CHAPTER V

INJECTION CAPACITY AND PERFORMANCE

As mentioned before, the main objectives of this thesis work is to determine the injection capacity and performance of sand units A and B under fracture pressure. Reservoir simulation can be used to investigate the injection capacity and performances in different injection rates and single well and both wells simultaneous injection options. To investigate the capacity and performance, all simulations run are categorized in two scenarios and under each scenario there are a number of cases run.

5.1 Fracture Pressure

Before going into detail discussion of each scenario it is worth to discuss about the fracture pressure because it dictates the injection process. As it is mentioned earlier that the injection pressure should not be high enough to cause any fracture in the reservoirs therefore before running any case the fracture pressure of each sands should be calculated. M field reservoir engineers develop the following equation to calculate formation fracture pressure from depth:

$$P_{fracture} = 0.433 x 10.764 x \left(0.000755 Z + 1.36977\right) Z \qquad (5.1)$$

where, Z = sub sea depth, ft

Using the above equation the fracture pressure for each reservoir can be calculated as shown in Table 5.1 and Figure 5.1.

Table 5.1: Fracture Pressures of different reservoirs.

Reservoir Name	Depth ft (TVDSS)	Fracture Pressure (psia)
10-15	3782.60	2677.13
10-50	3875.16	2754.36
10-80	4133.67	2969.65
10-90	4248.94	3067.32
11-20	4472.60	3259.14
11-50	4499.76	3282.63
11-75	4542.20	3319.45
12-05	4605.51	3375.44
12-20	4655.50	3419.13
12-30	4685.42	3445.36
12-35	4711.89	3467.72
12-40	4723.06	3477.55
12-55	4798.68	3544.24
12-80	4853.58	3592.87
12-95	4873.33	3610.41
13-10	4905.47	3639.90
13-15	4925.85	3657.17
13-20	4949.40	3678.19
13-30	4965.30	3693.30
13-50	5061.04	3778.31
13-60	5117.23	3828.98

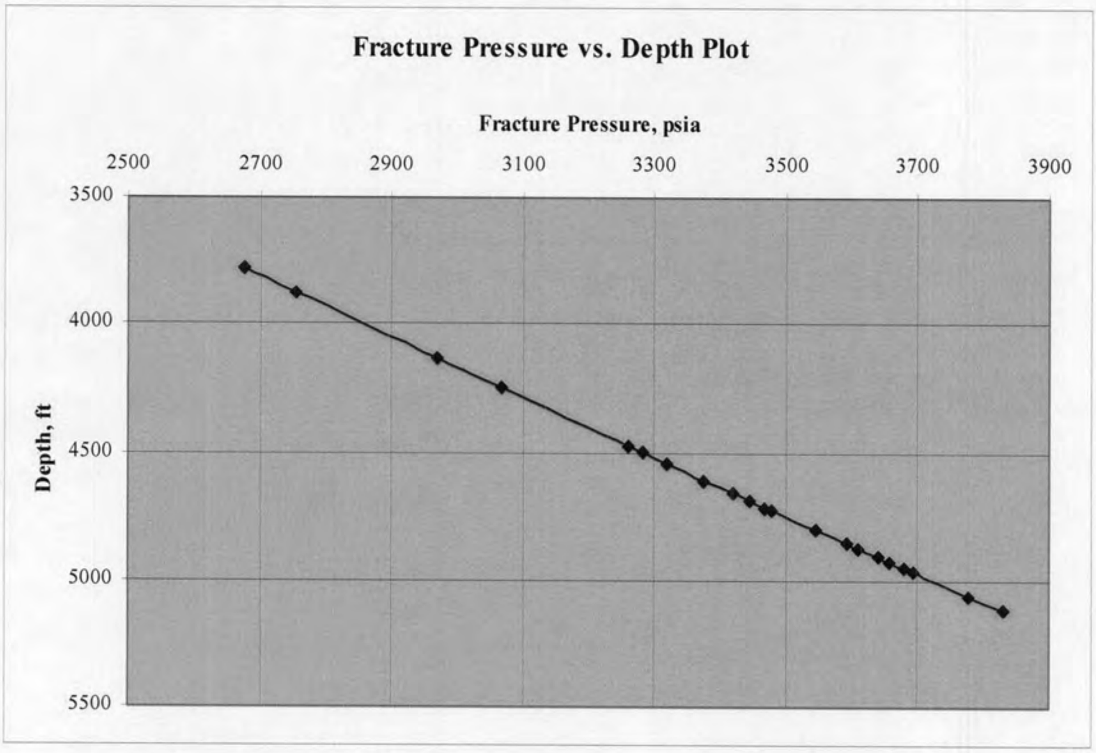

Figure 5.1: Fracture pressure gradient of M field.

It is seen that fracture pressure increases with depth. During injection if it is ensure that the topmost layer were not reach at fracture pressure therefore, all other deeper layers would automatically below fracture pressure as their fracture pressure are higher. As the injection takes place into both sands simultaneously, therefore, fracture pressure of topmost layer, located at top of sand unit A, is used as the maximum fracture pressure limit.

5.2 Injection Scenarios

Since the original model is homogeneous model (HM) therefore, to introduce heterogeneity into the model channels are introduced into the model. Thus, the prediction scenarios are broadly classified into homogeneous model (HM), channel model. Under channel model two models are generated namely Channel-I and Channel-II. Detailed description of each channel models are in later respective channel sections. Therefore, total three models were run to investigate injection capacity and performances.

The original model used as close boundary. In essence, at field condition the model area is not close boundary therefore, to flow the injected water passing through the edge of the model area, all the aforesaid three models were enlarged by 6890 ft by introducing pseudo grid blocks around 3 sides, the rest side is impermeable fault. The pseudo grid blocks are maximum 984 ft x 984 ft in dimension and having high porosities and permeabilities such as permeability 603.36 and 119.23 mD for A and B sand units and porosity ranges from 0.30 to 0.32 for the whole sand unit. It is better to make clear from here that 'model' would mean 'enlarged model'.

As mentioned earlier, there are two injection wells therefore, single well (MN-1 or MN-2) and multi wells option (MN-1 and MN-2) were used for PWI. The selected initial injection rates were 5000, 9000 and 13000 STB/D; injection rate 13000 STB/D was selected as maximum injection rate as that is limited by pump capacity. By varying single or both well injection and injection rates, the simulation can be organized into 9 cases for each model therefore, total 27 cases were run under 3 different models. The numbering process of different cases of HM is shown in Table 5.2 as sample and the same procedures were followed for the rest two models. From following table it is seen that cases 3 cases for each mode of injection, where injection by MN-1 appeared first and numbered K1-K3, then injection by multi wells appeared and numbered K4-K6 and finally, injection by MN-2 numbered K7-K9. Following the same numbering sequences, all cases for the remaining two models were numbered and would not indicate further.

Table 5.2: Different simulation cases of HM.

	Case Number	Initial Well Injection Rate STB/D
Injected by MN-1	K1	5000
	K2	9000
	K3	13000
Injected by MN-1 & MN-2	K4	5000
	K5	9000
	K6	13000
Injected by MN-2	K7	5000
	K8	9000
	K9	13000

All simulated cases start PW injection on 10 February 2007 and simulated for the next 20 years. The injection process takes place in the condition that the injection pressure should not be high enough to create any fracture in the formation.

During simulation of all the 27 cases, wells were initially controlled by surface injection rates and once the injection pressure reached the set maximum THP then wells were controlled by THP upto the end of simulation. Maximum THP is the pressure that corresponds to the fracture pressure limit (i.e. 2677.13 psia) at a particular injection rate. The reason to control the simulator by THP is that it is the parameter that can be controlled most easily in field operations. The injection capacity and performance of the three different models are discussed as follows:

5.2.1 Homogeneous Model (HM)

HM is the original model having the same petrophysical and other properties those are described in Chapter IV. The investigation of the capacity and performances for HM is as follows:

Under HM, single well (i.e. MN-1 or MN-2) and multi well (i.e. MN-1 and MN-2) options injections mode with 3 different initial well rates, total 9 cases, as shown in Table 5.2, were run and discuss the results. For every run, wells are initially controlled by surface injection rates and once the injection pressure reached the set maximum THP then wells are controlled by THP, i.e. by lowering THP. THP lowering sequences and the corresponding injection rates are shown later in this section. However, by repeating the THP lowering process, where it needs, 20 years injection were completed for every cases. After running all the 9 cases, it is seen that cases K5 and K6 were reached the set maximum THP during injection period. In Figure 5.2, CIV for all cases are presented here. CIV into A and B individual sand units are shown in Table 5.3 and 5.4.

From Figure 5.2, it is seen that CIVs of cases K1 & K7 increase linearly with time as both of the cases did not reach the set maximum THP. As the initial well injection rates for both of the cases were 5000 STB/D therefore, they give the same CIV which is 36 MMSTB over 20 years of injection. On the other hand, cases K2 & K8 and K3 & K9 follow the same manner quietly. As cases K2 and K8 did not reach the set maximum THP therefore, CIVs increase linearly with time and with injection rate 9000 STB/D, each of cases K2 and K8 give same CIV which is 64.84 MMSTB. Again, cases K3 and K9 did not reach the set maximum THP too therefore, CIVs increase linearly with time and with injection rate 13000 STB/D, each of cases K3 and K9 give same CIV which is 93.65 MMSTB.

For multi well injection, all cases but K4 reached the set maximum THP. Therefore, CIV of case K4 increases linearly with time and with initial well injection rate 5000 STB/D it becomes 72 MMSTB. For case K5, both the wells reached the set maximum THP at 5794 days and then wells were controlled by THP. As the wells were controlled by THP therefore, to maintain constant THP injection in 2 steps, i.e. from 5794 days to 6394 days and from 6394 days to 7204 days, both of the times injection rates were decline over time. Consequently, CIV increases linearly upto

5794 days and then became curvature and less steeper over time and finally, CIV became 119.7 MMSTB. On the other hand, cases K6 reached the set maximum set THP at 3634 and then wells were controlled by same method as mentioned above. As the wells were controlled by THP therefore, to maintain constant THP injection in 4 steps, i.e. from 3634 days to 4174 days, from 4174 days to 5014 days, from 5014 days to 6304 days and finally, from 6304 days to 7204 days, all the times injection rates were decline over time. Therefore, CIV increases linearly upto 3634 days and then became curvature and less steeper over time and finally, CIV became 127.9 MMSTB.

The explanation of Figure 5.2 requires further discussion. For both well injection cases K5 and K6 reached the set maximum THP at 5794 and 3634 days with CIV at 104.3 and 94.5 MMSTB respectively. Therefore, it is seen that for lower total injection rate case the wells reach the set maximum THP 2160 days later and give 9.8 MMSTB higher CIV than the maximum injection rate case. This implies that at initial well injection rate of 13000 STB/D pressure builds up around the wells are higher than initial well injection rate of 9000 STB/D which makes to reach the set maximum THP quicker. As mentioned before, after reaching the set maximum THP wells were controlled by THP and to maintain constant THP at each step injection rates are decline over time. On the other hand, model volume is confined and after reaching the set THP the successive well injection rates decline as injection takes place at constant THP at every steps and therefore, cases K5 and K6 are converging.

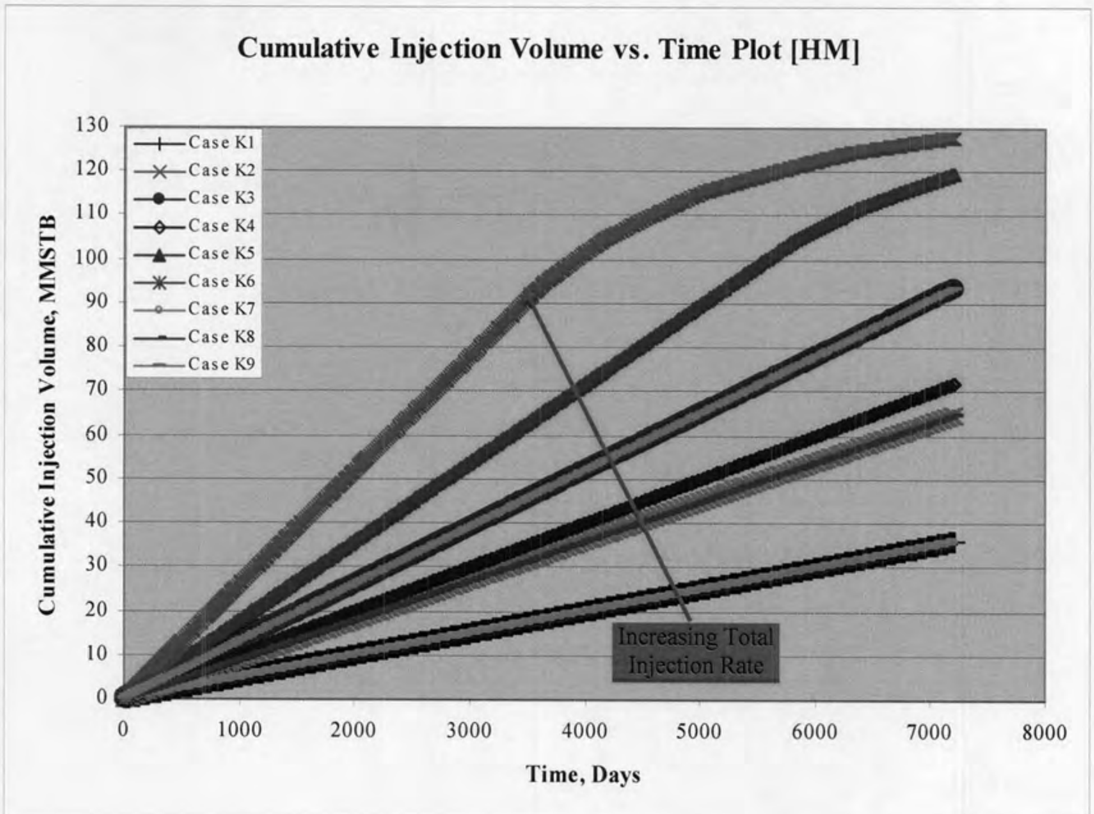

Figure 5.2: Cumulative injection volumes of cases K1-K9.

After running all the 9 cases it is seen that the evolution of THP in all cases behave in the similar manner and only cases K5 and K6 were reached the set maximum THP during injection period. As mentioned earlier, wells were initially controlled by surface injection rates and once the injection pressure reached the set maximum THP then wells were controlled by THP, by lowering THP in steps. THP and injection rates performances of cases K3, K6 and K9 are presented here in Figure 5.3 and Figure 5.4.

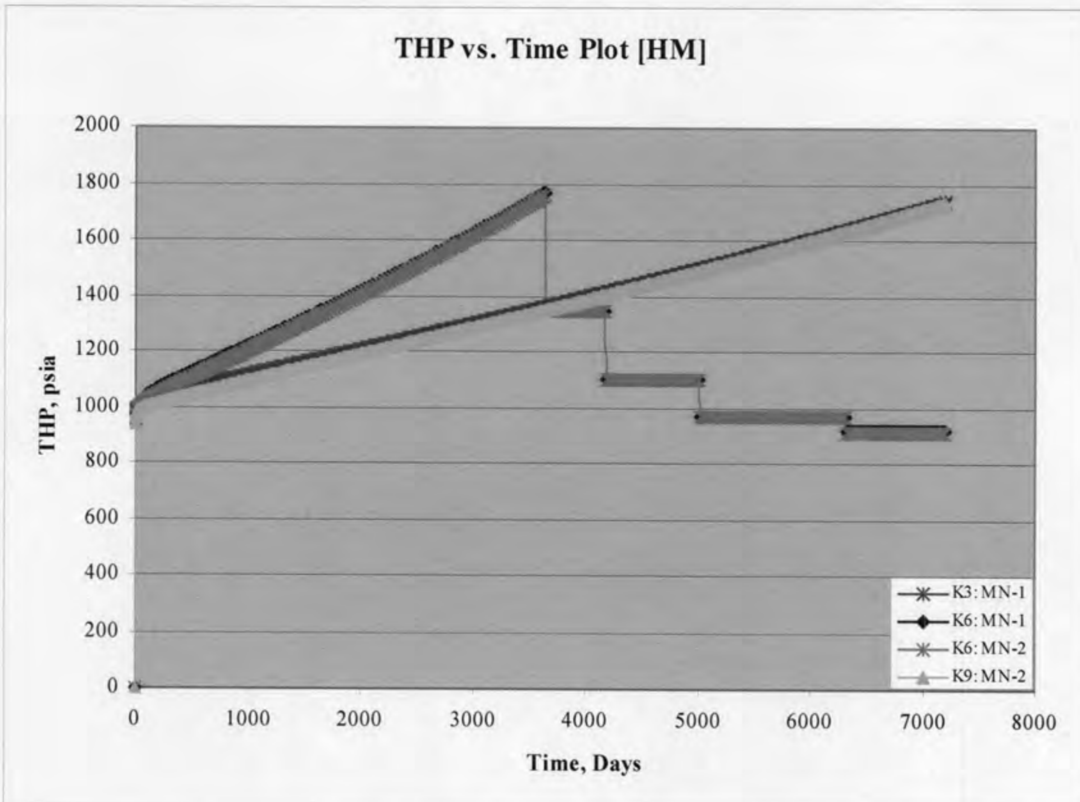

Figure 5.3: THP of cases K3, K6 and K9.

It is seen from Figure 5.3, THP is increasing with time because of increasing the cumulative volume injected into the reservoir. As the increment of cumulative water injected, reservoir pressure builds up, consequently BHP increases. Therefore, THP required to increases to continue injection at constant well injection rate. It is seen from Figure 5.3, cases K3 and K9 did not reached the set maximum THP therefore, the THP increased continuously and finally reached at 1737.5 and 1735 psia respectively, corresponding BHP were 2542.2 and 2601 psia for MN-1 and MN-2. On the other hand, both wells of case K6 reached the set maximum THP, i.e. 1769.4 and 1759 psia respectively, corresponding BHP were 2574.4 and 2625.5 psia respectively for MN-1 and MN-2 on 3634 days therefore, lowered THP to 1350 psia and keep injecting. Then at 4174 and 5014 days, THP lowered to 1350 and 1100 psia respectively and finally, at 6304 days THP was lowered to 920 and 915 psia respectively for MN-1 and MN-2, as depicted in Figure 5.3, to maintain BHP below the fracture pressure. The final BHP became 2644.3 and 2670.5 psia respectively for MN-1 and MN-2 of case K6. As lowering THP was manually control therefore it was intention to complete the runs by maximum four times lowering the THP to finish this study within constraint timeframe. Moreover, to select the THP lowering steps, substantial injection time before reached at the fracture pressure with a specific THP was also considered, at least 540 days injection in one THP lowering step.

For cases K3 and K9, the initial well injection rate was 13000 STB/D. As mentioned before, cases K3 and K9 did not reached the set maximum THP therefore, that injection rate was maintained constant throughout the whole injection period. On the other hand, case K6 reached the set maximum THP at 3634 days therefore it was required to lower the THP as discussed on above paragraph. When the wells are in THP control and start injecting into the reservoir it increases reservoir pressure successively as the cumulative injected water volume is increasing. Therefore, the drawdown pressure will decrease successively. Consequently, there is high well injection rate in early period and low in late time of constant THP injection for every step, which can be seen from Figure 5.3 and Figure 5.4. Since 3634 days, as the wells were controlled by THP therefore, to maintain different constant THP in 4 steps, all the times injection rates were decline over time as depicted in Figure 5.4. It is seen from Figure 5.3 and Figure 5.4 that initial rate for both wells of case K6 was 13000 STB/D and after 3634 days as wells reached the set maximum THP then the wells were in THP controlled. Therefore, to maintain constant THP at each step all the times injection rates were declined over time. Finally, injection rates became 1802 and 1877 STB/D at 920 and 915 psia for MN-1 and MN-2 respectively. The THP and injection rates of MN-1 and MN-2 of cases K1, K4 & K7 and K2, K5 & K8 are shown in Figure A1-Figure A2 and Figure A3-Figure A4 in Appendix A.

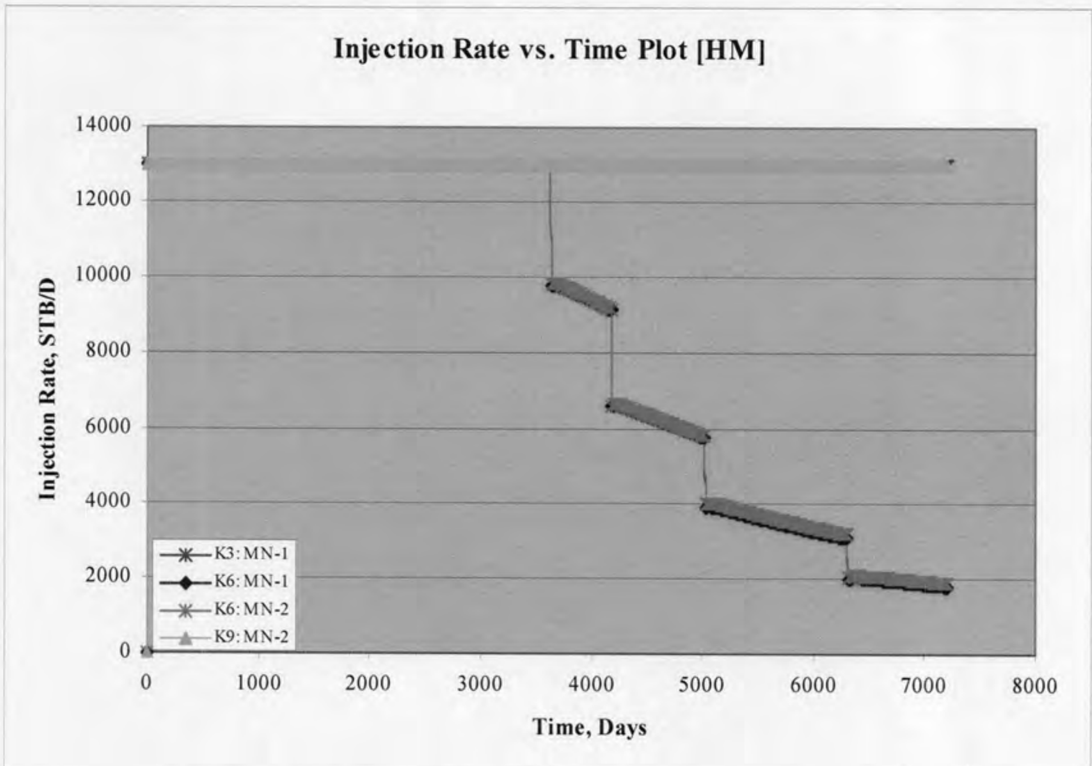

Figure 5.4: Injection rates of cases K3, K6 and K9.

Injectivity Index (II) is one of the key factors in achieving a long term water injection project. The term II is analogized to Productivity Index (PI) in oil and gas production term (Kalwant, 2002). It is defined as the degree of communication between a well and the reservoir. Here steady-state injectivity index is defined as the injection rate divided by draw down. The draw down is the difference between well's bottom hole pressure and the reservoir pressure at the edge of the well's zone of influence. Thus, the II is defined as

$$II = \frac{q_{inj}}{\left(P_{wf,inj} - P_d\right)} \tag{5.2}$$

q_{inj} is the injection rate, STB/D, $P_{wf,inj}$ is the bottom hole injection pressure of each layer and P_d is the reservoir pressure at the edge of well's zone of influence of each layer where both $P_{wf,inj}$ and P_d. are in psia.

After running all the cases, K1-K9, it is seen that the IIs of MN-1 in single and multi well injection options are same and the IIs of MN-2 in single and multi well injection options are same also. As sample cases K3, K6 and K9 are presented here in Figure 5.5. It is seen that the IIs of MN-1 for cases K3 & K6 starts from 358.2

STB/D/psi and then stabilized at 456 STB/D/psi. On the other hand, the IIs of MN-2 for cases K6 & K9 starts from 244.2 STB/D/psi and then stabilized at 311 STB/D/psi. It is seen from simulation injectivity index reports for both wells that initial IIs are different from the stabilized IIs because of higher initial draw down. All the other cases behave in the similar manner. The IIs of MN-1 and MN-2 of cases K1, K4 & K7 and K2, K5 & K8 are shown in Figure A5 and Figure A6 in Appendix A.

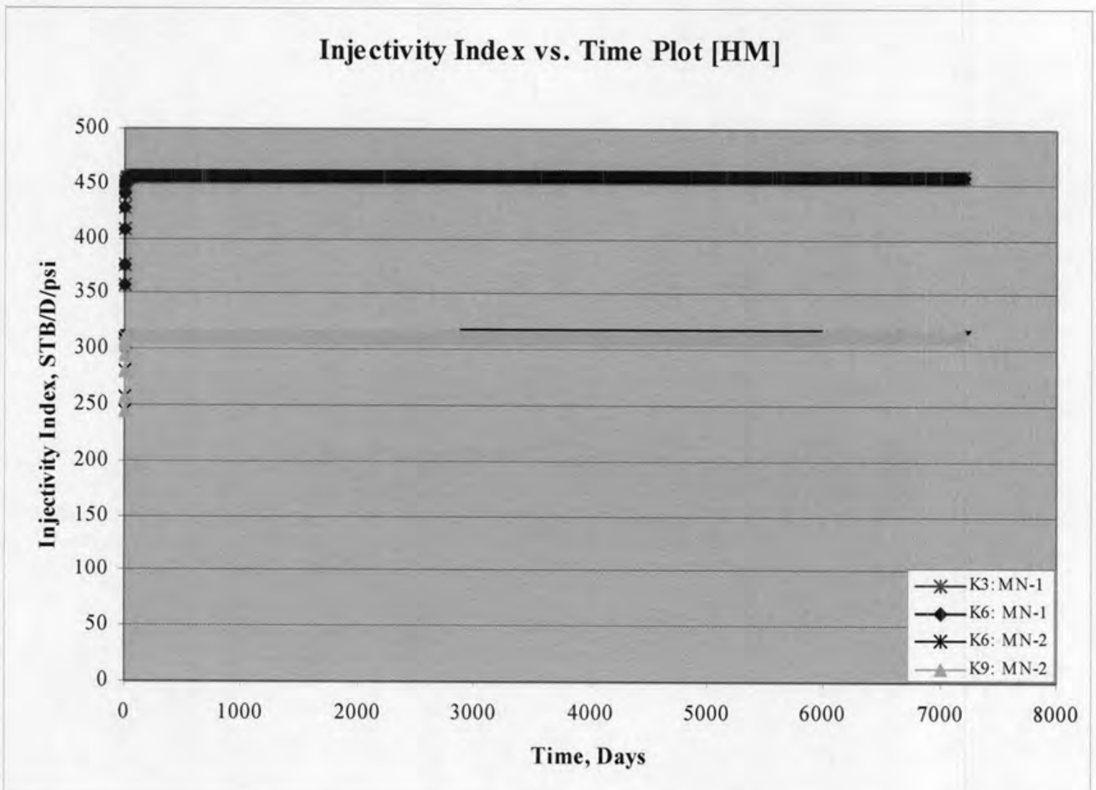

Figure 5.5: IIs of MN-1 and MN-2 of case K3, K6 and K9.

Furthermore, it is seen from Figure 5.2 and Table 5.3, cases K1-K3 and cases K7-K9 behave in the same manner. At each same rate cases K1-K3, i.e. well MN-1, gives same CIV with cases K7-K9, i.e. well MN-2. As the well properties were not taken into account therefore both wells were behaving in the same manner. Therefore, it can be concluded that well location has no effect on CIV in this model.

CIV into A and B individual sand units for single well injection and both well injection are shown in Table 5.3 and 5.4.

Table 5.3: CIV of single well injection in HM.

Single Well Injection		Case Name	Initial Well Rate, STB/D	Cumulative Injection Volume (CIV)				
				A		B		Total
				MMSTB	%	MMSTB	%	MMSTB
HM	Injected by MN-1	K1	5000	33.72	93.6	2.30	6.4	36.02
		K2	9000	60.55	93.4	4.29	6.6	64.84
		K3	13000	87.24	93.2	6.41	6.8	93.65
	Injected by MN-2	K7	5000	33.66	93.4	2.36	6.6	36.02
		K8	9000	60.58	93.4	4.25	6.6	64.83
		K9	13000	87.42	93.3	6.23	6.7	93.65

Table 5.4: CIV of both wells injection in HM.

Both Well Injection		Case Name	Initial Rate Well STB/D	Cumulative Injection Volume (CIV)						
				MN-1	MN-2	Total	A		B	
				MMSTB	MMSTB	MMSTB	MMSTB	%	MMSTB	%
HM	Injected by MN-1 & MN-2	K4	5000	36.02	36.02	72.04	65.27	90.6	6.77	9.4
		K5	9000	59.82	59.90	119.72	107.37	89.7	12.35	10.3
		K6	13000	63.83	64.10	127.93	112.92	88.3	15.01	11.7

Finally, the impact of initial well injection rate changing shows as the injection rate goes higher then the CIV line becomes steeper and it can be explained that CIV is higher with higher injection rate. In the case where injection pressure reached the set maximum THP the lower injection rate would give more CIV than higher rate before THP reached the set maximum value. In single well injection all the rates can be maintained throughout the injection period conversely, in multi well injection only low injection rate can be maintained. Therefore, well location has no effect on CIV in this model.

5.2.2 Channel Models

As mentioned in Chapter IV, in M field the sand deposition was in fluvio-deltaic environment. In fluvio-deltaic deposition environment sands are classified are channel and bar sands. Sharp base sand bodies with either a blocky or upward fining well log motif are classified as channels. These sands are often associated with seismic amplitude anomalies and can be mapped using 3D seismic data. Bar sands are defined as relatively thin sands with upward coarsening well log patterns (Turner, *et. al.*, 2004).

The targeted sand units A and B are represented by paralic deposits resulted from the interaction between fluvial and marine processes is Middle to Late Miocene age. Paralic sand bodies have a tremendous range in the dimensions. Most paralic reservoirs are discontinuous or channelized. Depending on the width and sinuosity, channels are interpreted as (Turner, *et. al.*, 2004):

- Fluvial or distributary channels: low sinuosity, upto 2461 ft wide,
- Incised valley fill: large sinuous complexes, exceeding 2461 ft wide,
- Distributary mouth bar channels: narrow shoestring channels upto 656.2 ft wide.

In M filed fluvial or distributary channel sands are common. The fluvial channels are low sinusoids and have width upto 2461 ft. After a consolidation session with chief geologist of M field, it's gained that it is unpredictable to conclude whether the channels are interconnected or not. Therefore, two models are designed with individual and interconnected channel sands. The main objectives of these cases are to investigate the variation of injection capacity and performances in presence of channels.

Here channel sand bodies are modeled as rectangular bars. The porosites and permeabilities used for different layers in channels are the same as respective layers in HM. Therefore, the flow of injected water is believed almost through the channels. On the other hand, porosities and permeabilities outside of the channel are assumed too poor, thus, a little amount of injected water can pass through. Following two models are designed with channels:

5.2.2.1 Channel-I

In this model, channels are in north-west (N-W) to south-east (S-E) and north-east (N-E) to S-E oriented. As it is mentioned earlier, all the channels are fluvial or distributary channels, therefore all the channels introduced here are in 656.2 ft to 2461 ft wide. The width to thickness ratio (W/T) ranges from 21 to 179 and where the W/T changes, there the width changes. The available information shows channel density is higher in A sand unit compared to B sand unit. For the whole model, 37% of total sand volume is occupied by channels whereas 40.1% of A volume and 24.2% of B volume is occupied by channels. The total numbers of channels in this model are 68. Following Figure 5.6 shows the 3-D view of Channel-I model.

As mentioned before, outside of the channel the porosities and permeabilities are very poor, for example, porosity ranges from 0.1 to 0.15 and therefore, permeabilities become in the ranges from 1.19 to 5.81 mD. Inside the channel, the porosities and permeabilities of each layer are the same as the HM. Excluding the enlarged grids, the cross section of Channel-I model is shown in Figure 5.7.

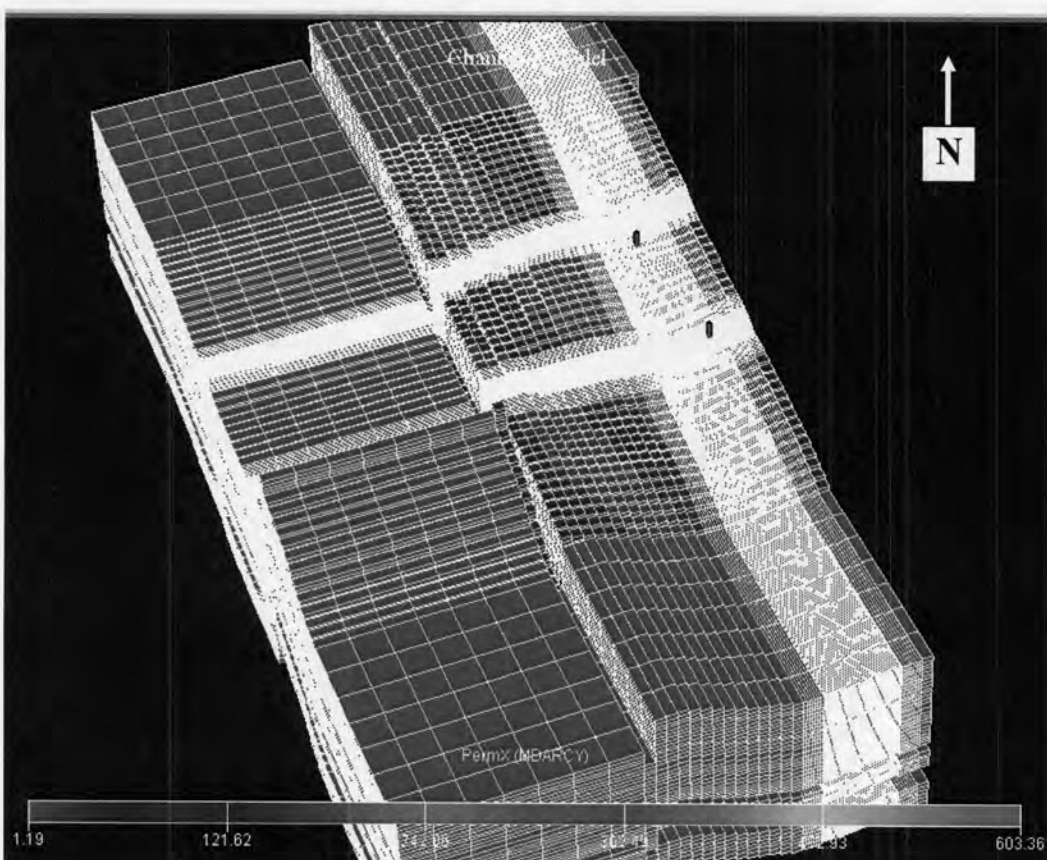

Figure 5.6: 3-D view of Channel-I model.

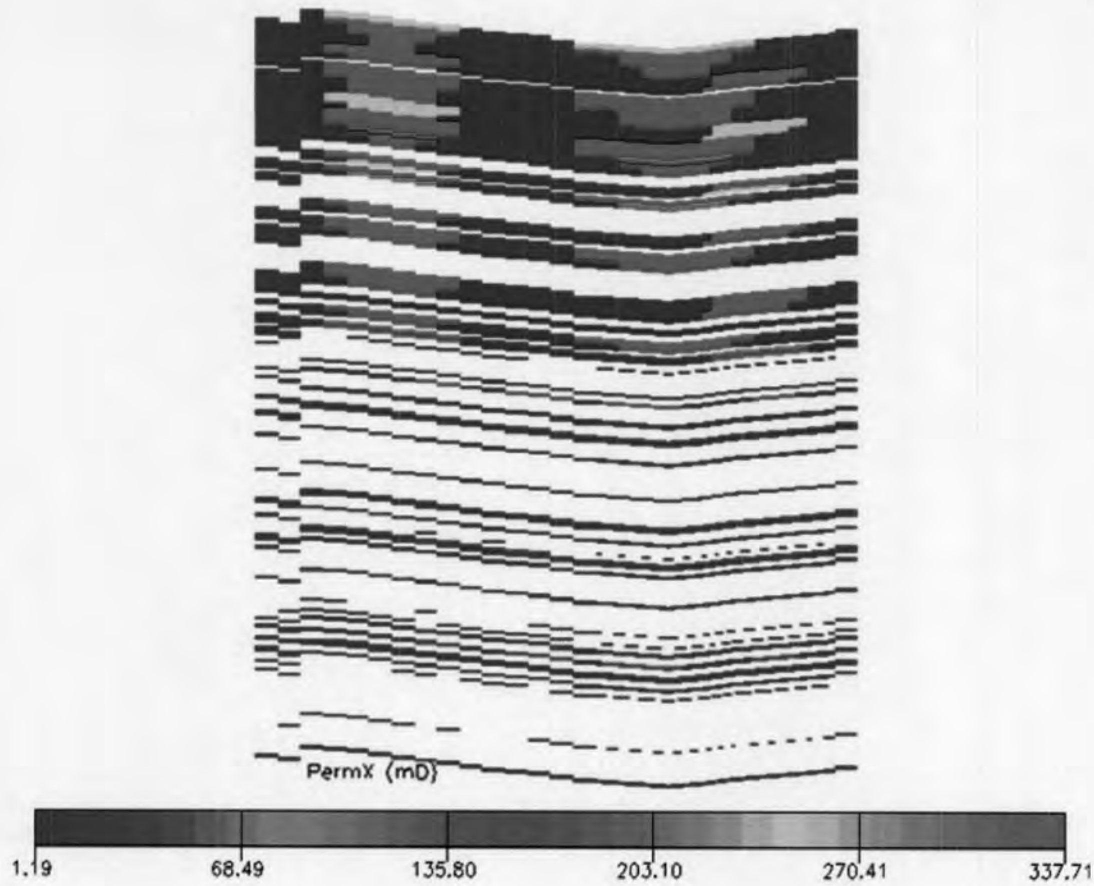

Figure 5.7: Cross section of Channel-I model.

To perform this job, single well (MN-1 or MN-2) and multi well option (MN-1 and MN-2), same as HM, were used for PW injection. The initial well injection rates were also same as HM. By varying single or multi well injection and initial well injection rates, the simulation cases were 9 and they are K10-K18. The main objective of these cases is to investigate the variation of injection capacity and performances in presence of channels. After simulation run for all cases, results are discussed as follows:

Under Channel-I model, single well (i.e. MN-1 or MN-2) and multi well (i.e. MN-1 and MN-2) options injections mode, total 9 cases were run with 3 different initial well injection rates and discuss the results. Following the same numbering process shown in Table 5.2, the cases designated as Case K10-K18. i.e. 3 cases for each well, K10-K12 for MN-1 and K16-K18 for MN-2 and 3 cases for multi well injection option K13-K15. For every run, wells are initially controlled by surface injection rates and once the injection pressure reached the set maximum THP then wells are controlled by THP, i.e. by lowering THP. THP lowering sequences and the corresponding injection rates are shown in Figure 5.9 and Figure 5.10. However, by repeating the THP lowering process, where it needs, 20 years injection was completed for every cases. After running all the 9 cases, it is seen that all but cases K10, K16 and K17 were reached the set maximum THP during injection period. In Figure 5.8, CIV for all cases are presented here. CIV into A and B individual sand units are shown in Table 5.5 and 5.6. After running all the 9 cases, it is seen that all the cases behave in the similar manner like HM cases and the descriptions of each cases would not indicate further here.

The parameters affecting injection capacity and performances were selected for sensitivity analysis are injection rate, single well and multi well injection. By varying the initial well injection rate the impact of changing well injection rate on injection capacity and performance can be analyzed. For cases K10-K12 corresponds to well MN-1 injection at 3 different initial well injection rates and it is seen that with the increasing of initial well injection rate, the CIV is increasing. Moreover, at lower injection rate, i.e. 5000 STB/D, well initial injection rate can be maintained throughout the injection period. For cases K16-K18 corresponds to well MN-2 injection at 3 different initial well injection rates and it is seen that with the increasing of initial well injection rate the CIV is increasing and for the well injection rates lower than 9000 STB/D well injection can be maintained throughout the injection period. For cases K13-K15 corresponds to well MN-1 and MN-2 simultaneous injection at 3 different initial well injection rates and it is seen that the CIV is behaving in the similar manner with single well injection and only at lower rate well injection rate can be maintained throughout the simulation period.

As mentioned earlier, outside of the channel porosities and permeabilities are very poor that results lower pore volume (PV) than HM. Therefore, it is obvious that if a well intersects with many channels it would give high CIV. It is seen from Figure 5.8 that at higher rate the CIV of well MN-1 becomes curvature and less steeper. At the highest rate the CIV of well MN-2 becomes less curvature and giving more CIV. From a closer look of every layer channel distribution shows that well MN-2 intersects more channels than well MN-1, hence well location placement is important.

The explanation of Figure 5.8 requires further discussion. For both well injection cases K14 and K15, after reaching the maximum set THP they look like to be converging. It can be explained as the model is confined volume and after reaching the set maximum THP the successive well injection rates decline as injection takes place at THP at every steps and therefore they are going to converge over time.

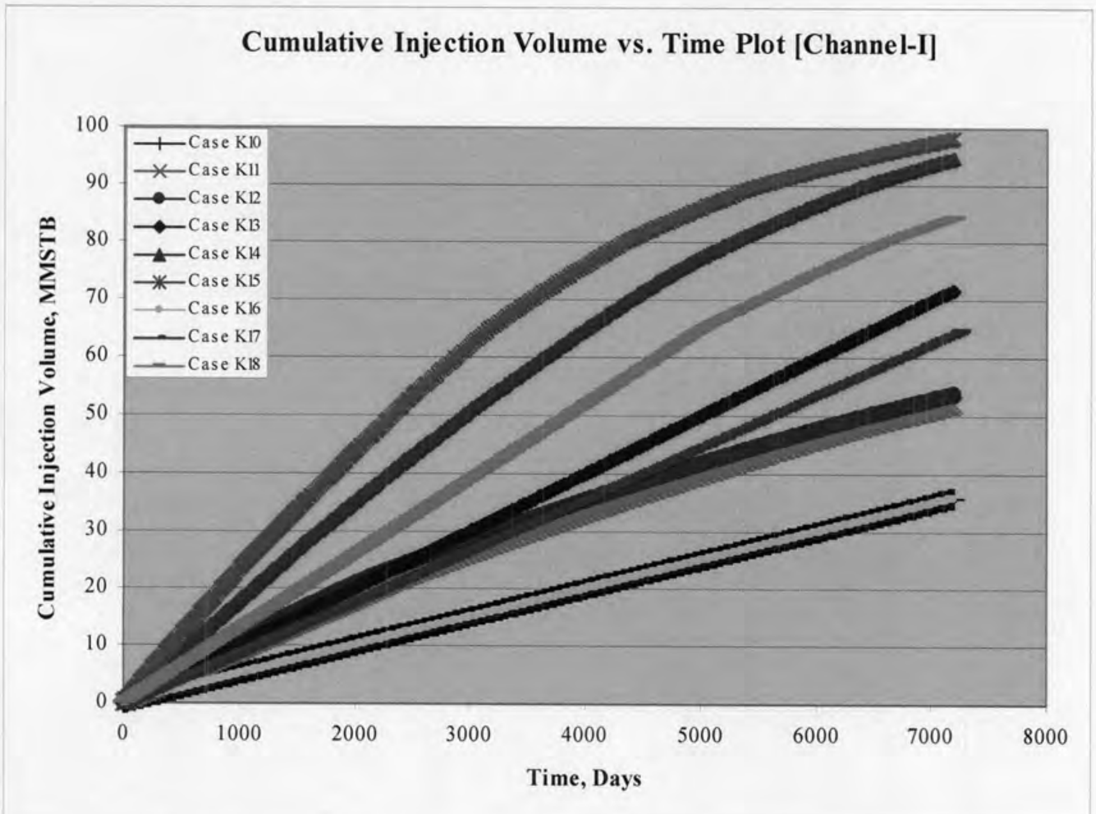

Figure 5.8: Cumulative injection volume of cases K10-K18 for Channel-I.

After running all the 9 cases it is seen that the evolution of THP in all cases behave in the similar manner and only cases K10, K16 and K17 did not reached the set maximum THP during injection period. As mentioned before, wells were initially controlled by surface injection rates and once the injection pressure reached the set maximum THP then wells are controlled by THP, i.e. by lowering THP in steps. After reaching the set maximum THP, the THP lowering sequences follow the similar manner as HM and the descriptions of each cases would not indicate further here. THP and injection rates performances of cases K12, K15 and K18 are presented here in Figure 5.9 and Figure 5.10.

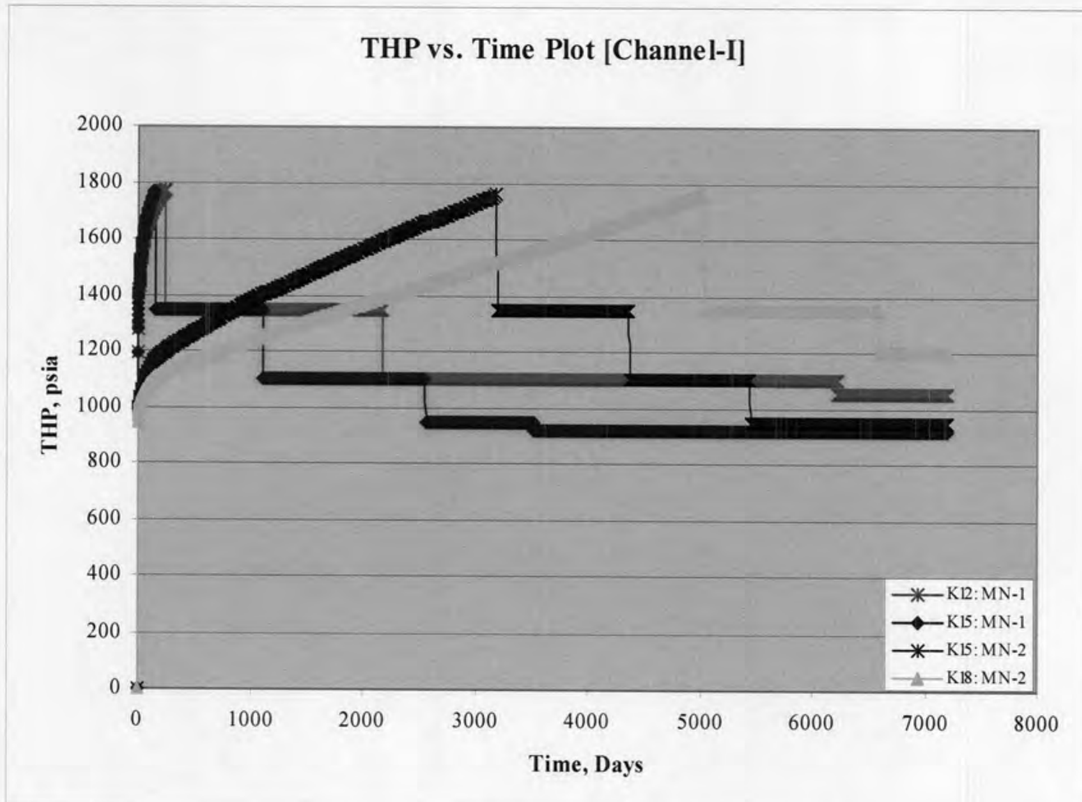

Figure 5.9: THP of cases K12, K15 and K18.

It is seen from Figure 5.9, in case K15, well MN-1 and MN-2 reached the set maximum THP at different times, i.e. at 147 and 3184 days respectively. After reaching the set maximum THP both wells are following different injection durations and well injection rates at the same THP level at each step. It is noticeable that well MN-1 follows sharp well injection rate declination whereas MN-2 follows sluggish well injection rate declination. In addition, injection pressure changes faster for well MN-1. Same observation is found for same well in single and multi well injection cases. This implies that MN-2 accepts injected water easily rather than MN-1. From a closer look of channel orientation it is seen that MN-2 intersects more channels in A sand unit than MN-1, thus MN-2 has higher CIV. Therefore, well location has effects on CIV and performances in Channel-I model. In addition, for multi well injection cases rates change faster also. The THP and injection rates of all cases are shown in Appendix A.

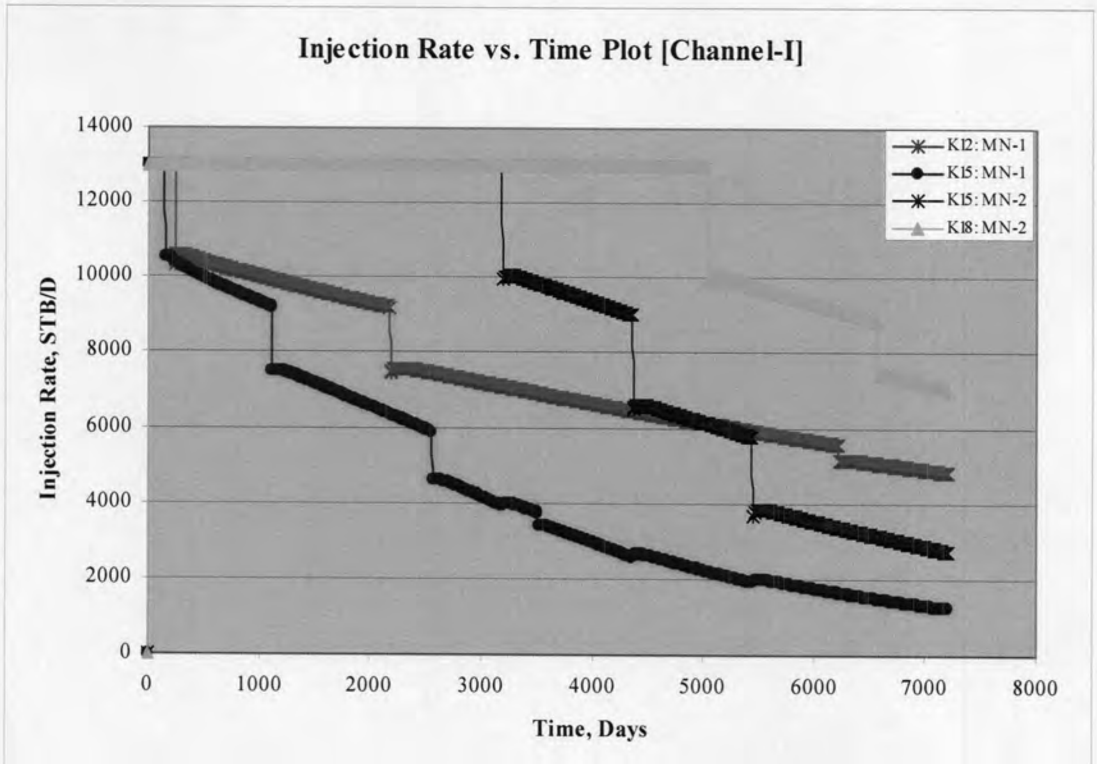

Figure 5.10: Injection rates of cases K12, K15 and K18.

After running all the cases, K10-K18, it is seen that the IIs of MN-1 in single and multi well injection options are same the and the IIs of MN-2 in single and multi well injection options are the same also. As sample cases K12, K15 and K18 are presented in Figure 5.11. It is seen that the IIs of MN-1 for cases K12 & K15 starts from 98.7 STB/D/psi and then stabilized at 130 STB/D/psi. On the other hand, the II's of MN-2 for cases K15 and K18 starts from 230.5 STB/D/psi and then stabilized at 300 STB/D/psi. It is seen from simulation injectivity index reports for both wells that initial IIs are different from the stabilized IIs because of higher initial draw down. It is noticeable that the IIs of MN-1 and MN-2 are decreased 326 STB/D/psi and 11 STB/D/psi comparing to the homogeneous model due to the poor porosities and permeabilities out side of the channels. All the other cases behave in the similar manner, shown in Appendix A.

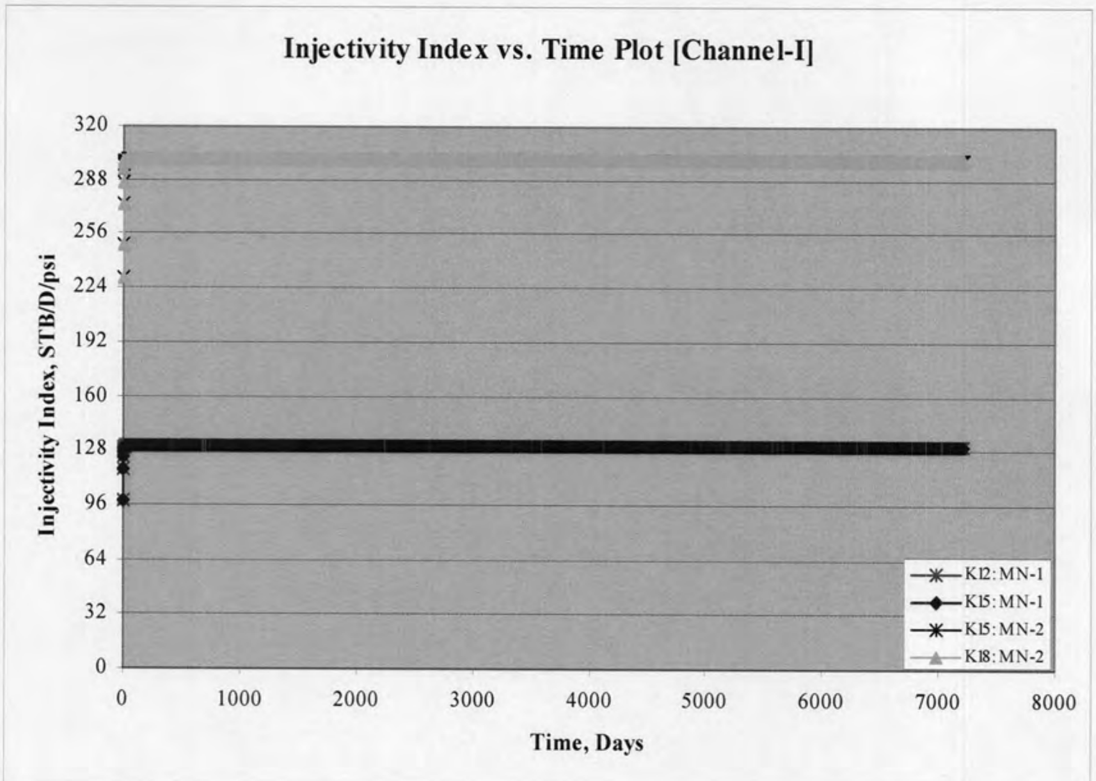

Figure 5.11: II of MN-1 and MN-2 of case K12, K15 and K18.

CIV into A and B individual sand units for single and both wells injection are shown in Table 5.5 and 5.6.

Table 5.5: CIV of single well injection in Channel-I model.

Single Well Injection		Case Name	Initial Well Rate, STB/D	Cumulative Injection Volume (CIV)				
				A		B		Total
				MMSTB	%	MMSTB	%	MMSTB
Channel-I	Injected by MN-1	K10	5000	33.62	93.3	2.40	6.7	36.02
		K11	9000	48.36	93.0	3.64	7.0	52.0
		K12	13000	49.88	92.9	3.79	7.1	53.67
	Injected by MN-2	K16	5000	35.64	98.9	0.38	1.1	36.02
		K17	9000	64.15	98.9	0.70	1.1	64.84
		K18	13000	83.62	98.9	0.96	1.1	84.58

Table 5.6: CIV of both well injection in Channel-I model.

Both Well Injection		Case Name	Initial Rate Well STB/D	Cumulative Injection Volume (CIV)						
				MN-1	MN-2	Total	A		B	
				MMSTB	MMSTB	MMSTB	MMSTB	%	MMSTB	%
Channel-I	Injected by MN-1 & MN-2	K13	5000	35.87	36.02	71.89	68.54	95.3	3.54	4.9
		K14	9000	37.56	57.30	94.86	90.41	95.3	4.45	4.7
		K15	13000	33.04	65.16	98.2	93.53	95.2	4.67	4.8

Finally, from above discussion it can be concluded that well initial injection rate can be maintained throughout at lower rate of well MN-1 whereas the first two well injection rates can be maintained throughout for well MN-2 in single well injection. Because of intersection with more channels, well MN-2 is giving higher CIV than well MN-1. At higher injection rate, increasing the injection rate has less effect on the increase in CIV. In multi well injection cases, wells reach the set maximum THP sooner than the single well injection option. At higher rate in both well injection, CIV curves are going to converge.

In single well and multi well injection cases, well MN-2 has different behaviors after reaching the maximum set THP. In both cases MN-2 has the same decline rate but different injection durations at a specific injection THP as can be seen in Figure 5.10. It shows some effect of MN-1 injection on the MN-2 performance. Again, in single well and multi well injection cases, well MN-1 has different rate declinations after reaching the set maximum THP. In single well injection MN-1 has longer duration and lower decline rate compared to multi well injection. This means that the presence of MN-2 injection has more effect on the MN-1 injection performance than vice versa. In addition, well location has influence on CIV in this model as it shows in Table 5.5 for single well injection.

5.2.2.2 Channel-II

In this model, channels are in N-W to S-E, south-west (S-W) to north-east (S-E) and north to south oriented. As it is mentioned earlier, all the channels are fluvial or distributary channels, therefore all the channels introduced here are in 656.2 ft to 2461 ft wide. The width to thickness ratio (W/T) ranges from 21 to 200 and where the W/T changes, there the width changes. The available information shows that density is higher also in A sand unit compared to B sand unit. For the whole model, 44.5% of total sand volume is occupied by channels where 48.7% of A volume and 28% of B volume are occupied by channels. Total numbers of channels in this model are 103. The porosities and permeabilities used inside and outside of channels are the same as Channel-I. The main differences of Channel-I and Channel-II are density of and orientation of channels and percentage of volume occupied by the channels. Following Figure 5.12 shows 3-D view of Channel-II model. Excluding the enlarged grids, the cross section of Channel-II model is shown in Figure 5.13.

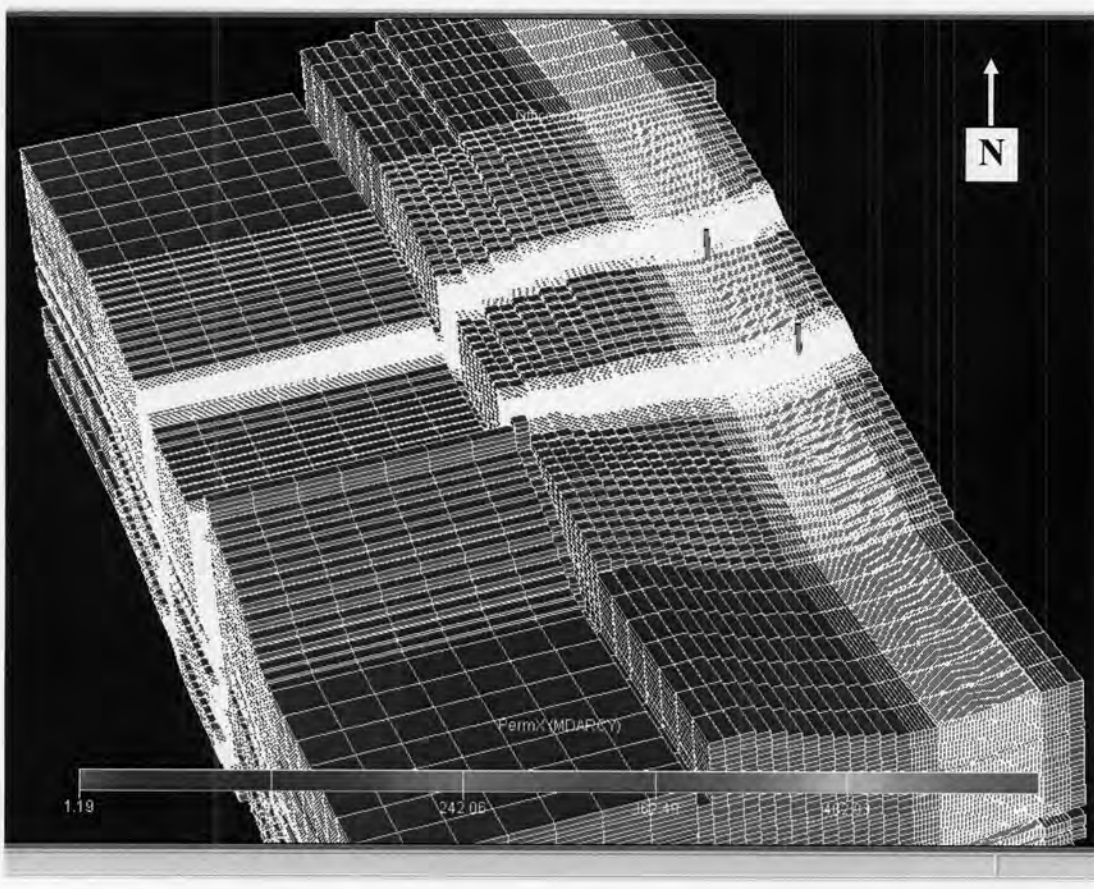

Figure 5.12: 3-D model view with channels of Channel-II model.

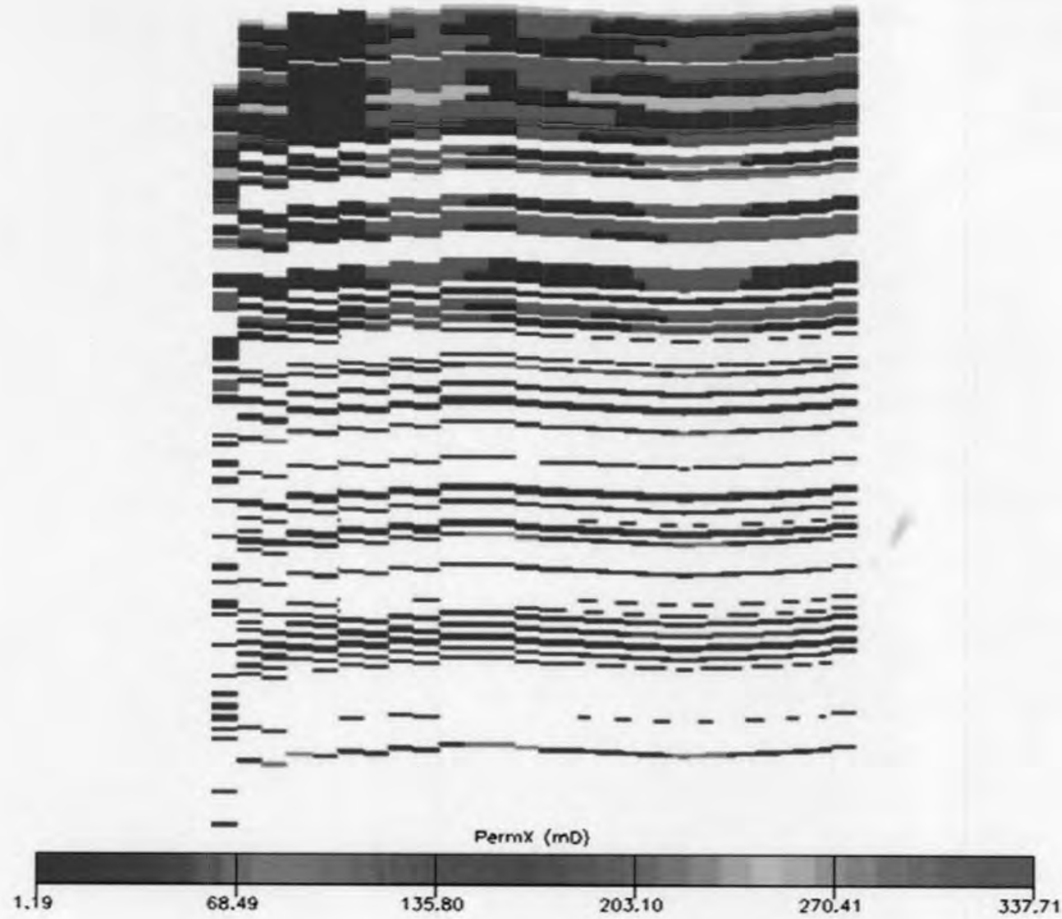

Figure 5.13: Cross section of Channel-II model.

To perform this job, single well (MN-1 or MN-2) and multi well option (MN-1 and MN-2), same as HM and Channel-I models, were used for PW injection. The initial well injection rates are also same as the other two models. By varying single or multi well injection and injection rates, the numbers of the simulation cases are 9 and they are K19-K27. The main objective of these cases is to investigate the variation of injection capacity and performances in presence of channels. After simulation run for all cases, results are discussed as follows:

Under Channel-II model, single well (i.e. MN-1 or MN-2) and multi well (i.e. MN-1 and MN-2) options injections mode, total 9 cases were run with 3 different initial well injection rates and discuss the results. Following the same numbering process shown in Table 5.2, the cases designated as Case K19-K27. i.e. 3 cases for each well, K19-K21 for MN-1 and K25-K27 for MN-2 and 3 cases for multi well injection option K22-K24. For every run, wells are initially controlled by surface injection rates and once the injection pressure reached the set maximum THP then wells are controlled by THP, i.e. by lowering THP. THP lowering sequences and the corresponding injection rates are shown in Figure 5.15 and Figure 5.16. However, by repeating the THP lowering process, where it needs, 20 years injection was completed for every cases. After running all the 9 cases, it is seen that cases K21, K23, K24 and K27 were reached the set maximum THP during injection period. In Figure 5.14, CIV for all cases are presented here. CIV into A and B individual sand units are shown in Table 5.7 and 5.8. After running all the 9 cases, it is seen that all the cases behave in the similar manner like HM and Channel-I model and the descriptions of each individual cases would not indicate further here.

As mentioned before, the parameters affecting injection capacity and performances were selected for sensitivity analysis are injection rate, single well and multi well injection. By varying the initial well injection rate the impact of changing well injection rate on injection capacity and performance can be analyzed. For cases K19-K21 corresponds to well MN-1 injection at 3 different initial well injection rates and it is seen that with the increasing of initial well injection rate, the CIV is increasing. Moreover, at the first 2 rates, i.e. 5000 and 9000 STB/D, initial well injection rates can be maintained throughout the injection period. Similarly, for cases K25-K27 corresponds to well MN-2 injection, it is seen that with the increasing of initial well injection rate the CIV is increasing and for the well injection rates lower than 9000 STB/D well injection can be maintained throughout the injection period. Similarly, for cases K22-K24 corresponds to well MN-1 and MN-2 simultaneous injection, the CIV is behaving in the similar manner with single well injection and only at lower rate initial well injection rate can be maintained throughout the simulation period.

As mentioned earlier, outside of the channel the porosities and permeabilities are very poor that results lower PV than HM. Therefore, it is obvious that if a well intersects with many channels it would give high CIV. It is seen from Figure 5.14 that at maximum initial well injection rate the CIV of well MN-1 becomes curvature and less steeper. From a closer look of every layer channel distribution shows that well MN-2 intersects more channels than well MN-1.

The explanation of Figure 5.14 requires further discussion. For both well injection cases K23 and K24, after reaching the maximum set THP they look like to be converging. It can be explained as the model is confined volume and after reaching the set maximum THP the successive well injection rates decline as injection takes place at THP at every steps and therefore they are going to converge over time.

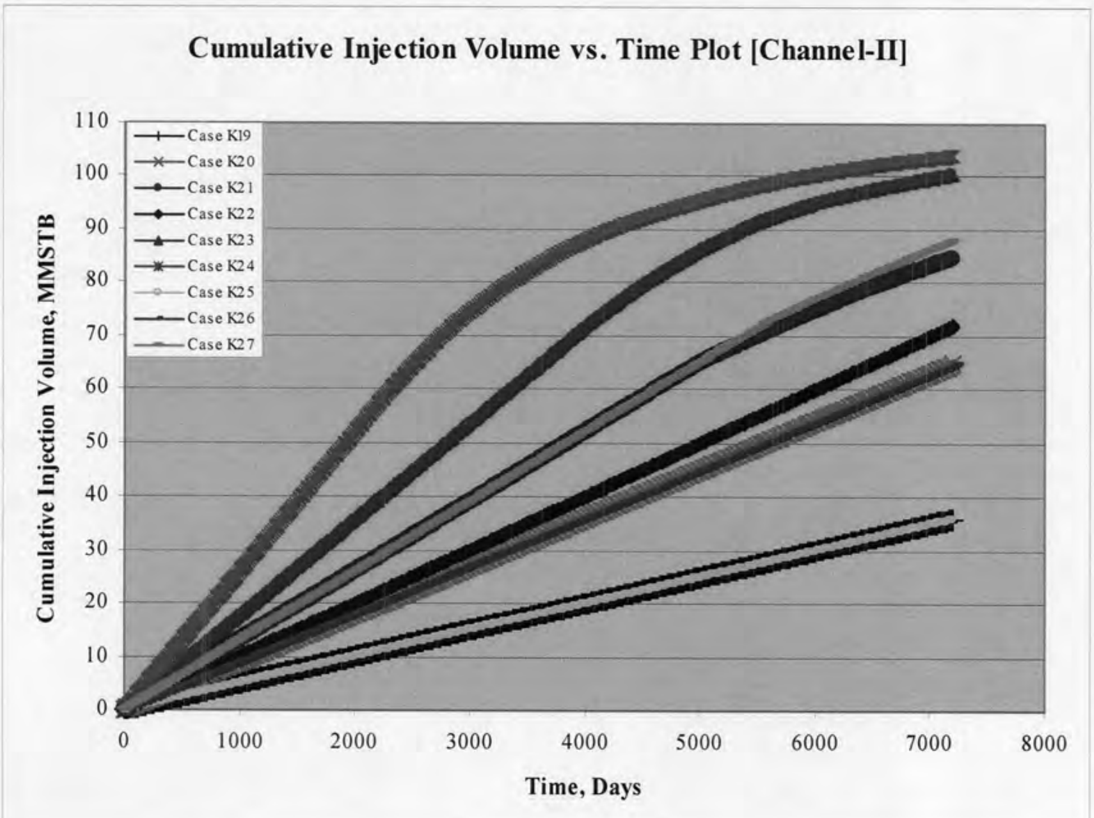

Figure 5.14: Cumulative injection volume of cases K19-K27.

After running all the 9 cases it is seen that the evolution of THP in all cases behave in the similar manner and only cases with total injection rates are more than 10000 STB/D reached the set maximum THP during injection period. As mentioned before, wells were initially controlled by surface injection rates and once the injection pressure reached the set maximum THP then wells are controlled by THP, i.e. by lowering THP. After reaching the set maximum THP, the THP lowering sequences follow the similar manner as two other previous models and the description of each case would not indicate further here. As sample THP and injection rates performances of cases K21, K24 and K27 are presented here in Figure 5.15 and Figure 5.16.

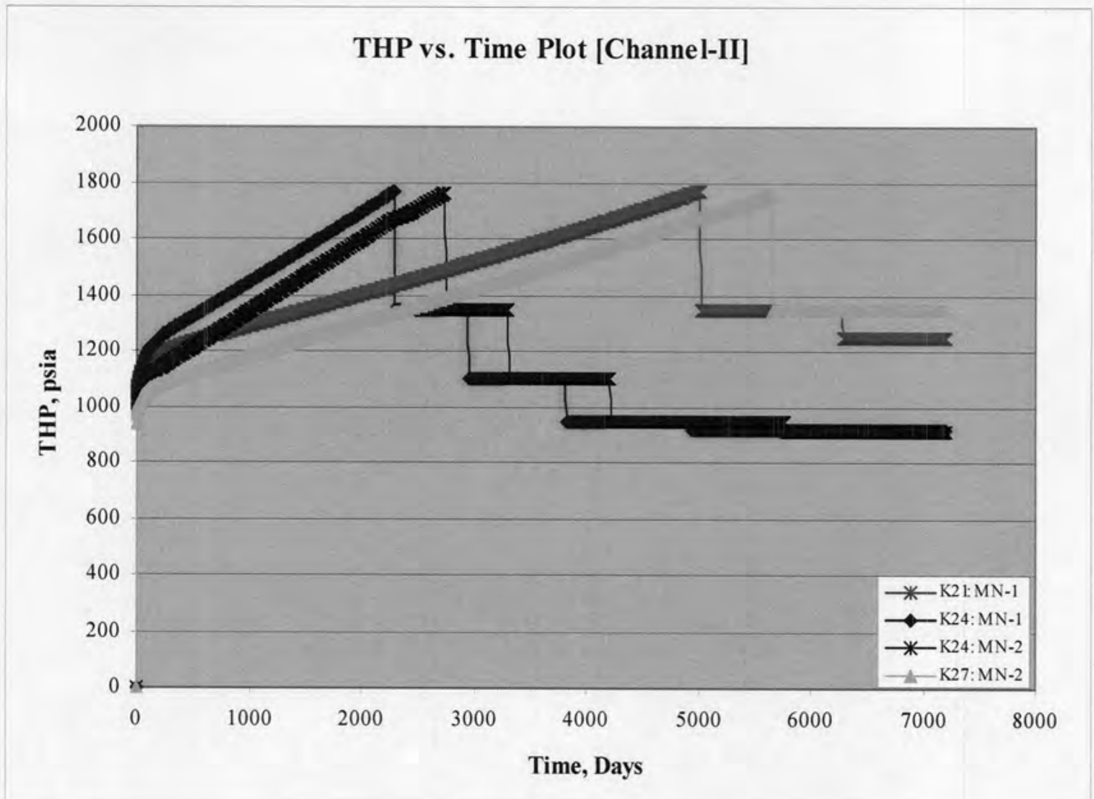

Figure 5.15: THP of cases K21, K24 and K27.

It is seen from Figure 5.15, in case K24, well MN-1 and MN-2 reached the set maximum THP at different times, i.e. at 2284 and 2784 days respectively. After reached the set maximum THP both wells are following different injection durations and well injection rates at same THP at each step. It is noticeable that well MN-1 follows lower well injection rate whereas MN-2 follows relatively higher well injection rate. In addition, injection pressure changes faster at every step for well MN-1. Same observation is found for same well in single and multi well injection. This implies that MN-2 accept injected water easily rather than MN-1. From a closer look of channel orientation at every layer it is seen that MN-2 intersects with more channels in A sand unit than MN-1, thus MN-2 has higher CIV. Therefore, well location has effects on CIV and performances in Channel-II model. In addition, for multi well injection, injection rate and injection pressure change faster also. The THP and injection rates of all other cases are shown in Appendix A.

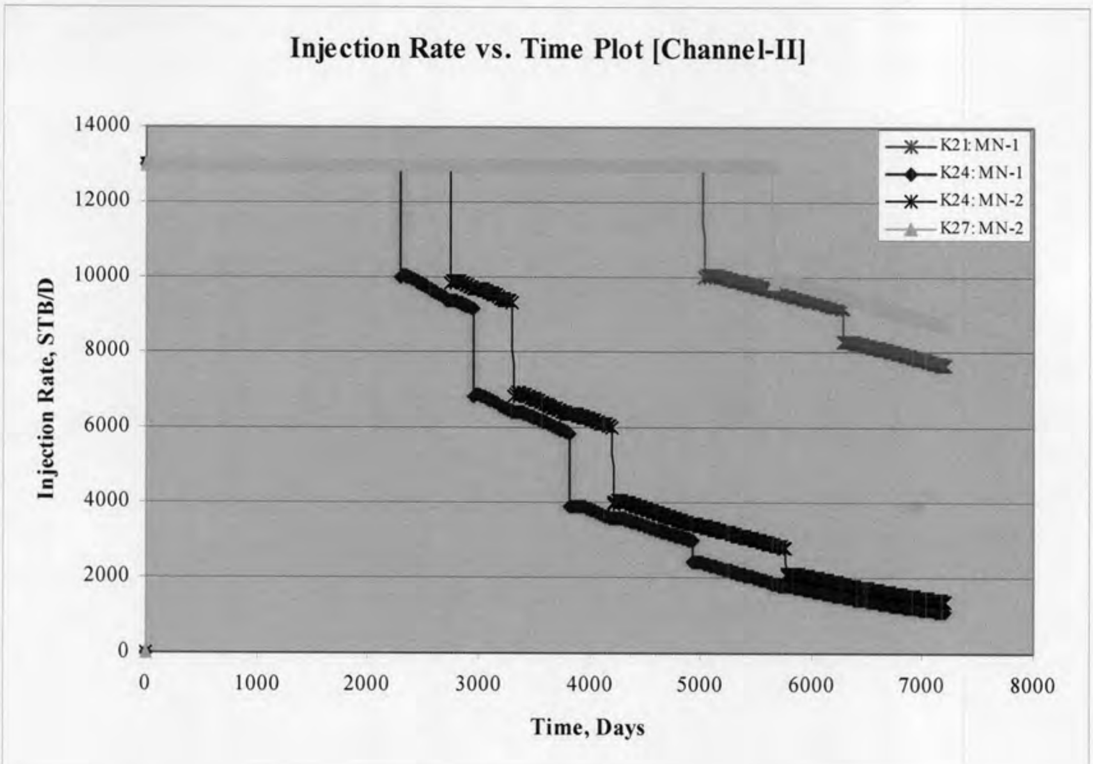

Figure 5.16: Injection rates of cases K21, K24 and K27.

After running all the 9 cases, K19-K27, it is seen that the IIs of MN-1 in single and multi well injection options are the same and the IIs of MN-2 in single and multi well injection options are the same also. As sample cases K21, K24 and K27 are presented in Figure 5.17. It is seen that the IIs of MN-1 for cases K21 and K24 starts from 241 STB/D/psi and then stabilized at 314 STB/D/psi. On the other hand, the II's of MN-2 for cases K24 and K27 starts from 234.3 STB/D/psi and then stabilized at 303 STB/D/psi. It is seen from simulation injectivity index reports for both wells that initial IIs are different from the stabilized IIs because of higher initial draw down. It is noticeable that the IIs of MN-1 and MN-2 are decreased by 142 STB/D/psi and 8 STB/D/psi respectively comparing to the homogeneous model and increased by 184 STB/D/psi and 3 STB/D/psi respectively due to the poor porosities and permeabilities out side of the channels. All other cases behave in the similar manner, shown in Appendix A.

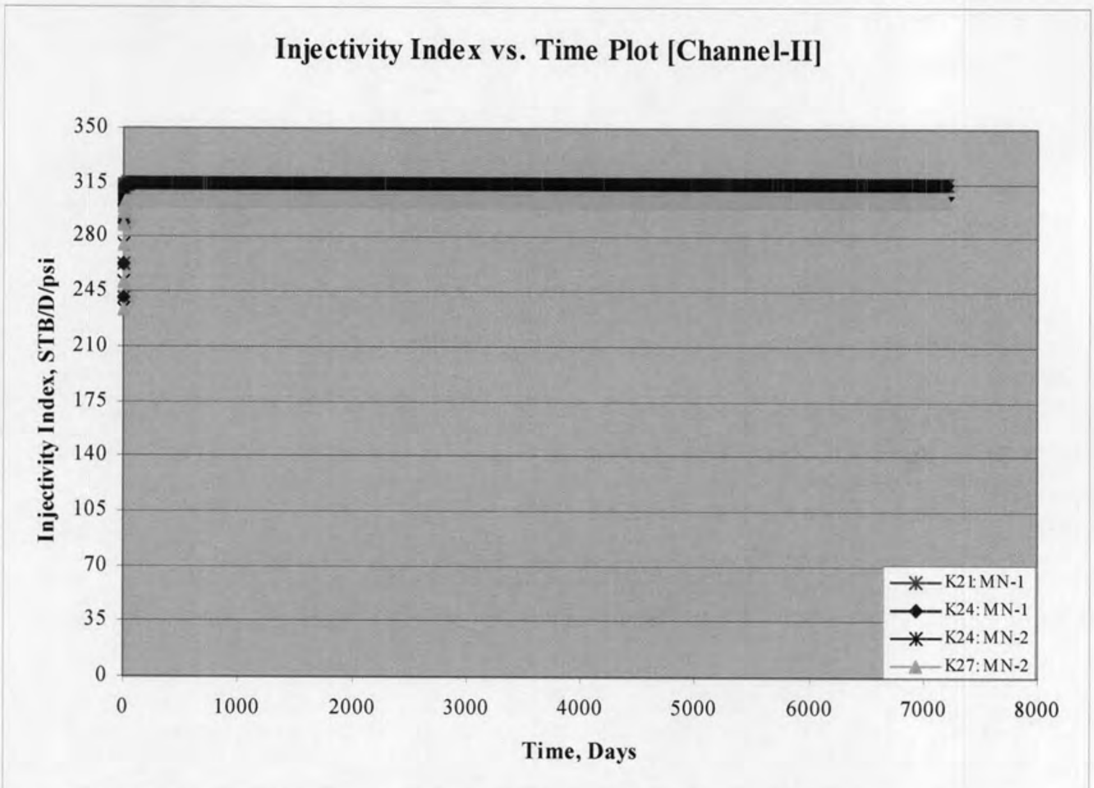

Figure 5.17: II of MN-1 and MN-2 of case K21, K24 and K27.

CIV into A and B individual sand units for single and both wells injection are shown in Table 5.5 and 5.6.

Table 5.7: CIV of single well injection in Channel-II model.

Single Well Injection		Case Name	Initial Well Rate, STB/D	Cumulative Injection Volume (CIV)				
				A		B		Total
				MMSTB	%	MMSTB	%	MMSTB
Channel-II	Injected by MN-1	K19	5000	35.28	97.9	0.74	2.1	36.02
		K20	9000	63.49	97.9	1.35	2.1	64.84
		K21	13000	82.92	97.8	1.87	2.2	84.79
	Injected by MN-2	K25	5000	34.94	97.0	1.08	3.0	36.02
		K26	9000	62.91	97.0	1.93	3.0	64.84
		K27	13000	85.89	96.9	2.72	3.1	88.61

Table 5.8: CIV of both well injection in Channel-II model.

Both Well Injection		Case Name	Initial Rate Well STB/D	Cumulative Injection Volume (CIV)						
				MN-1	MN-2	Total	A		B	
				MMSTB	MMSTB	MMSTB	MMSTB	%	MMSTB	%
Channel-II	Injected by MN-1 & MN-2	K22	5000	36.02	36.02	72.04	69.34	96.3	2.7	3.7
		K23	9000	48.64	51.97	100.61	96.29	95.7	4.32	4.3
		K24	13000	49.33	54.58	103.86	99.96	95.3	4.9	4.7

From Figure 5.14 and Table 5.7 it is seen that at the highest injection rate in single well injection the CIV of well MN-2 becomes steeper than well MN-1 and thus, gives higher value. From a closer look of channel distribution it shows that well MN-2 intersects more channels than MN-1. Therefore, well location has effect on CIV in this model.

Finally, from above discussion it can be concluded that 5000 and 9000 STB/D well injection rates can be maintained throughout for well MN-1 and MN-2 in single well injection. Because, in this model, both wells intersect with more channels than Channel-I model specially at A sand unit. In multi wells injection wells reach the set maximum THP sooner than the single well injection option. At higher rate in multi well injection, CIV curves are going to converge.

In single well and multi well injection cases, well MN-2 has different behaviors after reaching the max set THP. In both cases MN-2 has the same decline rates but different injection durations at a specific THP injection as can be seen in Figure 5.16. It shows some effect of MN-1 injection on the MN-2 performance. Again, in single well and multi well injection cases, well MN-1 has different rate declinations after reaching the set maximum THP. In single well injection MN-1 has longer duration and lower decline rate compared to multi well injection. This means that the presence of MN-2 injection has more effect on the MN-1 injection performance. In addition, well location has influence on CIV in this model as it shows in Table 5.7 for single well injection.

After running all the 27 cases, it is seen that pressure build up of different layers of different cases behave in similar manner. As examples, the following pressure maps of case K24 can be used for better understanding of reservoir pressure build up of different layers during injection operations. Figure 5.20 to Figure 5.25 illustrate the extent of pressure build up of topmost layer, layer 33 and layer 42 with MN-1 and MN-2 wells after 1, 2, 5, 10 and 20 years of injection. Topmost layer is the reference layer and having effective kh 1235.4 and 187.1 mD-ft, i.e. well MN-1 intersects 2 grid blocks at topmost layer, first grid i, j = 57, 66 and second grid i, j = 56, 65. Layer 33 is having effective kh 1211.6 and 631.6 mD-ft i.e. well MN-1 intersects 2 grid blocks at layer 33, first grid i, j= 46, 70 and second grid i, j= 45, 70, and layer 44 is having effective kh 2453.2 mD-ft i.e. well MN-1 intersects grid i, j= 41, 72 at layer 42. It is mentioned that layer 33 having the closest effective kh value of topmost layer and layer 42 having the highest kh value. As effective kh value is one of the dominating factors that influences the injection result therefore, other two layers are selected based on effective kh values to show injection performances of those three layers.

Topmost layer is located in sand unit A. In addition, the layer is having the other properties such as permeability, porosity, gross thickness and NTG are 252.65 mD, 0.27 and 9.94 ft and 0.2275; the layer having initial water saturation (Sw) 0.95 or initial gas saturation (Sg) 0.05. Topmost layer permeability and porosity distribution are shown in Figure 5.18 and Figure 5.19.

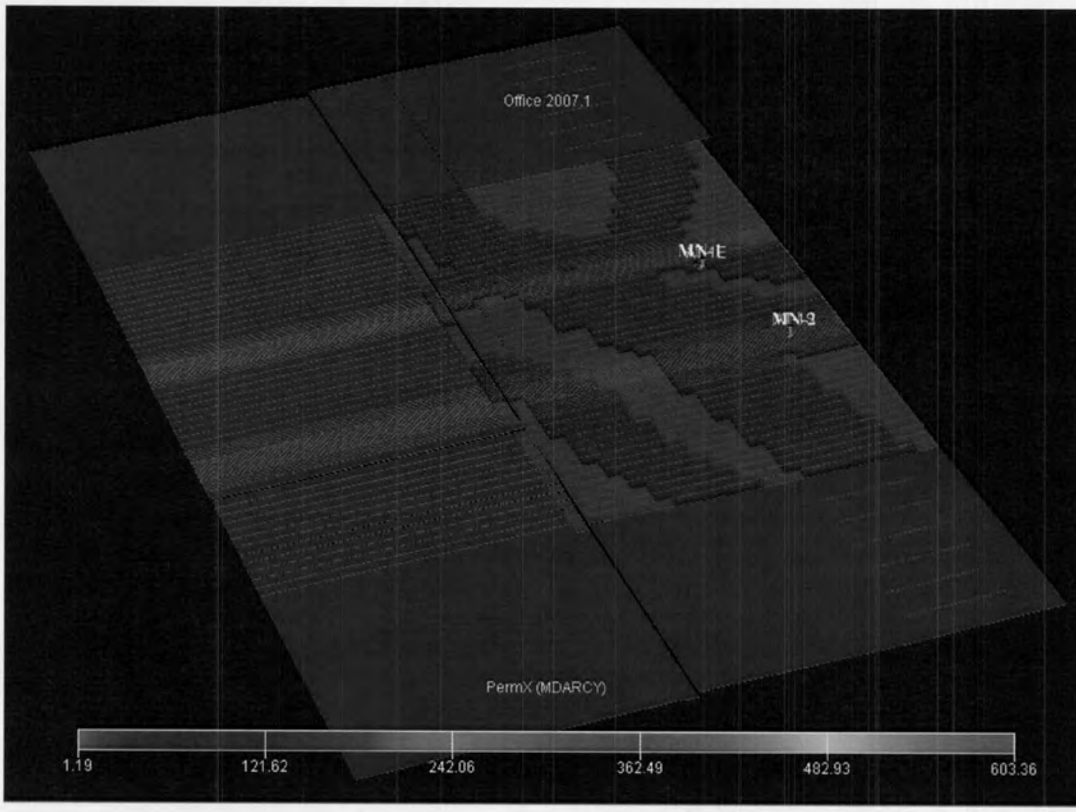

Figure 5.18: Topmost layer permeability distribution.

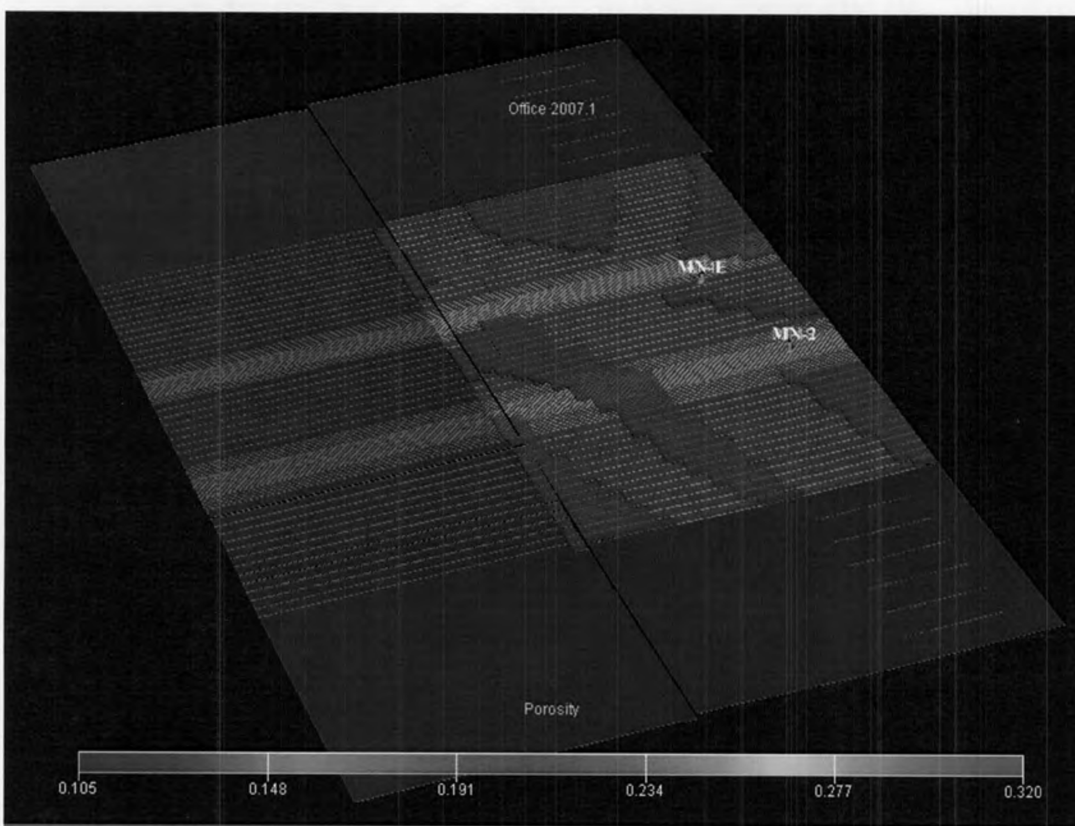

Figure 5.19: Topmost layer porosity distribution.

In Figure 5.21, it is seen after one year of injection, reservoir pressure of layer one increased to 1774.6 psia from its initial value 1675.5 psia. It is seen from Figure 5.21, there are many distinguished high pressure zones developed due to injection around both of the wells. From regional cumulative injection volume (RCIV) report Table 5.11 is prepared and it is seen from Table 5.11, after one year of injection, layer one intakes 183 MSTB which is 12.2% of CIV of layer one. From Figure 5.22, it is seen that after 2 years of injection, reservoir pressure increased to 1872 psia and similarly, from Table 5.11, it is seen that 365.5 MSTB intakes by layer one which is 24.4% of CIV of layer one. The figure also shows many distinguished high pressure zones developed due to injection around both of the wells. Similarly, from Figure 5.23 and 5.24, it is seen that after 5 and 10 years of injection, reservoir pressure increased to 2170 and 2530.5 psia respectively. Similarly, from Table 5.11, it is seen after 5 and 10 years of injection, CIV become 875 and 1354 MSTB respectively and which are equivalent to 58.3% and 90.2% respectively. Figure 5.25 shows green color around the wells indicates high pressure development due to injection. It is also seen from Figure 5.21 to Figure 5.23 that the pressure dissipation in the direction of the S-E corner of the model. It is also seen from Figure 5.25, 20 years pressure map, reservoir pressure is 2655.3 psia and similarly from Table 5.11, CIV of topmost layer is 1501 MSTB after 20 years of injection.

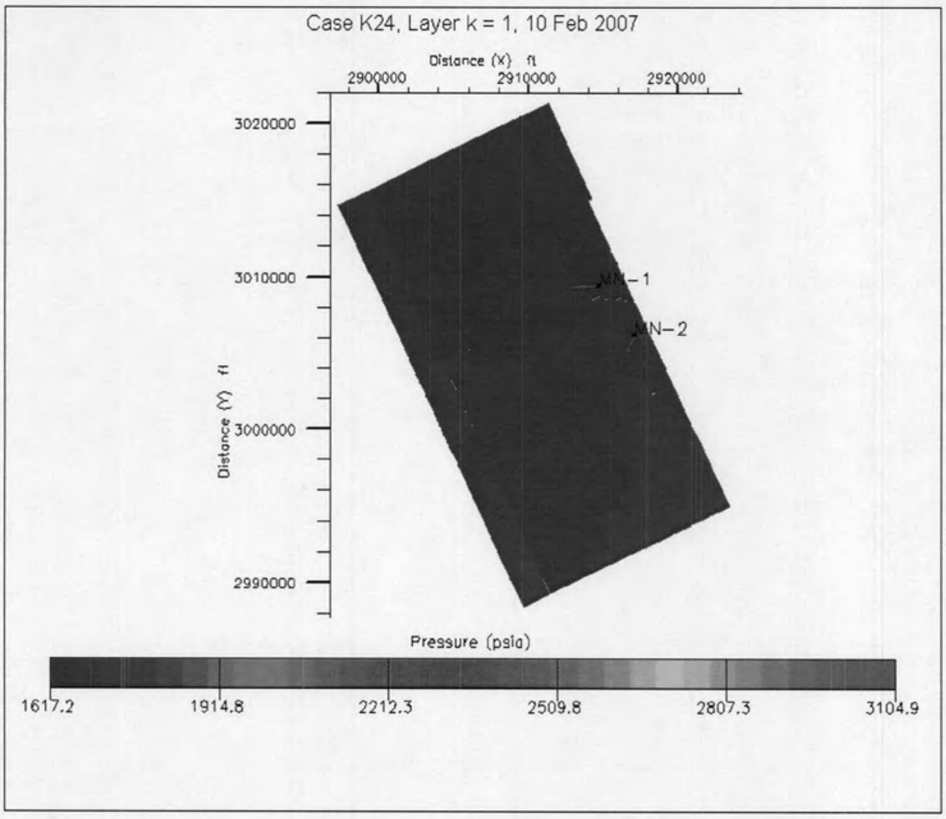

Figure 5.20: Topmost layer areal pressure distribution at time zero.

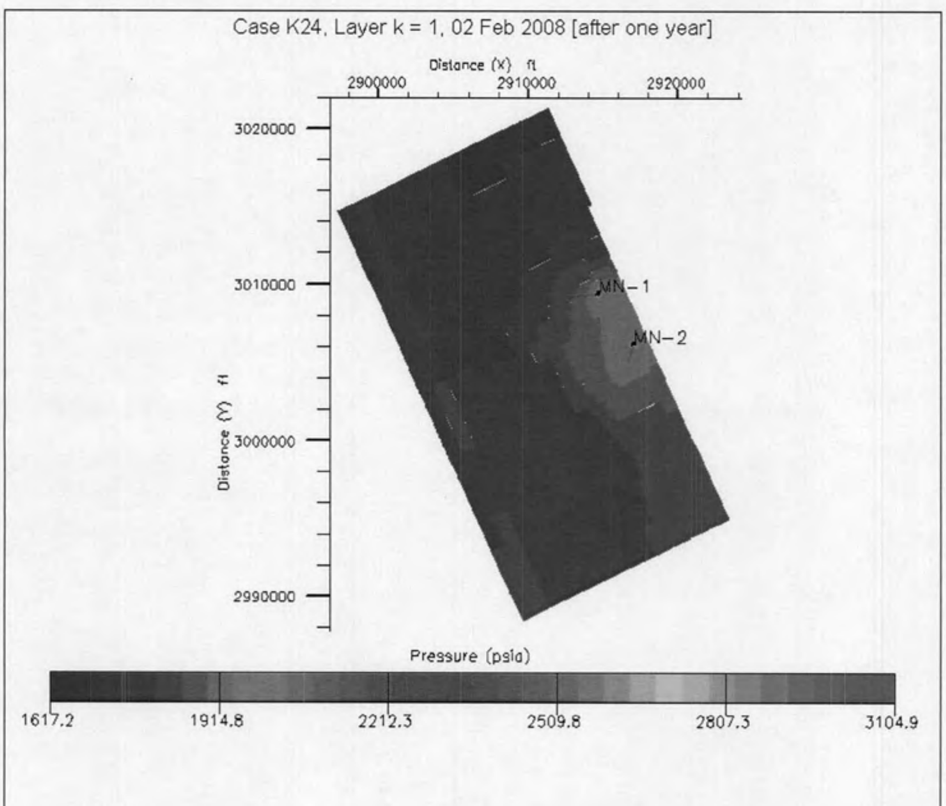

Figure 5.21: Topmost layer areal pressure distribution after one year.

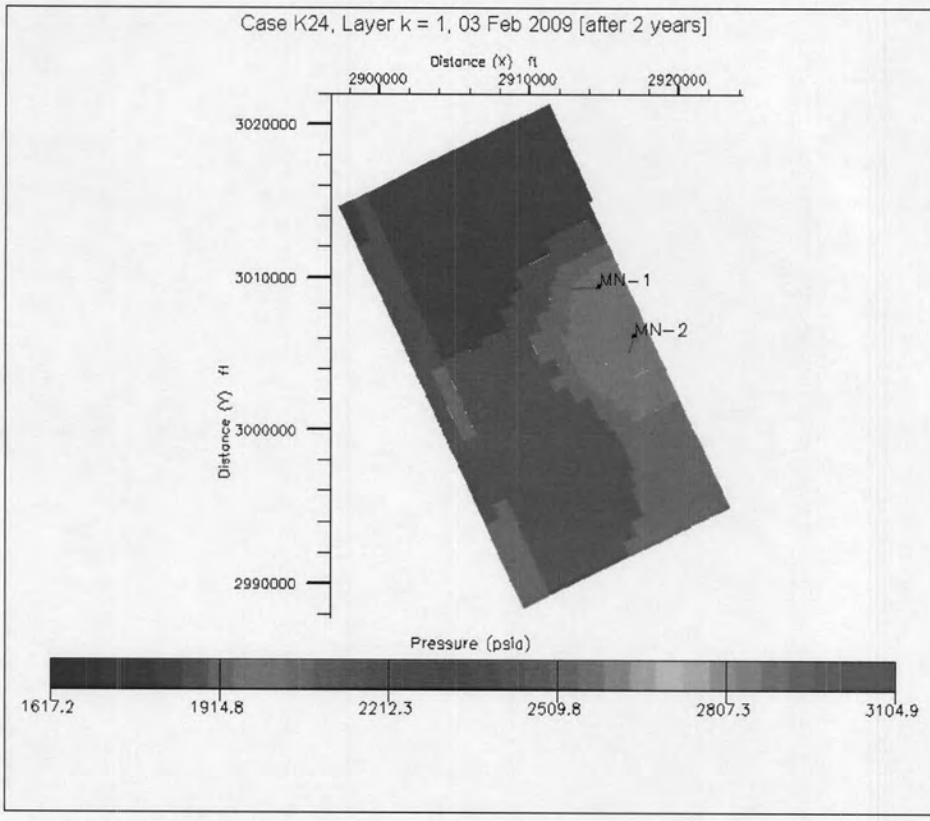

Figure 5.22: Topmost layer areal pressure distribution after 2 years.

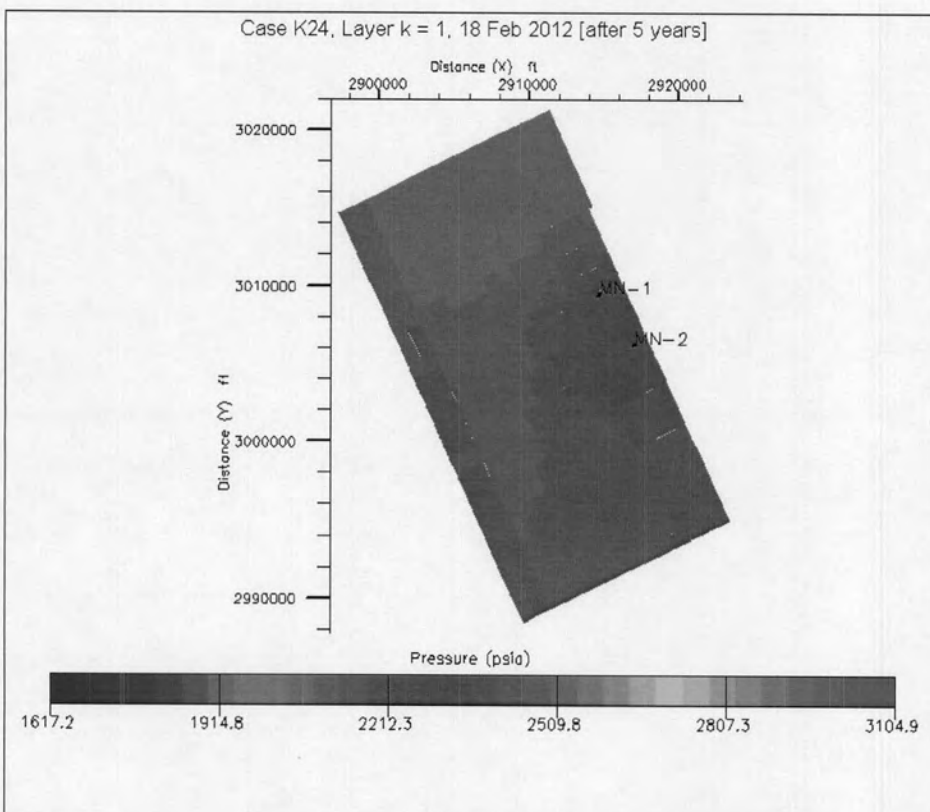

Figure 5.23: Topmost layer areal pressure distribution after 5 years.

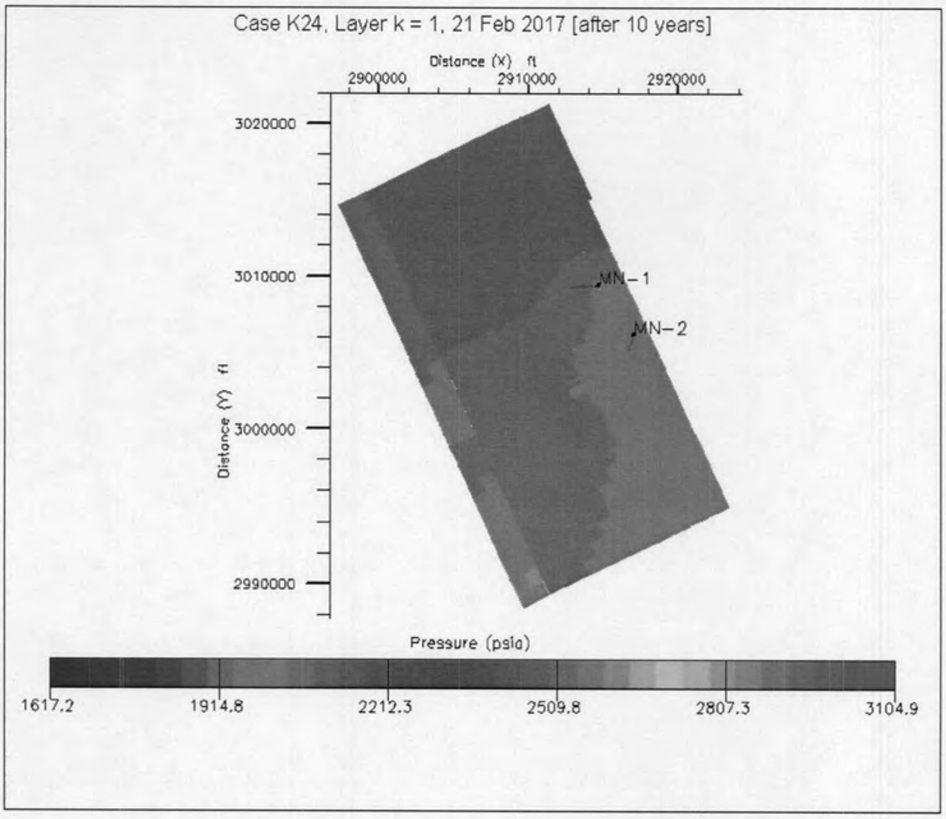

Figure 5.24: Topmost layer areal pressure distribution after 10 years.

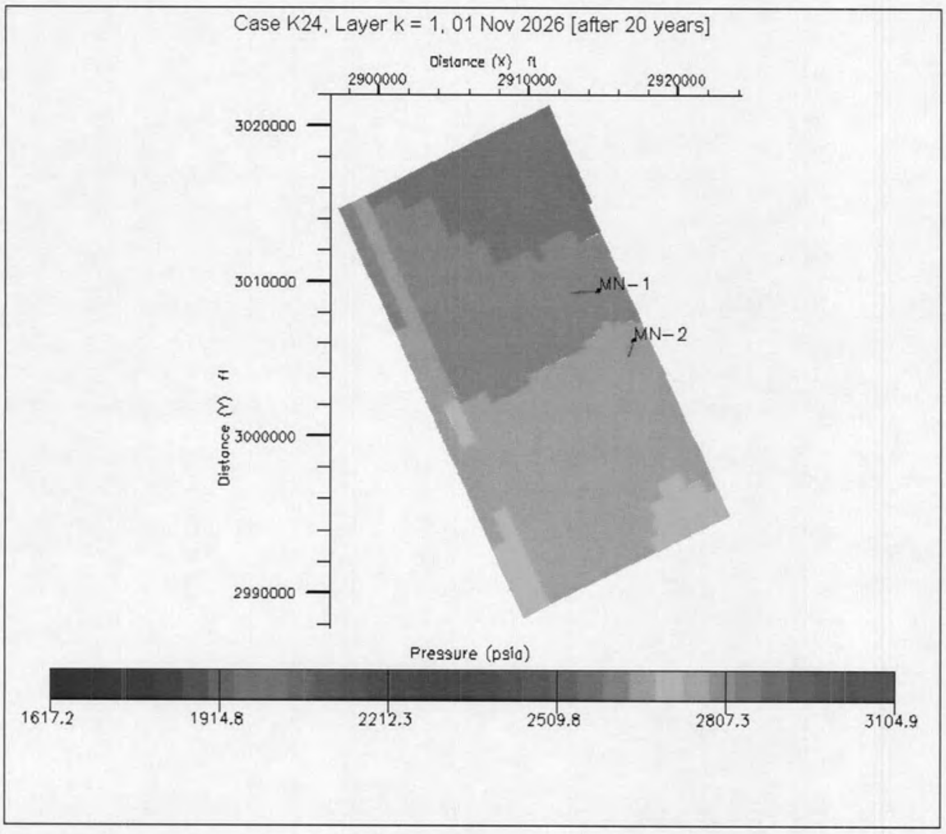

Figure 5.25: Topmost layer areal pressure distribution after 20 years.

Similarly, pressure maps shown in Figure 5.28-5.33 can be described for pressure build up of layer 33 during injection operations. The figures illustrate the extent of pressure build up with MN-1 and MN-2 wells after 1, 2, 5, 10 and 20 years of injection. As mentioned earlier, layer 33 is having closest effective kh value of topmost layer therefore, at each time the injected volume can be compared to topmost layer.

Layer 33 is located into same sand unit and located at deeper part than topmost layer. The layer 33 is having the other properties such as permeability, porosity, gross thickness and NTG are 337.71 mD, 0.287 and 11.58 ft and 0.2168; layer 33 having initial water saturation (Sw) 0.864 or initial gas saturation (Sg) 0.136. Layer 33 permeability and porosity distribution are shown in Figure 5.26 and Figure 5.27.

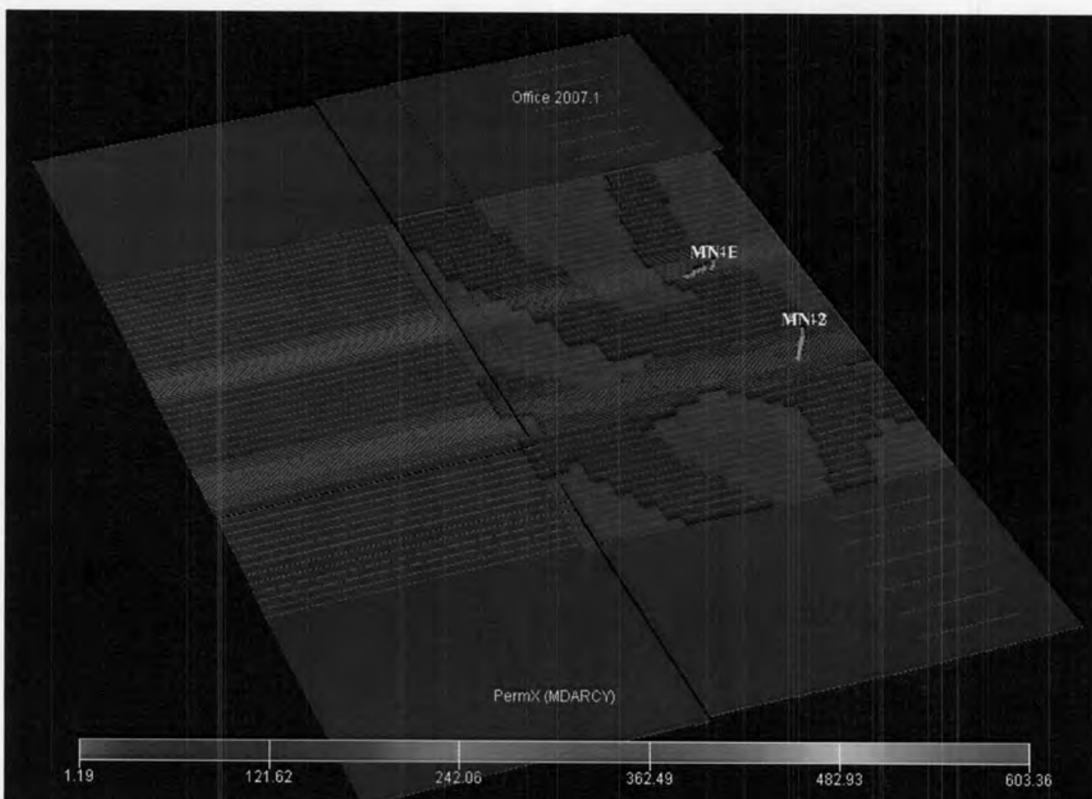

Figure 5.26: Layer 33 permeability distribution.

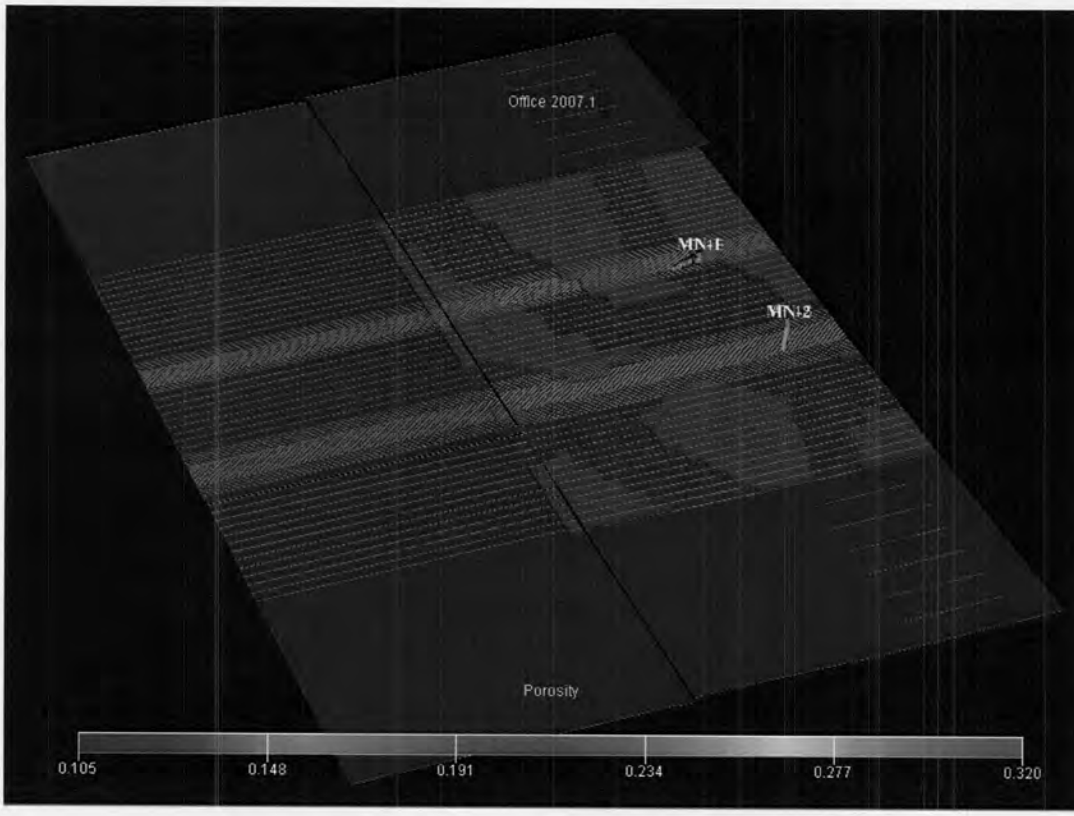

Figure 5.27: Layer 33 porosity distribution.

In Figure 5.29, it is seen after one year of injection, reservoir pressure of layer 33 increased to 1884.4 psia from its initial value 1691.6 psia. It is seen from Figure 5.29, there are many distinguished high pressure zones developed due to injection around both of the wells and pressure dissipation occurs in the direction of the S-E corner of the model. From Table 5.11, it is seen after one year of injection, layer 33 intakes 278 MSTB which is 8.6% of CIV of layer 33. From Figure 5.30, it is seen that after 2 years of injection, reservoir pressure increased to 1945.5 psia and similarly, from Table 5.11, it is seen that 552 MSTB intakes by layer 33 which is 17.1% of CIV. The figure also shows many distinguished high pressure zones i.e. green color around the wells and next to green there is turquoise color, developed due to injection around both of the wells. From Figure 5.31 and 5.32, it is seen that after 5 and 10 of injection, reservoir pressure increased to 2164.4 and 2550.5 psia respectively. Similarly, from Table 5.11, it is seen after 5 and 10 years of injection, CIV become 1418 and 2616 MSTB respectively and which are equivalent to 44% and 81.1% respectively. In Figure 5.31 and Figure 5.32, green (changing to yellow) and yellow colors around well bore indicate high pressure development around well bore due to injection after 5 and 10 years. Again, from Figure 5.33, 20 years pressure map, reservoir pressure is 2792 psia and similarly from Table 5.11, CIV of layer 33 is 3225.5 MSTB after 20 years of injection. Around well bore to the direction of S-E corner of the model light orange color shows clear evidence of pressure build up due to injection.

From above discussion it is seen that layer 33 accommodates 115% higher CIV than topmost layer. On the other hand, pressure build up due to that injection in layer 33 is 967 psi whereas pressure build up in topmost layer is 981 psi. Layer 33 accommodates 115% higher CIV with 14 psi less pressure build up because of having high kh value and 8.3% lower gas saturation.

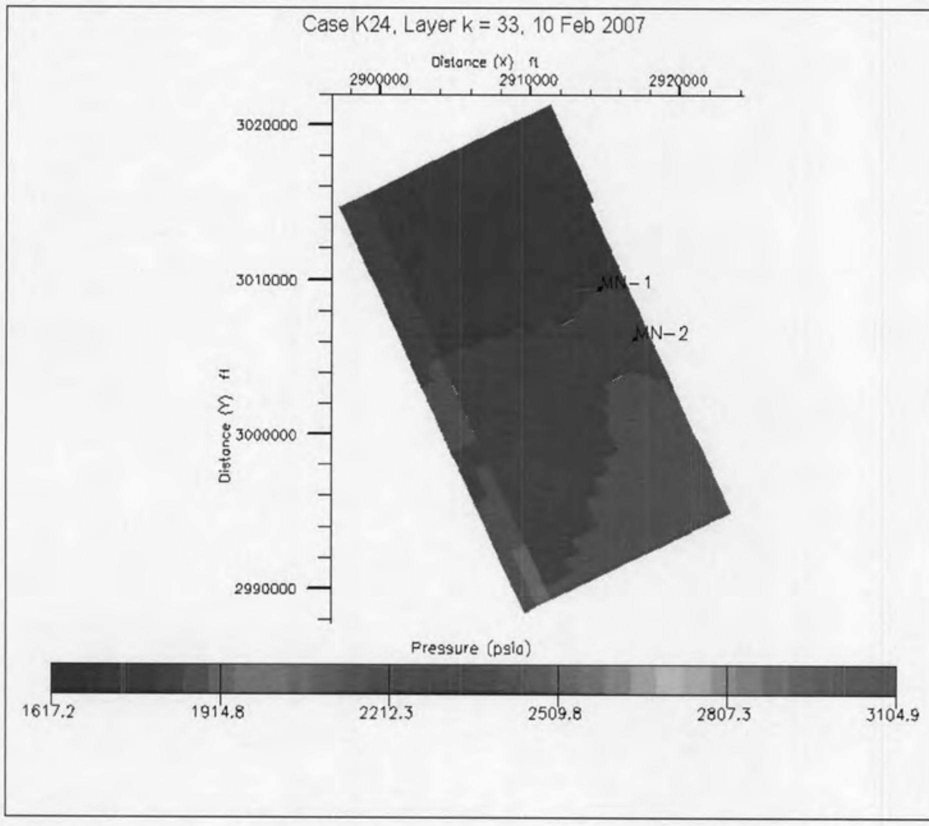

Figure 5.28: Layer 33 areal pressure distribution at time zero.

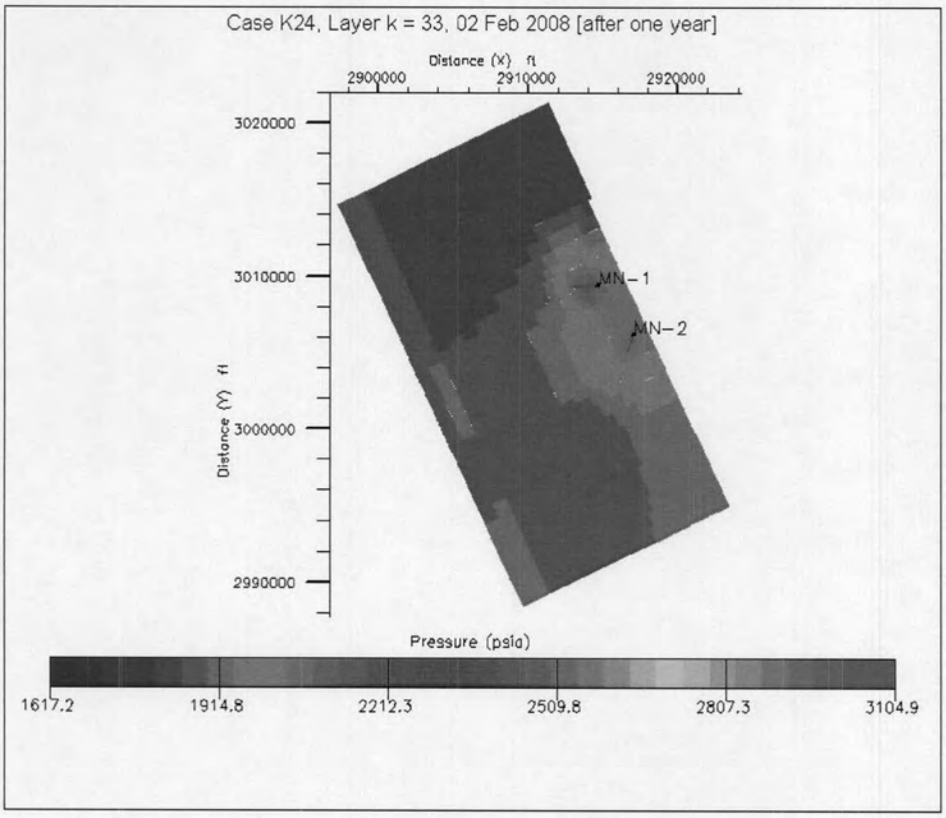

Figure 5.29: Layer 33 areal pressure distribution after one year.

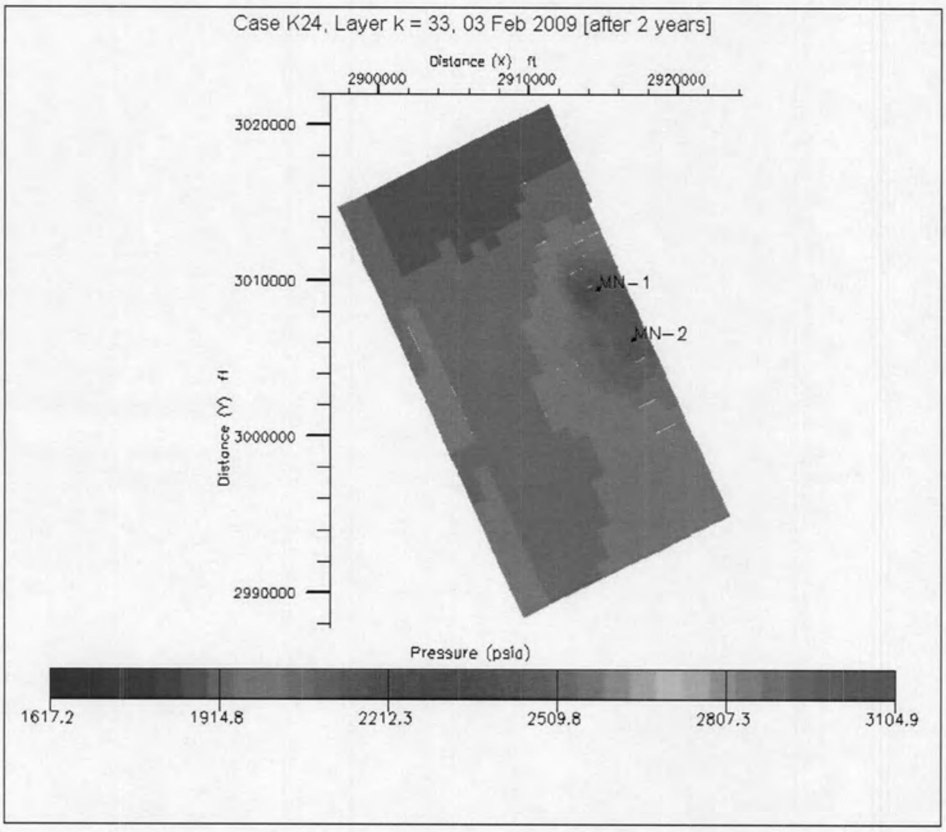

Figure 5.30: Layer 33 areal pressure distribution after 2 years.

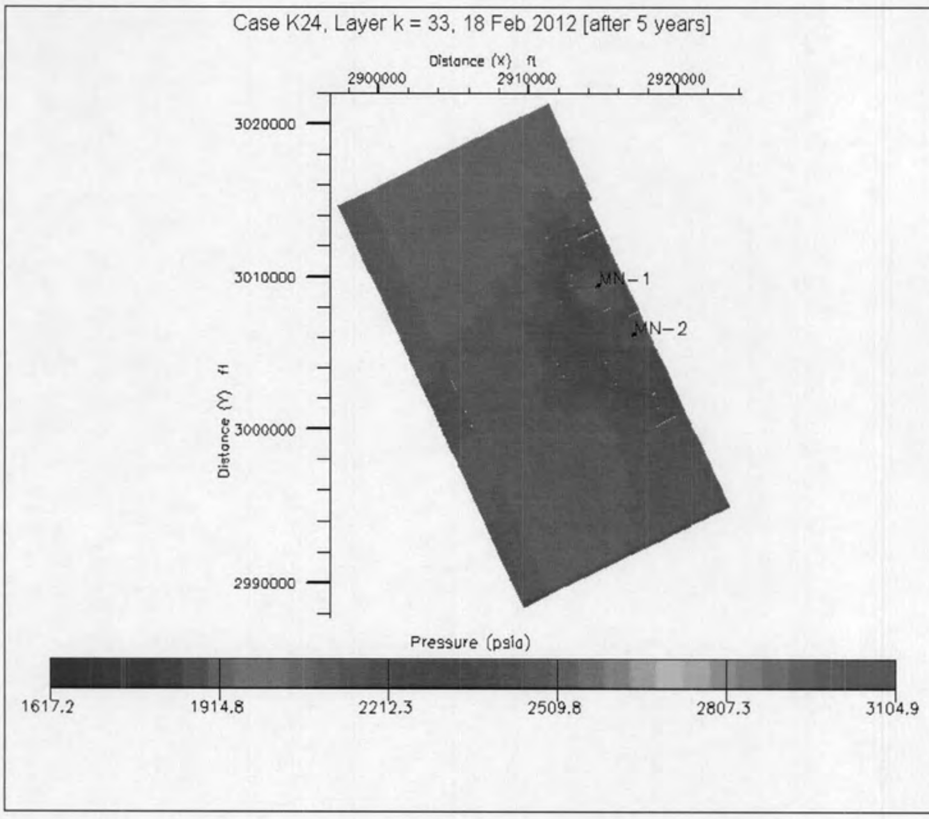

Figure 5.31: Layer 33 areal pressure distribution after 5 years.

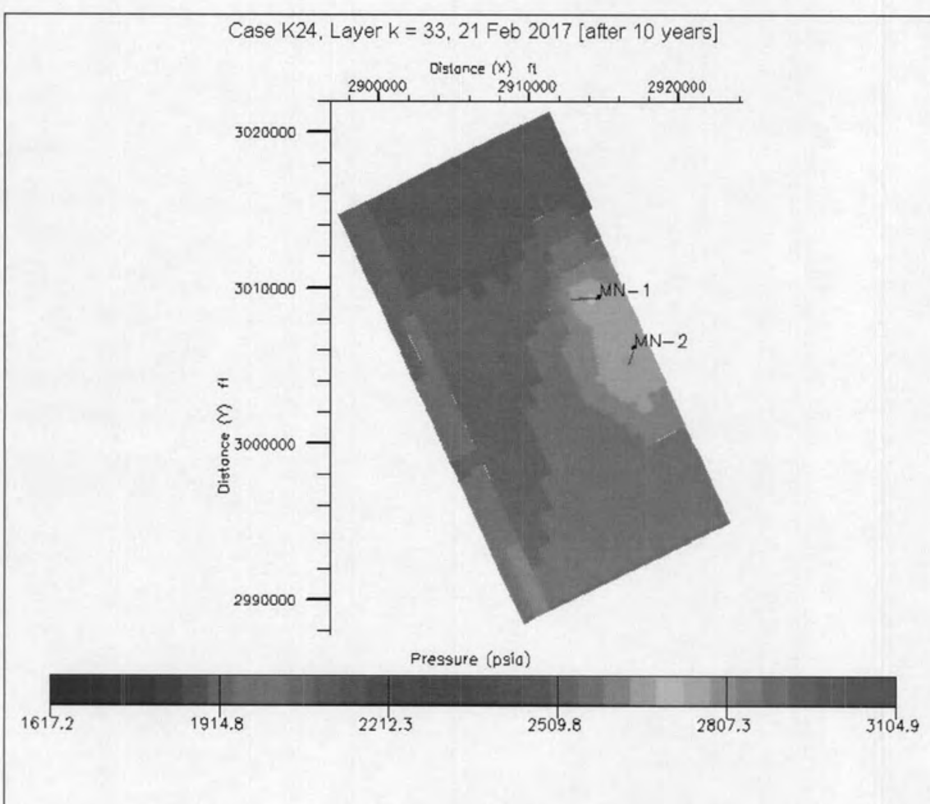

Figure 5.32: Layer 33 areal pressure distribution after 10 years.

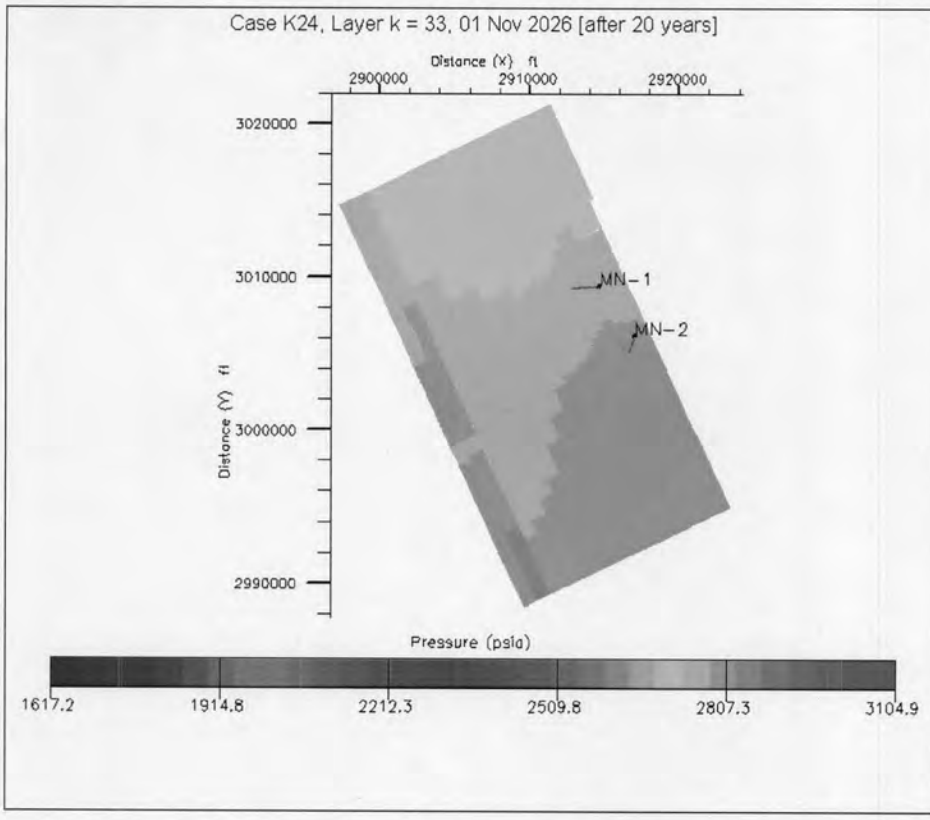

Figure 5.33: Layer 33 areal pressure distribution after 20 years.

Similar pressure maps are shown in Figure 5.36-5.41 and can be described for pressure build up of layer 42 during injection operations. The figures illustrate the extent of pressure build up with MN-1 and MN-2 wells after 1, 2, 5, 10 and 20 years of injection. As mentioned earlier, layer 42 having effective kh value 2453.2 mD-ft, which is the highest kh value therefore, at each time the cumulative injected volume can be compared to topmost and layer 33.

On the other hand, layer 42 is located into same sand unit with previous two layers and at deeper than layer 33. The layer is having the other properties such as permeability, porosity, gross thickness and NTG are 337.71 mD, 0.31 and 15.91 ft and 0.151; layer 42 having initial water saturation (Sw) 0.97 or initial gas saturation (Sg) 0.03. Layer 42 permeability and porosity distribution are shown in Figure 5.34 and Figure 5.35.

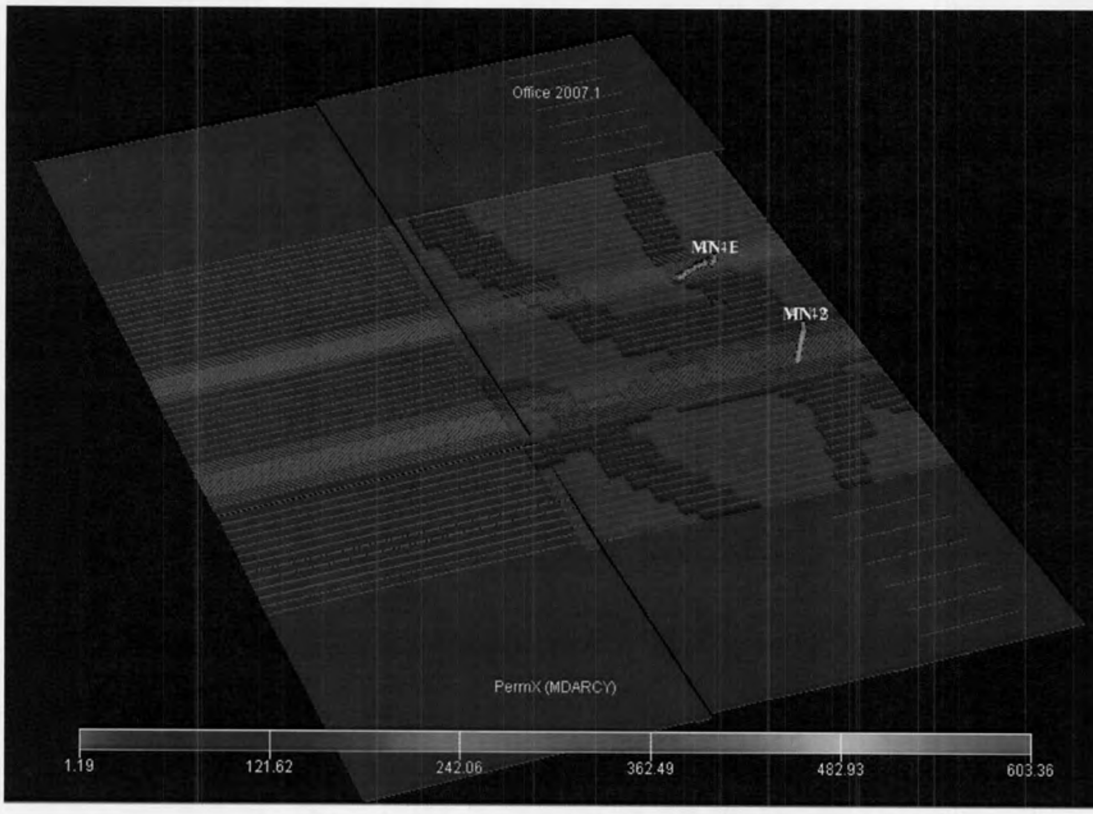

Figure 5.34: Layer 42 permeability distribution.

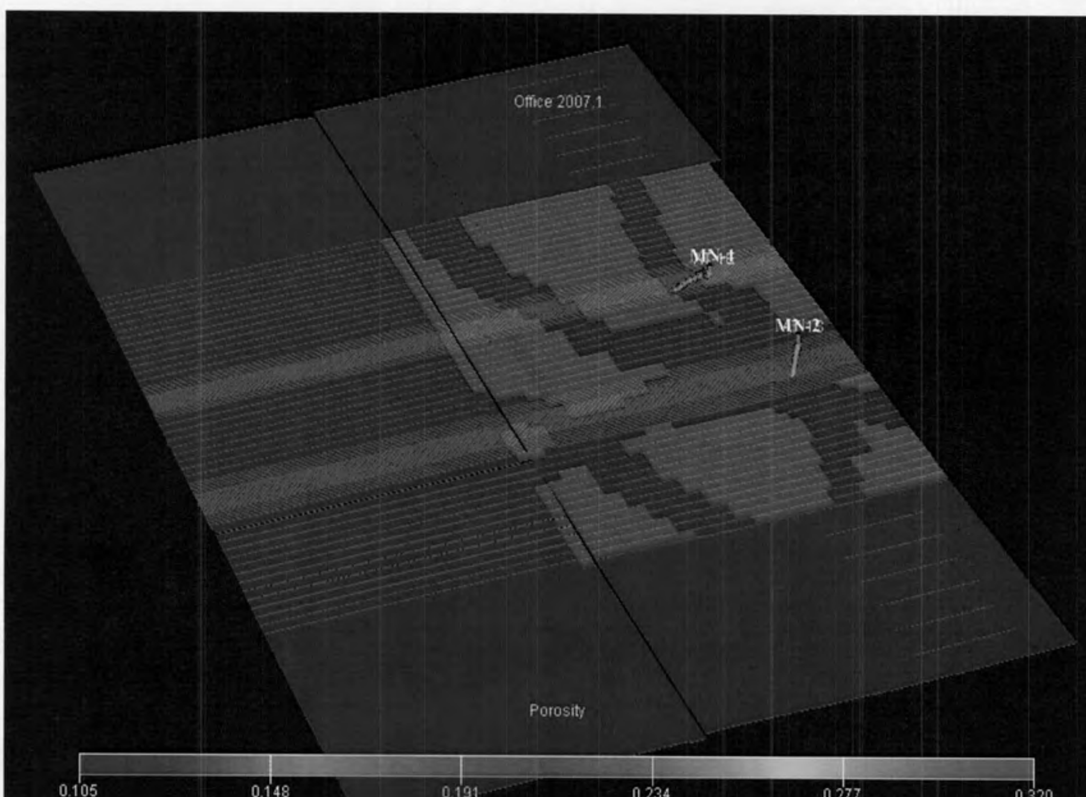

Figure 5.35: Layer 42 porosity distribution.

In Figure 5.37, it is seen after one year of injection, reservoir pressure of layer 42 increased to 1965.4 psia from its initial value 1887.4 psia. From Figure 5.37, it is seen that around both the wells there are green color and next to green color there is turquoise color that indicates high pressure development due to injection and pressure dissipation occurs in all the three directions of the model but fast in the direction of S-E corner of the model. From Table 5.11, it is seen after one year of injection, layer 42 intakes 355.5 MSTB which is 10% of CIV of layer 42. From Figure 5.38, it is seen that after 2 years of injection, reservoir pressure increased to 2015.1 psia and similarly, from Table 5.11, it is seen that 684 MSTB intakes by layer 42 which is 19.2% of CIV. In Figure 5.38, green color around well bore indicates high pressure development around both wells due to injection and pressure dissipation occurs in all the three directions of the model. From Figure 5.39 and 5.40, it is seen that after 5 and 10 of injection, reservoir pressure increased to 2233 and 2624.5 psia respectively. In Figure 5.39, very light yellow color around wells indicate high pressure is developing due to injection and in Figure 5.40 it is seen that from 5 years light yellow becomes light orange around both of the wells due to injection. Similarly, from Table 5.11, it is seen after 5 and 10 years of injection, CIV become 1644 and 2932.5 MSTB respectively and which are equivalent to 46% and 82.1% respectively. It is also seen from Figure 5.41, 20 years pressure map, reservoir pressure is 2862.1 psia and similarly Table 5.11, CIV of layer 42 is 3572 MSTB after 20 years of injection.

From above discussion it is seen that layer 42 accommodates 138% and 11% higher CIV than topmost and layer 33. On the other hand, pressure build up due to that injection in layer 42 is 975 psi whereas pressure build up in topmost and layer 33 are 981 and 967 psi. The higher CIV and in between pressure build up of layer 42 can be explained of having high kh value and 0.04 and 0.023 higher porosity compared to topmost layer and layer 33.

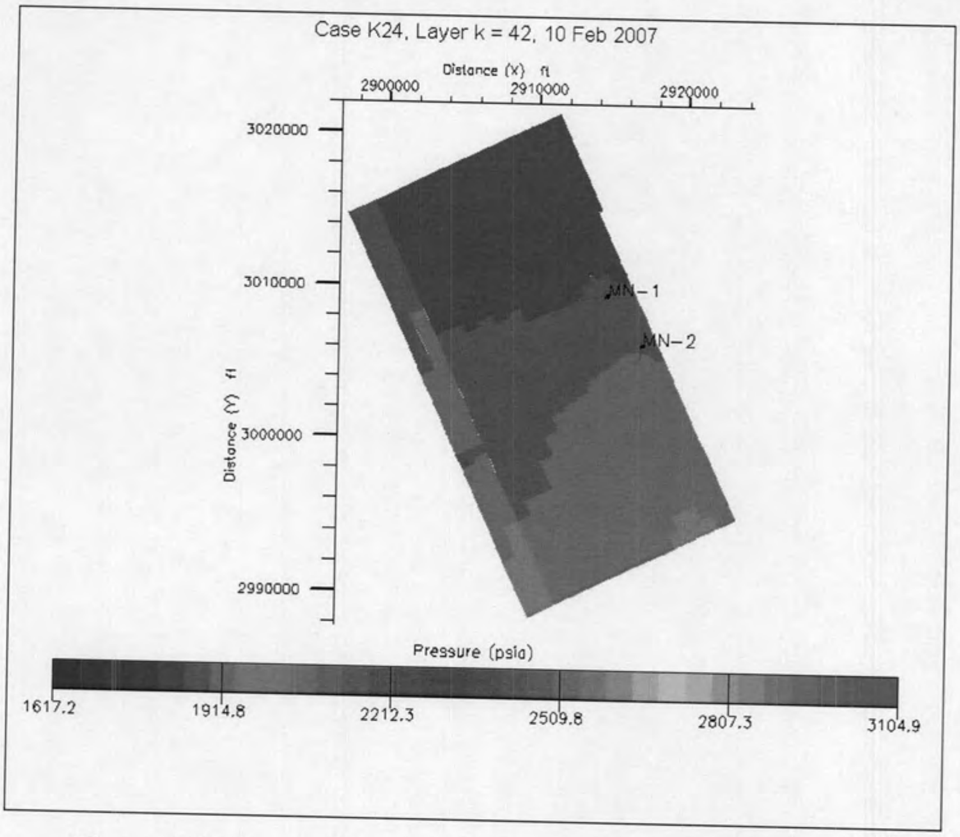

Figure 5.36: Layer 42 areal pressure distribution at time zero.

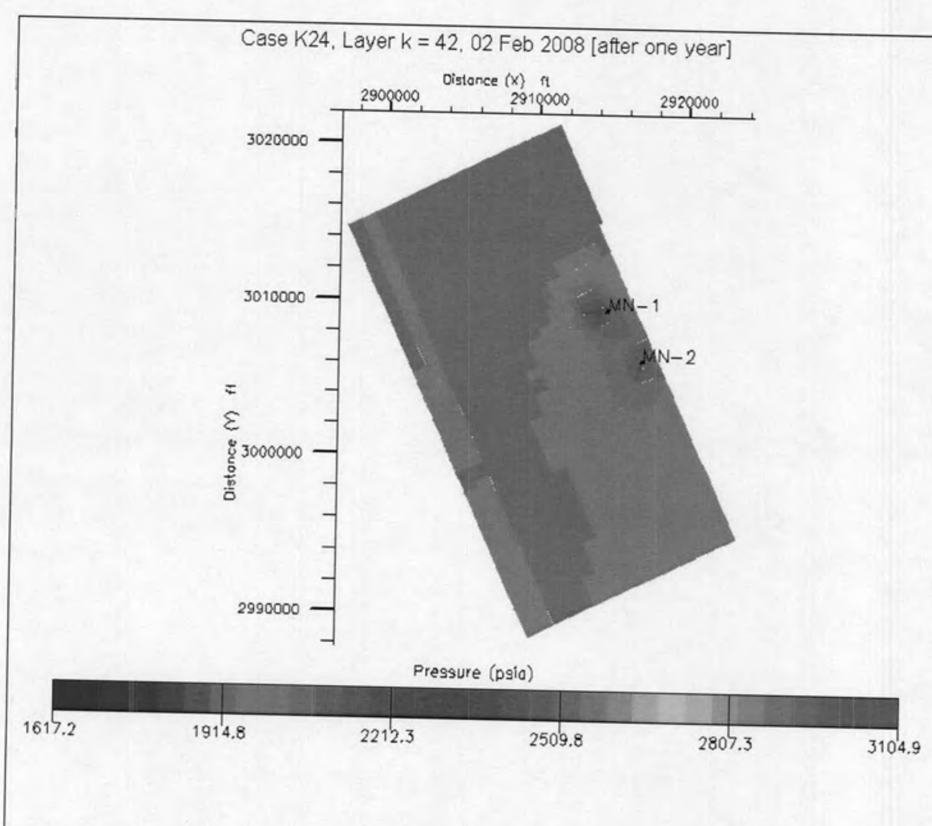

Figure 5.37: Layer 42 areal pressure distribution after one year.

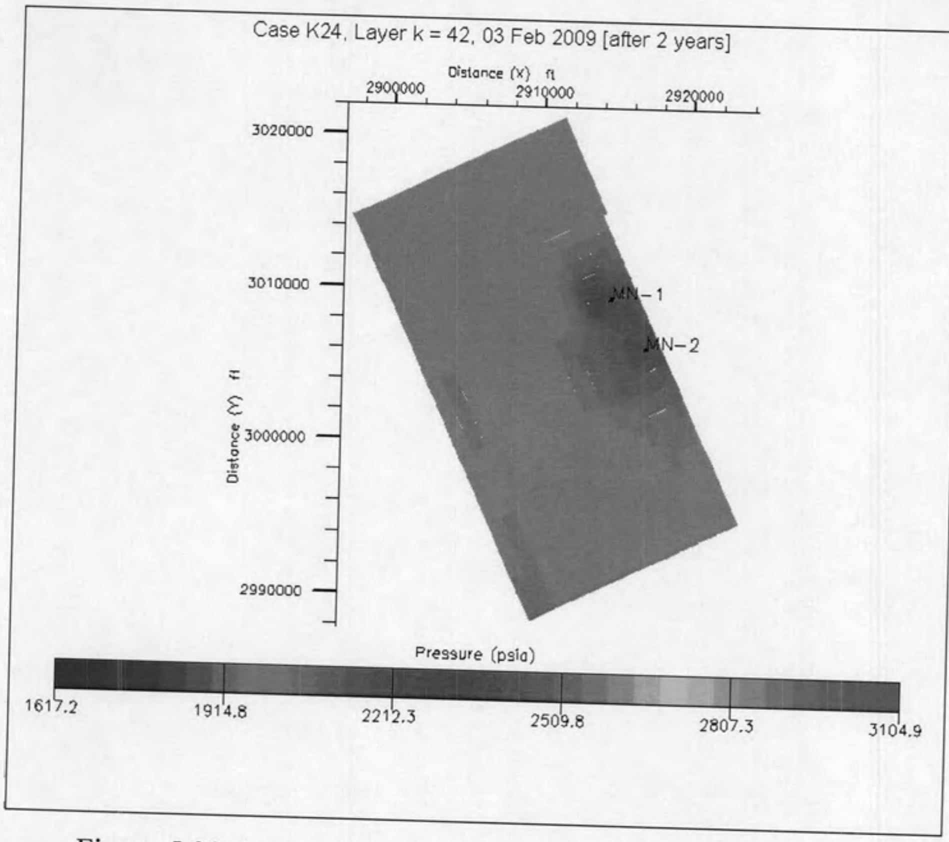

Figure 5.38: Layer 42 areal pressure distribution after 2 years.

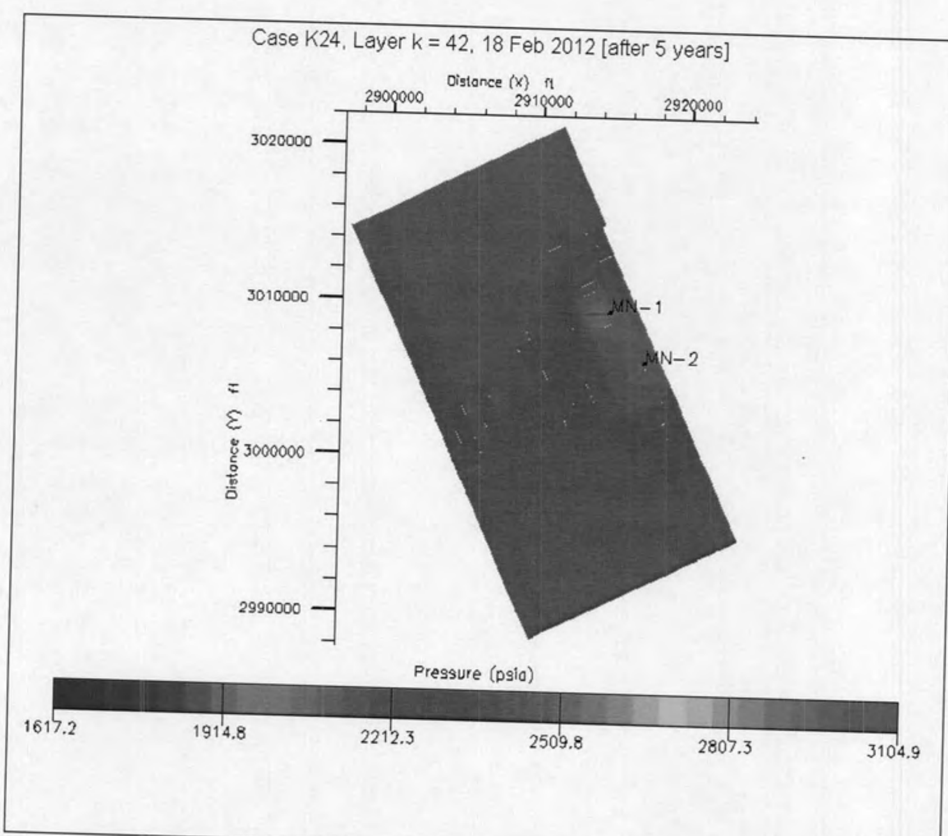

Figure 5.39: Layer 42 areal pressure distribution after 5 years.

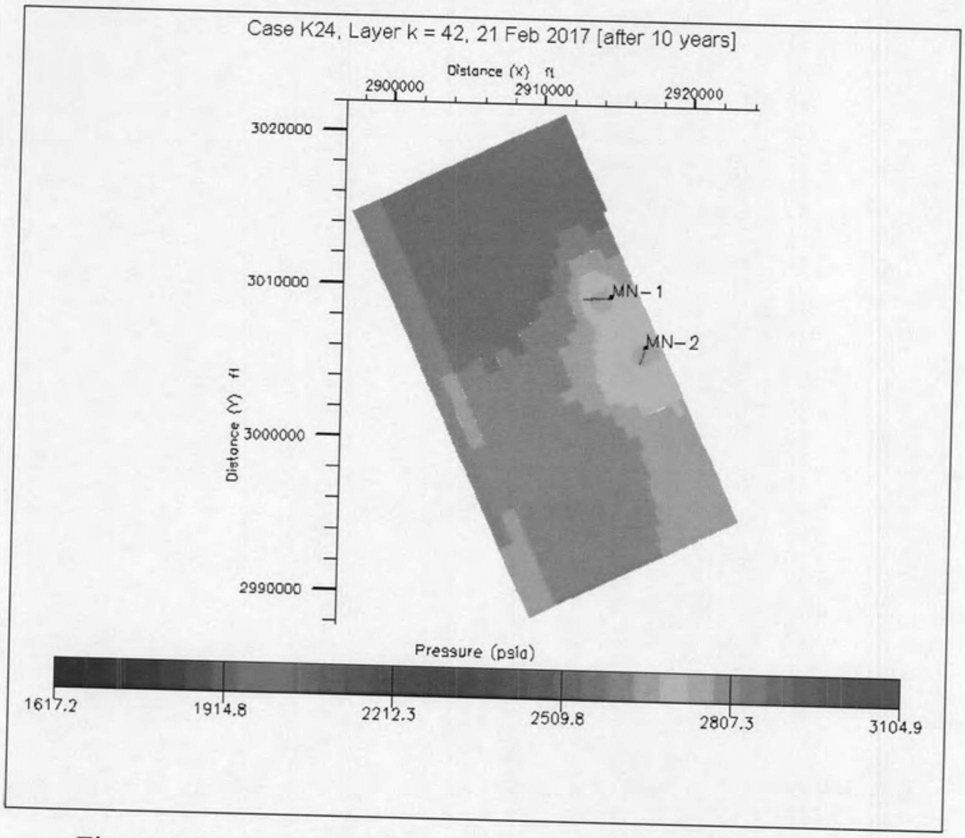

Figure 5.40: Layer 42 areal pressure distribution after 10 years.

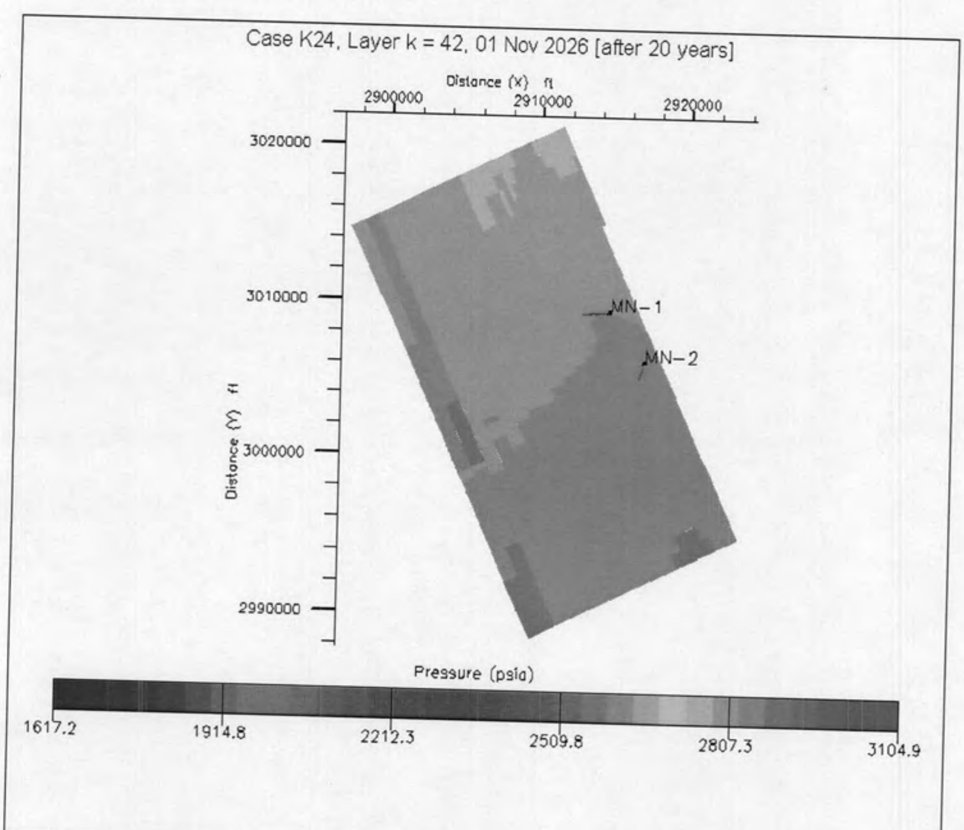

Figure 5.41: Layer 42 areal pressure distribution after 20 years.

All the pressure maps discussed so far are showing the areal pressure distribution of topmost layer, layer 33 and layer 42. They are not reflecting the presence and orientation of channels because even though channels have high porosity and permeability than out side of the channel. The poor porosity and permeability are enough to leak the injected water out. Therefore the pressure profiles are not localized. But during running simulation, the author observed localized saturation changes through the channels. For all the cases, CIV and the extent pressure build up of topmost layer, layer having closest kh value of topmost layer and the layer having highest kh value after 1, 2, 5, 10 and 20 years of injection are shown in Table.5.10, 5.11 and 5.12.

In addition, all the models having initial reservoir pressure at datum 3783.13 ft ss of 1914 psia. The following Table 5.9 shows reservoir pressure at datum at 10 and 20 years of injection with CIV in multi well injection at the highest initial well injection rate. In HM, pressure builds up 416 psi with 93.7 MMSTB CIV, i.e. 4.4 psi/MMSTB, by 10 years. Similarly, 634 psi pressure builds up with 127.9 MMSTB CIV, i.e. 5.0 psi/MMSTB, after 20 years of injection. On the other hand, pressure builds up for other two models are different from HM model. In Channel-I model, pressure builds up 324 psi with 71 MMSTB CIV, i.e. 4.6 psi/MMSTB by 10 years and 476 psi with 98.2 MMSTB CIV, i.e. 4.9 psi/MMSTB by 20 years. Again, in Channel-II model, pressure builds up 380 psi with 83.4 MMSTB CIV, i.e. 4.6 psi/MMSTB by 10 years and 500 psi with 103.9 MMSTB CIV, i.e. 4.8 psi/MMSTB, by 20 years. The pressures build up in the channel models are quite similar and both are different from HM model because of the differences in the initial gas pore volumes. Therefore, the initial gas pore volume has an effect on the pressure build up as water is injected.

Table 5.9: Reservoir pressure builds up with CIV at maximum injection rate after 10 and 20 years of injection.

	Initial Gas PV	10 Years		20 Years	
	MMSTB	CIV, MMSTB	P, psia	CIV, MMSTB	P, psia
HM	363	93.7	2330	127.9	2548
Channel-I	334	71	2238	98.2	2390
Channel-II	338	83.4	2294	103.9	2414

Finally, from the above discussion of pressure maps can be concluded that layer 42 accommodates the highest CIV. In addition, kh value strongly influences the CIV and if the kh value is high, the CIV is likely to be high. In addition, gas saturation has also high influence on CIV.

5.2.3 Intermittent Injection (INI)

Under previous two scenarios, continuous injections mode were opted in single and both wells injection options. Here under intermittent injection (INI) option, the capacity and performances variation of MN-1 and MN-2 are discussed. The concept of INI is to start injection by a particular well and whenever it reaches the set maximum THP then shut it in for certain time and start injection again. It is seen that injection performance becomes higher at the injection period after each shut in.

Under this injection option, four cases were run for the highest initial well injection rate i.e. 13000 STB/D, for both of the channel models. Therefore, for each well one case was run for Channel-I and the other for Channel-II. According to previous numbering convention, injection by MN-1 and MN-2 in Channel-I are designated as Case K28 and K29. Similarly, injection by MN-1 and MN-2 in Channel-II are designated as Case K30 and K31. No case was run for HM because no well was reached the set maximum THP therefore, it was not required to shut the wells. The capacity and performances of INI are discussed as follows:

As mentioned earlier, under INI single wells were used for injection intermittently for Channel-I and Channel-II models. For every cases, wells were initially controlled by surface injection rates, as before, and once the injection pressure reached the set maximum THP then wells were shut in for some time. After shut in period, wells were started injection again controlled by THP. However, by following injection and shut in process 20 years injection was completed for every cases. After running all the four cases, it is seen that every cases reached the set maximum THP at different times. In Figure 5.42, CIV for all cases are presented here. CIV into A and B individual sand units are shown in Table.5.12.

Table 5.10: CIV and layer pressure build up of Cases K1-K9 after 1, 2, 5, 10 and 20 years of injection.

	Layer No	CIV, MSTB					CIV, %					Layer Pressure, psia						Layer Pressure Build Up, psi				
		1st Yr	2nd Yr	5th Yr	10th Yr	20th Yr	1st Yr	2nd Yr	5th Yr	10th Yr	20th Yr	P_i	P_1	P_2	P_5	P_{10}	P_{20}	ΔP_1	ΔP_2	ΔP_5	ΔP_{10}	ΔP_{20}
Case K1	k=1	41.7	80.3	176.2	304.1	530.2	7.9	15.1	33.2	57.4	100	1675.4	1702.6	1720.3	1765.2	1827.1	1943	27.2	44.9	89.8	151.7	267.6
	k=33	59.3	119.2	300.8	597.8	1152.5	5.1	10.3	26.1	51.9	100	1824.1	1836.5	1847.7	1882.5	1941.8	2061.9	12.4	23.6	58.4	117.7	237.8
	k=42	62.6	124.1	311	623	1218.2	5.1	10.2	25.5	51.1	100	1886.8	1894.7	1905.6	1940.4	2001.6	2123.3	7.9	18.8	53.6	114.8	236.5
Case K2	k=1	74.6	142.6	313	542.8	958.1	7.8	14.9	32.7	56.7	100	1675.4	1718	1750	1833.2	1951.9	2187.5	42.6	74.62	157.8	276.5	512.1
	k=33	103	207.5	528.2	1057	2042.6	5.0	10.2	25.9	51.7	100	1824.1	1844.7	1864.6	1927.9	1940.9	2285.1	20.6	40.47	103.8	116.8	461
	k=42	110.2	219.2	552.8	1110	2165.2	5.1	10.1	25.5	51.3	100	1886.8	1901.4	1920.7	1983.7	2098.4	2344.3	14.6	33.95	96.9	211.6	457.5
Case K3	k=1	107.6	205.1	449.6	781.6	1395.5	7.7	14.7	32.2	56.0	100	1675.4	1733.7	1780.5	1903.9	2085.6	2465.2	58.3	105.1	228.5	410.2	789.8
	k=33	146.8	296.3	756.6	1515.3	2922.0	5.0	10.1	25.9	51.9	100	1824.1	1853.0	1881.8	1975.3	2149.1	2546.4	28.9	57.7	151.2	325.0	722.3
	k=42	157.6	314.2	794.4	1592.9	3099.7	5.1	10.1	25.6	51.4	100	1886.8	1908.0	1936.1	2028.8	2202.9	2603.6	21.2	49.3	142.0	316.1	716.8
Case K4	k=1	39.2	74.5	162.3	285.4	509.7	7.7	14.6	31.8	56.0	100	1675.4	1717.5	1747.5	1825.4	1944.9	2195.9	42.1	72.1	150.0	269.5	520.5
	k=33	110.5	222.6	559.4	1095.7	2070.8	5.3	10.7	27.0	52.9	100	1824.1	1847	1869.3	1939.2	2060.2	2316.8	22.9	45.2	115.1	236.1	492.7
	k=42	128.7	253.6	618.2	1194.1	2250.8	5.7	11.3	27.5	53.1	100	1886.8	1906	1929.3	2001	2127.4	2389.8	19.2	42.5	114.2	240.6	503.0
Case K5	k=1	69.8	130.8	280.7	492.6	803.5	8.7	16.3	34.9	61.3	100	1675.4	1746.2	1802.5	1952.8	2196.3	2616.5	70.8	127.1	277.4	520.9	941.1
	k=33	193.6	391.8	993.4	1948.9	3358.8	5.8	11.7	29.6	58.0	100	1824.1	1863.6	1904	2036.3	2282.5	2746	39.5	79.9	212.2	458.4	921.9
	k=42	224.6	444.6	1092.2	2117.2	3647.7	6.2	12.2	29.9	58.0	100	1886.8	1921.1	1962.8	2097.2	2348	2819	34.3	76.0	210.4	461.2	932.2
Case K6	k=1	100.5	187.3	399.8	704.9	811.7	12.38	23.1	49.3	86.8	100	1675.4	1775.5	1859.7	2090.3	2481.2	2649.5	100.1	184.3	414.9	805.8	974.1
	k=33	277.2	562.1	1428.3	2796.4	3491	7.94	16.1	40.9	80.1	100	1824.1	1880.4	1939.8	2142.4	2544.0	2797.7	56.3	115.7	318.3	719.9	973.6
	k=42	320.1	634.8	1563.1	3029.5	3793.9	8.437	16.7	41.2	79.9	100	1886.8	1936.5	1997.5	2201.6	2605.7	2871.0	49.7	110.7	314.8	718.9	984.2
Case K7	k=1	24.3	46.3	105.4	190.8	345	7.0	13.4	30.6	55.3	100	1675.4	1700	1715.2	1756.6	1818.7	1937.8	24.6	39.8	81.2	143.3	262.4
	k=33	51.8	104.7	266	532.4	1039.5	5.0	10.1	25.6	51.2	100	1824.1	1835.8	1846.7	1880.3	1938.1	2057.2	11.7	22.6	56.2	114.0	233.1
	k=42	64.7	127.5	310	603	1157.9	5.6	11.0	26.8	52.1	100	1886.8	1897	1909	1944.5	2005.6	2132.3	10.2	22.2	57.7	118.8	245.5
Case K8	k=1	45.2	86.7	196.9	353.8	636.4	7.1	13.6	30.9	55.6	100	1675.4	1714.9	1744.2	1824.9	1946.6	2188.5	39.5	68.8	149.5	271.2	513.1
	k=33	90.9	184	470.5	948.4	1857.9	4.9	9.9	25.3	51.0	100	1824.1	1843.9	1863.2	1924.7	2035.4	2279.8	19.8	39.1	100.6	211.3	455.7
	k=42	110.8	219.2	539.2	1061.4	2056	5.4	10.7	26.2	51.6	100	1886.8	1905	1925.9	1990	2108.2	2359	18.2	39.1	103.2	221.4	472.2
Case K9	k=1	66.3	127.3	288.9	516.8	932.8	7.1	13.6	31.0	55.4	100	1674.4	1729.9	1773.9	1896.2	2083.7	2472.4	55.5	99.5	221.8	409.3	798.0
	k=33	130.2	263.7	676	1365	2668.7	4.9	9.9	25.3	51.1	100	1824.1	1852.0	1880.0	1971.0	2141.8	2541.3	27.9	55.9	146.9	317.7	717.2
	k=42	156.9	310.5	767.5	1518.1	2944.8	5.3	10.5	26.1	51.6	100	1886.8	1913.0	1943.0	2037.6	2216.7	2621.6	26.2	56.2	150.8	329.9	734.8

Table 5.11: CIV and layer pressure build up of Cases K10-K18 after 1, 2, 5, 10 and 20 years of injection.

	Layer No	CIV, MSTB					CIV, %					Layer Pressure, psia						Layer Pressure Build Up, psi				
		1st Yr	2nd Yr	5th Yr	10th Yr	20th Yr	1st Yr	2nd Yr	5th Yr	10th Yr	20th Yr	P_i	P_1	P_2	P_5	P_{10}	P_{20}	ΔP_1	ΔP_2	ΔP_5	ΔP_{10}	ΔP_{20}
Case K10	k=1	8.3	18.2	51.8	116	270.3	3.1	6.7	19.2	42.9	100	1675.9	1687.4	1692	1707.8	1739.2	1819.2	11.5	16.1	31.9	63.3	143.3
	k=5	9.4	20.7	58.5	130.8	304.5	3.1	6.8	19.2	43.0	100	1691.6	1700.6	1702.9	1722.8	1757.2	1839.7	9.0	11.3	31.2	65.6	148.1
	k=42	178	336.2	766.7	1389.8	2393.2	7.4	14.0	32.0	58.1	100	1887.4	1926.5	1940.8	2027.5	2176.5	2447.7	39.1	53.4	140.1	289.1	560.3
Case K11	k=1	15.5	33.9	95.2	201.8	412.6	3.8	8.2	23.1	48.9	100	1675.9	1690.9	1699.8	1729.9	1784.2	1898	15.0	23.9	54.0	108.3	222.1
	k=5	17.7	38.4	107.4	227.5	464.8	3.8	8.3	23.1	48.9	100	1691.6	1707.2	1711.1	1743.4	1801.1	1918	15.6	19.5	51.8	109.5	226.4
	k=42	310.6	588.5	1348.4	2282.6	3265.8	9.5	18.0	41.3	69.9	100	1887.4	1962.2	1984.8	2146.8	2403.5	2728.2	74.8	97.4	259.4	516.1	840.8
Case K12	k=1	21.6	43.2	111.3	218.5	429.6	5.0	10.1	25.9	50.9	100	1675.9	1693.9	1704.5	1738.2	1793.1	1907.6	18.0	28.6	62.3	117.2	231.7
	k=5	24.4	48.8	125.5	246.2	483.9	5.0	10.1	25.9	50.9	100	1691.6	1711.9	1715.9	1751.5	1810.0	1927.7	20.3	24.3	59.9	118.4	236.1
	k=42	412.7	728.5	1543.7	2410.9	3320.2	12.4	21.9	46.5	72.6	100	1887.4	1990.0	2012.1	2192.9	2440.9	2747.5	102.6	124.7	305.5	553.5	860.1
Case K13	k=1	7.8	16.8	44.7	90.7	180	4.3	9.3	24.8	50.4	100	1675.9	1708.3	1736	1823.4	1978.8	2316.7	32.4	60.1	147.5	302.9	640.8
	k=5	77.5	160	414	834.7	1642.8	4.7	9.7	25.2	50.8	100	1691.6	1735.2	1749	1834.8	1995.2	2338.5	43.6	57.4	143.2	303.6	646.9
	k=42	220.6	405.1	884.4	1609.8	2887	7.6	14.0	30.6	55.8	100	1887.4	1936.8	1954	2051.9	2224	2587.6	49.4	66.6	164.5	336.6	700.2
Case K14	k=1	14.7	31.2	79.2	135.4	174.1	8.4	17.9	45.5	77.8	100	1675.9	1729.8	1783.4	1955.2	2234.3	2595.4	53.9	107.5	279.3	558.4	919.5
	k=5	144.4	300.5	774.9	1465.5	2261.9	6.4	13.3	34.3	64.8	100	1691.6	1773	1800.9	1963.4	2250	2618.9	81.4	109.3	271.8	558.4	927.3
	k=42	308.9	694.2	1513.4	2503.9	3458.1	8.9	20.1	43.8	72.4	100	1887.4	1980.5	2006	2186.5	2467.6	2808	93.1	118.6	299.1	580.2	920.6
Case K15	k=1	19	37.1	80.3	119	138.5	13.7	26.8	58.0	85.9	100	1675.9	1749.9	1824.7	2054.0	2393.3	2624.6	74.0	148.8	378.1	717.4	948.7
	k=5	207.5	423.2	1040.7	1842.7	2338.3	8.9	18.1	44.5	78.8	100	1691.6	1807.6	1847.8	2061.2	2410.2	2648.4	116.0	156.2	369.6	718.6	956.8
	k=42	491.4	860.1	1754	1792.1	3502.2	14.0	24.6	50.1	51.2	100	1887.4	2011.2	2039.5	2247.0	2566.6	2834.3	123.8	152.1	359.6	679.2	946.9
Case K16	k=1	24.3	48	115.4	219.3	406.2	6.0	11.8	28.4	54.0	100	1675.9	1701.5	1719.5	1771.7	1855.8	2018.2	25.6	43.6	95.8	179.9	342.3
	k=5	59.1	116.5	280.3	532.6	986.1	6.0	11.8	28.4	54.0	100	1691.6	1722.6	1731.7	1785.7	1874.2	2041.2	31.0	40.1	94.1	182.6	349.6
	k=42	70	136.1	325.2	631.8	1252.5	5.6	10.9	26.0	50.4	100	1887.4	1899.9	1910.3	1951.2	2024.7	2171.9	12.5	22.9	63.8	137.3	284.5
Case K17	k=1	45.1	89.5	216.8	408.2	743.5	6.1	12.0	29.2	54.9	100	1675.9	1717	1751.7	1854.5	2021.2	2350.3	41.1	75.8	178.6	345.3	674.4
	k=5	109.6	217.3	526.4	990.9	1804.6	6.1	12.0	29.2	54.9	100	1691.6	1748.6	1766	1866.3	2038.8	2373.3	57	74.4	174.7	347.2	681.7
	k=42	121.1	235.1	562.7	1110.9	2237.1	5.4	10.5	25.2	49.7	100	1887.4	1911.8	1928.5	1999.1	2129.7	2440.2	24.4	41.1	111.7	242.3	552.8
Case K18	k=1	66.3	131.9	320.4	596.4	953.2	7.0	13.8	33.6	62.6	100	1675.9	1732.8	1785.0	1942.8	2200.7	2581.0	56.9	109.1	266.9	524.8	905.1
	k=5	161.1	320.3	777.8	1447.6	2313.5	7.0	13.8	33.6	62.6	100	1691.6	1775.7	1802.6	1952.8	2217.6	2604.8	84.1	111.0	261.2	526.0	913.2
	k=42	171.4	332.1	797	1591.5	2923.7	5.9	11.4	27.3	54.4	100	1887.4	1923.9	1946.6	2047.8	2247.6	2669.4	36.5	59.2	160.4	360.2	782.0

Table 5.12: CIV and layer pressure build up of Cases K19-K27 after 1, 2, 5, 10 and 20 years of injection.

	Layer No	CIV, MSTB					CIV, %					Layer Pressure, psia						Layer Pressure Build Up, psi				
		1st Yr	2nd Yr	5th Yr	10th Yr	20th Yr	1st Yr	2nd Yr	5th Yr	10th Yr	20th Yr	P_i	P_1	P_2	P_5	P_{10}	P_{20}	ΔP_1	ΔP_2	ΔP_5	ΔP_{10}	ΔP_{20}
Case K19	k=1	72.8	149	367.5	694.2	1274.4	5.7	11.7	28.8	54.5	100	1675.5	1700.1	1717.8	1769.3	1849.5	2002	24.6	42.3	93.8	174.0	326.5
	k=33	60.4	120	301.7	608.7	1223.1	4.9	9.8	24.7	49.8	100	1824.8	1838.1	1850.1	1887.6	1953.9	2100.2	13.3	25.3	62.8	129.1	275.4
	k=42	75.2	143.7	341.5	669.3	1326	5.7	10.8	25.8	50.5	100	1887.4	1900.6	1909.9	1950.2	2021.2	2165	13.2	22.5	62.8	133.8	277.6
Case K20	k=1	133.3	270.6	662.3	1248.7	2306	5.8	11.7	28.7	54.2	100	1675.5	1714.1	1746.7	1843	1996.7	2307.8	38.6	71.2	167.2	321.2	632.3
	k=33	106.8	211.5	532.4	1082.7	2186.8	4.9	9.7	24.3	49.5	100	1824.8	1847.4	1868.8	1937	2065.2	2371.7	22.6	44.0	112.3	240.4	546.9
	k=42	130	248.8	597.3	1185.1	2366.8	5.5	10.5	25.2	50.1	100	1887.4	1913.6	1927.9	1998	2127.4	2431.2	26.2	40.5	110.8	240.0	543.8
Case K21	k=1	194.7	393.7	958.9	1806.4	2985.9	6.5	13.2	32.1	60.5	100	1675.5	1728.2	1776.3	1919.5	2156.6	2531.0	52.7	100.8	244.0	481.1	855.5
	k=33	152.9	302.8	764.7	1560.5	2854.5	5.4	10.6	26.8	54.7	100	1824.8	1856.6	1887.6	1989.0	2189.1	2595.6	31.8	62.8	164.2	364.3	770.8
	k=42	183.2	351.3	851.9	1700	3088.8	5.9	11.4	27.6	55.0	100	1887.4	1926.8	1945.9	2045.1	2246.6	2652.2	39.4	58.5	157.7	359.2	764.8
Case K22	k=1	68.5	139.3	339.7	640.7	1201.4	5.7	11.6	28.3	53.3	100	1675.5	1717	1750.9	1848	2005.3	2338.9	41.5	75.4	172.5	329.8	663.4
	k=33	109.2	217.5	552.8	1124.3	2265.1	4.8	9.6	24.4	49.6	100	1824.8	1848.7	1872	1946.7	2087.1	2426.7	23.9	47.2	121.9	262.3	601.9
	k=42	144.4	279.2	663	1285	2521.4	5.7	11.1	26.3	51.0	100	1887.4	1915.5	1936.5	2015.7	2161.2	2496.9	28.1	49.1	128.3	273.8	609.5
Case K23	k=1	125.2	252.1	606.2	1132.7	1526.3	8.2	16.5	39.7	74.2	100	1675.5	1745.4	1809.9	2001.2	2323.1	2635.4	69.9	134.4	325.7	647.6	959.9
	k=33	193.7	385	918.7	2025	3145.8	6.2	12.2	29.2	64.4	100	1824.8	1866.6	1908.4	2049.7	2346.3	2756.9	41.8	83.6	224.9	521.5	932.1
	k=42	251	484.6	1154.6	2282.7	3485.8	7.2	13.9	33.1	65.5	100	1887.4	1940.6	1976	2119.7	2418.1	2828.8	53.2	88.6	232.3	530.7	941.4
Case K24	k=1	182.9	366.7	875.1	1354.4	1501.2	12.2	24.4	58.3	90.2	100	1675.5	1774.6	1871.9	2169.9	2530.5	2656.3	99.1	196.4	494.4	855.0	980.8
	k=33	277.9	551.7	1417.8	2616.1	3226.5	8.6	17.1	43.9	81.1	100	1824.8	1884.4	1945.5	2164.4	2550.5	2791.8	59.6	120.7	339.6	725.7	967.0
	k=42	355.5	684.4	1644.3	2932.5	3572.3	10.0	19.2	46.0	82.1	100	1887.4	1966.4	2016.1	2233.1	2624.5	2862.1	79.0	128.7	345.7	737.1	974.7
Case K25	k=1	24.6	47.9	113	210.6	388	6.3	12.3	29.1	54.3	100	1675.5	1701.6	1719	1768.5	1846	1996.9	26.1	43.5	93	170.5	321.4
	k=33	53.5	107	276.6	555.8	1113.8	4.8	9.6	24.8	49.9	100	1824.8	1837.7	1849.4	1886.7	1952.7	2096.6	12.9	24.6	61.9	127.9	271.8
	k=42	71.1	140.2	339.4	660.8	1278.3	5.6	11.0	26.6	51.7	100	1887.4	1898.9	1912.7	1955.4	2030.7	2176	11.5	25.3	68	143.3	288.6
Case K26	k=1	45.4	89.2	211.1	391.6	713.1	6.4	12.5	29.6	54.9	100	1675.5	1717.1	1750.7	1847.6	2001.5	2308.6	41.6	33.6	172.1	326	633.1
	k=33	95	190.1	486.4	990.4	1997.1	4.8	9.5	24.4	49.6	100	1824.8	1846.7	1867.8	1936.2	2063.2	2365.7	21.9	21.1	111.4	238.4	540.9
	k=42	123.7	243.7	593.5	1157.9	2267	5.5	10.7	26.2	51.1	100	1887.4	1910.2	1932.9	2008.6	2143.8	2449.8	22.8	22.7	121.2	256.4	562.4
Case K27	k=1	66.7	131.1	311.1	572.4	961.5	6.9	13.6	32.4	59.5	100	1675.5	1733	1783.4	1931.5	2169.9	2574.9	57.5	107.9	256.0	494.4	899.4
	k=33	136.7	273.6	698.7	1428.4	2707.4	5.0	10.1	25.8	52.8	100	1824.8	1855.8	1886.5	1987.6	2186.1	2626.4	31	61.7	162.8	361.3	801.6
	k=42	176	346.6	841.7	1653.1	3055.2	5.8	11.3	27.5	54.1	100	1887.4	1921.8	1953.6	2062.5	2268.6	2710.0	34.4	66.2	175.1	381.2	822.6

Cases K28 and case K29 reached the set maximum THP at different times. Case K28 and K29 reached the set maximum THP at 238 and 5014 days respectively and then after shut in for both of the cases, wells were controlled by THP. As wells were controlled by THP therefore, to maintain constant THP all the times, injection rates were decline over time. Consequently, for cases K28 and K29, CIV increases linearly upto 238 and 5014 days and thereafter CIV became curvature and less steeper over time. Therefore, at 238 days both of the wells give same CIV which is 4.4 MMSTB. Then MN-1 in case K28 shut in during 238-424 days and start injection during 424- 3064 days and again following shut in between 3064-3264 days then resume injection till the end of injection period. On the other hand, after first shut in during 5014-5254 days MN-2 in case K29 finished injection upto the end of injection period. Thus, K29 gives CIV is 83.78 which is 23.85 MMSTB higher than case K28. This CIV variation is because of less channels intersection by well MN-1. In addition, shut-in periods for MN-1 also higher than well MN-2.

In Channel-I model, by continuous injection well MN-1 gives CIV at 53.7 MMSTB. In intermittent injection, well MN-1 gives CIV at 59.9 MMSTB which is 6.2 MMSTB higher than continuous injection. Conversely, well MN-2 in intermittent injection gives 0.8 MMSTB lower CIV than continuous injection. The difference in CIV for well MN-1 is quite significant. On the other hand, the difference in CIV for well MN-2 is negligible considering the total injection period, i.e. 20 years. Moreover, the down time for both wells in intermittent injection was not considered here. The most important in intermittent injection is the gain of injection rate or IP after shut in period. In addition, with MN-1 as only injector the intermittent injection gives better overall performance than continuous injection.

Again, cases K30 and case K31 reached the set maximum THP at different times. Case K30 and K31 reached the set maximum THP at 5014 and 5644 days respectively and then after shut in both cases, wells were controlled by THP. As wells were controlled by THP therefore, to maintain constant THP all the times, injection rates were decline over time. Consequently, for cases K30 and K31, CIV increases linearly upto 5014 and 5644 days and thereafter CIV curve became curvature and less steeper over time. Therefore, at 5014 days both of the wells give same CIV which is 65.2 MMSTB. Then MN-1 in case K30, following shut in during 5014-5254 days then resume injection till the end of injection period. On the other hand, after shut in during 5644-5884 days MN-2 in case K31 finished injection upto the end of injection period. Thus, K31 gives CIV at 85.62 MMSTB which is 2.82 MMSTB higher than case K30. The CIV of MN-1 and MN-2 in cases K30 and K31 are different because in Channel-II model still MN-2 intersects with more channels than well MN-1.

In Channel-II model, by continuous injection well MN-1 gives CIV at 84.8 MMSTB. In intermittent injection, well MN-1 gives 1 MMSTB lower CIV. Similarly, well MN-2 in intermittent injection gives CIV 3 MMSTB lower than continuous injection, i.e. 3.4% of CIV of continuous injection. The differences in CIV for both wells are negligible comparing to the total injection period. Moreover, the down time for both wells in intermittent injection was not considered here. The most important in intermittent injection is the gain of injection rate or IP after shut in period.

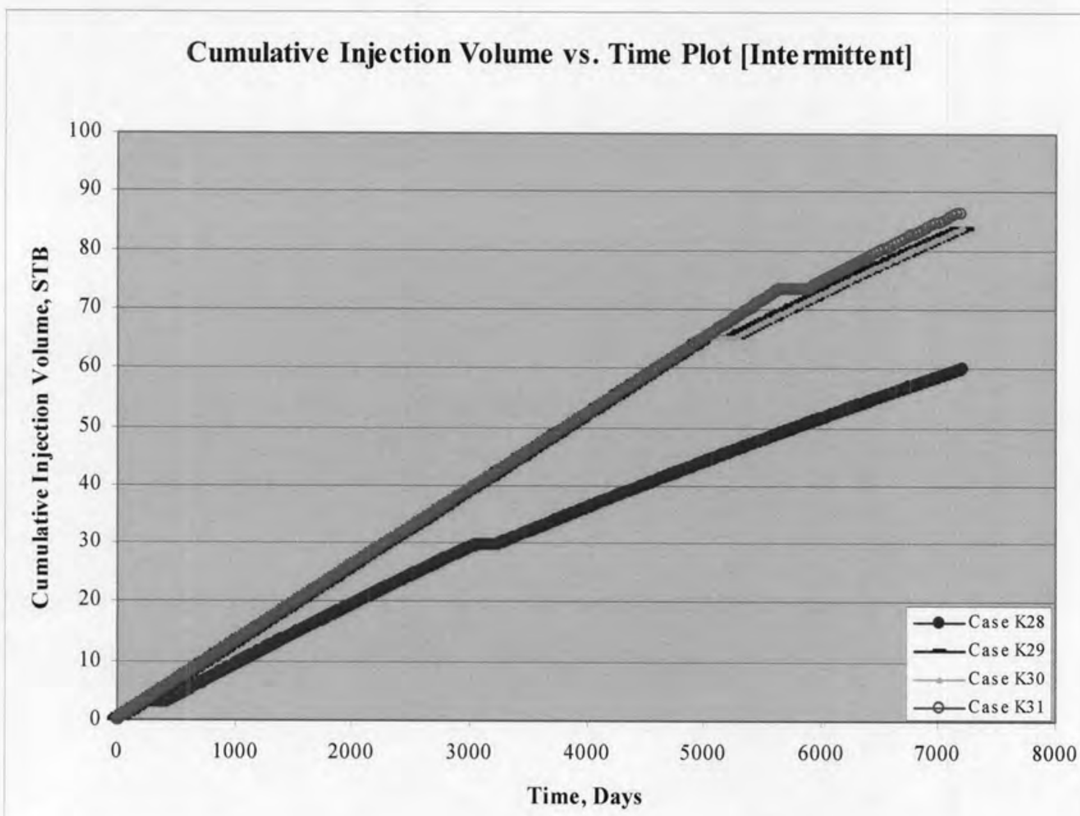

Figure 5.42: Cumulative injection volume of cases K28-K31
for Intermittent Injection.

After running all four cases, it is seen that the evolution of THP in all cases behave in the same manner. As mentioned before, wells were initially controlled by surface injection rate and once the injection pressure reached the set maximum THP then wells are shut in. After each shut in wells are controlled by THP. As example of THP and injection rate performances of cases K28 and K29 are presented in Figure 5.43 and Figure 5.44.

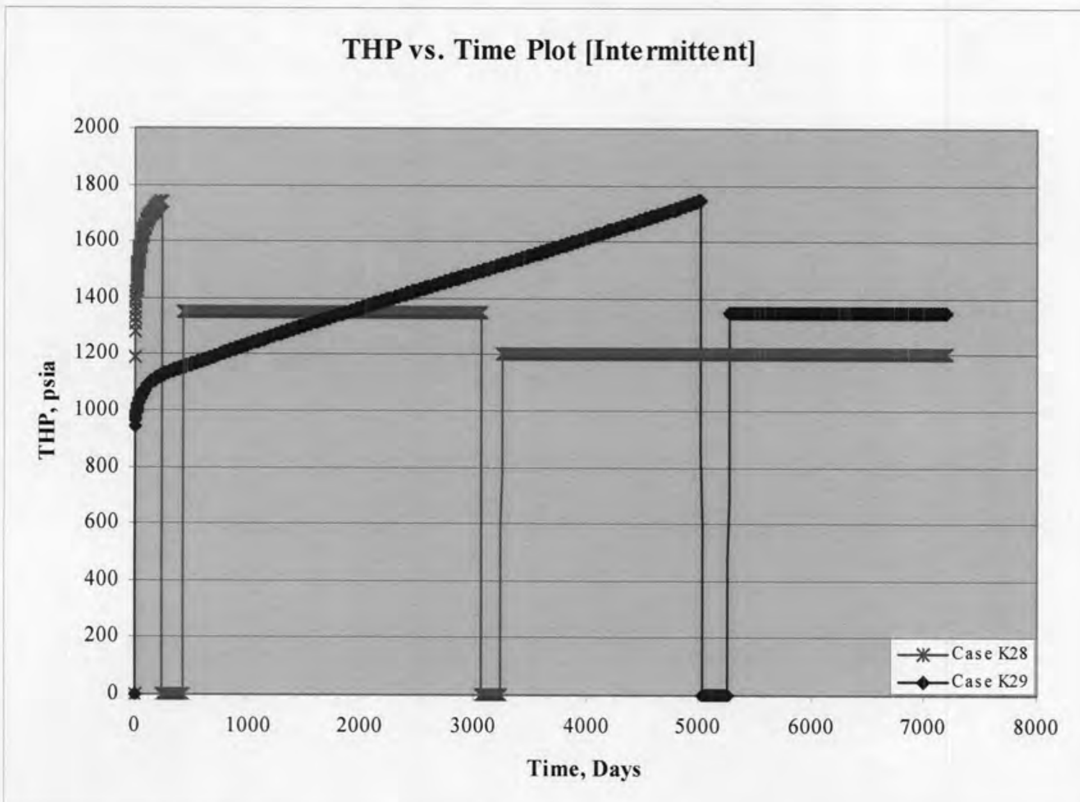

Figure 5.43: THP of cases K28 and K29 in intermittent injection.

It is seen from Figure 5.43, THP is increasing with time because of increasing the cumulative volume injected. As the increment of cumulative water injected, reservoir pressure builds up, consequently BHP increases. Therefore THP required to increase. It is seen from the same figure, wells in cases K28 and K29 reached the set maximum THP, i.e. 1743.4 and 1747.2 psia respectively at 238 and 5014 days, corresponding BHP were 2546 and 2611.4 psia respectively and then wells were shut in. After a careful look at BHP of K28 it is seen that minimum 180 days shut in gives nearly stable BHP. Therefore, after 238-424 days shut in well MN-1 for case K28 started injection under THP control and the THP was 1350 psia. Again shut in during

3064-3244 days and then started injection with THP 1200 psia and keep injecting until the end of simulation period. Similarly, following shut in 5014-5254 days, well MN-2 for case K29 started injection with 1350 psia THP until the end of injection period. Finally, BHP of MN-1 and MN-2 for cases K28 and K29 became 2662.9 and 2692.5 psia at 1250 and 1350 psia THP respectively.

For both cases, initial well injection rate was 13000 STB/D. In case K28 MN-1 reached the set maximum THP at 238 days first whereas MN-2 in case K29 reached the set maximum 5014 days and then shut in the wells. After each shut in wells were controlled by THP therefore to maintain constant THP all the times injection rates were declined over time. It is seen from Figure 5.44, initial well injection rates were 13000 STB/D. After each shut in period wells were controlled by THP therefore, it is seen that injection rates for MN-1 were decline from 12286 to 9377 STB/D after first shut in, i.e. 424 – 3064 days, and from 9535 to 6785 STB/D after second shut in, i.e. 3244-7204 days. Injection rates for MN-2 were decline from 11057 to 8725 STB/D after shut in, i.e. 5254 -7204 days.

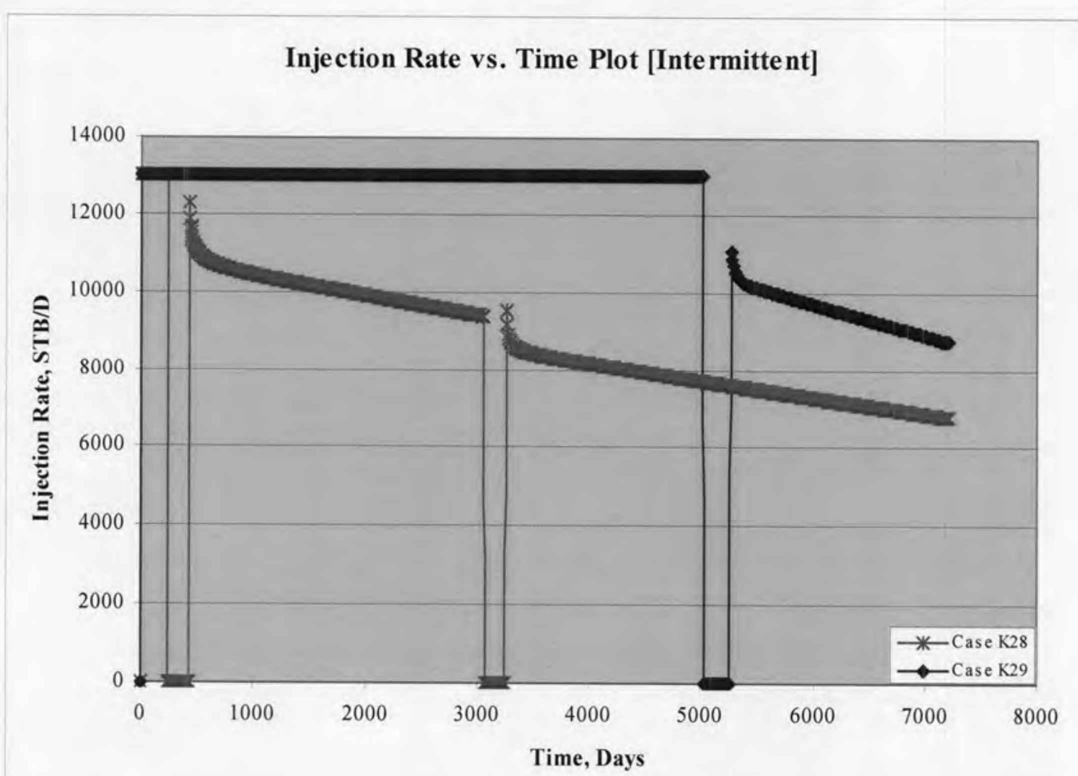

Figure 5.44: Injection rates of cases K28 and K29 in intermittent injection.

Injection performance (IP) is defined as follows:

$$IP = \frac{Injection \quad Rate}{Injection \quad \Pr essure} = \frac{q_{inj}}{THP} \tag{5.3}$$

q_{inj} is the injection rate, STB/D, and tubing head pressure (THP) is the corresponding injection pressure of q_{inj} is in psia.

After running all the four cases, K28-K31, it is seen that there is significant IP gain after each shut in period. As sample, case K28 and K29 are presented in Figure 5.41. In case K28, it is seen that after the first and the second shut in, i.e. at 186 and 180 days, the IP gained for MN-1 are from 7.5 STB/D/psi to 9.1 STB/D/psi and 5.9 STB/D/psi to 8 STB/D/psi. On the other hand, the IP of MN-2 in case K29 is gained from 7.4 STB/D/psi to 8.2 STB/D/psi after 240 days shut in. During each shut in period reservoir pressure decreases that results lower BHP requirements. As the required BHP is decreased therefore, there is an obvious decrease in THP. Hence it is giving higher IP in case of a specific THP injection. For instance, it can be shown that BHP of case K28 decreases from 2546 to 1710.2 psia and 2582.2 to 1939.3 psia respectively for the first and the second shut in periods. Conversely, BHP reduction of case K29 is seen from 2611.4 to 2270.5 psia during the shut in period. The IP of case K30 & K31 is shown in Figure A21 in Appendix A.

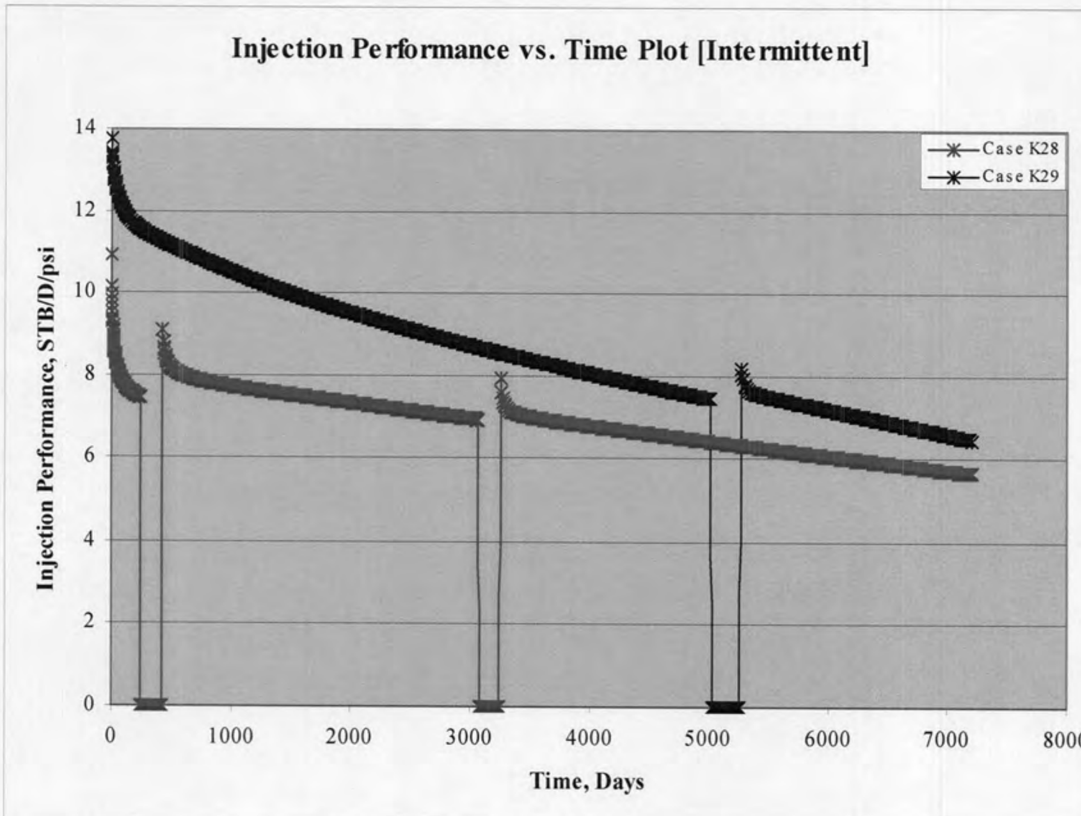

Figure 5.45: Injection Performance of cases K28 and K29.

CIV into A and B individual sand units for intermittent injection are shown in Table 5.3 and 5.4.

Table 5.13: CIV for Intermittent Injection.

Intermittent Injection	Case Name	Cumulative Injection Volume (CIV)						
		MN-1	MN-2	Total	A		B	
		MMSTB	MMSTB	MMSTB	MMSTB	%	MMSTB	%
Channel-I	K28	59.93	-	59.93	55.13	93.6	3.81	5.4
Channel-I	K29	-	83.78	83.78	81.36	97.1	2.42	2.9
Channel-II	K30	83.8	-	83.80	81	95.7	2.80	3.3
Channel-II	K31	-	85.62	85.62	83.27	95.1	3.35	3.9

In summary, from Table 5.4, it is seen that the Cumulative Injection Volume (CIV) for HM is 128 MMSTB whereas Table 5.6 and 5.8 show the CIV for Channel-I and Channel-II is 98 and 104 MMSTB respectively for 13000 STB/D initial well injection rate in multi well injection option. Again, from Table 5.3, it is seen that the CIV for HM is 94 MMSTB whereas Table 5.5 and 5.7 show the CIV for Channel-I and Channel-II is 54 and 85 MMSTB for 13000 STB/D injection rate by well MN-1. Again the CIV for HM is 87 MMSTB whereas the CIV for Channel-I and Channel-II is 84 and 86 MMSTB for 13000 STB/D initial injection rate by well MN-2. The reduction in CIV for Channel-I and Channel-II, single and multi well injection options are because of the poor porosities and permeabilities out side of channels.

From initialization report and Table 5.9, it is seen that the PV of HM is 2597 MMSTB where volume of water and gas are 2233.4 and 363.4 MMSTB. As the compressibility of water is much lower than the compressibility of gas, therefore the volume of gas plays the major role in the injection process. It is seen that, HM single well CIV maximum 26% of gas volume whereas in both well injection CIV maximum 35.2% of gas volume. In both well injection, injected water can get contact with more gas and thus the CIV becomes higher. Similarly, PV for Channel-I and Channel-II is found to be 2392.5 and 2426 MMSTB respectively. In Channel-I, the volume of water and gas are 2058.5 and 334 MMSTB whereas in Channel-II the volume of water and gas are 2087.7 and 338.3 MMSTB respectively. It is seen in Channel-I single well MN-1 CIV maximum 16% of gas volume whereas single well MN-2 CIV maximum 25.3% of gas volume and in multi well injection CIV maximum 29.4% of gas volume. It is seen that maximum percentage of CIV of MN-1 is lower than MN-2 in Channel-I because well MN-1 intersects lower number of channels than MN-2. For Channel-II, single well MN-1 CIV maximum 25.1% of gas volume whereas single well MN-2 CIV maximum 26.2% of gas volume and in both well injection CIV maximum 30.7% of gas volume. For the same reason stated in Channel-I, single well MN-1 is having lower percentage maximum CIV in Channel-II. For Channel-I and Channel-II, multi well injection, injected water can get contact with more gas and thus the CIV becomes higher.

Compare to HM, it is seen that steady-state injectivity index (II) in Channel-I decreased from 456 to 130 for MN-1 and 311 to 300 for MN-2; and from 456 to 314 for MN-1 and 311 to 303 for MN-2 in Channel-II model. The decrease of steady-state II in presence of channel is due to the increase of draw down. Moreover, in intermittent injection mode IP gained for MN-1 and MN-2 are maximum 1.6 STB/D/psi and 0.8 STB/D/psi in Channel-I model whereas 0.6 STB/D/psi and 0.5 STB/D/psi for Channel-II model.

In addition, it is seen from all the CIV tables of single and multi well injection that A sand unit intakes the major portion of injected water and ranges from 88.3% to 98.9% whereas B unit intakes only from 11.7% to 1.1%. This can be explained with the porosity and permeability variation between the two sand units. Again, when injection takes place by MN-2 in Channel-I model then sand unit A intakes approximately 99% of cumulative injected water and it is because well MN-2 intersects with very few numbers of channels at sand unit B whereas in both well injection in HM, sand unit B intakes highest percentage, 11.7%, of cumulative injected water.