.

Table 5.24: Well locations and recovery factor for each generation in the case of one vertical producer and two vertical injectors in 100-ft thick reservoir.

Generations	Well I1	Well I2	Well P1	RF %
1	18,17	14,5	13,19	35.60
2	22,12	28,5	13,30	38.41
3	26,23	29,5	6,19	38.72
4	26,23	29,5	6,19	38.72
5	26,23	29,5	6,19	38.72
6	26,23	29,5	6,19	38.72
7	26,23	29,5	6,19	38.72
8	26,23	29,5	6,19	38.72
9	27,30	29,8	2,19	40.60
10	27,30	29,8	2,19	40.60
11	27,30	29,8	2,19	40.60
12	27,30	28,5	2,19	40.71
13	27,30	28,5	2,17	41.65
14	26,30	30,5	2,15	41.95
15	26,30	29,3	2,17	42.71
16	26,30	29,3	1,17	42.98
17	26,30	29,3	1,17	42.98
18	27,30	29,3	1,14	43.01
19	27,30	29,3	1,14	43.01
20	30,29	30,3	1,15	43.15
21	30,29	30,3	1,15	43.15
22-40	30,30	30,1	1,15	43.19

Using single vertical producer and two vertical injectors with water injection rate of 5,000 STB/D is the best injection rate for this scenario. The highest oil recovery represented in **Table 5.25** and **Figure 5.38** closes to 43.19%. The oil recovery at injection rate of 5,000 STB/D is about 6 % more than that of other injection rates. Therefore, the use of single vertical producer with two vertical injectors at water injection rate of 5,000 STB/D is the most suitable for this scenario. The cumulative oil recovery of 34,455 MSTB is produced at the end of 21,184 days of production. The breakthrough time for this case is about 2,090 days. The cumulative water production is 160,351 MSTB while the amount of water injection is 211,552 MSTB.

For this scenario, the result at this thickness is not the same as that at 30-ft thick reservoir because of a large thick reservoir. The oil recovery at high injection rate is higher than the oil recovery at low injection rate because in the case of low injection rate water tends to move downward, resulting in segregation. As a result, in case of low injection rate water prefers moving at the bottom part of the reservoir, causing low efficiency of waterflooding process. For case of high injection rate, the water injection rate can reduce the problem of segregation because water flow rate in the horizontal direction is much higher than that in the vertical direction.

Table 5.25: Production data for the case of one vertical producer and two vertical injectors at injection rate of 2,500 STB/D and 5,000 STB/D in 100-ft thick reservoir.

		Break through			Abandonment					
Production rate/well	Injection rate/well	Time	Cumulative oil	Recovery	Time	Recovery	Cumulative oil	Cumulative produced gas	Cumulative produced water	Cumulative water injection
STB/D	STB/D	Days	STB	%	Days	%	STB	MSCF	MSTB	MSTB
3450	2500	4018	13862	17.38	18993	37.37	29814	50806	48874	94965
6900	**5000**	**2090**	**14423**	**18.08**	**21184**	**43.19**	**34455**	**45573**	**160351**	**211552**

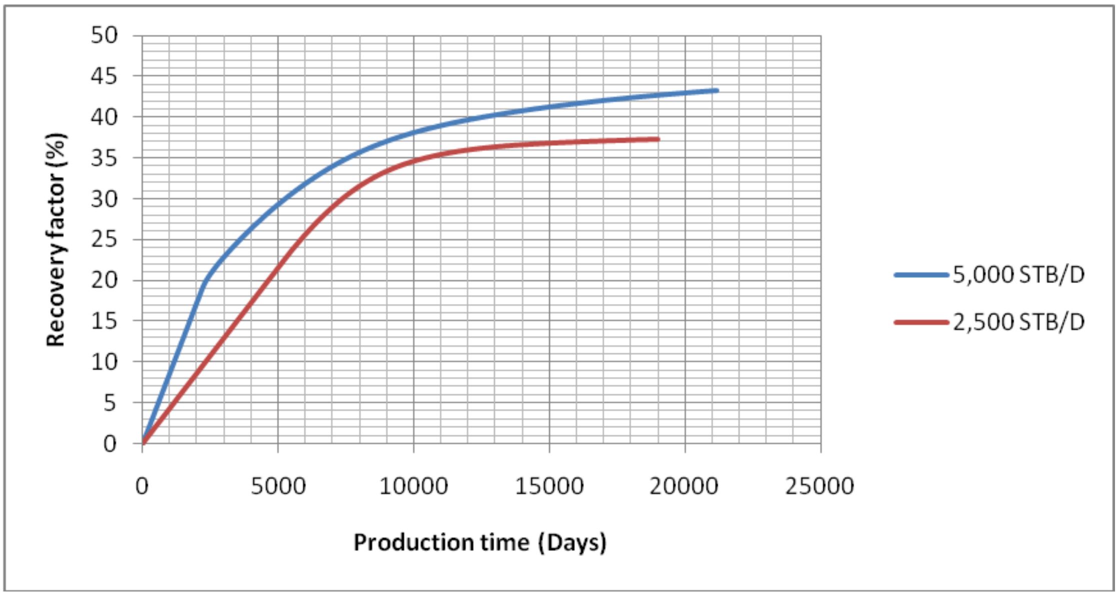

Figure 5.38: Recovery factor for the case of one vertical producer and two vertical injectors at injection rate of 2,500 STB/D and 5,000 STB/D in 100-ft thick reservoir.

5.2.1.4 One vertical producer with two horizontal injectors

Well placement for one vertical producer with two horizontal producers is performed by using genetic algorithm coupled with reservoir simulation**.** In **Figure 5.39**, the 1st generation of the genetic algorithm (GA) tries to search regions with high oil recovery. From the 1st generation to the 2nd generation, oil recovery factor increases from 42.32% to 43.03%. The first local maximum occurs in the 2nd to the 6th generation. After the 6th generation, oil recovery factor increases to 44.43% in the 8th generation. After the 8th generation, the local maxima are also occurs several times. The last local maximum is improved by the process of mutation and crossover in the 31st generation. From the 31st to the 40th generation, the mutation and crossover cannot improve the solution. Therefore, well location optimization for this scenario is found in the 31st generation.

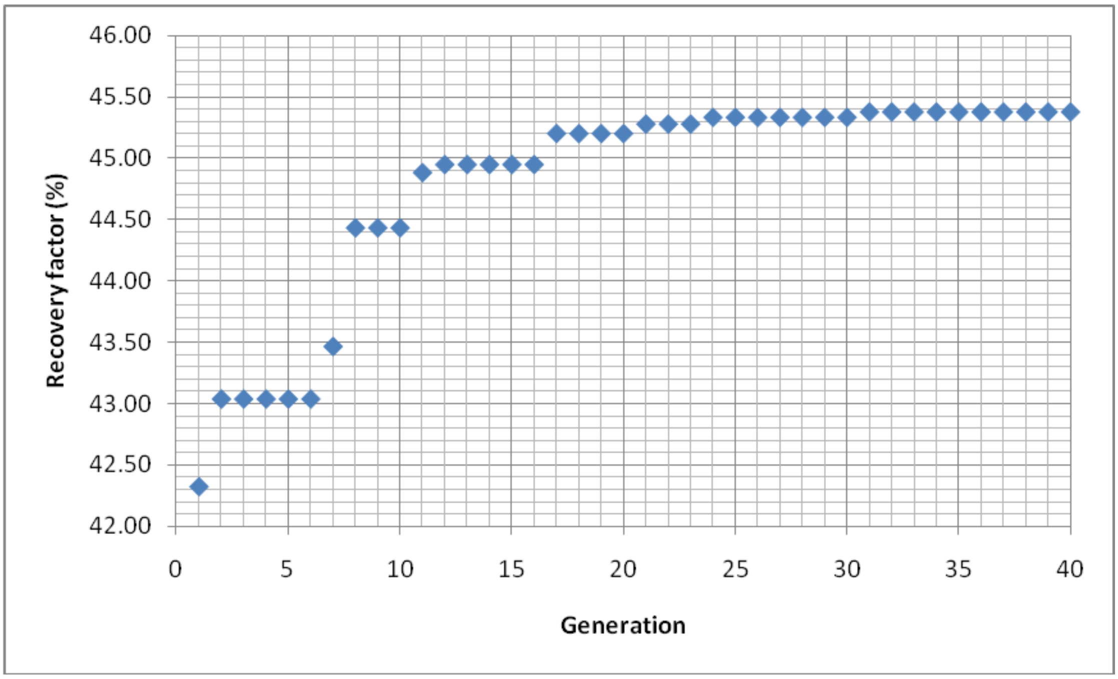

Figure 5.39: Recovery factor as a function of generation in the case of one vertical producer with two horizontal injectors in 100-ft thick reservoir.

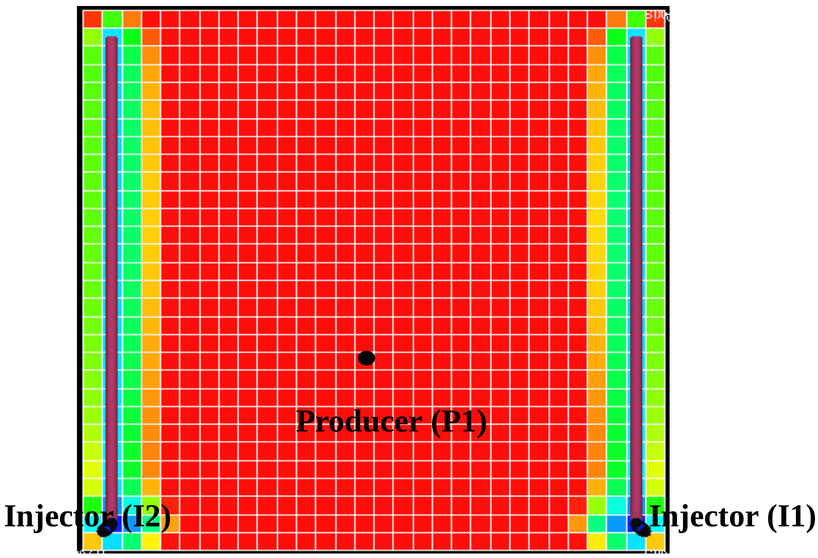

Figure 5.40: Well location for the case of one vertical producer and two horizontal injectors at injection rate of 10,000 STB/D in 100-ft thick reservoir.

The well location of the vertical producer and the two horizontal injectors for the best injection rate are shown in **Figure 5.40**. These locations are at the (i,j) blocks of (15,19), ((29,2),(29,29)) and ((2,2),(2,29)), respectively. In this scenario, the production well is located as illustrated in **Figure 5.40** because pressure in horizontal well affects the flow of water from horizontal injector to vertical producer. The pressure drop of horizontal injector occurs by wellbore friction assigned in this horizontal model. The pressure of horizontal injection well slightly increases from heel to toe during water injection. Therefore, pressure of horizontal injector at the heel is higher than that at the toe. The injection water is easy to flow from the heel to vertical producer. Therefore, the location of producer moves to the (i,j) block of (15,19) for reducing the problem of the early breakthrough. **Table 5.26** shows the result of well locations and oil recovery factor for each generation of this scenario.

Table 5.26: Well locations and recovery factor for each generation in the case of one vertical producer and two horizontal injectors in 100-ft thick reservoir.

	Well I1		Well I2			RF
Generations	Toe	Heel	Toe	Heel	Well P1	%
1	3,1	3,20	15,21	15,22	23,19	42.32
2	16,1	16,20	5,7	5,22	21,19	43.03
3	16,1	16,20	5,7	5,22	21,19	43.03
4	16,1	16,20	5,7	5,22	21,19	43.03
5	16,1	16,20	5,7	5,22	21,19	43.03
6	16,1	16,20	5,7	5,22	21,19	43.03
7	22,1	22,20	3,2	3,22	13,19	43.46
8	22,1	22,20	3,4	3,26	13,19	44.43
9	22,1	22,20	3,4	3,26	13,19	44.43
10	22,1	22,20	3,4	3,26	13,19	44.43
11	25,1	25,28	3,3	3,26	16,19	44.88
12	25,2	25,28	2,3	2,28	16,19	44.95
13	25,2	25,28	2,3	2,26	16,19	44.95
14	25,2	25,28	2,3	2,28	16,19	44.95
15	25,2	25,28	2,3	2,28	16,19	44.95
16	25,2	25,28	2,3	2,28	16,19	44.95
17	28,2	28,29	2,1	2,28	16,17	45.20
18	28,2	28,29	2,1	2,28	16,17	45.20
19	28,2	28,29	2,1	2,28	16,17	45.20
20	28,2	28,29	2,1	2,28	16,17	45.20
21	28,1	28,29	2,3	2,30	15,22	45.28
22	28,1	28,29	2,3	2,30	15,22	45.28
23	28,1	28,29	2,3	2,30	15,22	45.28
24	28,2	28,29	2,2	2,30	15,19	45.34
25	28,2	28,29	2,2	2,30	15,19	45.34
26	28,2	28,29	2,2	2,30	15,19	45.34
27	28,2	28,29	2,2	2,30	15,19	45.34
28	28,2	28,29	2,2	2,30	15,19	45.34
29	28,2	28,29	2,2	2,30	15,19	45.34
30	28,2	28,29	2,2	2,30	15,19	45.34
31	29,2	29,29	2,2	2,29	15,19	45.38

The results of this scenario are shown in **Table 5.27** and **Figure 5.41**. The maximum oil recovery factor of 45.38 % is obtained in this scenario with water injection rate of 10,000 STB/D. The cumulative oil recovery of 36,207 MSTB is produced at the end of 19,723 days of production. The breakthrough time for this scenario is about 730 days. The cumulative water production is 340,510 MSTB while the amount of water injection is 394,460 MSTB.

For this scenario, the result at this thickness is not the same as that at 30-ft thick reservoir because of thick reservoir. The oil recovery at high injection rate is higher than the oil recovery at low injection rate because in the case of low injection rate water tends to move downward, resulting in segregation. As a result, water prefers moving at the bottom of reservoir, causing low efficiency of waterflooding process. For case of high injection rate, the water injection rate can reduce the problem of segregation because water injection rate in horizontal direction is much higher than that in vertical direction.

Table 5.27: Production data for the case of one vertical producer and two horizontal injectors at injection rate of 5,000 STB/D and 10,000 STB/D in 100-ft thick reservoir.

Production rate/well	Injection rate/well	Break through			Abandonment					
		Time	Cumulative oil	Recovery	Time	Recovery	Cumulative oil	Cumulative produced gas	Cumulative produced water	Cumulative water injection
STB/D	STB/D	Days	STB	%	Days	%	STB	MSCF	MSTB	MSTB
6900	5000	1461	10081	12.64	18628	40.69	32457	49129	135612	186280
13800	**10000**	**730**	**10074**	**12.63**	**19723**	**45.38**	**36207**	**41117**	**340510**	**394460**

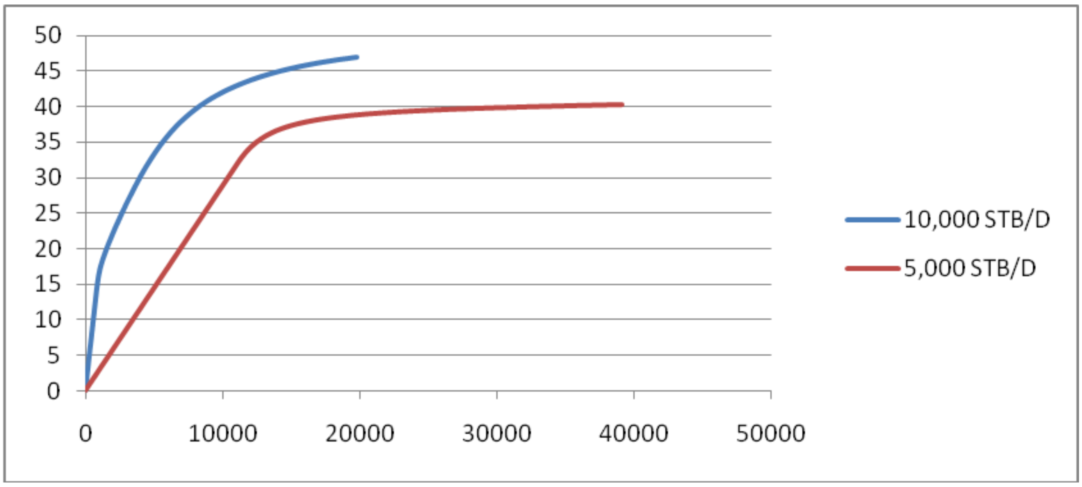

Figure 5.41: Recovery factor for the case of one vertical producer and two horizontal injectors at injection rate of 5,000 STB/D and 10,000 STB/D in 100-ft thick reservoir.

5.2.2 Well placement of two producers with one injector

5.2.2.1 Two horizontal producers with one vertical injector

After running genetic algorithm coupled with reservoir simulator for well optimizations of two horizontal producers with one vertical injector, the well placement is shown in **Figure 5.42**. In the 1st generation, the genetic algorithm tries to search region with high oil recovery and oil recovery factor of 34.49% is obtained in this generation. Oil recovery factor climbs to 37.45% in the 3rd generation. The local maximum occurs in the 3rd generation to the 6th generation. After the 6th generation, oil recovery gradually increases and reaches 39.10% in the 10th generation. The last local maximum is improved by the process of mutation and crossover in the 32nd generation. The 32nd generation provides the highest oil recovery factor. The converged generation of the well optimization is at the 32nd generation because oil recovery doesn't improve after the 32nd generation even though genetic algorithm reaches the terminated generation (the 40th generation).

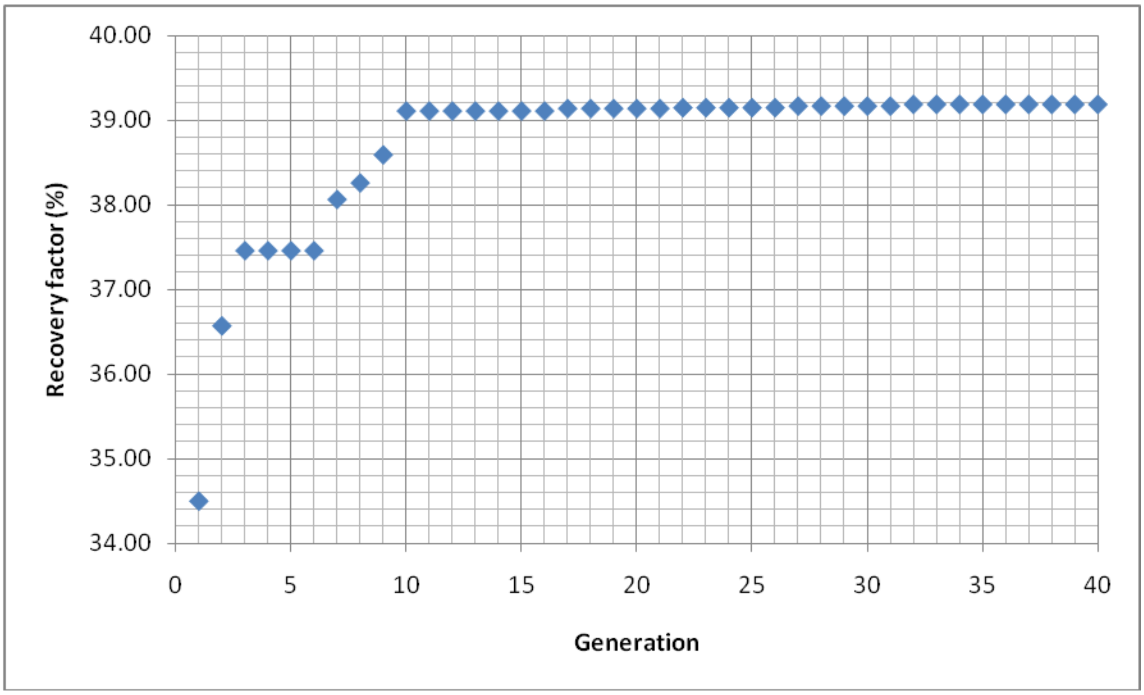

Figure 5.42: Recovery factor as a function of generation in the case of two horizontal producers with one vertical injector in 100-ft thick reservoir.

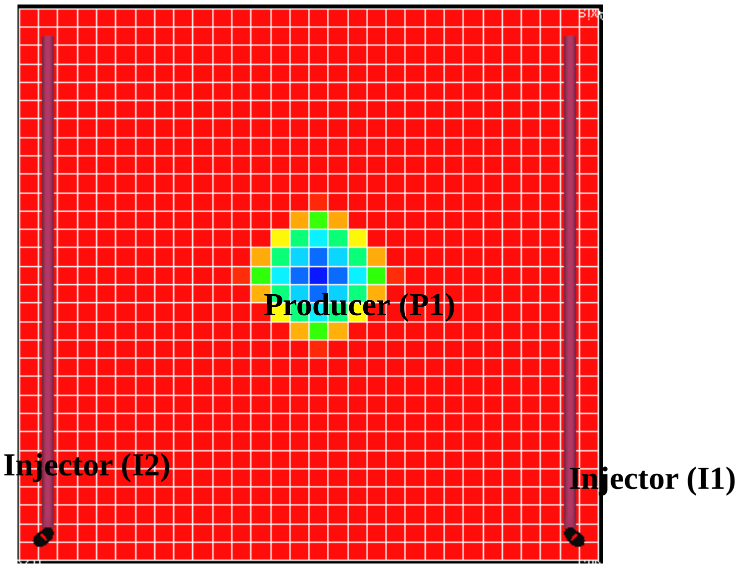

Figure 5.43: Well placement for the case of two horizontal producers and one vertical injector at injection rate of 5,000 STB/D in 100-ft thick reservoir.

The optimum locations of two horizontal producers and a vertical injector obtained from the 32th generation of optimization are at the (i,j) blocks of ((2,2),(2,29)), ((29,2),(29,29)) and (15,18), respectively as shown in **Figure 5.43.** In this scenario, the injection well is located as shown in **Figure 5.43** because pressure drop in horizontal production well affect the flow of water from the vertical injector to the horizontal producers. The pressure drop is occurred by wellbore friction assigned in this model. The pressure of horizontal production well slightly decreases from toe to heel during producing oil. Therefore, pressure of horizontal producer at the heel is lower than that at the toe. The injection water is easy to breakthrough at the heel. Therefore, the location of injector moves to the (i,j) block of (15,18) to reduce the problem of the early breakthrough. The results of well location for each generation are represented in **Table 5.28.**

Table 5.28: Well locations and recovery factor for each generation in the case of two horizontal producers and one vertical injector in 100-ft thick reservoir.

		Well P1		Well P2		RF
Generations	Well I1	Toe	Heel	Toe	Heel	%
1	17,21	27,25	27,1	16,27	16,7	34.49
2	14,21	27,9	27,30	4,17	4,30	36.56
3	13,21	29,9	29,22	6,5	6,24	37.45
4	13,21	29,9	29,22	6,5	6,24	37.45
5	13,21	29,9	29,22	6,5	6,24	37.45
6	13,21	29,9	29,22	6,5	6,24	37.45
7	13,19	29,9	29,24	3,5	3,24	38.06
8	13,19	30,2	30,24	3,2	3,28	38.25
9	13,19	30,2	30,24	3,2	3,28	38.58
10	14,17	30,2	30,26	3,2	3,28	39.10
11	14,17	30,2	30,26	3,2	3,28	39.10
12	14,17	30,2	30,26	3,2	3,28	39.10
13	14,17	30,2	30,26	3,2	3,28	39.10
14	14,17	30,2	30,26	3,2	3,28	39.10
15	14,17	30,2	30,26	3,2	3,28	39.10
16	14,17	30,2	30,26	3,2	3,28	39.10
17	15,15	29,1	29,29	2,2	2,27	39.13
18	15,15	29,1	29,29	2,2	2,27	39.13
19	15,15	29,1	29,29	2,2	2,27	39.13
20	15,15	29,1	29,29	2,2	2,27	39.13
21	15,15	29,1	29,29	2,2	2,27	39.13
22	15,15	30,2	30,28	2,1	2,29	39.14
23	15,15	30,2	30,28	2,1	2,29	39.14
24	15,15	30,2	30,28	2,1	2,29	39.14
25	15,15	30,2	30,28	2,1	2,29	39.14
26	15,15	30,2	30,28	2,1	2,29	39.14
27	15,18	30,2	30,29	2,2	2,29	39.16
28	15,18	30,2	30,29	2,2	2,29	39.16
29	15,18	30,2	30,29	2,2	2,29	39.16
30	15,18	30,2	30,29	2,2	2,29	39.16
31	15,18	30,2	30,29	2,2	2,29	39.16
32-40	15,18	29,2	29,29	2,2	2,29	39.18

The results from reservoir simulation runs for cases of using two horizontal producers with one vertical injector are shown in **Table 5.29** and **Figure 5.44**. The injection rate of 5,000 STB/D is the most attractive since it has the shortest production time although its oil recovery closes to another injection rate. The production time at injection rate of 5,000 STB/D shown in **Figure 5.45** is about 50 % of that at injection rate of 2,500 STB/D. Therefore, the use of two horizontal producers with single vertical injector at water injection rate of 5,000 STB/D is the most suitable for this scenario. The cumulative oil recovery of 31,285 MSTB is produced at the end of 15,523 days of production. The breakthrough time for this case is about 2,557 days. The cumulative water production is 33,558 MSTB while the amount of water injection is 77,615 MSTB. In this scenario, oil recovery is not significantly different but the production time in case of high injection rate is small.

Table 5.29: Production data for the case of two horizontal producers and one vertical injector at injection rate of 2,500 STB/D and 5,000 STB/D in 100-ft thick reservoir.

Production rate/well	Injection Rate/well	Break through			Abandonment					
		Time	Cumulative oil	Recovery	Time	Recovery	Cumulative oil	Cumulative produced gas	Cumulative produced water	Cumulative water injection
STB/D	STB/D	Days	STB	%	Days	%	STB	MSCF	MSTB	MSTB
860	2500	4018	6911	8.66	27394	39.18	31253	54463	29457	68485
1720	**5000**	**2557**	**8796**	**11.03**	**15523**	**39.22**	**31285**	**54610**	**33558**	**77615**

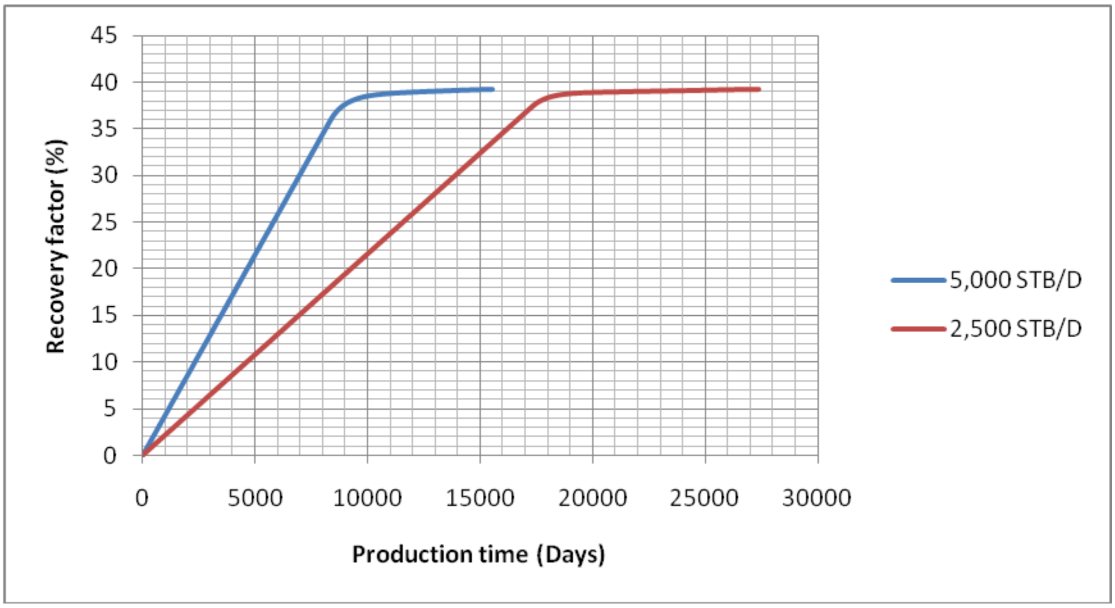

Figure 5.44: Recovery factors for the case of two horizontal producers with one vertical injector at injection rate of 2,500 STB/D and 5,000 STB/D in 100-ft thick reservoir.

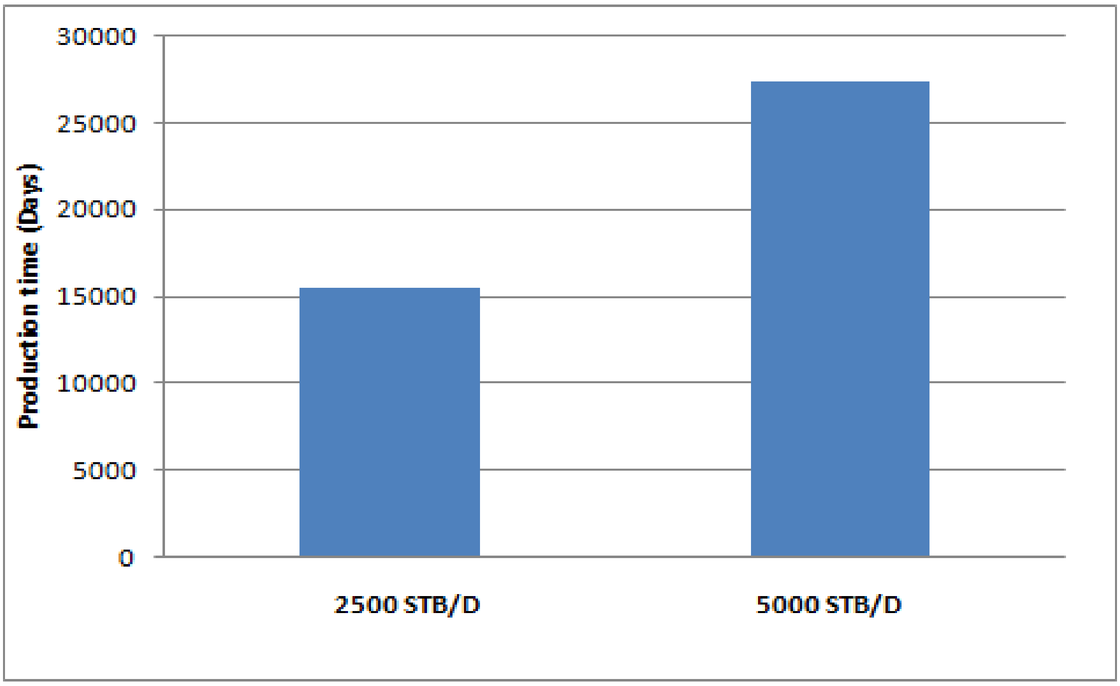

Figure 5.45: Production times for the case of two horizontal producers and one vertical injector at injection rate of 2,500 STB/D and 5,000 STB/D in 100-ft thick reservoir.

5.2.2.2 Two horizontal producers with one horizontal injector

Well placement for two horizontal producers with one horizontal injector is performed by using genetic algorithm coupled with reservoir simulator. In the 1st generation, illustrated in **Figure 5.46**, the genetic algorithm (GA) tries to search regions with high oil recovery in order to narrow down the search area for the next generation. Oil recovery factor climbs to 38.09% in the 6th generation. A high oil recovery factor is obtained in the 7th generation. After the 7th generation, local maxima occur from well optimization of two horizontal producers with one horizontal injector. The last local maximum is improved by the process of mutation and crossover in the 34th generation. Even though the genetic algorithm is continued until it reaches the terminated generation (the 40th generation) but the solution is still not improved after the 34th generation. Thus, the 34th generation is the converged generation. The generation to reach the convergence in this scenario is more than that in the case of one horizontal producer with two vertical injectors because of a larger number of unknowns.

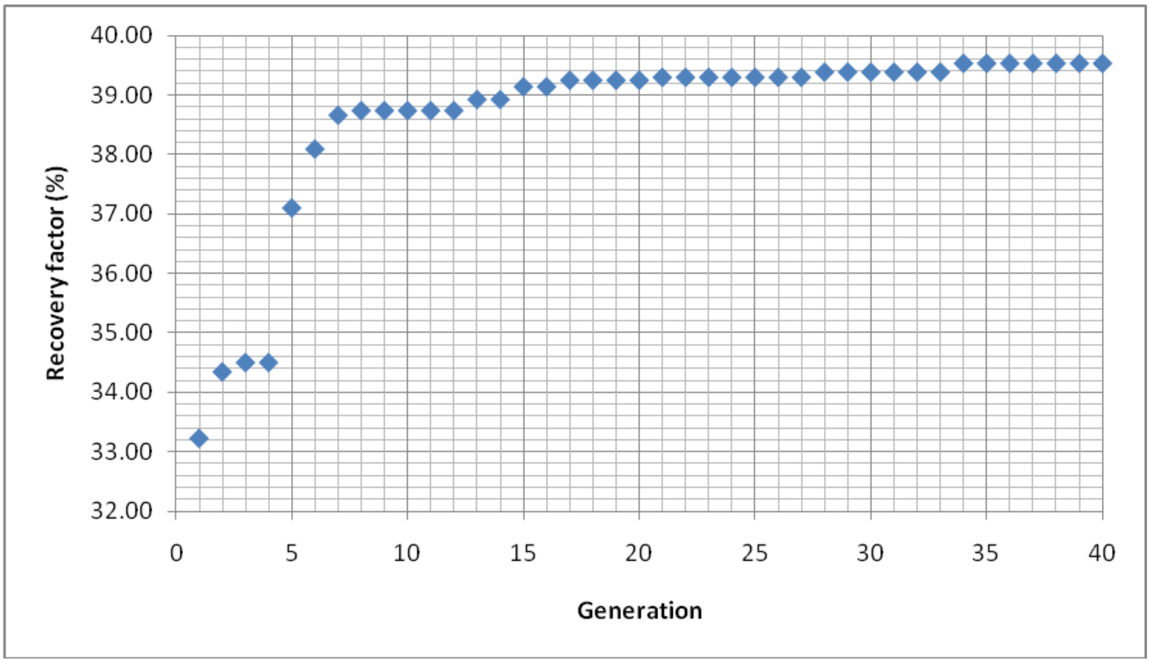

Figure 5.46: Recovery factor as a function of generation in the case of two horizontal producers and one horizontal injector in 100-ft thick reservoir.

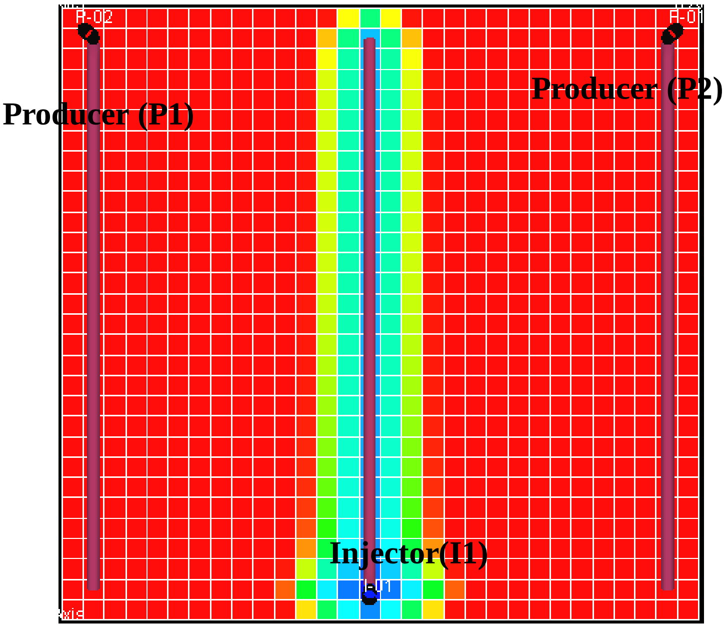

Figure 5.47: Well placement for the case of two horizontal producers and one horizontal injector at injection rate of 10,000 STB/D in 100-ft thick reservoir.

The best well placement of two horizontal producers and one horizontal injector are obtained in the 33rd generation of optimization. These locations are at the (i,j) blocks of ((29,29), (29,2)), ((2,29), (2,2)) and ((15,2),(15,29)), respectively as shown in **Figure 5.47**. In this scenario, the well pattern is symmetrical. Genetic algorithm locates the injector between producers P1 and P2 because these producer locations help water injection break through at both horizontal producer at the same time. Therefore, the areal sweep efficiency and recovery factor at breakthrough are high when genetic algorithm provides locations of wells as illustrated in **Figure 5.47.** The result of well locations and oil recovery factor for each generation is shown in **Table 5.30**.

Table 5.30: Well locations and recovery factor for each generation in the case of two horizontal producers and one horizontal injector in 100-ft thick reservoir.

	Well I1		Well P1		Well P2		RF
Generations	Toe	Heel	Toe	Heel	Toe	Heel	%
1	28,20	28,10	30,9	30,27	2,30	2,12	33.22
2	14,20	14,27	29,30	29,1	2,30	2,12	34.34
3	14,20	14,27	29,30	29,1	2,30	2,16	34.49
4	14,20	14,27	29,30	29,1	2,30	2,16	34.49
5	14,7	14,22	29,30	29,1	2,30	2,16	37.10
6	14,7	14,25	29,30	29,2	2,30	2,5	38.09
7	16,7	16,25	29,30	29,2	1,30	1,5	38.66
8	16,4	16,28	29,30	29,2	1,30	1,5	38.73
9	16,4	16,28	29,30	29,2	1,30	1,5	38.73
10	16,4	16,28	29,30	29,2	1,30	1,5	38.73
11	16,4	16,28	29,30	29,2	1,30	1,5	38.73
12	16,4	16,28	29,30	29,2	1,30	1,5	38.73
13	16,2	16,28	29,29	29,2	2,30	2,7	38.92
14	16,2	16,28	29,29	29,2	2,30	2,7	38.92
15	15,1	15,29	29,27	29,2	1,30	1,3	39.14
16	15,1	15,29	29,27	29,2	1,30	1,3	39.14
17	15,2	15,29	29,27	29,2	2,29	2,3	39.25
18	15,2	15,29	29,27	29,2	2,29	2,3	39.25
19	15,2	15,29	29,27	29,2	2,29	2,3	39.25
20	15,2	15,29	29,27	29,2	2,29	2,3	39.25
21	15,2	15,28	30,29	30,2	2,29	2,2	39.29
22	15,2	15,28	30,29	30,2	2,29	2,2	39.29
23	15,2	15,28	30,29	30,2	2,29	2,2	39.29
24	15,2	15,28	30,29	30,2	2,29	2,2	39.29
25	15,2	15,28	30,29	30,2	2,29	2,2	39.29
26	15,2	15,28	30,29	30,2	2,29	2,2	39.29
27	15,2	15,28	30,29	30,2	2,29	2,2	39.29
28	15,2	15,28	30,29	30,1	2,29	2,2	39.38
29	15,2	15,28	30,29	30,1	2,29	2,2	39.38
30	15,2	15,28	30,29	30,1	2,29	2,2	39.38
31	15,2	15,28	30,29	30,1	2,29	2,2	39.38
32	15,2	15,28	30,29	30,1	2,29	2,2	39.38
33	15,2	15,28	30,29	30,1	2,29	2,2	39.38
34-40	15,2	15,29	29,29	29,2	2,29	2,2	39.53

The injection rate at 10,000STB/D is the best choice for this scenario. The oil recovery of all injection rates demonstrated in **Table 5.31** and **Figure 5.48** is not significantly different. In **Figure 5.49**, the production time at injection rate of 10,000STB/D is about 57 % less than that at injection rate of 5,000STB/D. Therefore, the use of two horizontal producers with single horizontal injector at water injection rate of 10,000 STB/D is suitable for this scenario. The cumulative oil recovery of 31,362 MSTB is produced at the end of 9,131 days of production. The breakthrough time for this case is about 1,461 days. The cumulative water production is 44,905 MSTB while the amount of water injection is 91,310 MSTB.

Table 5.31: Production data for the case of two horizontal producers and one horizontal injector at injection rate of 5,000 STB/D and 10,000 STB/D in 100-ft thick reservoir.

Production rate/well	Injection rate/well	Break through			Abandonment					
		Time	Cumulative oil	Recovery	Time	Recovery	Cumulative oil	Cumulative produced gas	Cumulative produced water	Cumulative water injection
STB/D	STB/D	Days	STB	%	Days	%	STB	MSCF	MSTB	MSTB
1720	5000	3287	11307	14.17	15889	39.53	31536	54770	32464	79443
3450	**10000**	**1461**	**10081**	**12.64**	**9131**	**39.31**	**31362**	**54123**	**44905**	**91310**

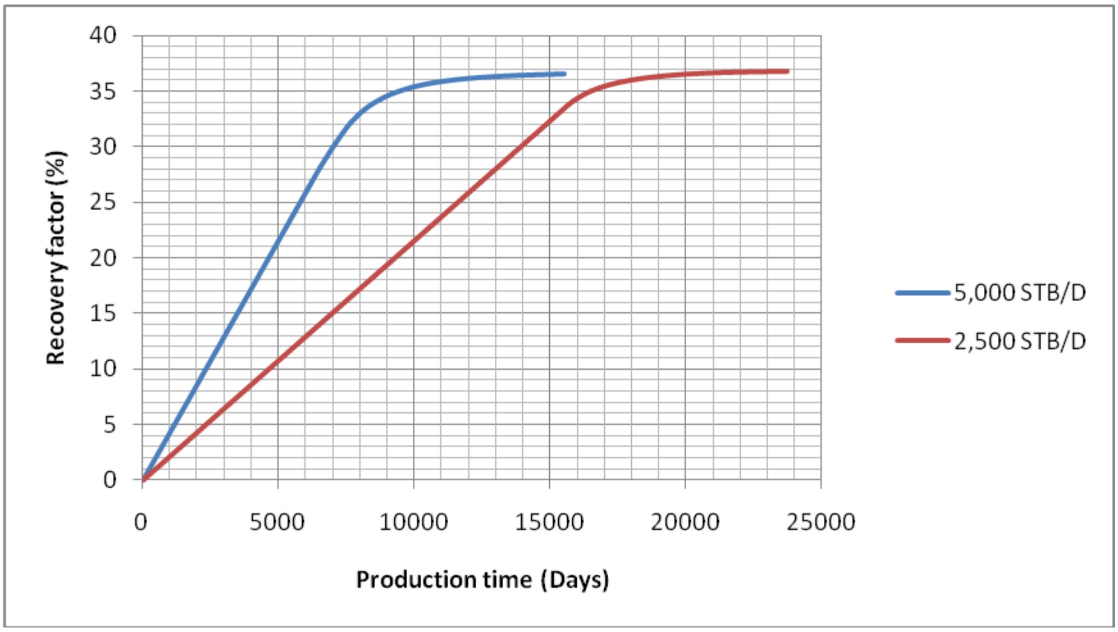

Figure 5.48: Recovery factor for the case of two horizontal producers and one horizontal injector at injection rate of 5,000 STB/D and 10,000 STB/D in 100-ft thick reservoir.

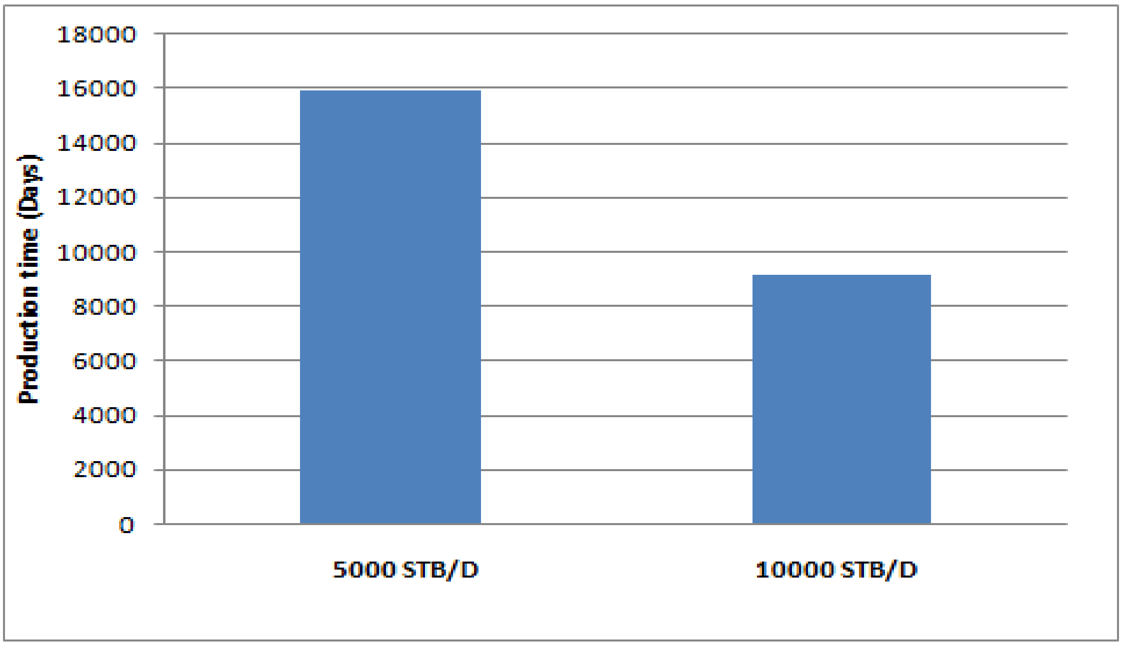

Figure 5.49: Production times for the case of two horizontal producers and one horizontal injector at injection rate of 5,000 STB/D and 10,000 STB/D in 100-ft thick reservoir.

5.2.2.3 Two vertical producers with one vertical injector

For well placement for two vertical producers with one vertical injector, the results of well locations and oil recovery factor for each generation are shown in **Figure 5.50**. The genetic algorithm (GA) tries to search regions with high oil recovery in the 1^{st} generation. From the 1^{st} to the 2^{nd} generation, oil recovery factor climbs from 27.14% to 32.08%. The first local maximum occurs in the 4^{th} generation but the solution is improved by the process of mutation and crossover in the 8^{th} generation. After the 9^{th} generation, oil recovery gradually increases until it reaches 34.78% in the 16^{th} generation. A high oil recovery factor is obtained after the 22^{nd} generation. Even though the genetic algorithm is continued until it reaches the terminated generation (the 40^{th} generation) but the solution doesn't improve after the 25^{th} generation. Therefore, optimization of well location for two vertical producers with one vertical injector is at the 25^{th} generation. The number of generation to reach the convergence in this scenario is less than that in the case of one horizontal producer with two vertical injectors because the genetic algorithm finds high oil recovery in the 17^{th} generation.

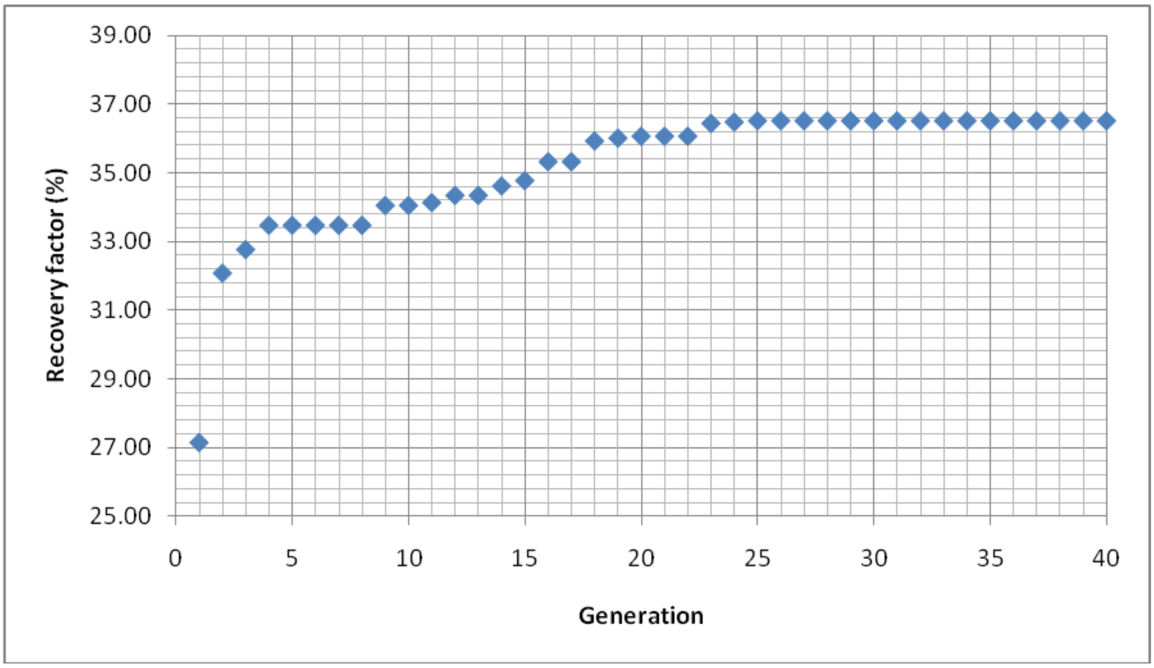

Figure 5.50: Recovery factor as a function of generation in the case two vertical producers and one vertical injector in 100-ft thick reservoir.

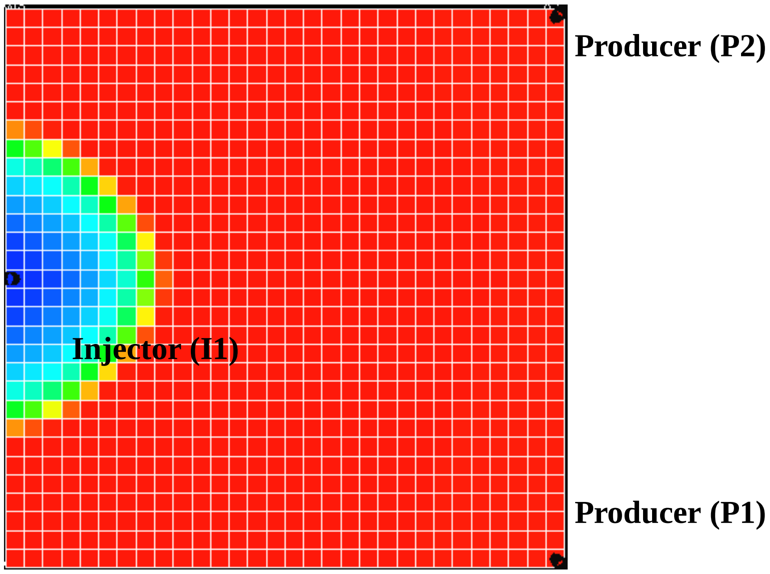

Figure 5.51: Well placement for the case of two vertical producers and one vertical injector at injection rate of 10,000 STB/D in 100-ft thick reservoir.

The locations of two vertical injectors and a vertical producer for the best injection rate are shown in **Figure 5.51**. These locations are at the (i,j) blocks of (30,30), (30,1), and (1,15), respectively. In this scenario, there are no horizontal well. The pressure drop doesn’t affect on location of production well. Therefore, the production wells P1 and P2 is located at the upper and lower right corners as uniform well pattern. The result of well locations and oil recovery factor for each generation is shown in **Table 5.32**.

Table 5.32: Well locations and recovery factor for each generation in the case of two vertical producers and one vertical injector in 100-ft thick reservoir.

Generations	Well I1	Well P1	Well P2	RF %
1	23,24	17,14	28,11	27.14
2	7,15	30,14	28,4	32.08
3	6,15	30,22	28,5	32.77
4	3,12	30,22	30,5	33.47
5	3,12	30,22	30,5	33.47
6	3,12	30,22	30,5	33.47
7	3,12	30,22	30,5	33.47
8	3,12	30,22	30,5	33.47
9	4,14	29,29	29,3	34.05
10	4,14	29,29	29,3	34.05
11	4,14	29,30	29,3	34.13
12	3,14	29,29	29,3	34.35
13	3,14	29,29	29,3	34.35
14	3,16	29,29	29,3	34.62
15	3,14	29,30	30,3	34.78
16	3,16	29,30	30,3	35.33
17	3,16	29,30	30,3	35.33
18	1,14	29,30	30,3	35.93
19	2,15	29,30	29,3	36.02
20	2,15	29,30	29,1	36.07
21	2,15	29,30	29,1	36.07
22	2,15	29,30	29,1	36.07
23	1,14	29,30	29,1	36.45
24	1,14	30,29	30,1	36.48
25-40	1,15	30,30	30,1	36.52

The oil recovery of all injection rates demonstrated in **Table 5.33** and **Figure 5.52** closes to 37 %. However, the shortest production time at injection rate of 10,000 STB/D may be the best choice of this scenario. The cumulative oil recovery of 29,133 MSTB is produced at the end of 15,523 days of production. The breakthrough time for this scenario is about 2,374 days. The cumulative water production is 37,483 MSTB while the amount of water injection is 77,615 MSTB.

Table 5.33: Production time for the case of two vertical producers and one vertical injector at injection rate of 2,500 STB/D and 5,000 STB/D in 100-ft thick reservoir.

Production rate/well	Injection rate/well	Break through			Abandonment					
		Time	Cumulative oil	Recovery	Time	Recovery	Cumulative oil	Cumulative produced gas	Cumulative produced water	Cumulative water injection
STB/D	STB/D	Days	STB	%	Days	%	STB	MSCF	MSTB	MSTB
860	2500	6574	11307	14.17	23741	36.81	29363	53686	27285	59353
1720	**5000**	**2374**	**8167**	**10.24**	**15523**	**36.52**	**29133**	**52701**	**37483**	**77615**

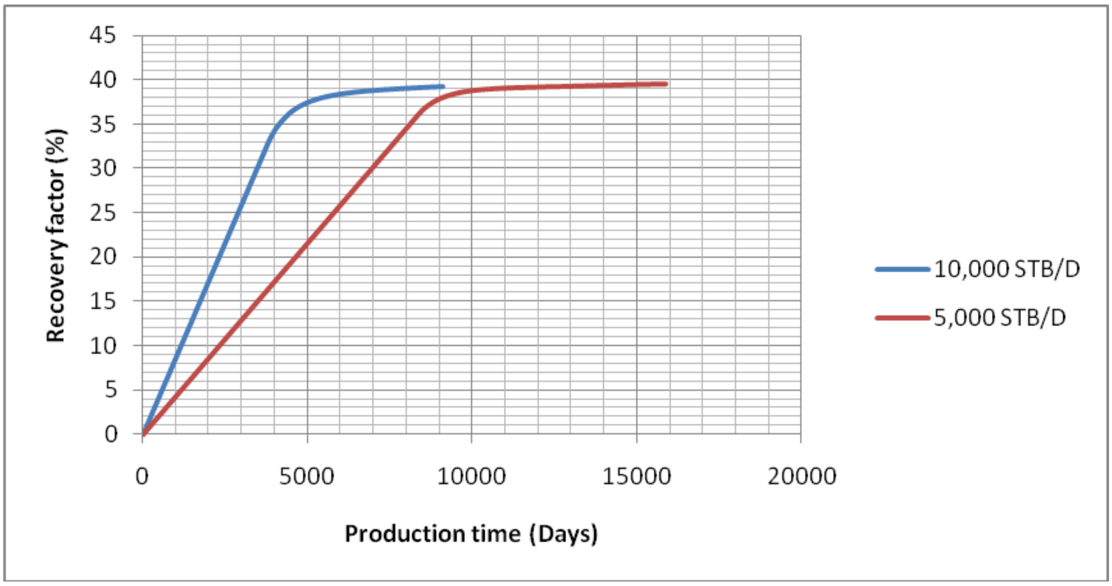

Figure 5.52: Recovery factor for the case of two vertical producers and one vertical injector at injection rate of 2,500 STB/D and 5,000 STB/D in 100-ft thick reservoir.

5.2.2.4 Two vertical producers with one horizontal injector

Well placement for two vertical producers with one horizontal injector is performed by using genetic algorithm coupled with reservoir simulation**.** In **Figure 5.53**, the 1st to 4th generation of the genetic algorithm (GA) tries to search regions with high oil recovery. From the 4th to the 7th generation, oil recovery factor increases from 30.66% to 36.04%. After the 7th generation, the local maxima occur several times but the solution is still improved by the process of mutation and crossover. In the 18th generation, oil recovery factor climbs to 40.95%. From the 29th to 40th generation, the mutation and crossover cannot improve the solution. Therefore, well location optimization for this scenario is found in the 29th generation. The optimum locations of two vertical producers and one horizontal injector obtain from the 29th generation of optimization. The converged generation of this scenario is less than that of optimization of one horizontal producer with two vertical injectors because the search closes to high oil recovery since it continues in the 6th generation.

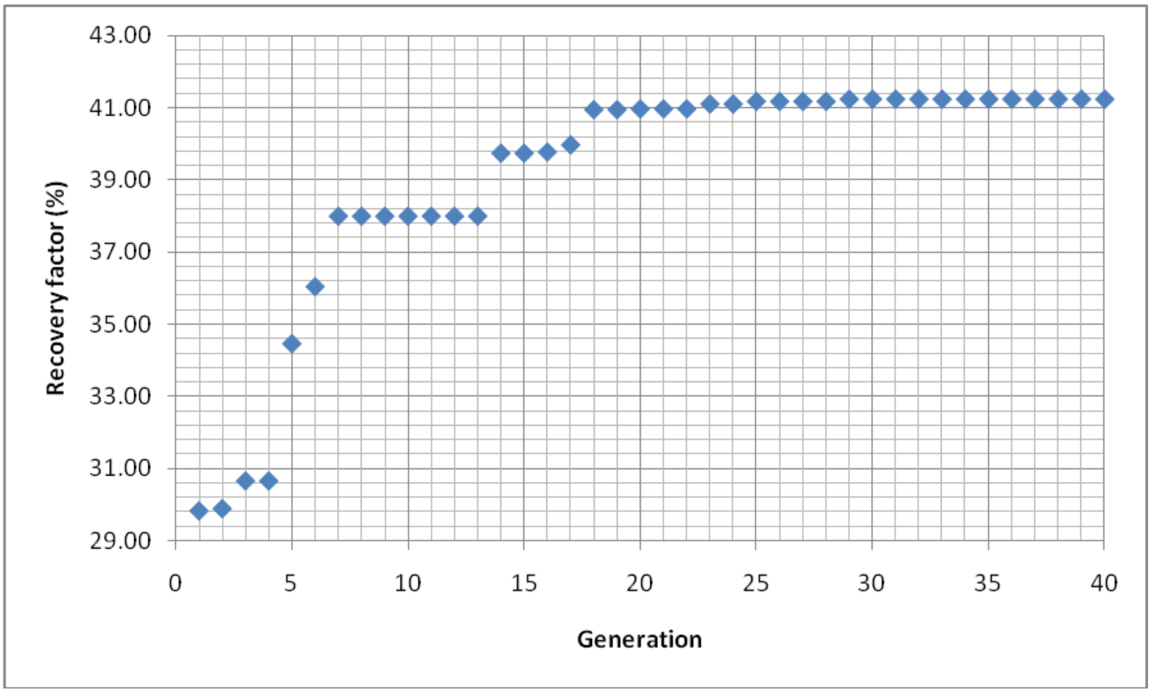

Figure 5.53: Recovery factor as a function of generation in the case of two vertical producers and one horizontal injector in 100-ft thick reservoir.

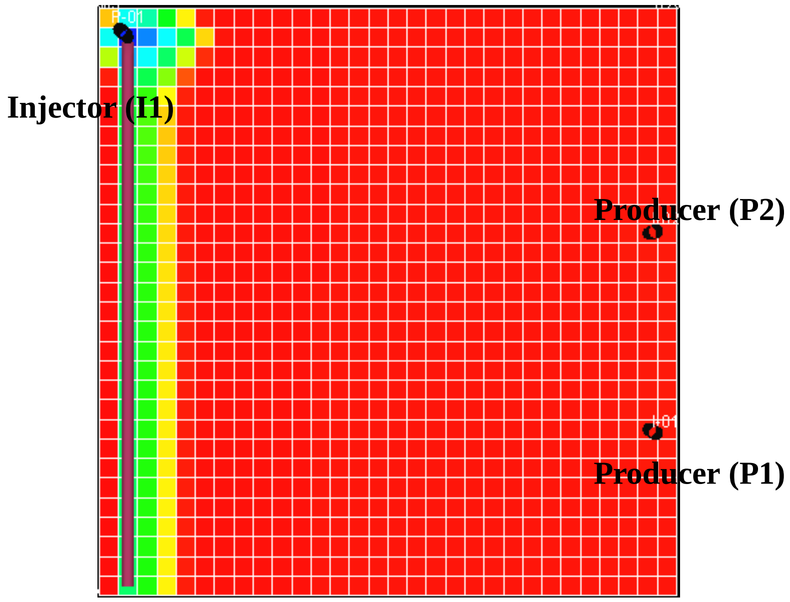

Figure 5.54: Well placement for the case of two vertical producers and one horizontal injector at injection rate of 10,000 STB/D in 100-ft thick reservoir.

In this scenario, the pressure drop in horizontal well occurs by wellbore friction assigned in this model. The pressure of horizontal injection well slightly increases from heel to toe during water injection. Therefore, pressure at the heel is higher than that at the toe. The genetic algorithm tries to locate the production wells at location that genetic algorithm provide high oil recovery. These locations are at the (i,j) blocks of (29,13), (29,22) and ((2,29),(2,2)), respectively as shown in **Figure 5.54**. **Table 5.34** shows the result of well locations and oil recovery factor for each generation of this scenario.

Table 5.34: Well locations and recovery factor for each generation in the case of two vertical producers and one horizontal injector in 100-ft thick reservoir.

	Well I1				RF
Generations	Toe	Heel	Well P1	Well P2	%
1	15,2	15,13	26,2	8,30	29.83
2	23,22	23,15	26,2	8,30	29.89
3	23,22	23,14	26,2	3,30	30.66
4	23,26	23,14	26,2	3,30	30.66
5	4,27	4,12	22,6	13,30	34.46
6	4,30	4,12	22,6	21,29	36.04
7	1,30	1,12	22,6	22,27	38.00
8	1,30	1,12	22,6	22,27	38.00
9	1,30	1,12	22,6	22,27	38.00
10	1,30	1,12	22,6	22,27	38.00
11	1,30	1,12	22,6	22,27	38.00
12	1,30	1,12	22,6	22,27	38.00
13	1,30	1,12	22,6	22,27	38.00
14	1,30	1,7	22,20	21,24	39.74
15	1,30	1,7	22,20	21,24	39.74
16	2,30	2,4	22,20	21,24	39.77
17	2,30	2,4	22,20	21,24	39.97
18	2,30	2,4	25,25	23,27	40.95
19	2,30	2,4	25,25	23,27	40.95
20	2,29	2,4	22,25	23,29	40.97
21	2,29	2,4	22,25	23,29	40.97
22	2,29	2,4	22,25	23,29	40.97
23	2,29	2,2	27,24	26,29	41.10
24	2,29	2,2	27,24	26,29	41.10
25	2,29	2,2	30,22	29,13	41.18
26	2,29	2,2	30,22	29,13	41.18
27	2,29	2,2	30,22	29,13	41.18
28	2,29	2,2	30,22	29,13	41.18
29-40	2,29	2,2	29,22	29,13	41.24

The highest oil recovery factor of 41.21 % represented in **Table 5.35** and **Figure 5.55** is obtained in this scenario with water injection rate of 10,000 STB/D. The cumulative oil recovery of 32,896 MSTB is produced at the end of 17,532 days of production. The breakthrough time for this scenario is about 1,826 days. The cumulative water production is 125,709 MSTB while the amount of water injection is 175,320 MSTB. Although the production time is not significantly different, but the amount of cumulative oil at injection rate of 10,000 STB/D is 4% times more than that at injection rate of 5,000 STB/D. Therefore, producing with the injection rate of 10,000STB/D is the best alternative for this scenario.

In this study, the oil recovery at high injection rate is higher than the oil recovery at low injection rate because in the case of low injection rate water trends to move downward, resulting in segregation. As a result, water prefers moving at the bottom part of the reservoir, causing low efficiency of waterflooding process. For case of high injection rate, the water injection rate can reduce the problem of segregation because water flow rate in the horizontal direction is much higher than that in the vertical direction.

Table 5.35: Production data for the case of two vertical producers and one horizontal injector at injection rate of 5,000 STB/D and 10,000 STB/D in 100-ft thick reservoir.

		Break through			Abandonment					
Production rate	Injection rate	Time	Cumulative oil	Recovery	Time	Recovery	Cumulative oil	Cumulative produced gas	Produced water	Cumulative water injection
STB/D	STB/D	Days	STB	%	Days	%	STB	MSCF	MSTB	MSTB
1720	5000	3835	13192	16.54	16436	36.93	29462	52076	39104	82180
3450	**10000**	**1826**	**12599**	**15.79**	**17532**	**41.24**	**32896**	**48022**	**125709**	**175320**

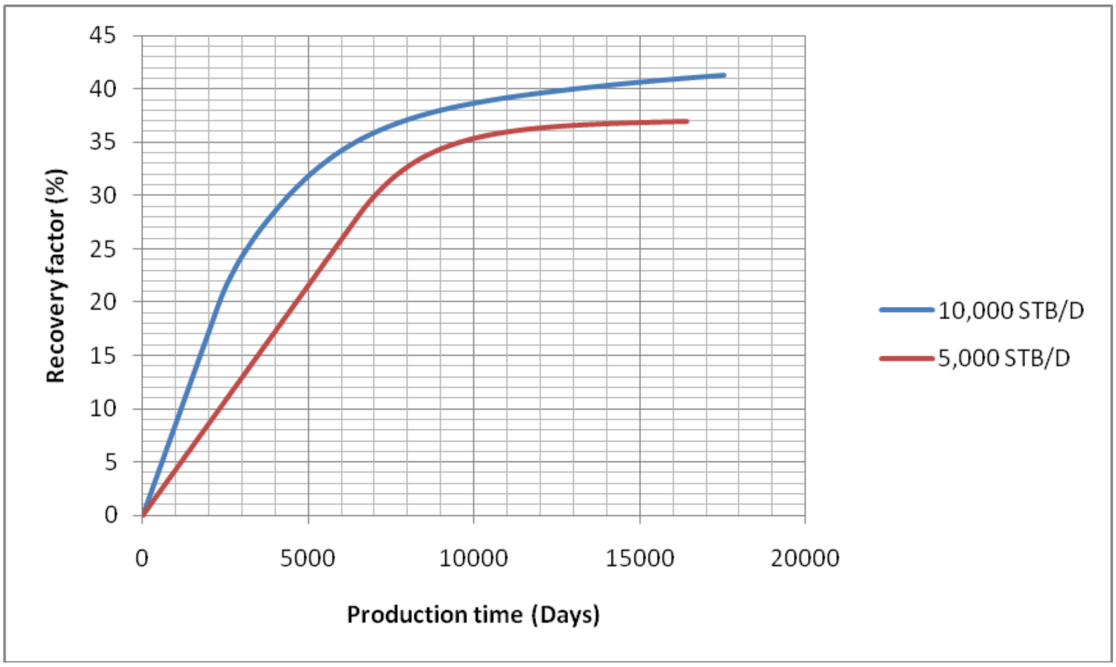

Figure 5.55: Recovery factor for the case of two vertical producers with one horizontal injector at injection rate of 5,000 STB/D and 10,000 STB/D for 100-ft thick reservoir.

5.2.3 Summary for well placement in 100-ft thick reservoir

The cause of difference in well locations for each scenario is the same as the cause in 30-thick reservoir. For the effect of injection rate, the result in this case is different from the case of 30-ft thick reservoir. In all cases, the oil recovery at high injection rate is higher than the oil recovery at low injection rate because in the case of low injection rate water tends to move downward, resulting in segregation. Injecting water with high rate can be performed in this thickness because in thick reservoir injection well can provide low bottom hole pressure even though the well is injected with high rate.

Tables 5.36 and **5.37** illustrate well placement results in 100-ft thick reservoir. The two best scenarios are obtained from case of high injection rate as shown in **Table 5.37**. For well placement optimization of this thickness, using a single vertical producer with two horizontal injectors with injection rate of 10,000 STB/D is the best choice as it yields the highest oil recovery even though the water production is higher than the other case. In addition, the drilling cost for a single vertical producer plus two horizontal injectors is lower than that for one horizontal producer plus two horizontal injectors.

Table 5.36: Well placement results for 100-ft thick reservoir at medium injection rate.

Type	Production rate/well	Break through				Abandonment					
		Injection rate/well	Time	Cumulative oil	Recovery	Time	Recovery	Cumulative oil	Cumulative produced Gas	Cumulative produced water	Cumulative water injection
Scenarios	STB/D	STB/D	Days	STB	%	Days	%	STB	MSCF	MSTB	MSTB
1HP-2VI	3450	2500	4018	13862	17.38	15706	37.84	30188	53760	33556	78530
1HP-2HI	6900	5000	1795	12383	15.52	11596	39.45	31471	53266	66895	115958
1VP-2VI	3450	2500	4018	13862	17.38	18993	37.37	29814	50806	48874	94965
1VP-2HI	6900	5000	1461	10081	12.64	18628	40.69	32457	49129	135612	186280
2HP-1VI	860	2500	4018	6911	8.66	27394	39.18	31253	54463	29457	68485
2HP-1HI	1720	5000	3287	11307	14.17	15889	39.53	31536	54770	32464	79443
2VP-1VI	860	2500	6574	11307	14.17	23741	36.81	29363	53686	27285	59353
2VP-1HI	1720	5000	3835	13192	16.54	16436	36.93	29462	52076	39104	82180

Table 5.37: Well placement results for 100-ft thick reservoir at high injection rate.

Type	Production rate/well	Break through				Abandonment					
		Injection rate/well	Time	Cumulative oil	Recovery	Time	Recovery	Cumulative oil	Cumulative produced Gas	Cumulative produced water	Cumulative water injection
Scenarios	STB/D	STB/D	Days	STB	%	Days	%	STB	MSCF	MSTB	MSTB
1HP-2VI	6900	5000	2006	13821	17.32	17167	39.99	31903	51852	121076	171670
1HP-2HI	**13800**	**10000**	**798**	**11017**	**13.81**	**13149**	**43.54**	**34732**	**50711**	**209955**	**262980**
1VP-2VI	6900	5000	2090	14423	18.08	21184	43.19	34455	45573	160351	211552
1VP-2HI	**13800**	**10000**	**730**	**10074**	**12.63**	**19723**	**45.38**	**36207**	**41117**	**340510**	**394460**
2HP-1VI	1720	5000	2557	8796	11.03	15523	39.22	31285	54610	33558	77615
2HP-1HI	3450	10000	1461	10081	12.64	9131	39.31	31362	54123	44905	91310
2VP-1VI	1720	5000	2374	8167	10.24	15523	36.52	29133	52701	37483	77615
2VP-1HI	3450	10000	1826	12599	15.79	17532	41.24	32896	48022	125709	175320

5.3 Well placement in 300 ft-reservoir thickness

In this reservoir thickness, the scenarios used for the study are the same as those for other reservoir thickness except for the case of low injection rate. The best scenario for this thickness is the same as that obtained for 100-ft thick reservoir because vertical production well in this case can produce with high productivity index. Because of a large of reservoir thickness, the injection rates of 5,000 STB/D and 10,000 STB/D are used for investigation. The results of each scenario for this thickness were illustrated in the following sections.

5.3.1 Well placement of one producer with two injectors

5.3.1.1 One horizontal producer with two vertical injectors

After running genetic algorithm coupled with reservoir simulator for well optimization of one horizontal producer with two vertical injectors, the result of well placement is represented in **Figure 5.56**. The genetic algorithm tries to search region with high oil recovery in the first two generation. Oil recovery factor climbs to 36.14% in the 3rd generation. After the 5th generation, the local maximum occurs several times but the local maxima are improved by the process of mutation and crossover. Oil recovery factor reaches to 40.05% in the 28th generation. The genetic algorithm provides high oil recovery factor since it reaches the 28th generation. The converged generation of the well optimization is at the 29th generation because oil recovery doesn’t improve after the 28th generation even though genetic algorithm is run until the terminated generation (the 40th generation). The optimum locations of two vertical producers and a horizontal injector is obtained from the 28th generation of optimization. The converged generation in this scenario is less than that in the case of one horizontal producer with two vertical injectors for 30-ft thick reservoir because the search reaches high oil recovery since it continues in the 5th generation.

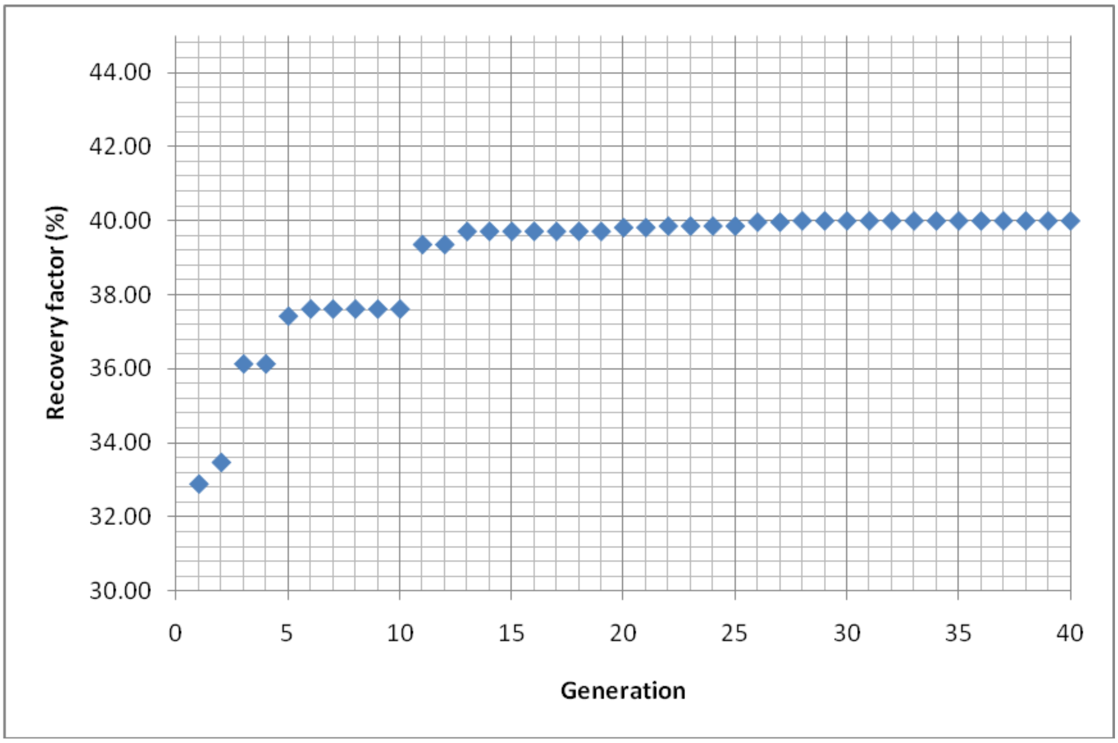

Figure 5.56: Recovery factor as a function of generation in the case of one horizontal producer and two vertical injectors in 300-ft thick reservoir.

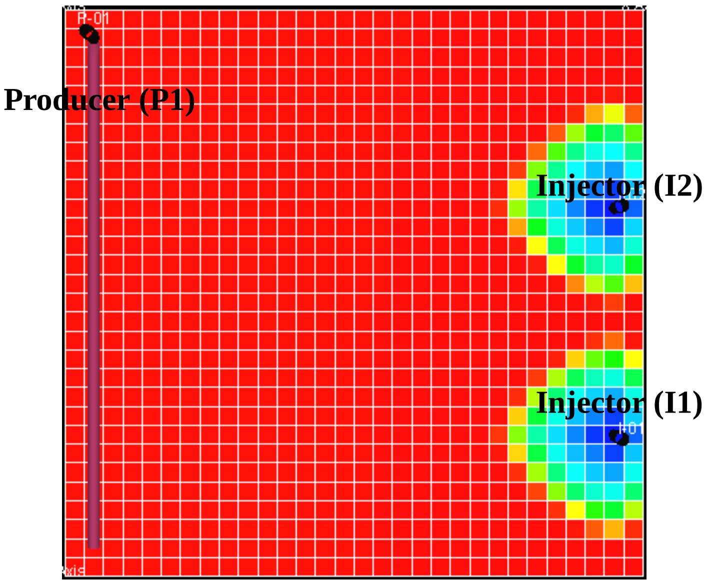

Figure 5.57: Well placement for the case of one horizontal producer and two vertical injectors at injection rate of 5,000STB/D in 300-ft thick reservoir.

In this scenario, the injection wells I1 and I2 are not located at the upper and lower right corner due to pressure drop in horizontal well. The pressure drop occurs by wellbore friction assigned in this model. The pressure of horizontal well slightly decreases from toe to heel as oil flows from toe to heel. Therefore, pressure at the heel is lower than that at the toe. The injection water is easy to break through at the heel. To solve the early breakthrough at the heel, genetic algorithm shifts the location of injection well I2 to the (i,j) block of (29,11) and the location of injection well I1 to the (i,j) block of (29,23), respectively as shown in **Figure 5.57**. The optimum horizontal producer length from the toe to heel is 6,076 ft. **Table 5.38** shows the result of well locations and oil recovery factor for each generation of this scenario.

Table 5.38: Well locations and recovery factor for each generation in the case of one horizontal producer and two vertical injectors in 300-ft thick reservoir.

Generations	Well I1	Well I2	Well P1		RF
			Toe	Heel	%
1	14,11	12,8	2,29	2,8	32.90
2	5,11	7,8	25,20	25,8	33.48
3	6,15	2,28	25,28	25,1	36.14
4	6,15	2,28	25,28	25,1	36.14
5	29,22	2,6	10,21	10,27	37.43
6	29,13	2,6	10,21	10,27	37.62
7	29,13	2,6	10,21	10,27	37.62
8	29,13	2,6	10,21	10,27	37.62
9	29,13	2,6	10,21	10,27	37.62
10	29,13	2,6	10,21	10,27	37.62
11	29,22	19,11	2,21	2,30	39.36
12	29,22	19,11	2,21	2,30	39.36
13	26,23	22,11	2,27	2,2	39.72
14	26,23	22,11	2,27	2,2	39.72
15	26,23	22,11	2,27	2,2	39.72
16	26,23	22,11	2,27	2,2	39.72
17	26,23	22,11	2,27	2,2	39.72
18	26,23	22,11	2,27	2,2	39.72
19	26,23	22,11	2,27	2,2	39.72
20	29,23	29,11	2,25	2,2	39.82
21	29,23	29,11	2,25	2,2	39.82
22	29,23	29,11	2,27	2,2	39.86
23	29,23	29,11	2,27	2,2	39.86
24	29,23	29,11	2,27	2,2	39.86
25	29,23	29,11	2,27	2,2	39.86
26	29,23	29,11	2,29	2,3	39.97
27	29,23	29,11	2,29	2,3	39.97
28-40	29,23	29,11	2,29	2,2	40.05

The oil recovery factor of all injection rates shown in **Table 5.39** and **Figure 5.58** closes to 40.05 %, but the injection rate of 5,000 STB/D can reduce the time required to produce oil. The comparison between production time of injection rate of 5,000 STB/D and 2,500 STB/D is represented in **Figure 5.59**. Although the amount of water production at injection rate of 5,000 STB/D is 60% more than that at injection rate of 2,500 STB/D, but the production time of injection rate at 5000 STB/D is approximately 60% of that at injection rate of 2500 STB/D. The cumulative oil recovery of 95,840 MSTB is produced at the end of 30,316 days of production. The breakthrough time for this scenario is about 6,027 days. The cumulative water production is 163,442 MSTB while the amount of water injection is 303,160 MSTB. Therefore, producing with the injection rate of 5000STB/D is the best alternative for this scenario.

Table 5.39: Production data for the case of one horizontal producer and two vertical injectors at injection rate of 2,500 STB/D and 5,000 STB/D in 300-ft thick reservoir.

Production rate/well	Injection rate/well	Break through			Abandonment					
		Time	Cumulative oil	Recovery	Time	Recovery	Cumulative oil	Cumulative produced gas	Cumulative produced water	Cumulative water injection
STB/D	STB/D	Days	STB	%	Days	%	STB	MSCF	MSTB	MSTB
3450	2500	12053	41583	17.37	50403	40.02	95779	163796	108332	252015
6900	**5000**	**6027**	**41583**	**17.37**	**30316**	**40.05**	**95840**	**160310**	**163442**	**303160**

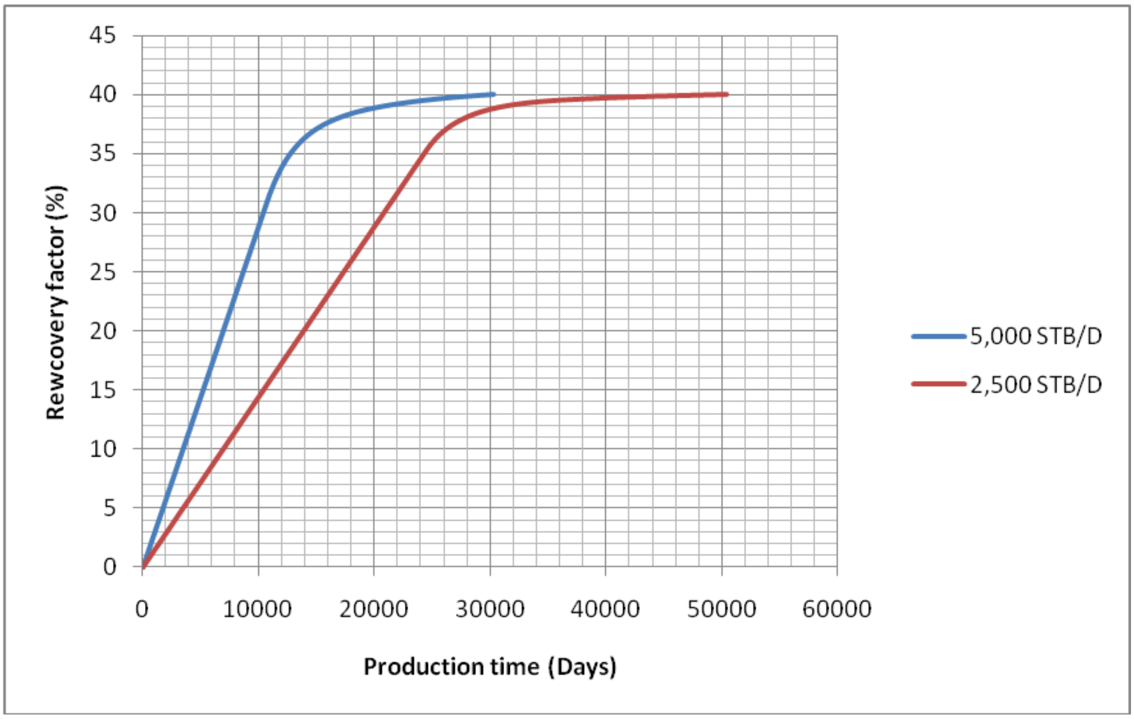

Figure 5.58: Recovery factor for the case of one horizontal producer and two vertical injectors at injection rate of 2,500 STB/D and 5,000 STB/D in 300-ft thick reservoir.

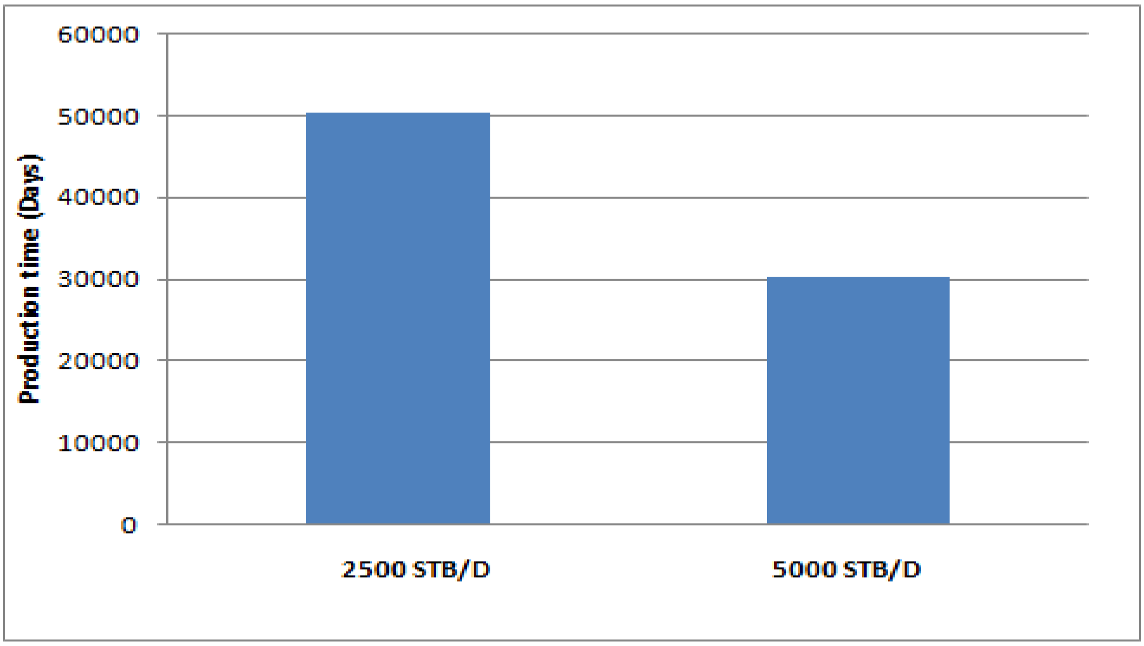

Figure 5.59: Production time for the case of one horizontal producer and two vertical injectors at injection rate of 2,500 STB/D and 5,000 STB/D in 300-ft thick reservoir

5.3.1.2 One horizontal producer with two horizontal injectors

Well placement for one horizontal producer with two horizontal injectors is performed by using genetic algorithm coupled with reservoir simulator. From the 1st to the 4th generation in **Figure 5.60**, the genetic algorithm (GA) tries to search regions with high oil recovery in order to narrow down the search area for the next generation. Oil recovery factor climbs to 37.92% in the 5th generation. After the 6th generation, oil recovery factor gradually increases until it reaches the 33rd generation. The genetic algorithm is continued until it reaches the terminated generation (the 40th generation) but the solution is not improved after the 33rd generation. Thus, the 33rd generation is the converged generation. This scenario needs more generations to reach the converged solution than the previous case because the binary string of this scenario is longer than that of one horizontal producer and two vertical injectors in previous scenario.

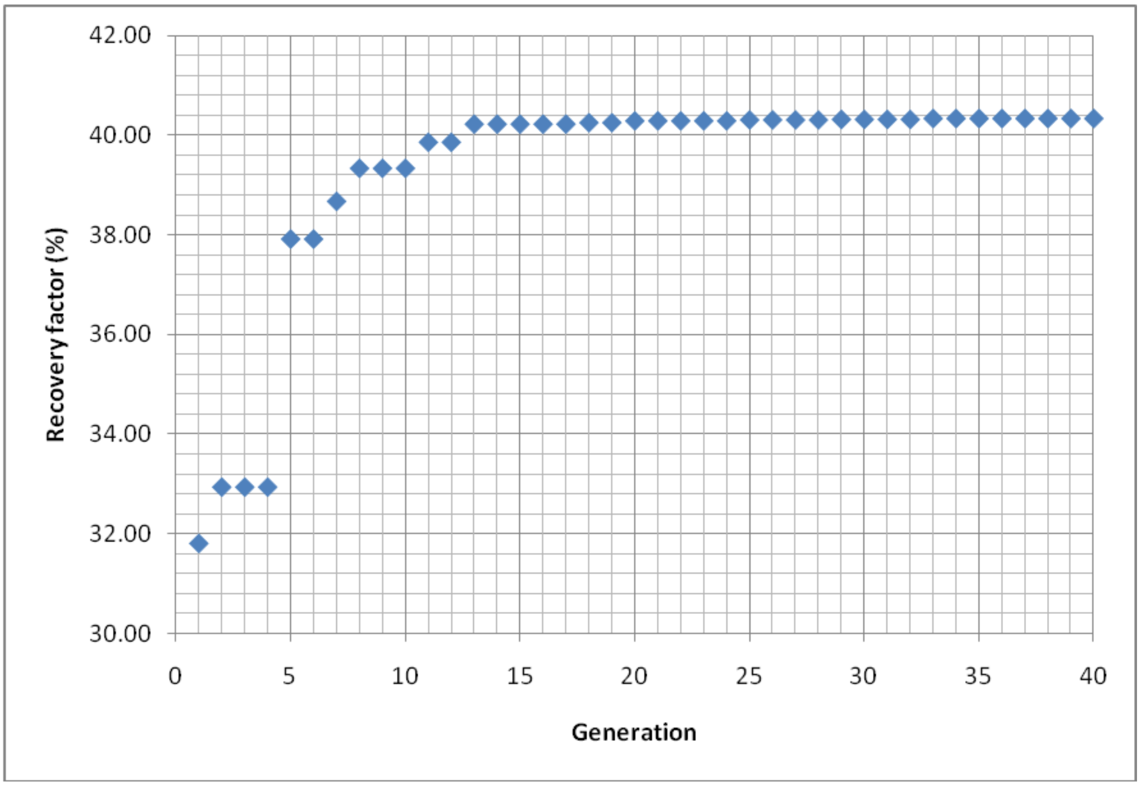

Figure 5.60: Recovery factor as a function of generation in the case of one horizontal producer and two horizontal injectors in 300-ft thick reservoir.

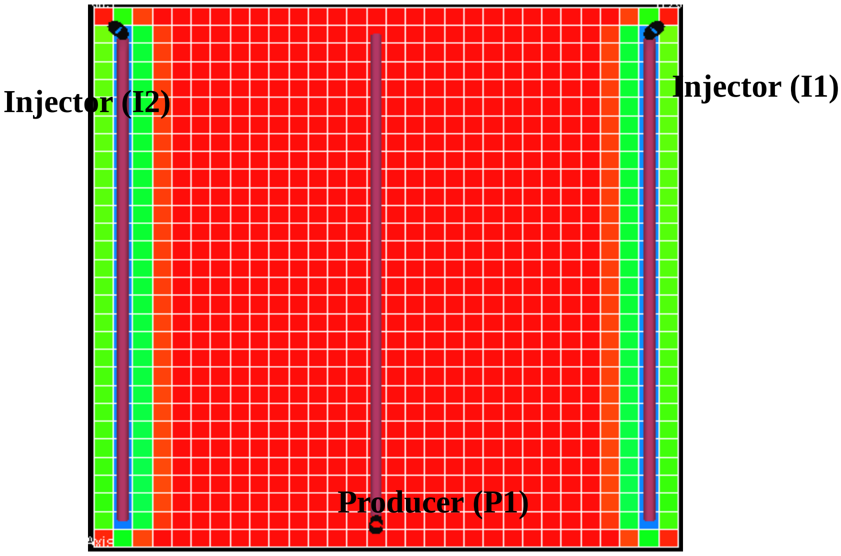

Figure 5.61: Well placement for the case of one horizontal producer and two horizontal injectors at injection rate of 10,000 STB/D in 300-ft thick reservoir.

The optimum locations of two horizontal injectors and one horizontal producer are obtained in the 34th generation of optimization. These locations are at the (i,j) blocks of ((29,29),(29,2)), ((2,29),(2,2)) and ((15,2),(15,29)), respectively as shown in **Figure 5.61**.In this scenario, the well pattern is symmetrical. Genetic algorithm locates the producer P1 between injectors I1 and I2 because these injector locations help water injection break through at both sides of the horizontal producer at the same time. Therefore, the areal sweep efficiency and recovery factor at breakthrough are high when genetic algorithm provides locations of wells as illustrated in **Figure 5.61**. The result of well locations and oil recovery factor for each generation is shown in **Table 5.40**.

Table 5.40: Well locations and recovery factor for each generation in the case of one horizontal producer and two horizontal injectors in 300-ft thick reservoir.

	Well P1		Well I1		Well I2		RF
Generations	Toe	Heel	Toe	Heel	Toe	Heel	%
1	23,21	23,14	3,8	3,26	9,12	9,28	31.81
2	5,9	5,14	1,26	1,2	9,29	9,11	32.94
3	5,9	5,14	1,26	1,2	9,29	9,11	32.94
4	5,9	5,14	1,26	1,2	9,29	9,11	32.94
5	15,17	15,20	29,5	29,2	2,29	2,2	37.92
6	15,17	15,20	29,5	29,2	2,29	2,2	37.92
7	15,17	15,29	29,29	29,2	2,29	2,2	38.68
8	15,20	15,29	29,29	29,2	2,29	2,2	39.34
9	15,20	15,29	29,29	29,2	2,29	2,2	39.34
10	15,20	15,29	29,29	29,2	2,29	2,2	39.34
11	15,7	15,29	28,29	28,2	2,29	2,3	39.86
12	15,7	15,29	28,29	28,2	2,29	2,3	39.86
13	15,6	15,29	29,29	29,2	2,29	2,3	40.23
14	15,6	15,29	29,29	29,2	2,28	2,3	40.23
15	15,6	15,29	29,29	29,2	2,28	2,3	40.23
16	15,6	15,29	29,29	29,2	2,28	2,3	40.23
17	15,6	15,29	29,29	29,2	2,28	2,3	40.23
18	14,2	14,29	29,29	29,2	3,29	3,2	40.26
19	14,2	14,29	29,29	29,2	3,29	3,2	40.26
20	14,2	14,29	29,29	29,2	3,29	3,1	40.29
21	14,2	14,29	29,29	29,2	3,29	3,1	40.29
22	14,2	14,29	29,29	29,2	3,29	3,1	40.29
23	14,2	14,29	29,29	29,2	3,29	3,1	40.29
24	14,2	14,29	29,29	29,2	3,29	3,1	40.29
25	14,2	14,29	29,29	29,2	3,29	3,2	40.31
26	14,2	14,29	29,29	29,2	3,29	3,2	40.31
27	14,2	14,29	29,29	29,2	3,29	3,2	40.31
28	14,2	14,29	29,29	29,2	3,29	3,2	40.31
29	14,2	14,29	29,29	29,2	2,29	2,2	40.32
30	14,2	14,29	29,29	29,2	2,29	2,2	40.32
31	14,2	14,29	29,29	29,2	2,29	2,2	40.32
32	14,2	14,29	29,29	29,2	2,29	2,2	40.32
33-40	15,2	15,29	29,29	29,2	2,29	2,2	40.34

The oil recovery is demonstrated in **Table 5.41** and **Figure 5.62**. All injection rates that provide high recovery factor, but injection rate of 10,000 STB/D seems to be the best option that reduces the time required to produce oil. In **Figure 5.63**, the production time at injection rate of 10,000 STB/D is about 50 % less than that of injection rate at 5,000 STB/D. Therefore, the use of two horizontal injectors with single horizontal producer at water injection rate of 10,000 STB/D is suitable for this scenario. In this scenario, the cumulative oil recovery of 96,544 MSTB is produced at the end of 19,723 days of production. The breakthrough time for this case is about 1,826 days. The cumulative water production is 256,828 MSTB while the amount of water injection is 394,460 MSTB.

Table 5.41: Production data for the case of one horizontal producer and two horizontal injectors at injection rate of 5000 STB/D and 10000 STB/D in 300-ft thick reservoir.

		Break through			Abandonment					
Production rate/well	Injection Rate/well	Time	Cumulative oil	Recovery	Time	Recovery	Cumulative oil	Cumulative produced gas	Cumulative produced water	Cumulative water injection
STB/D	STB/D	Days	STB	%	Days	%	STB	MSCF	MSTB	MSTB
13800	**10000**	**1826**	**25199**	**10.53**	**19723**	**40.34**	**96544**	**156390**	**256828**	**394460**
6900	5000	4018	27724	11.58	39081	40.19	96193	163159	238058	390810

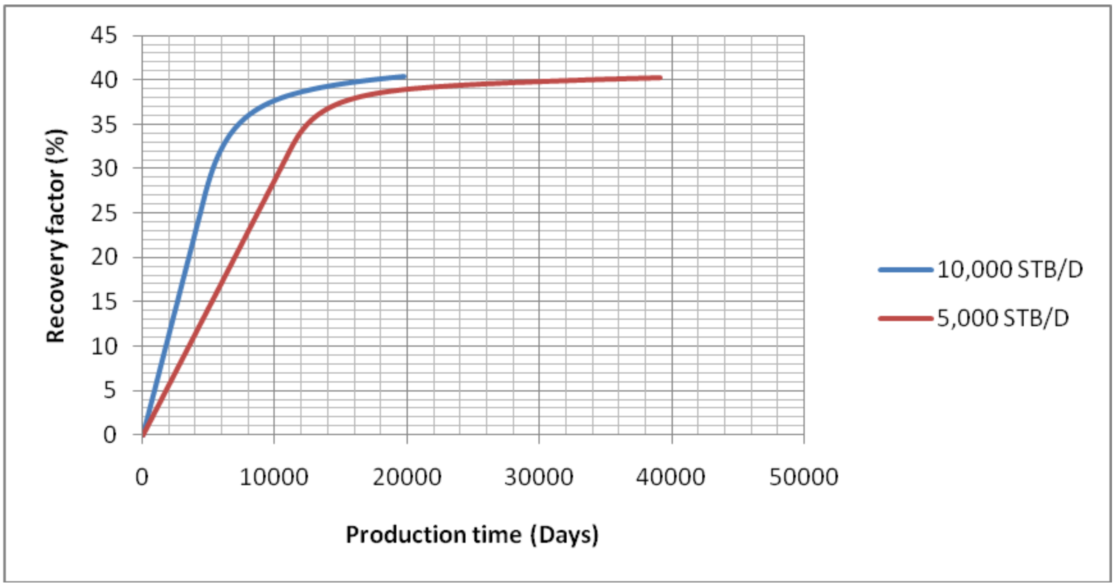

Figure 5.62: Recovery factor for the case of one horizontal producer and two horizontal injectors at injection rate of 5000 STB/D and 10000 STB/D in 300-ft thick reservoir.

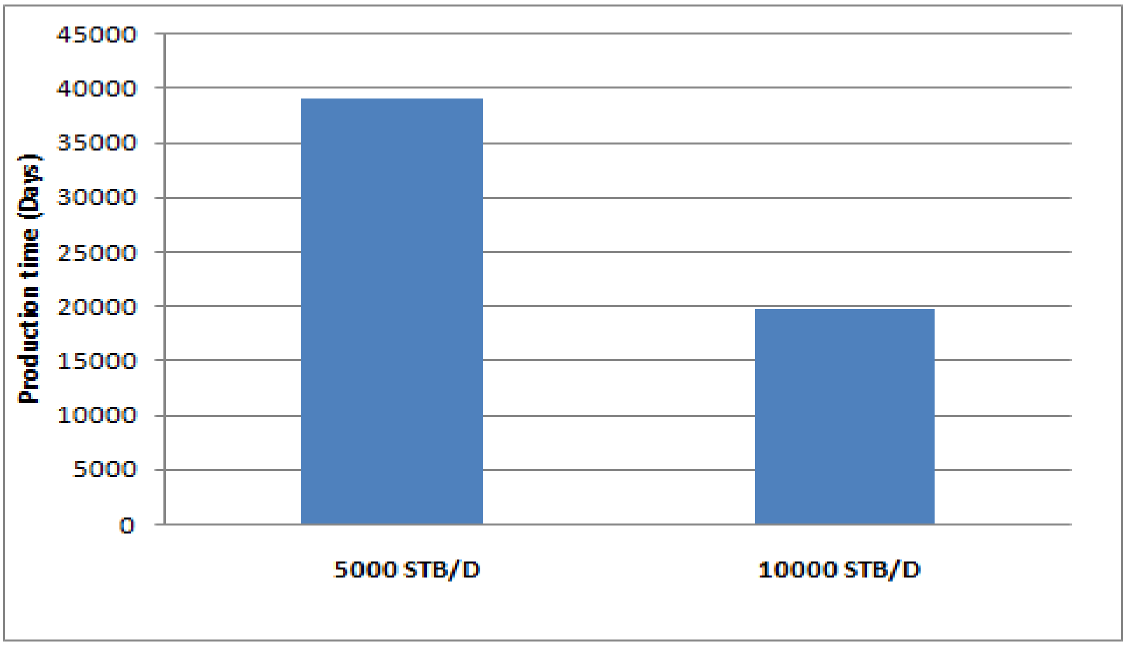

Figure 5.63: Production time for the case of one horizontal producer and two horizontal injectors at injection rate of 5000 STB/D 10000 STB/D in 300-ft thick reservoir.

5.3.1.3 One vertical producer with two vertical injectors

For well placement for one vertical producer with two vertical injectors, the result of well placement is represented in **Figure 5.64**. The genetic algorithm (GA) tries to search regions with high oil recovery in the 1st generation. Oil recovery factor of 28.98% is obtained in the 1st generation. From the 1st to the 2nd generation, oil recovery factor climbs from 24.52% to 27.96%. After the 3rd generation, the local maximum occurs and the solution is improved by the process of mutation and crossover in the 9th generation. After the 9th generation, oil recovery climb to high oil recovery zone. Even though the genetic algorithm is continued until it reaches the terminated generation (the 40th generation) but the solution doesn't improve after the 24th generation. Therefore, optimization of well location for one vertical producer with two vertical injectors is found in the 24th generation. The number of generation to reach the convergence in this scenario is less than that in the case of one horizontal producer with two vertical injectors because the genetic algorithm finds high oil recovery in the 12th generation.

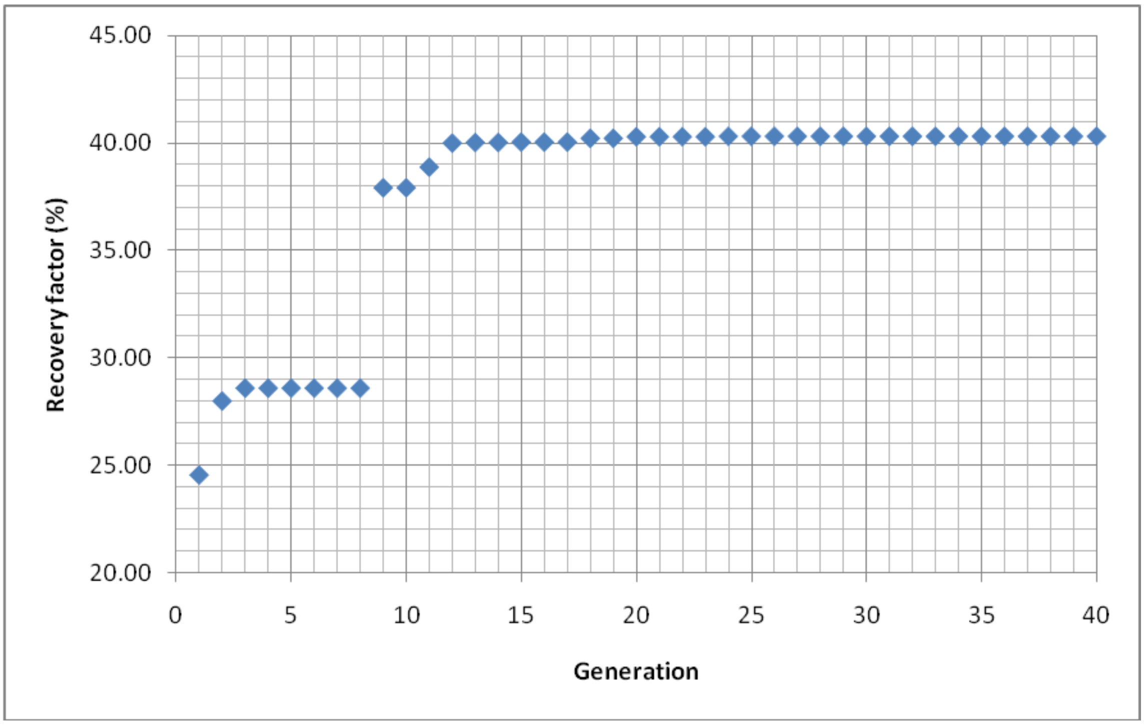

Figure 5.64: Recovery factor as a function of generation in the case one vertical producer and two vertical injectors in 300-ft thick reservoir.

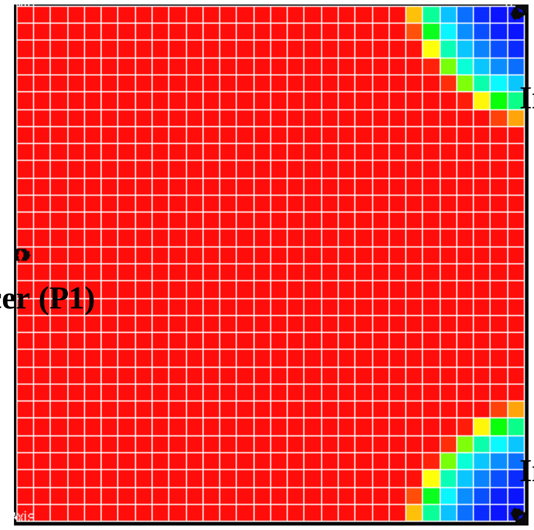

Figure 5.65: Well placement for the case of one vertical producer and two vertical injectors at injection rate of 5,000 STB/D in 300-ft thick reservoir.

The optimum locations of a vertical producer and two vertical injectors obtained from the 24th generation are at the (i,j) blocks of (1,15), (30,1) and (30,30), respectively as shown in **Figure 5.65**. In this scenario, there are no horizontal well. The pressure drop doesn’t affect on location of injection well. Therefore, the injection well I1 and I2 is located at the upper and lower right corner as uniform well pattern. The result of well locations and oil recovery factor for each generation is shown in **Table 5.42**.

Table 5.42: Well locations and recovery factor for each generation in the case of one vertical producer and two vertical injectors in 300-ft thick reservoir.

Generations	Well I1	Well I2	Well P1	RF %
1	11,8	2,8	2,12	24.52
2	29,15	5,14	1,30	27.96
3	29,3	5,14	1,14	28.57
4	29,3	5,14	1,14	28.57
5	29,3	5,14	1,14	28.57
6	29,3	5,14	1,14	28.57
7	29,3	5,14	1,14	28.57
8	29,3	5,14	1,14	28.57
9	26,23	25,1	5,18	37.89
10	26,23	25,1	5,18	37.89
11	30,23	25,1	1,18	38.86
12	30,18	27,1	1,18	39.98
13	30,18	29,1	1,12	40.00
14	30,18	29,1	1,12	40.00
15	30,27	28,1	1,12	40.02
16	30,27	28,1	1,12	40.02
17	30,27	28,1	1,12	40.02
18	30,30	28,1	1,12	40.20
19	30,30	28,1	1,12	40.20
20	30,30	28,1	1,13	40.27
21	30,30	28,1	1,13	40.27
22	30,30	28,1	1,13	40.27
23	30,30	28,1	1,13	40.27
24	30,30	30,1	1,15	40.29

The high oil recovery is provided from all injection rates as shown in **Table 5.43** and **Figure 5.66**. However, using single vertical producer and two vertical injectors with water injection rate of 5,000 STB/D seems to be the best injection rate for this scenario because the production time is the shortest. The cumulative oil recovery of 96,420 MSTB is produced at the end of 33,602 days of production. The breakthrough time for this case is about 6,392 days. The cumulative water production is 193,201 MSTB while the amount of water injection is 336,020 MSTB.

Table 5.43: Production data for the case of one vertical producer and two vertical injectors at injection rate of 2,500 STB/D and 5,000 STB/D in 300-ft thick reservoir.

Production rate/well	Injection Rate/well	Break through			Abandonment					
		Time	Cumulative oil	Recovery	Time	Recovery	Cumulative oil	Cumulative produced gas	Cumulative produced water	Cumulative water injection
STB/D	STB/D	Days	STB	%	Days	%	STB	MSCF	MSTB	MSTB
3450	2500	12784	44105	18.43	50769	39.78	95214	162079	114048	253845
6900	**5000**	**6392**	**44101**	**18.43**	**33602**	**40.29**	**96420**	**149646**	**193210**	**336020**

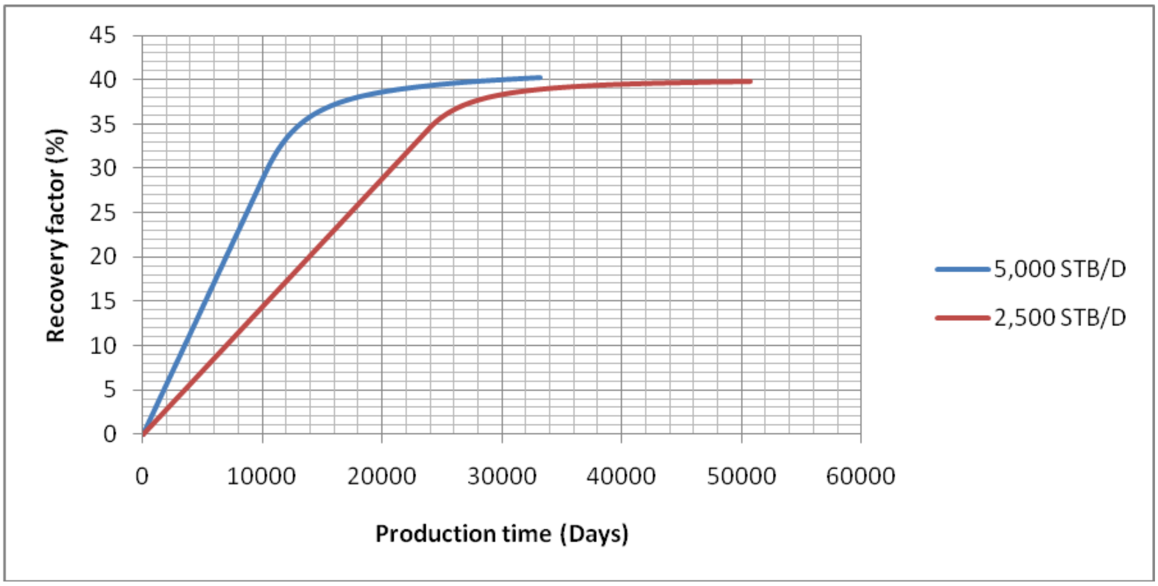

Figure 5.66: Recovery factor for the case of one vertical producer and two vertical injectors at injection rate of 2,500 STB/D and 5,000 STB/D in 300-ft thick reservoir.

5.3.1.4 One vertical producer with two horizontal injectors

Well placement for one vertical producer with two horizontal producers is performed by using genetic algorithm coupled with reservoir simulation**.** In **Figure 5.67**, the 1st generation of the genetic algorithm (GA) tries to search regions with high oil recovery. From the 1st to 2nd generation, oil recovery factor increases from 38.43% to 39.36%. The first local maximum occurs from the 3rd to the 6th generation. In the 7th generation, oil recovery factor climbs to 40.35%. After the 7th generation, oil recovery gradually increases and reaches 41.21% in the 30th generation. From the 30th to the 40th generation, the mutation and crossover cannot improve the solution. Therefore, well location optimization for this scenario is found in the 30th generation.

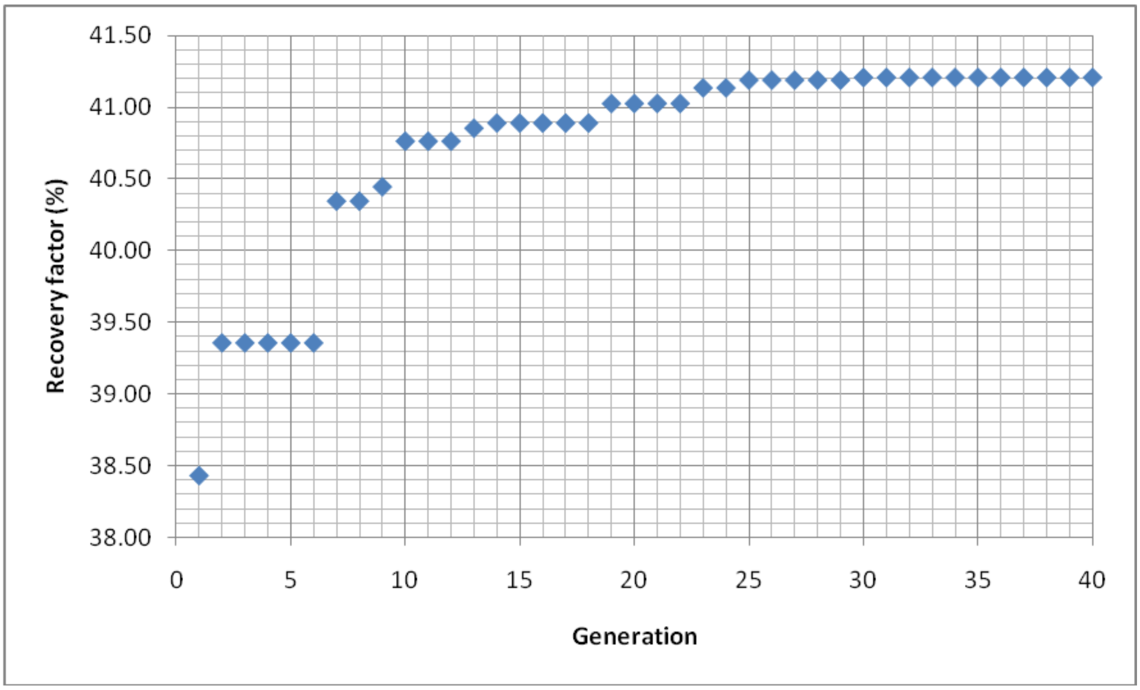

Figure 5.67: Recovery factor as a function of generation in the case of one vertical producer and two horizontal injectors in 300-ft thick reservoir.

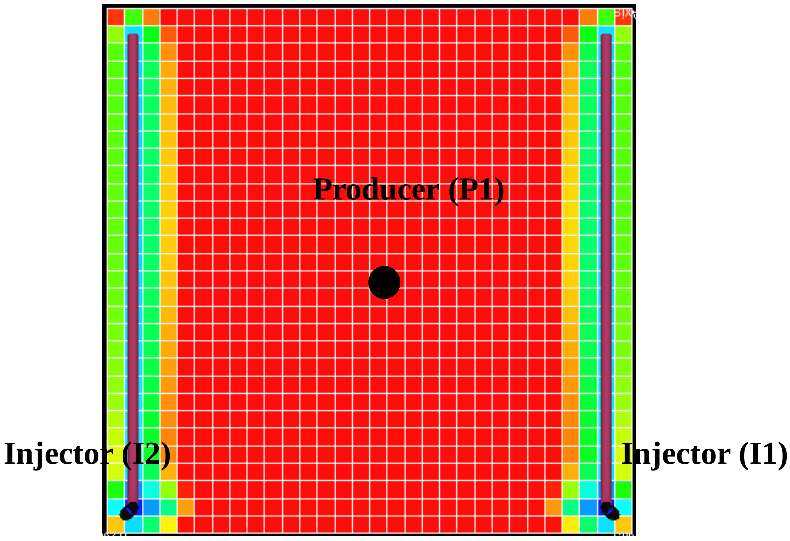

Figure 5.68: Well placement for the case of one vertical producer and two horizontal injectors at injection rate of 10,000 STB/D in 300-ft thick reservoir.

The locations of two horizontal producers and one vertical injector obtained from the 22th generation of optimization are at the (i,j) blocks of ((2,2),(2,29)), ((29,2),(29,29)) and (15,19), respectively as shown in **Figure 5.68.** In this scenario, the production well is located as illustrated in **Figure 5.68** because pressure in horizontal well affects the flow of water from the vertical injector to the horizontal producers. The pressure drop is by wellbore friction assigned in this model. The pressure of horizontal injection well slightly increases from heel to toe during water injection. Therefore, pressure of horizontal injector at the heel is higher than that at the toe. The injection water is easy to flow from the heel. Therefore, the location of producer moves to the (i,j) block of (15,19) to reduce the problem of early breakthrough. **Table 5.44** shows the result of well locations and oil recovery factor for each generation of this scenario.

Table 5.44: Well locations and recovery factor for each generation in the case of one vertical producer and two horizontal injectors in 300-ft thick reservoir.

	Well I1		Well I2			RF
Generations	Toe	Heel	Toe	Heel	Well P1	%
1	22,10	22,3	18,8	18,16	6,22	38.43
2	24,29	24,3	18,2	18,29	16,22	39.36
3	24,29	24,3	18,2	18,29	16,22	39.36
4	24,29	24,3	18,2	18,29	16,22	39.36
5	24,29	24,3	18,2	18,29	16,22	39.36
6	24,29	24,3	18,2	18,29	16,22	39.36
7	28,29	28,18	2,2	2,29	16,16	40.35
8	28,29	28,18	2,2	2,29	16,16	40.35
9	28,2	28,18	2,2	2,29	16,16	40.45
10	28,2	28,24	2,4	2,29	16,19	40.77
11	28,2	28,24	2,4	2,29	16,19	40.77
12	28,2	28,24	2,4	2,29	16,19	40.77
13	28,2	28,24	2,4	2,30	15,19	40.86
14	28,2	28,29	2,4	2,30	13,16	40.89
15	28,2	28,29	2,4	2,30	13,16	40.89
16	28,2	28,29	2,4	2,30	13,16	40.89
17	28,2	28,29	2,4	2,30	13,16	40.89
18	28,2	28,29	2,4	2,30	13,16	40.89
19	29,2	29,29	2,2	2,30	13,16	41.03
20	29,2	29,29	2,2	2,30	13,16	41.03
21	29,2	29,29	2,2	2,30	13,16	41.03
22	29,2	29,29	2,2	2,30	13,16	41.03
23	29,2	29,29	2,2	2,30	13,14	41.14
24	29,2	29,29	2,2	2,30	13,14	41.14
25	29,2	29,29	2,2	2,29	15,14	41.19
26	29,2	29,29	2,2	2,29	15,14	41.19
27	29,2	29,29	2,2	2,29	15,14	41.19
28	29,2	29,29	2,2	2,29	15,14	41.19
29	29,2	29,29	2,2	2,29	15,14	41.19
30-40	29,2	29,29	2,2	2,29	15,19	41.21

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The maximum oil recovery factor is obtained from all injection rates. In **Table 5.45** and **Figure 5.69**, because the time required to produce oil at injection rate of 10,000 STB/D is the shortest, using injection rate of 10,000 STB/D is the best choice. The cumulative oil recovery of 98,622 MSTB is produced at the end of 21,550 days of production. The breakthrough time for this scenario is about 2,009 days. The cumulative water production is 287,041 MSTB while the amount of water injection is 431,000 MSTB.

Table 5.45: Production data for the case of one vertical producer and two horizontal injectors at injection rate of 5000 STB/D 10000 STB/D in 300-ft thick reservoir.

Production rate/well	Injection Rate/well	Break through			Abandonment					
		Time	Cumulative oil	Recovery	Time	Recovery	Cumulative oil	Cumulative produced gas	Cumulative produced water	Cumulative water injection
STB/D	STB/D	Days	STB	%	Days	%	STB	MSCF	MSTB	MSTB
6900	5000	4383	30243	12.64	38715	40.07	95904	160007	236380	387150
13800	**10000**	**2009**	**27717**	**11.58**	**21550**	**41.21**	**98622**	**151403**	**287041**	**431000**

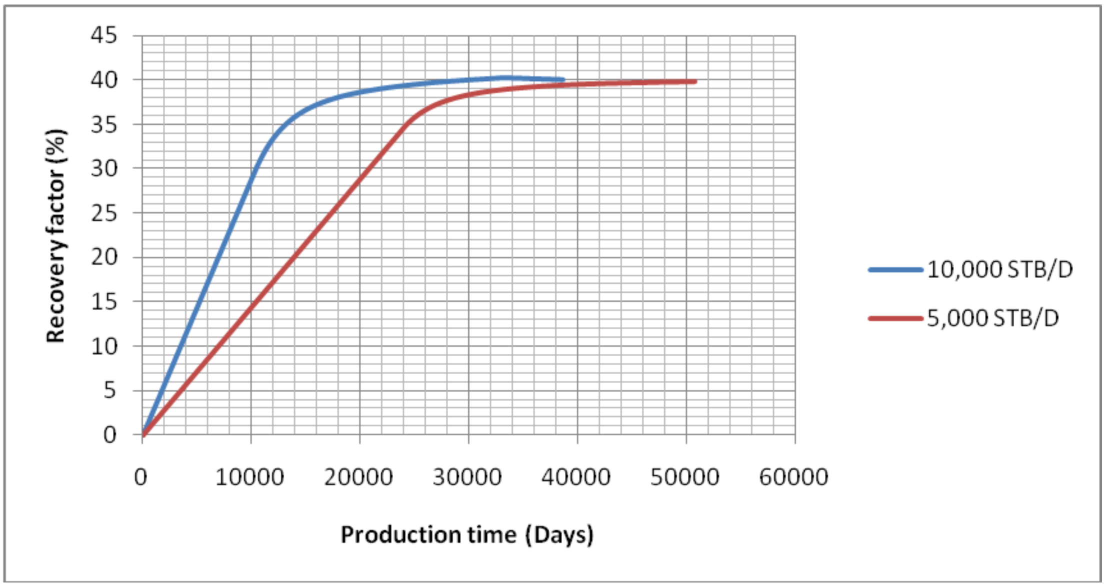

Figure 5.69: Recovery factor for the case of one vertical producer and two horizontal injectors at injection rate of 5000 STB/D 10000 STB/D in 300-ft thick reservoir.

5.3.2 Well placement of two producers with one injector

5.3.2.1 Two horizontal producers with one vertical injector

After running genetic algorithm coupled with reservoir simulator for well optimizations of two horizontal producers with one vertical injector, the result of well placement is represented in **Figure 5.70**. For the 1st generation the genetic algorithm tries to search region with high oil recovery in order to narrow down the search area for the next generation. Oil recovery factor of 30.47% is obtained in the 1st generation. Oil recovery factor climbs to 32.61% in 3rd generation. The local maximum occurs in the 3rd generation to the 7th generation. A high oil recovery is obtained after the 11th generation. The last local maximum is improved by the process of mutation and crossover in the 28th generation. This generation provides the highest oil recovery factor. The converged generation of the well optimization is found in the 28th generation because oil recovery doesn't improve after the 28th generation even though genetic algorithm reaches the terminated generation (the 40th generation).

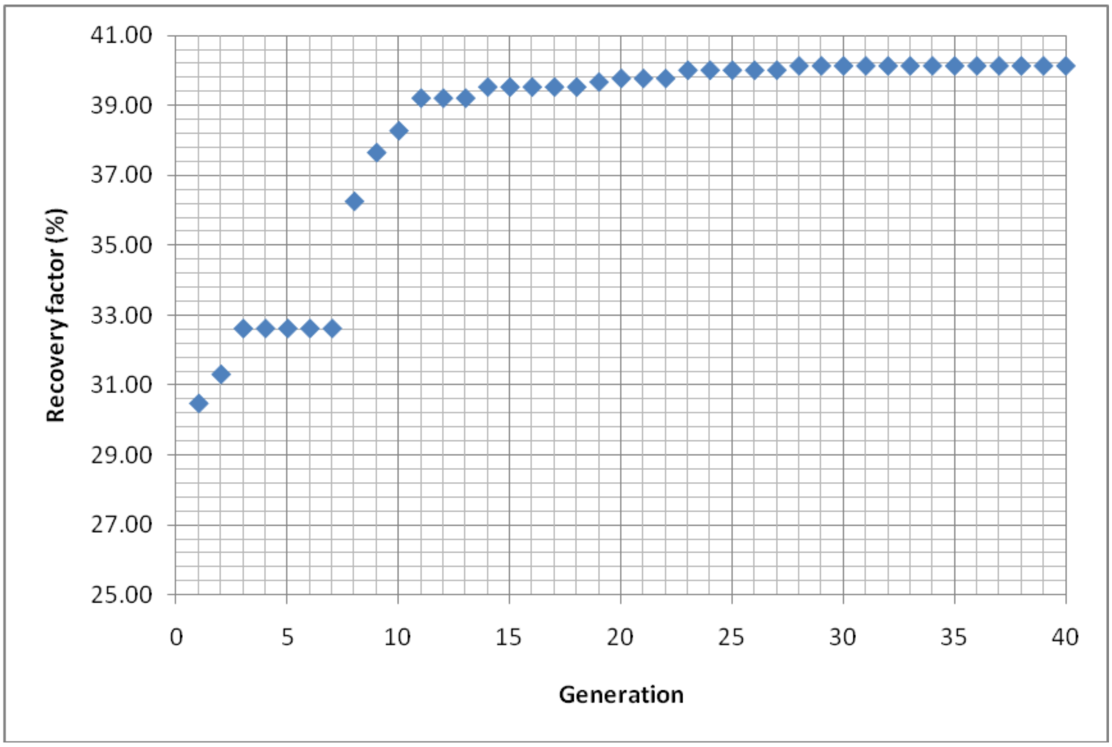

Figure 5.70: Recovery factor as a function of generation in the case of two horizontal producers and one vertical injector in 300-ft thick reservoir.

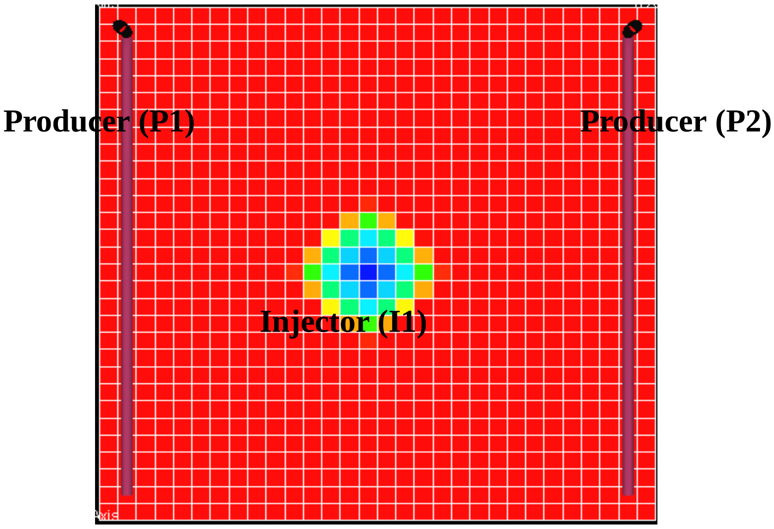

Figure 5.71: Well placement for the case of two horizontal producers and one vertical injector at injection rate of 5,000 STB/D in 300-ft thick reservoir.

In this scenario, the injection well is located as shown in **Figure 5.71** because pressure drop in horizontal production well affect on location of injector. The pressure drop occurs by wellbore friction assigned in this model. The pressure of horizontal production well slightly decreases from toe to heel as oil flow from toe to heel. Therefore, pressure of horizontal producer at the heel is lower than that at the toe. The injection water is easy to breakthrough at the heel. Therefore, the location of injector moves to the (i,j) block of (15,16) to reduce the problem of early breakthrough.

The optimum locations of two horizontal producers and a vertical injector obtained from the 28th generation of optimization are at the (i,j) blocks of ((2,29),(2,2)), ((29,29),(29,2)) and (15,16), respectively as shown in **Figure 5.71. Table 5.44** shows the result of well locations and oil recovery factor for each generation of this scenario.

Table 5.46: Well locations and recovery factor for each generation in the case of two horizontal producers and one vertical injector in 300-ft thick reservoir.

		Well P1		Well P2		RF
Generations	Well I1	Toe	Heel	Toe	Heel	%
1	9,24	8,28	8,3	26,1	26,22	30.47
2	1,2	22,24	22,3	26,30	26,17	31.30
3	1,7	13,24	13,1	30,16	30,5	32.61
4	1,7	13,24	13,1	30,16	30,5	32.61
5	1,7	13,24	13,1	30,16	30,5	32.61
6	1,7	13,24	13,1	30,16	30,5	32.61
7	1,7	13,24	13,1	30,16	30,5	32.61
8	18,16	13,29	13,4	27,22	27,5	36.25
9	9,16	5,29	5,1	27,29	27,5	37.64
10	9,16	5,29	5,1	27,29	27,5	38.27
11	15,12	5,29	5,1	30,29	30,5	39.20
12	15,12	5,29	5,1	30,29	30,5	39.20
13	15,12	5,29	5,1	30,29	30,5	39.20
14	15,12	3,28	3,1	30,29	30,5	39.52
15	15,12	3,28	3,1	30,29	30,5	39.52
16	15,12	3,28	3,1	30,29	30,5	39.52
17	15,12	3,28	3,1	30,29	30,5	39.52
18	15,12	3,28	3,1	30,29	30,5	39.52
19	15,16	2,29	2,1	29,29	29,2	39.66
20	15,14	2,29	2,3	29,29	29,2	39.76
21	15,14	2,29	2,3	29,29	29,2	39.76
22	15,14	2,29	2,3	29,29	29,2	39.76
23	15,16	2,29	2,4	29,29	29,2	40.00
24	15,16	2,29	2,4	29,29	29,2	40.00
25	15,16	2,29	2,4	29,29	29,2	40.00
26	15,16	2,29	2,4	29,29	29,2	40.00
27	15,16	2,29	2,4	29,29	29,2	40.00
28-40	15,16	2,29	2,2	29,29	29,2	40.12

The recovery factor of approximately 40.00 % is obtained from injection rate of 2,500 and 5,000 STB/D as shown in **Table 5.47** and **Figure 5.72**. The shortest production time is obtained from using injection rate of 5,000 STB/D. The production time of this injection rate is about 50,038 days. For lower injection rate, the time required to produce oil is more than 80 years. Therefore, the use of two horizontal producers with single vertical injector at water injection rate of 5,000 STB/D is the most suitable for this scenario. The cumulative oil recovery of 96,009 MSTB and the breakthrough time for this case is about 6,574 days. The cumulative water production is 112,923 MSTB while the amount of water injection is 250,190 MSTB.

Table 5.47: Production data for the case of two horizontal producers and one vertical injector at injection rate of 5,000 STB/D in 300-ft thick reservoir.

Production rate/well	Injection rate/well	Break through			Abandonment					
		Time	Cumulative oil	Recovery	Time	Recovery	Cumulative produced oil	Cumulative produced gas	Cumulative produced water	Cumulative water injection
STB/D	STB/D	Days	STB	%	Days	%	STB	MSCF	MSTB	MSTB
1720	**5000**	**6574**	**22615**	**9.45**	**50038**	**40.12**	**96009**	**164350**	**112923**	**250190**
860	2500	13149	22616	9.45	89849	40.13	96046	163840	99847	224623

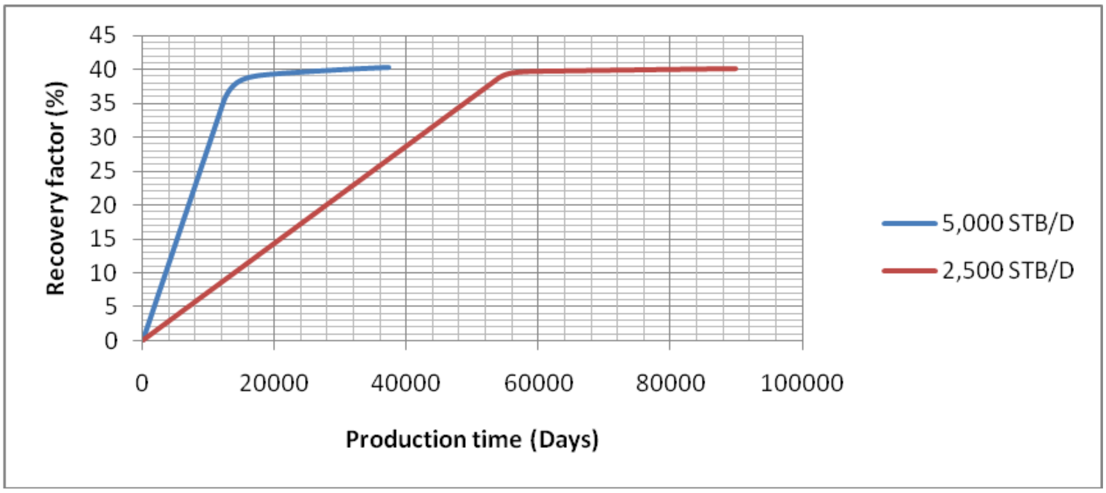

Figure 5.72: Recovery factor for the case of two horizontal producers and one vertical injector at injection rate of 2,500 STB/D and 5,000 STB/D in 300-ft thick reservoir.

5.3.2.2 Two horizontal producers with one horizontal injector

Well placement for two horizontal producers with one horizontal injector is performed by using genetic algorithm coupled with reservoir simulator. From the 1st generation in **Figure 5.73**, the genetic algorithm (GA) tries to search regions with high oil recovery in order to narrow down the search area for the next generation. Oil recovery factor climbs to 35.61% in the 4th generation. From the 5th generation to 8th generation, the local maximum occurs. A high oil recovery factor is obtained in the 14th generation. After the 14th generation, there are local maximums occurred from well optimization of two horizontal producers with one horizontal injector. The last local maximum is improved by the process of mutation and crossover in the 33rd generation. Even though the genetic algorithm is continued until it reaches the terminated generation (the 40th generation) but the solution is still not improved after the 33rd generation. Thus, the 33rd generation is the converged generation. The generation to reach the convergence in this scenario is more than that in the case of one horizontal producer with two vertical injectors because of a larger number of unknowns.

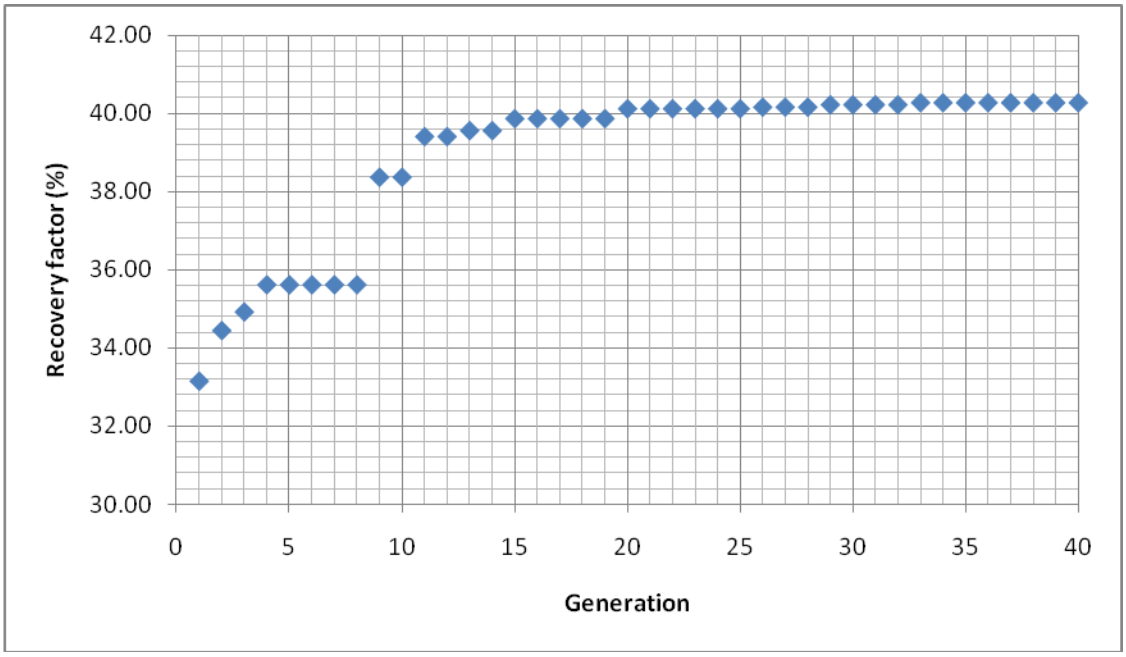

Figure 5.73: Recovery factor as a function of generation in the case of two horizontal producers and one horizontal injector in 300-ft thick reservoir.

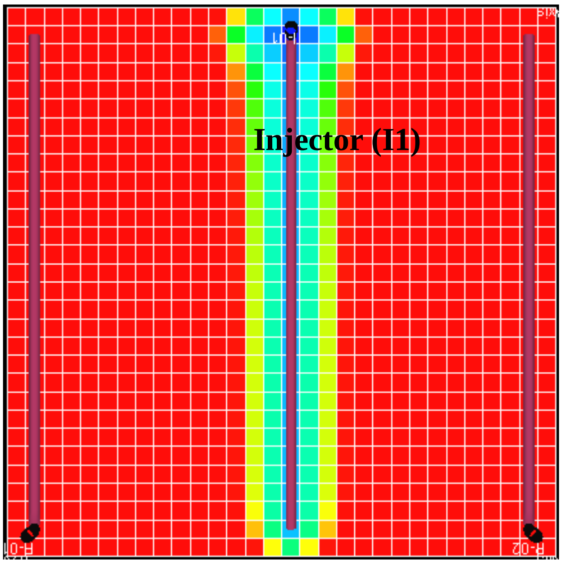

Figure 5.74: Well placement for the case location of two horizontal producers and one horizontal injector at injection rate of 10,000 STB/D in 300-ft thick reservoir.

The best well placement of two horizontal injectors and one horizontal producer obtain from the 33rd generation of optimization. These locations are at the (i,j) blocks of ((29,2), (29,29)), ((2,2), (2,29)) and ((15,29),(15,2)), respectively as shown in **Figure 5.74**. In this scenario, the well pattern is symmetrical. Genetic algorithm locates the injector between producers P1 and P2 because these producer locations help water injection break through at both sides of the horizontal producer at the same time. Therefore, the areal sweep efficiency and recovery factor at breakthrough are high when genetic algorithm provides locations of wells as illustrated in **Figure 5.74**. The result of well locations and oil recovery factor for each generation is shown in **Table 5.48**.

Table 5.48: Well locations and recovery factor for each generation in the case of two horizontal producers and one horizontal injector in 300-ft thick reservoir.

	Well I1		Well P1		Well P2		RF
Generations	Toe	Heel	Toe	Heel	Toe	Heel	%
1	17,24	17,1	27,29	27,25	8,19	8,17	33.15
2	17,30	17,20	2,18	2,25	21,19	21,2	34.44
3	7,29	7,7	15,18	15,26	5,18	5,8	34.92
4	12,29	12,7	28,18	28,2	3,18	3,8	35.61
5	12,29	12,7	28,18	28,2	3,18	3,8	35.61
6	12,29	12,7	28,18	28,2	3,18	3,8	35.61
7	12,29	12,7	28,18	28,2	3,18	3,8	35.61
8	12,29	12,7	28,18	28,2	3,18	3,8	35.61
9	12,29	12,7	28,10	28,2	3,18	3,28	38.36
10	12,29	12,7	28,10	28,2	3,18	3,28	38.36
11	14,29	14,1	29,16	29,2	3,5	3,28	39.40
12	14,29	14,1	29,16	29,2	3,5	3,28	39.40
13	14,29	14,1	29,16	29,1	3,5	3,28	39.56
14	14,29	14,1	29,16	29,1	3,5	3,28	39.56
15	14,29	14,3	29,6	29,25	3,2	3,28	39.86
16	14,29	14,3	29,6	29,25	3,2	3,28	39.86
17	14,29	14,3	29,6	29,25	3,2	3,28	39.86
18	14,29	14,3	29,6	29,25	3,2	3,28	39.86
19	14,29	14,3	29,6	29,25	3,2	3,28	39.86
20	15,29	15,3	29,2	29,25	3,1	3,28	40.12
21	15,29	15,3	29,2	29,25	3,1	3,28	40.12
22	15,29	15,3	29,2	29,25	3,1	3,28	40.12
23	15,29	15,3	29,2	29,25	3,1	3,28	40.12
24	15,29	15,3	29,2	29,25	3,1	3,28	40.12
25	15,29	15,3	29,2	29,25	3,1	3,28	40.12
26	15,29	15,3	29,2	29,29	2,2	2,29	40.16
27	15,29	15,3	29,2	29,29	2,2	2,29	40.16
28	15,29	15,3	29,2	29,29	2,2	2,29	40.16
29	15,29	15,2	29,1	29,29	2,2	2,29	40.22
30	15,29	15,2	29,1	29,29	2,2	2,29	40.22
31	15,29	15,2	29,1	29,29	2,2	2,29	40.22
32	15,29	15,2	29,1	29,29	2,2	2,29	40.22
33-40	15,29	15,2	29,2	29,29	2,2	2,29	40.27

The optimum horizontal producer length is same as the optimal length of other thickness which is 6,070 ft. The oil recovery for all injection rate represented in **Table 5.49** and **Figure 5.75** is about 40.00%. In this scenario, the use of two horizontal producers with single horizontal injector at water injection rate of 10,000 STB/D is suitable for this scenario because it can reduce the production time. The cumulative oil recovery of 96,377 MSTB is produced at the end of 37,254 days of production. The breakthrough time for this case is about 3,652 days. The cumulative water production is 220,024 MSTB while the amount of water injection is 372,540 MSTB.

Figure 5.49: Production data for the case of two horizontal producers and one horizontal injector at injection rate of 10000 STB/D in 300-ft thick reservoir.

Production rate/well	Injection rate/well	Break through			Abandonment					
		Time	Cumulative oil	Recovery	Time	Recovery	Cumulative produced oil	Cumulative produced gas	Cumulative produced water	Cumulative water injection
STB/D	STB/D	Days	STB	%	Days	%	STB	MSCF	MSTB	MSTB
3450	**10000**	**3652**	**25199**	**10.53**	**37254**	**40.27**	**96377**	**164538**	**220024**	**372540**
1720	5000	7670	26385	11.02	52230	40.07	95892	164317	122678	261150

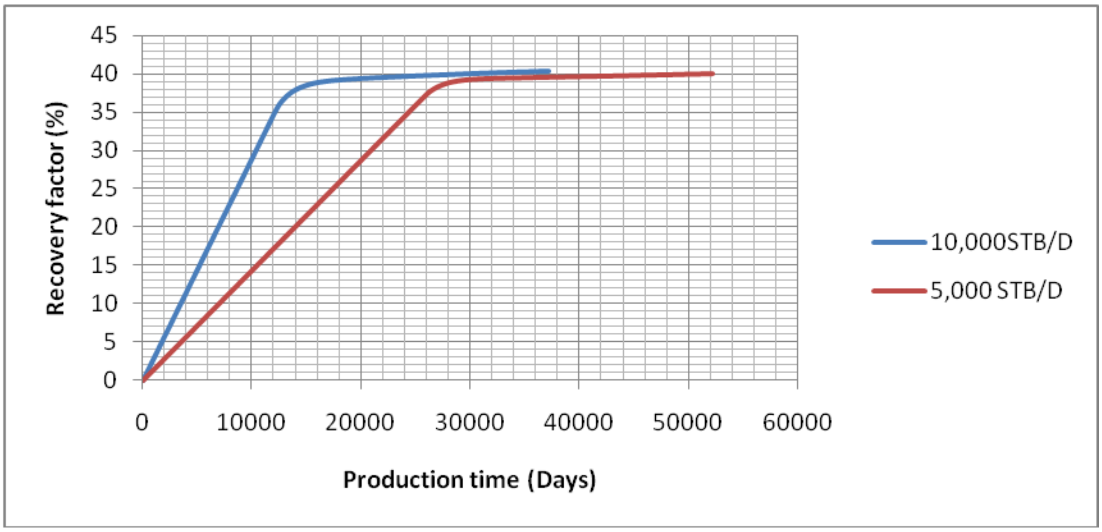

Figure 5.75: Recovery factor for the case of two horizontal producers and one horizontal injector at injection rate of 5000 STB/D 10000 STB/D in 300-ft thick reservoir.

5.3.2.3 Two vertical producers with one vertical injector

For optimization of well location for two vertical producers with one vertical injector, the well placement result is shown in **Figure 5.76**, the genetic algorithm (GA) tries to search regions with high oil recovery in the 1st generation. Oil recovery factor of 29.58% is obtained in the 1st generation. From the 2nd to the 4th generation, oil recovery factor climbs from 31.86% to 36.48%. After the 4th generation, the first local maximum is occurred but the solution is improved by the process of mutation and crossover in the 9th generation. A high oil recovery factor is obtained after the 13th generation. Even though the genetic algorithm is continued until it reaches the terminated generation (the 40th generation) but the solution doesn't improve after the 28th generation. Therefore, optimization of well location for two vertical producers with one vertical injector is found in the 28th generation. The number of generation to reach the convergence in this scenario is less than that in the case of one horizontal producer with two vertical injectors because the genetic algorithm finds high oil recovery in the 10th generation.

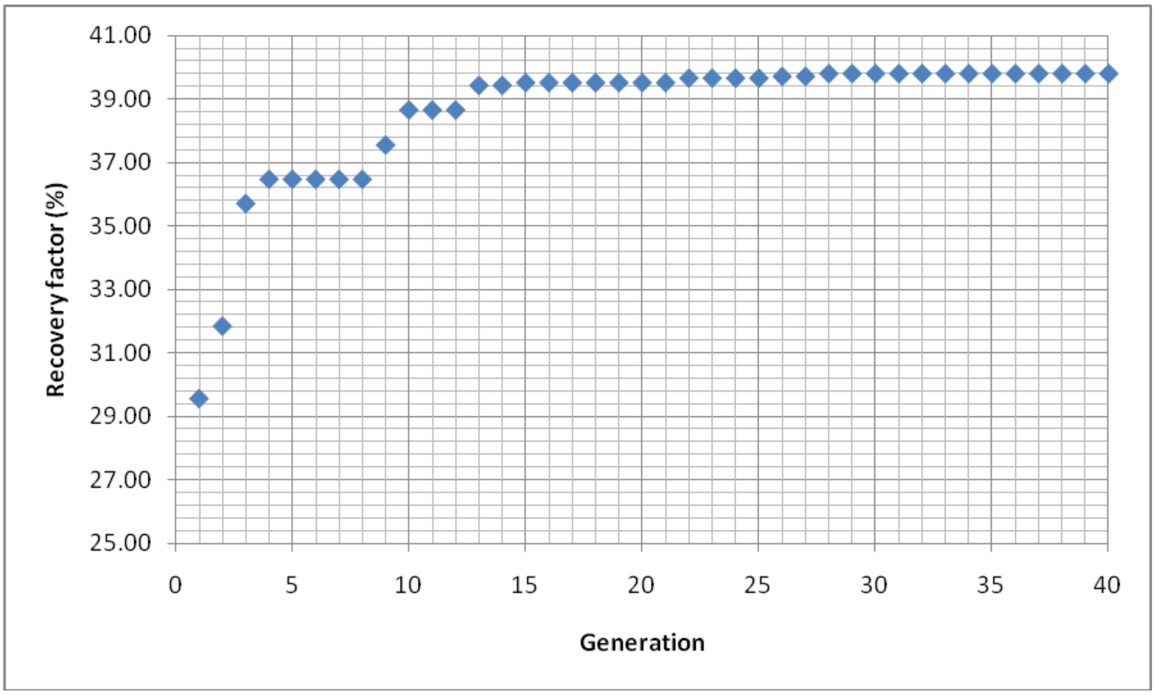

Figure 5.76: Recovery factor as a function of generation in the case of two vertical producers and one vertical injector in 300-ft thick reservoir.

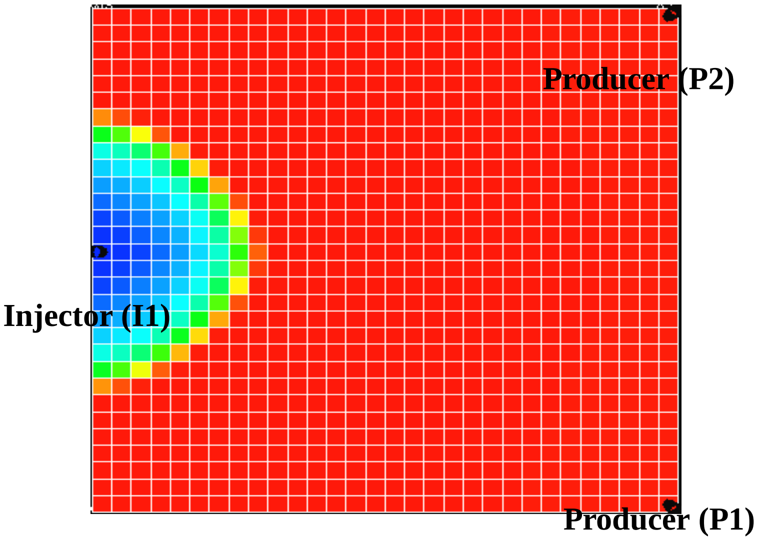

Figure 5.77: Well placement for the case of two vertical producers and one vertical injector at injection rate of 5,000 STB/D in 300-ft thick reservoir.

The best well placement of the two vertical injectors and one vertical producer for the best injection rate are shown in **Figure 5.77**. These locations are at the (i,j) blocks of (30,30), (30,1), and (1,15), respectively. In this scenario, there are no horizontal well. The pressure drop doesn't affect the flow of water. Therefore, the production wells P1 and P2 is located at the upper and lower right corner as uniform well pattern. The result of well locations and oil recovery factor for each generation is shown in **Table 5.50**.

Table 5.50: Well locations and recovery factor for each generation in the case of two vertical producers and one vertical injector in 300-ft thick reservoir.

Generations	Well I1	Well P1	Well P2	RF %
1	24,28	28,30	12,11	29.58
2	9,6	19,30	12,11	31.86
3	1,6	24,25	12,13	35.71
4	1,6	24,30	12,6	36.48
5	1,6	24,30	12,6	36.48
6	1,6	24,30	12,6	36.48
7	1,6	24,30	12,6	36.48
8	1,6	24,30	12,6	36.48
9	7,17	29,30	30,10	37.55
10	7,13	29,30	30,10	38.66
11	7,13	29,30	30,10	38.66
12	7,13	29,30	30,10	38.66
13	4,22	25,30	30,10	39.43
14	4,22	28,30	30,10	39.43
15	4,17	30,27	28,6	39.52
16	4,17	30,27	28,6	39.52
17	4,17	30,27	28,6	39.52
18	4,17	30,27	28,6	39.52
19	4,17	30,27	28,6	39.52
20	4,17	30,27	28,6	39.52
21	4,17	30,27	28,6	39.52
22	3,15	30,26	28,1	39.66
23	3,15	30,26	28,1	39.66
24	3,15	30,26	28,1	39.66
25	3,15	30,26	28,1	39.66
26	1,15	30,27	30,1	39.71
27	1,15	30,27	30,1	39.71
28-40	1,15	30,30	30,1	39.80

The highest oil recovery factor of 39.80 % shown in **Table 5.51** and **Figure 5.78** is found in this scenario with water injection rate of 5,000 STB/D. The cumulative oil recovery of 95,275 MSTB is produced at the end of 47,847 days of production. The breakthrough time for this scenario is about 12,418 days. The cumulative water production is 101,737 MSTB while the amount of water injection is 239,235 MSTB.

Table 5.51: Production data of two vertical producers and one vertical injector at injection rate of 2,500 STB/D, and 5,000 STB/D in 300-ft thick reservoir.

Production rate/well	Injection rate/well	Break through			Abandonment					
		Time	Cumulative oil	Recovery	Time	Recovery	Cumulative produced oil	Cumulative produced gas	Cumulative produced water	Cumulative water injection
STB/D	STB/D	Days	STB	%	Days	%	STB	MSCF	MSTB	MSTB
1720	**5000**	**12418**	**42718**	**17.85**	**47847**	**39.80**	**95257**	**163105**	**101737**	**239235**
860	2500	14975	25757	10.76	67570	38.62	92426	160905	87611	168925

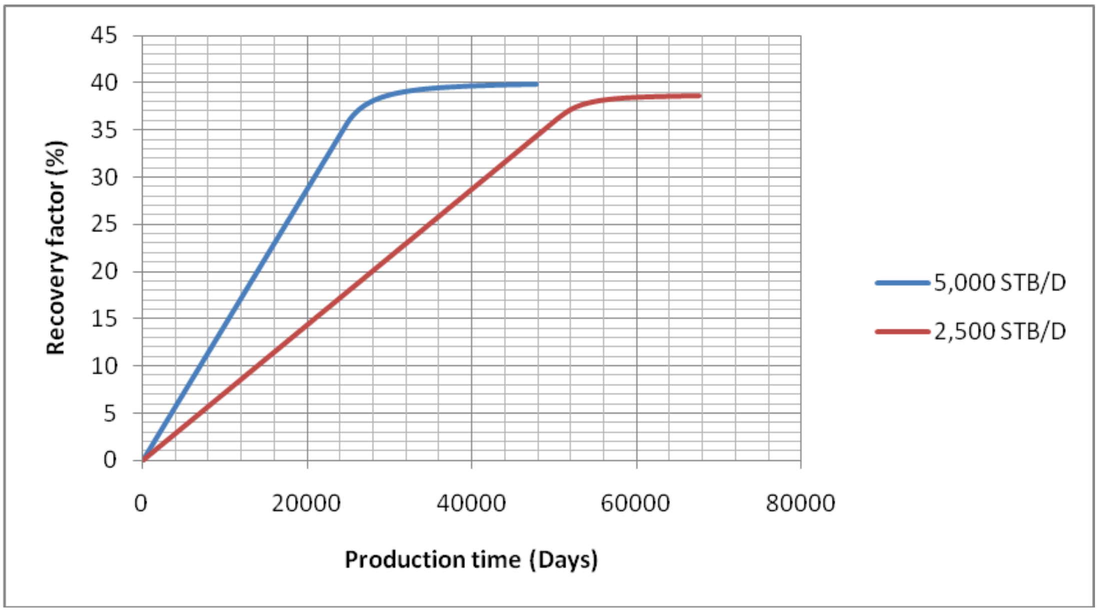

Figure 5.78: Recovery factor of two vertical producers and one vertical injector at injection rate of 2,500 STB/D, and 5,000 STB/D in 300-ft thick reservoir.

5.3.2.4 Two vertical producers with one horizontal injector

In well location optimization of this scenario, mutation and crossover can help the search escape local maximum. After running genetic algorithm coupled with reservoir simulator, the optimum locations of two vertical producers and a horizontal injector is obtained from the 28th generation of optimization. In **Figure 5.79**, the 1st to the 3rd generation of the genetic algorithm (GA) tries to search regions with high oil recovery. From the 3rd to the 6th generation, oil recovery factor increases from 29.96% to 38.23%. After the 6th generation, the local maxima occur several times but the solution is still improved by the process of mutation and crossover. In the 28th generation, oil recovery factor climbs to 39.67%. From the 28th to the 40th generation, the mutation and crossover cannot improve the solution. Therefore, well location optimization for this scenario is found in the 28th generation.

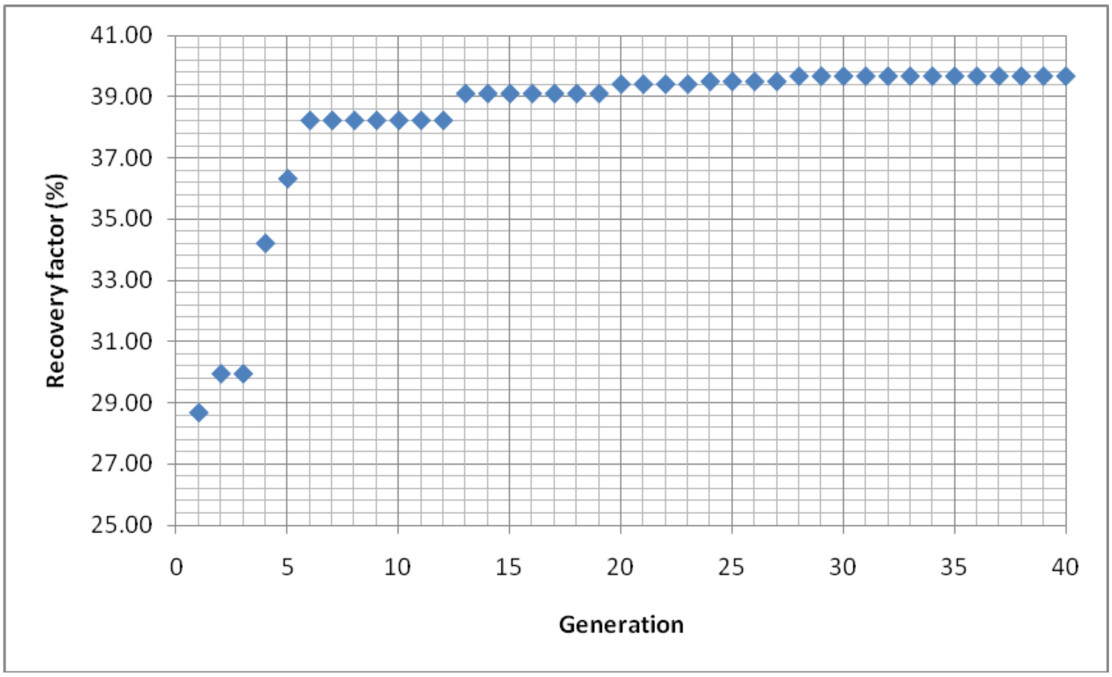

Figure 5.79: Recovery factor as a function of generation in the case of two vertical producers with one horizontal injector in 300-ft thick reservoir.

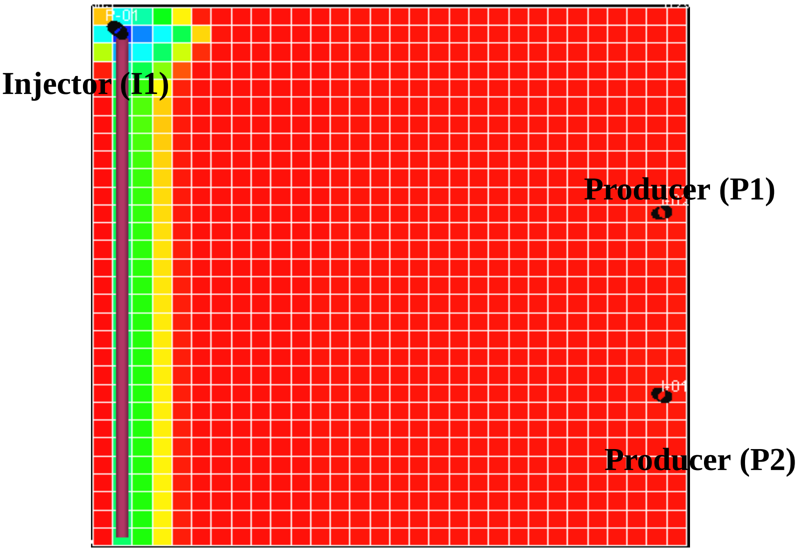

Figure 5.80: Well placement for the case of two vertical producers and one horizontal injector at injection rate of 10,000 STB/D in 300-ft thick reservoir.

The best well placement are at the (i,j) blocks of (29,12), (29,22) and ((2,29),(2,2)), respectively as shown in **Figure 5.80**. In this scenario, the pressure drop in horizontal well is occurred by wellbore friction assigned in this model. The pressure of horizontal injection well slightly increases from heel to toe during in water injection. Therefore, pressure at the heel is higher than that at the toe. The genetic algorithm tries to locate the production wells P1 and P2 at the (i,j) block of (29,12) and (29,22), respectively. **Table 5.52** represents result of well location and recovery factor in each generation.

Table 5.52: Well locations and recovery factor for each generation in the case of two vertical producers and one horizontal injector in 300-ft thick reservoir.

Generations	Well I1		Well P1	Well P2	RF
	Toe	Heel			%
1	17,8	17,18	15,12	8,2	28.69
2	24,23	24,12	22,12	28,8	29.96
3	24,23	24,12	22,12	28,8	29.96
4	2,23	2,12	22,1	28,8	34.22
5	2,23	2,12	22,25	28,13	36.32
6	2,23	2,1	19,25	28,15	38.23
7	2,23	2,1	19,25	28,15	38.23
8	2,23	2,1	19,25	28,15	38.23
9	2,23	2,1	19,25	28,15	38.23
10	2,23	2,1	19,25	28,15	38.23
11	2,23	2,1	19,25	28,15	38.23
12	2,23	2,1	19,25	28,15	38.23
13	3,30	3,1	25,22	29,12	39.10
14	3,30	3,1	25,22	29,12	39.10
15	3,30	3,1	25,22	29,12	39.10
16	3,30	3,1	25,22	29,12	39.10
17	3,30	3,1	25,22	29,12	39.10
18	3,30	3,1	25,22	29,12	39.10
19	3,30	3,1	25,22	29,12	39.10
20	1,30	1,2	27,22	29,12	39.41
21	1,30	1,2	27,22	29,12	39.41
22	1,30	1,2	27,22	29,12	39.41
23	1,30	1,2	27,22	29,12	39.41
24	1,29	1,2	27,22	29,12	39.50
25	1,29	1,2	27,22	29,12	39.50
26	1,29	1,2	27,22	29,12	39.50
27	1,29	1,2	27,22	29,12	39.50
28-40	2,29	2,2	29,22	29,12	39.67

The oil recovery of all injection rates is not significantly different, but the production time at the injection rate of 10,000 STB/D represented in **Figure 5.81** is 50 % less than that at injection rate of 5,000 STB/D. Therefore, the injection rate of 10,000 STB/D should be used for this scenario. The cumulative oil recovery of 94,929 MSTB is produced at the end of 27,759 days of production. The breakthrough time for this scenario is about 6,027 days. The cumulative water production is 138,520 MSTB while the amount of water injection is 227,590 MSTB.

Table 5.53: Production data for the case of two vertical producers and one horizontal injector at injection rate of 10,000 STB/D in 300-ft thick reservoir.

Production rate/well	Injection Rate/well	Break through			Abandonment					
		Time	Cumulative oil	Recovery	Time	Recovery	Cumulative oil	Cumulative produced gas	Cumulative produced water	Cumulative water injection
STB/D	STB/D	Days	STB	%	Days	%	STB	MSCF	MSTB	MSTB
3450	**10000**	**6027**	**41583**	**17.37**	**27759**	**39.67**	**94929**	**160721**	**138520**	**277590**
1720	5000	12053	41462	17.32	47481	39.82	95305	163604	99305	237405

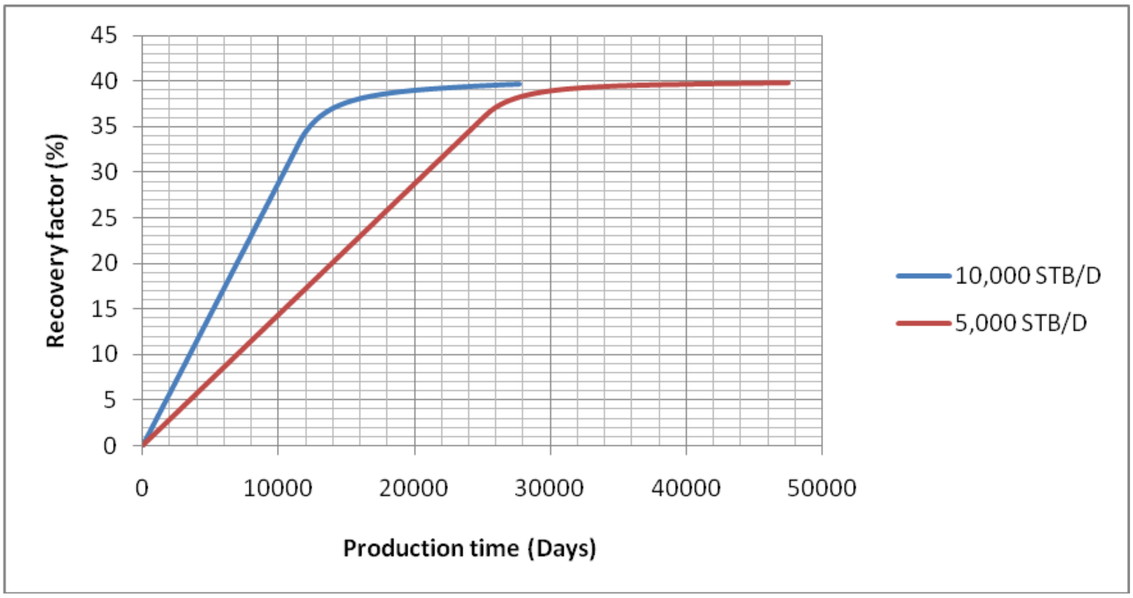

Figure 5.81: Recovery factor for the case of two vertical producers and one horizontal injector at injection rate of 5,000 STB/D and 10,000 STB/D in 300-ft thick reservoir.

5.3.3 Summary for well placement in 300-ft thick reservoir

Like other thicknesses, the difference in optimal well locations for each scenario occurs in this thickness. For the effect of injection rate, the result in this case is different from other thicknesses. In all cases, the oil recovery at high injection rate is close to the oil recovery at low injection rate because of a large thickness. Even though injection rate doesn't affect oil recovery, high injection rate still provides less production time.

In all the scenarios for 300-ft thick reservoir shown in **Table 5.54** and **5.55**, the oil recoveries are similar, but there are two scenarios that provide the smallest production time. These two scenarios are: (1) single vertical producer with two horizontal injectors and (2) single horizontal producer with two horizontal injectors. Even though the water production in the case of one vertical producer with two horizontal injectors is higher than that in the other cases but this scenario yields the highest oil recovery. In addition, the first scenario seems to be the most attractive because drilling cost of vertical producer is less than that of horizontal production well.

Table 5.54: Well placement results for 300-ft thick reservoir at medium injection rate.

			Break through			Abandonment						
Type	Production rate/well	Injection rate/well	Time	Cumulative oil	Recovery	Time	Oil rate	Recovery	Cumulative produced oil	Cumulative produced Gas	Cumulative produced water	Cumulative water injection
Scenarios	STB/D	STB/D	Days	STB	%	Days	STB/D	%	STB	MSCF	MSTB	MSTB
1HP-2VI	3450	2500	12053	41583	17.37	50403	60.56	40.02	95779	163796	108332	252015
1HP-2HI	6900	5000	4018	27724	11.58	39081	90.82	40.19	96193	163159	238058	390810
1VP-2VI	3450	2500	12784	44105	18.43	50769	48.24	39.78	95214	162079	114048	253845
1VP-2HI	6900	5000	4383	30243	12.64	38715	92.03	40.07	95904	160007	236380	387150
2HP-1VI	860	2500	13149	22616	9.45	89849	22.31	40.13	96046	163840	99847	224623
2HP-1HI	1720	5000	7670	26385	11.02	52230	73.77	40.07	95892	164317	122678	261150
2VP-1VI	860	2500	14975	25757	10.76	67570	31.08	38.62	92426	160905	87611	168925
2VP-1HI	1720	5000	12053	41462	17.32	47481	38.71	39.82	95305	163604	99305	237405

Table 5.55: Well placement results for 300-ft thick reservoir at high injection rate.

Type	Production rate/well	Break through				Abandonment					
		Injection rate/well	Time	Cumulative oil	Recovery	Time	Recovery	Cumulative oil	Cumulative produced Gas	Cumulative produced water	Cumulative water injection
Scenarios	STB/D	STB/D	Days	STB	%	Days	%	STB	MSCF	MSTB	MSTB
1HP-2VI	6900	5000	6027	41583	17.37	30316	40.05	95840	160310	163442	303160
1HP-2HI	**13800**	**10000**	**1826**	**25199**	**10.53**	**19723**	**40.34**	**96544**	**156390**	**256828**	**394460**
1VP-2VI	6900	5000	6392	44101	18.43	33602	40.29	96420	149646	193210	336020
1VP-2HI	**13800**	**10000**	**2009**	**27717**	**11.58**	**21550**	**41.21**	**98622**	**151403**	**287041**	**431000**
2HP-1VI	1720	5000	6574	22615	9.45	50038	40.12	96009	164350	112923	250190
2HP-1HI	3450	10000	3652	25199	10.53	37254	40.27	96377	164538	220024	372540
2VP-1VI	1720	5000	12418	42718	17.85	47847	39.8	95257	163105	101737	239235
2VP-1HI	3450	10000	6027	41583	17.37	27759	39.67	94929	160721	138520	277590

CHAPTER VI
CONCLUSIONS AND RECOMMENDATIONS

In this chapter, the conclusions of application of genetic algorithm in well placement for waterflooding process in different reservoir thicknesses are presented. Recommendations for future works are also outlined.

6.1 Conclusions

The performance of genetic algorithm used in this study depends on length of string and initial guesses of the solutions. The length of string varies with the number of well and type of well. In some scenario such as well placement of a horizontal producer with two horizontal injectors, the length of string is longer than that in other scenarios, resulting in longer computational time than other scenarios. The longer computational time may reduce attractiveness of the genetic algorithm. In addition, the problem concerning with local maximum needs to be considered because local maxima occur from the genetic algorithm before it reaches the converged solution. In this study, the process of mutation and crossover can search other locations in order to reach the global maximum. However, the maximum generation for terminating the process should also be adequate.

In this study, horizontal well is located at the middle depth of the reservoir. This is the cause of low recovery for low injection rate due to segregation but segregation can be reduced in case of high injection rate because flow rate in the horizontal direction is much higher than that in the vertical direction. For a thick reservoir, producing oil and injecting water with high rate can reduce the time required to produce oil. High injection rate can be used for a thick reservoir because a large cross sectional area can produce oil with high rate without a large bottomhole pressure. In case of a thin reservoir, the cross sectional area is less than that in case of a large thick reservoir. As a result, injection rate is limited by maximum injection pressure. The injection pressure at the bottom hole is high even though injecting water with low injection rate is performed. This problem is the cause of low oil recovery at high injection rate. In this study, it occurs for the case of 30-ft thick reservoir.

In all the cases investigated in this study, the scenario to obtain the highest recovery for each reservoir thickness is different. In case of a large reservoir thickness (100 ft and 300 ft in this study), the oil recovery is the highest when using a single vertical producer with two horizontal injectors at injection rate of 10,000 STB/D. This scenario provides high oil recovery and low water production. The production time required to produce oil is less than other scenarios. The advantage of using one vertical producer with two horizontal injectors is lower cost than using a single horizontal producer with two horizontal injectors. However, this scenario needs to be economically evaluated in order to determine the justification for drilling two horizontal injection wells and one vertical production well.

Although a single vertical producer with two horizontal injectors result in the highest oil recovery for a thick reservoir, this scenario is not suitable for a thin reservoir (30 ft in this study) due to an early breakthrough. A large amount of produced water is turned out since the scenario has the shortest production time. For thin reservoirs, using one horizontal producer with two horizontal injectors with injection rate of 10,000 STB/D is the best choice.

6.2 Recommendations

1. In this study, oil recovery factor is the objective function of genetic algorithm. The ratio between cumulative oil production and cumulative water injection is not considered because additional cost of water injection in case of high injection rate is insignificant when it is compared with additional profit of producing oil at high injection rate. For other reservoirs, this parameter should be investigated before selecting a suitable objective function for genetic algorithm.
2. Friction loss in horizontal well is important for finding suitable injector length. In this study, the size of horizontal well is fixed at only one value. For other diameters, suitable well length may be different.
3. The reservoir used in this study is an undersaturated oil reservoir. A horizontal well can be located at the middle of reservoir. In case of

saturated reservoir, a horizontal well cannot be located at the middle depth of reservoir due to expansion of the gas at the top of reservoir.

4. In this study, only three injection rates were analyzed. Therefore, other injection rates should be studied for obtaining the most suitable injection rate.

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APPENDIX

APPENDIX

Example of genetic algorithm code used in this study.

```
Sub Button1_Click()
          Dim i, J, K, G, NoOfPopu, NoOfGene, Max_Value As Integer
          Dim gene(100, 100) As String
          Dim Chromosome(100)  As String
          NoOfPopu = 20
          NoOfGene = 8
          Max_Value = 40

          G = Cells(31, 34)

          If G = 1 Then

           For i = 1 To NoOfPopu
'''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''
                    For J = 1 To NoOfGene
                      gene(i, J) = EncodeChromosome(Int((Max_Value  - 1) *
                  Rnd + 1))

'''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''
                   Cells(i + 5, J + 1 + 31) = gene(i, J)
                   Chromosome(i) = gene(i, 1) & gene(i, 2) & gene(i, 3) &
                   gene(i,  4) & gene(i, 5) & gene(i, 6) & gene(i, 7) &
                   gene(i, 8)
          Next J
    Cells(i + 5, 32) = Chromosome(i)
   Next i
Else
End If
'''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''
                                    'Transfer loop
'''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''
If G > 1 Then
```

```
    For i = 1 To NoOfPopu
       Chromosome(i) = Cells(i + 5, 32)
    Next i
Else
End If
‘’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’
                         'Evole part                         '
‘’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’
    Dim intParts As Integer
    Dim strChromosome As String
    Dim ValueMax, ValueMaxfit As Double
         Maxfititness = Cells (4, 4)
    Dim Value(100) As Double
    Dim Cut, bit As Integer
    Dim NewChromosome(100), ChromosomeF, ChromosomeM,
          GeneX1, GeneX2, GeneX3 As String
    Dim NoOfDie As Double
          bit = 40

    For i = 1 To NoOfPopu
          Value(i) = Cells(i + 5, 49)
    Next i
'Condition for substitute Parent
    ValueMax = 0
    For i = 1 To NoOfPopu
             If Value(i) >= ValueMax Then
                          ValueMax = Value(i)
             ElseIf Value(i) < ValueMax Then
                          ValueMax = ValueMax
             Else
             End If
    Next i
             ValueMaxfit = ValueMax
             ValueMax = 0
```

```
   For i = 1 To NoOfPopu
        If Value(i) <> ValueMaxfit Then
        If Value(i) >= ValueMax Then
        ValueMax = Value(i)
        ElseIf Value(i) < ValueMax Then
        ValueMax = ValueMax
        Else
        End If
        Else
        End If
   Next i

        ValueMaxfit1 = ValueMax


'Condition for select Parent
   For i = 1 To NoOfPopu
      If Value(i) = ValueMaxfit Then
                     ChromosomeF = Chromosome(i)
      ElseIf Value(i) = ValueMaxfit1 Then
                     ChromosomeM = Chromosome(i)
      Else
      End If
   Next i

'''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''
'                                 'Mutate                               '
'''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''
 Dim Realchromosome(100) As String
 Dim R, S As Integer
 Realchromosome(1) = ChromosomeF
 Realchromosome(2) = ChromosomeM
 For i = 1 To NoOfPopu                              ' 20% mutation
             R = Int(Rnd * 1)
```

```
If R = 1 Then
        S = 0
        Do
        Cut = (Int((bit - 1) * Rnd + 1))

        GeneX1 = Mid(ChromosomeF, 1, Cut)
        GeneX2 = Mid(ChromosomeF, Cut + 2)
        GeneX3 = Mid(ChromosomeF, Cut + 1, 1)
    If GeneX3 = 0 Then
            ChromosomeF = GeneX1 & 1 & GeneX2
    ElseIf GeneX3 = 1 Then
            ChromosomeF = GeneX1 & 0 & GeneX2
    Else
    End If
            S = S + 1
    Loop While S < 25
    NewChromosome(i) = ChromosomeF
    Realchromosome(i + 2) = NewChromosome(i)
Else
''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''

S = 0
    Do
    Cut = (Int((bit - 1) * Rnd + 1))
        GeneX1 = Mid(ChromosomeM, 1, Cut)
        GeneX2 = Mid(ChromosomeM, Cut + 2)
        GeneX3 = Mid(ChromosomeM, Cut + 1, 1)
        If GeneX3 = "0" Then
                ChromosomeM = GeneX1 & 1 & GeneX2
         ElseIf GeneX3 = "1" Then
                ChromosomeM = GeneX1 & 0 & GeneX2
     Else
    End If
            S = S + 1
    Loop While S < 25
    NewChromosome(i) = ChromosomeM
```

```
        Realchromosome(i + 2) = NewChromosome(i)
      End If
Next i

‘’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’
'                 'Cross                 '
‘’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’

For i = 1 To (NoOfPopu )                'Cross over 80 %

        Cut = (Int(bit - 1) * Rnd + 1)

        GeneX1 = Mid(Realchromosome(1), 1, Cut)
        GeneX2 = Mid(Realchromosome(1), Cut + 1)
        GeneX3 = Mid(Realchromosome(2), 1, Cut)
        GeneX4 = Mid(Realchromosome(2), Cut + 1)

        Realchromosome(2 * i + 6) = GeneX1 & GeneX4
        Realchromosome(2 * i + 7) = GeneX3 & GeneX2

Next i

‘’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’
'              Out put
‘’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’
For i = 1 To NoOfPopu
  Cells(i + 5, 32) = Realchromosome(i)
Next i
```

```
For i = 1 To NoOfPopu
            gene(i, 1) = Mid(Realchromosome(i), 1, 5)
            gene(i, 2) = Mid(Realchromosome(i), 6, 5)
            gene(i, 3) = Mid(Realchromosome(i), 11, 5)
            gene(i, 4) = Mid(Realchromosome(i), 16, 5)
            gene(i, 5) = Mid(Realchromosome(i), 21, 5)
            gene(i, 6) = Mid(Realchromosome(i), 26, 5)
            gene(i, 7) = Mid(Realchromosome(i), 31, 5)
           gene(i, 8) = Mid(Realchromosome(i), 36, 5)


Next i

    For i = 1 To NoOfPopu
        For J = 1 To NoOfGene
             If gene(i, J) = "00000" Then
             gene(i, J) = "00001"
             ElseIf gene(i, J) = "11111" Then
             gene(i, J) = "11110"
             Else
             End If
        Next J
    Next i



For i = 1 To NoOfPopu
    For J = 1 To NoOfGene
        Cells(i + 5, J + 32) = gene(i, J)
    Next J
Next i
```

```
'Execute Eclipse

Shell "explorer D:\Constant_Flow\2P-1I@Base\Left,1\Thesis.bat"
        MsgBox ("Generation " & G & "!" & vbCrLf & "Pleas run Eclipse Software")

For i = 1 To NoOfPopu
Sheet3.Cells(i, G) = Cells(i + 5, 49)
Next i
G = G + 1
Cells(31, 34) = G
End Sub



Private Function EncodeChromosome(lngDecimal As Long) As String



  Dim Remainder(1 To Max_Bits) As Double
  Dim DecimalNumber As Double
  Dim i As Integer

  'get value
        DecimalNumber = Val(lngDecimal)

  'calculate
  For i = 1 To Max_Bits
        Remainder(i) = DecimalNumber Mod 2
        DecimalNumber = DecimalNumber / 2
        DecimalNumber = Int(DecimalNumber)
  Next i

  'build chromosome
  For i = Max_Bits To 1 Step -1
        EncodeChromosome = EncodeChromosome & Remainder(i)
```

```
    Next i

    Erase Remainder

End Function


‘’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’
’’’’’’’’’’’’’’’’’Writing file’’’’’’’’’’’’’’’’’’’’’’’‘’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’’
Sub Button2_Click()
Dim TT As Double
TT = Sheets("sheet1").Cells(18, 26)

Sheets("sheet2").Cells(4, 7) = Sheets("sheet1").Cells(5 + TT, 30)     'X1,Y1 of Injector
Sheets("sheet2").Cells(5, 7) = Sheets("sheet1").Cells(5 + TT, 31)

Sheets("sheet2").Cells(4, 3) = Sheets("sheet1").Cells(5 + TT, 32)     ' X1,2 of horizontal
Sheets("sheet2").Cells(7, 3) = Sheets("sheet1").Cells(5 + TT, 32)

If Sheets("sheet1").Cells(5 + TT, 33) > Sheets("sheet1").Cells(5 + TT, 34) Then
Sheets("sheet2").Cells(5, 3) = Sheets("sheet1").Cells(5 + TT, 34)     ' Y1,2 of horizontal
Sheets("sheet2").Cells(8, 3) = Sheets("sheet1").Cells(5 + TT, 33)
ElseIf Sheets("sheet1").Cells(5 + TT, 33) < Sheets("sheet1").Cells(5 + TT, 34) Then
Sheets("sheet2").Cells(5, 3) = Sheets("sheet1").Cells(5 + TT, 33)
Sheets("sheet2").Cells(8, 3) = Sheets("sheet1").Cells(5 + TT, 34)
Else
End If
'Open "C:\Users\acer\Desktop\ww.txt" For Append As #1

'first set a string which contains the path to the file you want to create.
'this example creates one and stores it in the root directory
If TT = 1 Then
MyFile = "D:\Constant_Flow\1P-1I\New folder\Left\Thesis-1_sch.INC"
ElseIf TT = 2 Then
MyFile = "D:\Constant_Flow\1P-1I\New folder\Left\Thesis-2_sch.INC"
```

```
ElseIf TT = 3 Then
MyFile = "D:\Constant_Flow\1P-1I\New folder\Left\Thesis-3_sch.INC"
ElseIf TT = 4 Then
MyFile = "D:\Constant_Flow\1P-1I\New folder\Left\Thesis-4_sch.INC"
ElseIf TT = 5 Then
MyFile = "D:\Constant_Flow\1P-1I\New folder\Left\Thesis-5_sch.INC"
ElseIf TT = 6 Then
MyFile = "D:\Constant_Flow\1P-1I\New folder\Left\Thesis-6_sch.INC"
ElseIf TT = 7 Then
MyFile = "D:\Constant_Flow\1P-1I\New folder\Left\Thesis-7_sch.INC"
ElseIf TT = 8 Then
MyFile = "D:\Constant_Flow\1P-1I\New folder\Left\Thesis-8_sch.INC"
ElseIf TT = 9 Then
MyFile = "D:\Constant_Flow\1P-1I\New folder\Left\Thesis-9_sch.INC"
Else
MyFile = "D:\Constant_Flow\1P-1I\New folder\Left\Thesis-10_sch.INC"
End If
'set and open file for output
fnum = FreeFile()
Open MyFile For Output As fnum
'write project info and then a blank line. Note the comma is required
'Write #fnum, "I wrote this"
'Write #fnum,
'use Print when you want the string without quotation marks

Print #fnum, "--"
Print #fnum, "-- ---------------------------------------------------------------------------"
Print #fnum, "-- Office Schedule (SCHED) Data Section Version 2007.1 May 26 2007"
Print #fnum, "-- ---------------------------------------------------------------------------"
Print #fnum, "--"
Print #fnum, "-- File: Thesis-" & TT & "_sch.INC"
Print #fnum, "-- Created on: 01-Feb-2011 at: 00:36:14"
Print #fnum, "--"
```

```
Print #fnum, "--
***************************************************************************
**"
Print #fnum, "-- *                    WARNING                   *"
Print #fnum, "-- *        THIS FILE HAS BEEN AUTOMATICALLY GENERATED.
*"
Print #fnum, "-- *     ANY ATTEMPT TO EDIT MANUALLY MAY RESULT IN
INVALID DATA.     *"
Print #fnum, "--
***************************************************************************
**"
Print #fnum, "--"
Dim D, E, F, G(100), U, V(100) As String
Dim i, NoOfZ, H(100), J(100), K(100), L(100), M(100), N(100), O(100), P(100), Q(100), R,
S, T, Z As Double

D = Sheet2.Cells(3, 1) '"FIELD"
E = Sheet2.Cells(4, 1) 'No of well
F = Sheet2.Cells(5, 1) '" "
R = Sheet2.Cells(6, 1) 'No.Hor
S = Sheet2.Cells(7, 1) 'No.Ver
U = Sheet2.Cells(8, 1) '"1"
'INPUT DATA
For i = 1 To E + 10
G(i) = Sheet2.Cells(3, 2 + i) '" P-01" ""
H(i) = Sheet2.Cells(4, 2 + i) 'X1
J(i) = Sheet2.Cells(5, 2 + i) 'Y1
K(i) = Sheet2.Cells(6, 2 + i) 'Z1
L(i) = Sheet2.Cells(7, 2 + i) 'X2
M(i) = Sheet2.Cells(8, 2 + i) 'Y2
N(i) = Sheet2.Cells(9, 2 + i) 'Z2
O(i) = Sheet2.Cells(10, 2 + i) 'flow rate
P(i) = Sheet2.Cells(11, 2 + i) 'Bottom hole pressure
Q(i) = Sheet2.Cells(12, 2 + i) 'Diameter
V(i) = Sheet2.Cells(13, 2 + i) ''P-01'
```

```
Next i
''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''
T = 1 ' No.Well
''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''


Print #fnum, "-- Off SCHED Units: " & D
Print #fnum, "-- Off SCHED Wells:          " & E
For Z = 1 To R
   Print #fnum, "-- Off SCHED Well: " & Z & " " & H(Z) & " " & J(Z) & " 100 10 0 " &
K(Z) + (M(Z) - J(Z))
   Print #fnum, "-- Off SCHED Name: " & G(Z)

   For i = 1 To K(Z)
      Print #fnum, "-- Off SCHED Completion: " & i & " " & H(Z) & " " & J(Z) & " " & i
      Print #fnum, "-- Off SCHED LGR:" & F
      Print #fnum, "-- Off SCHED Compdat: 0.72916001 -9.9999999e+032"
   Next i

   For i = K(Z) + 1 To K(Z) + (M(Z) - J(Z))
      Print #fnum, "-- Off SCHED Completion: " & i & " " & H(Z) & " " & J(Z) + i - (K(Z))
& " " & K(Z)
      Print #fnum, "-- Off SCHED LGR:" & F
      Print #fnum, "-- Off SCHED Compdat: 0.72916001 -9.9999999e+032"

   Next i
Next Z

''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''
                                        'Vertical Well
''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''

For Z = 1 To S
```

```
   Print #fnum, "-- Off SCHED Well: " & Z + R & " " & H(4 + Z) & " " & J(4 + Z) & " 100 1
0 " & K(4 + Z)
   Print #fnum, "-- Off SCHED Name: " & G(4 + Z)

   For i = 1 To K(4 + Z)
      Print #fnum, "-- Off SCHED Completion: " & i & " " & H(4 + Z) & " " & J(4 + Z) & " "
& i
      Print #fnum, "-- Off SCHED LGR:" & F
      Print #fnum, "-- Off SCHED Compdat: 0.72916001 -9.9999999e+032"
   Next i
Next Z
''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''
                                        'Time
''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''


Print #fnum, "-- Off SCHED Groups:          1"
Print #fnum, "-- Off SCHED Group: " & U
Print #fnum, "-- Off SCHED Times:         26"
Print #fnum, "-- Off SCHED Date: 1 1 2010 0"
Print #fnum, "-- Off SCHED Time: 0 0"
Print #fnum, "-- Off SCHED Date: 1 1 2011 1"
Print #fnum, "-- Off SCHED Time: 365 365"
Print #fnum, "-- Off SCHED Date: 1 1 2012 1"
Print #fnum, "-- Off SCHED Time: 365 730"
Print #fnum, "-- Off SCHED Date: 1 1 2013 1"
Print #fnum, "-- Off SCHED Time: 366 1096"
Print #fnum, "-- Off SCHED Date: 1 1 2014 1"
Print #fnum, "-- Off SCHED Time: 365 1461"
Print #fnum, "-- Off SCHED Date: 1 1 2015 1"
Print #fnum, "-- Off SCHED Time: 365 1826"
Print #fnum, "-- Off SCHED Date: 1 1 2016 1"
Print #fnum, "-- Off SCHED Time: 365 2191"
Print #fnum, "-- Off SCHED Date: 1 1 2017 1"
Print #fnum, "-- Off SCHED Time: 366 2557"
```

```
Print #fnum, "-- Off SCHED Date: 1 1 2018 1"
Print #fnum, "-- Off SCHED Time: 365 2922"
Print #fnum, "-- Off SCHED Date: 1 1 2019 1"
Print #fnum, "-- Off SCHED Time: 365 3287"
Print #fnum, "-- Off SCHED Date: 1 1 2020 1"
Print #fnum, "-- Off SCHED Time: 365 3652"
Print #fnum, "-- Off SCHED Date: 1 1 2021 1"
Print #fnum, "-- Off SCHED Time: 366 4018"
Print #fnum, "-- Off SCHED Date: 1 1 2022 1"
Print #fnum, "-- Off SCHED Time: 365 4383"
Print #fnum, "-- Off SCHED Date: 1 1 2023 1"
Print #fnum, "-- Off SCHED Time: 365 4748"
Print #fnum, "-- Off SCHED Date: 1 1 2024 1"
Print #fnum, "-- Off SCHED Time: 365 5113"
Print #fnum, "-- Off SCHED Date: 1 1 2025 1"
Print #fnum, "-- Off SCHED Time: 366 5479"
Print #fnum, "-- Off SCHED Date: 1 1 2026 1"
Print #fnum, "-- Off SCHED Time: 365 5844"
Print #fnum, "-- Off SCHED Date: 1 1 2027 1"
Print #fnum, "-- Off SCHED Time: 365 6209"
Print #fnum, "-- Off SCHED Date: 1 1 2028 1"
Print #fnum, "-- Off SCHED Time: 365 6574"
Print #fnum, "-- Off SCHED Date: 1 1 2029 1"
Print #fnum, "-- Off SCHED Time: 366 6940"
Print #fnum, "-- Off SCHED Date: 1 1 2030 1"
Print #fnum, "-- Off SCHED Time: 365 7305"
Print #fnum, "-- Off SCHED Date: 1 1 2031 1"
Print #fnum, "-- Off SCHED Time: 365 7670"
Print #fnum, "-- Off SCHED Date: 1 1 2032 1"
Print #fnum, "-- Off SCHED Time: 365 8035"
Print #fnum, "-- Off SCHED Date: 1 1 2033 1"
Print #fnum, "-- Off SCHED Time: 366 8401"
Print #fnum, "-- Off SCHED Date: 1 1 2034 1"
Print #fnum, "-- Off SCHED Time: 365 8766"
Print #fnum, "-- Off SCHED Date: 1 1 2035 1"
```

```
Print #fnum, "-- Off SCHED Time: 365 9131"
Print #fnum, "-- Off SCHED END: 1 1 2035"
Print #fnum, " "
Print #fnum, "ECHO"


''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''
                                        'Compdat
''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''
'''''''''''''''''''''''''''''''''''''''''''''''''''''''''Well 1''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''
For Z = 1 To R

    Print #fnum, "WELSPECS"
    Print #fnum, "'" & V(Z) & " " & "'1' " & H(Z) & " " & J(Z) & " 5102 'OIL' 1* 'STD'
'SHUT' 'YES' 1* 'SEG' 3* 'STD' /"
    Print #fnum, " /"



    Print #fnum, "COMPDAT"
    Print #fnum, "'" & V(Z) & " " & H(Z) & " " & J(Z) & " 1 " & K(Z) & " " & "'OPEN' 2*
0.72916 3* 'Z' 1* /"
    Print #fnum, " /"

    Print #fnum, "COMPDAT"
    Print #fnum, "'" & V(Z) & " " & H(Z) & " " & J(Z) & " " & K(Z) & " " & K(Z) & " " &
"'OPEN' 2* 0.72916 3* 'Z' 1* /"
    Print #fnum, " /"

  For i = K(Z) + 1 To K(Z) + (M(Z) - J(Z))
    Print #fnum, "COMPDAT"
    Print #fnum, "'" & V(Z) & " " & H(Z) & " " & J(Z) + i - (K(Z)) & " " & K(Z) & " " &
K(Z) & " " & "'OPEN' 2* 0.72916 3* 'Z' 1* /"
    Print #fnum, " /"
  Next i
```

```
        Print #fnum, "WFRICTN"
        Print #fnum, "" & V(Z) & " 0.2917 8.333e-005 1* /"

    For i = 1 To K(Z)
        Print #fnum, "" & H(Z) & " " & J(Z) & " " & i & " 2* 'Z' 2* /"
    Next i

    For i = K(Z) + 1 To K(Z) + (M(Z) - J(Z))
        Print #fnum, "" & H(Z) & " " & J(Z) + i - (K(Z)) & " " & K(Z) & " 2* 'Y' 2* /"
    Next i
        Print #fnum, "/"
        Print #fnum, "WCONPROD"
        Print #fnum, "" & V(Z) & " 'OPEN' 'GRUP' " & O(Z) & " 4* " & P(Z) & " 3* /"
        Print #fnum, "/"
Next Z
''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''
                                   'Compdat
''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''
''''''''''''''''''''''''''''''''''''''''''''''''''''Well 2''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''''
For Z = 1 To S
    Print #fnum, "WELSPECS"
    Print #fnum, "" & V(4 + Z) & " '1' " & H(4 + Z) & " " & J(4 + Z) & " 5102 'OIL' 1* 'STD' 'SHUT' 'YES' 1* 'SEG' 3* 'STD' /"
    Print #fnum, " /"

    Print #fnum, "COMPDAT"
    Print #fnum, "" & V(4 + Z) & " 2* 1 " & K(4 + Z) & " 'OPEN' 2* 0.72916 3* 'Z' 1* /"
     Print #fnum, "/"

    Print #fnum, "WCONINJE"
    Print #fnum, "" & V(4 + Z) & " 'WATER' 'OPEN' 'GRUP' " & O(4 + Z) & " 1* " & P(4 + Z) & " 3* /"
    Print #fnum, " /"
Next Z
```

```
For Z = 1 To R

    Print #fnum, "WECON"
    Print #fnum, "" & V(Z) & " 10 4* 'WELL' 'YES' 1* 'POTN' 1* 'NONE' 2* /"
    Print #fnum, "/"
Next Z

    Print #fnum, "RPTRST"
    Print #fnum, "'BASIC=2' /"



Print #fnum, "RPTSCHED"
Print #fnum, "'PRES' 'SOIL' 'SWAT' 'SGAS' 'RS' 'RV' 'RESTART=2' /"
Print #fnum, "  "
Print #fnum, "TSTEP"
Print #fnum, "365 /"
Print #fnum, " "
Print #fnum, "TSTEP"
Print #fnum, "365 /"
Print #fnum, " "
Print #fnum, "TSTEP"
Print #fnum, "366 /"
Print #fnum, " "
Print #fnum, "TSTEP"
Print #fnum, "365 /"
Print #fnum, " "
Print #fnum, "TSTEP"
Print #fnum, "365 /"
Print #fnum, " "
Print #fnum, "TSTEP"
Print #fnum, "365 /"
Print #fnum, " "
Print #fnum, "TSTEP"
Print #fnum, "366 /"
```

```
Print #fnum, " "
Print #fnum, "TSTEP"
Print #fnum, "365 /"
Print #fnum, " "
Print #fnum, "TSTEP"
Print #fnum, "365 /"
Print #fnum, " "
Print #fnum, "TSTEP"
Print #fnum, "365 /"
Print #fnum, " "
Print #fnum, "TSTEP"
Print #fnum, "366 /"
Print #fnum, " "
Print #fnum, "TSTEP"
Print #fnum, "365 /"
Print #fnum, " "
Print #fnum, "TSTEP"
Print #fnum, "365 /"
Print #fnum, " "
Print #fnum, "TSTEP"
Print #fnum, "365 /"
Print #fnum, " "
Print #fnum, "TSTEP"
Print #fnum, "366 /"
Print #fnum, " "
Print #fnum, "TSTEP"
Print #fnum, "365 /"
Print #fnum, " "
Print #fnum, "TSTEP"
Print #fnum, "365 /"
Print #fnum, " "
Print #fnum, "TSTEP"
Print #fnum, "365 /"
Print #fnum, " "
Print #fnum, "TSTEP"
```

```
Print #fnum, "366 /"
Print #fnum, " "
Print #fnum, "TSTEP"
Print #fnum, "365 /"
Print #fnum, " "
Print #fnum, "TSTEP"
Print #fnum, "365 /"
Print #fnum, " "
Print #fnum, "TSTEP"
Print #fnum, "365 /"
Print #fnum, " "
Print #fnum, "TSTEP"
Print #fnum, "366 /"
Print #fnum, " "
Print #fnum, "TSTEP"
Print #fnum, "365 /"
Print #fnum, " "
Print #fnum, "TSTEP"
Print #fnum, "365 /"

Close #fnum
TT = TT + 1
Sheets("sheet1").Cells(18, 26) = TT


End Sub
```

VITAE

Niwat Jamrunsin was born on February 3, 1986 in Phang-Nga Thailand. He received his B.Eng. in Chemical Engineering from the Faculty of Engineering, Prince of Songkla University in 2008 with the 2nd class honors. After graduating, he continues his studies in the Master of Petroleum Engineering program at the Department of Mining and Petroleum Engineering, Faculty of Engineering, Chulalongkorn University.