PE 4631 Applied Reservoir Simulation

Final Project Report

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Group 5

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Abstract—Elizabeth

The objective of this assignment was to allow a team of aspiring petroleum engineers to gain hands-on experience with CMG and reservoir simulation, along with result and report analysis, teamwork, and leadership development. CMG is a computer software program that, when given input data, can simulate fluid flow in a reservoir. A simulated model on CMG was made possible by a given set of parameters and characteristics for this reservoir. Useful parameters such as: top depth, permeability, porosity, thickness of layers, PVT data for a black oil model, gas-oil and water-oil contacts, etc. With these parameters the model was then able to be applied to different scenarios such as changing the production rates, and combining layers. These different scenarios yielded varying results, but allowed the team to gain a better understanding of the nature of the reservoir. After running the model through IMEX, the Results Graph option in CMG allows the user to view results. The results generated or calculated were used to determine original oil in place (OOIP), original gas in place (OGIP), water breakthrough, recovery factor, etc. These results help to identify which perforations create optimal oil production. The Results 3D allows users to view how well the oil is swept through the reservoir. After completing the before-mentioned results process, and comparing the different scenarios, it was decided that the reservoir should not be produced due low recovery factors.

Introduction—Elizabeth

For this reservoir model an inverted 5-spot quick pattern was used. The fluid properties were input using a black oil model in CMG. This gives us a uniform square pattern in the xy-direction. This uniform pattern can be seen in both Figures 1 & 2. The z-direction has a different thickness based on the formation properties, which can be found in Table 1 and Figure 3. The reservoir is 7200 x 7500 x 359 ft. This formation is a gas, oil, and water formation with a gas-oil contact (GOC) at 9061 ft and an oil-water contact (OWC) at 9259 ft. Due to the gas cap in this formation, favorable oil production should be from wells that have perforations close to the GOC. A well that is perforated too close to the OWC will result in excess water production. This reservoir is an oil wet formation that has a rock compressibility $1.0*10^{-6}$/psi, a reference pressure of 3600 psi, and a reservoir temperature of 100°F. All of these characteristics were taken into consideration and utilized when assembling the model.

Reservoir Simulation—Alison and Mengbo

An inverted 5-spot pattern yields 4 producers on the corners of the reservoir model and an injector at the center. A total of 10 simulations were run, where some of the scenarios had different variations. Scenario 1 was run with three different production rates without the use of an injector, which can be seen in Figure 1. Figure 2 is an overview of the reservoir used for all the other scenarios. Scenario 2, 3, and 4 have a production rate of 500 bbl/day, 1000 bbl/day, and 100 bbl/day, respectively. The injection rates change accordingly, based on the injection/production ratio of 1, 0.5, and 0.1. Scenarios 5, 6, and 7 have production rates of 1000 bbl/day, 500 bbl/day, and 100 bbl/day, respectively. For these scenarios, the perforation layers change so that the well can be optimized. Scenarios 8, 9, and 10 combine layers 4, 5, 7, and 8 together to make the model simpler. They are then built in the same way as scenarios 2, 3, and 4.

An oil reserve is an important factor and the point of interest when it comes to any kind of reservoir or formation. Depending on the data received from the well site, such as from well logs and production data, the original oil in place (OOIP) and the original gas in place (OGIP) can be estimated. These values are then compared to the value from the reservoir simulation model. OOIP can be determined from the output file. OOIP will stay constant because it is the total amount of hydrocarbons present in the formation or reservoir. Once the amount of movable oil is calculated and the well starts producing, the next step is to address the issue of water movement to production of the oil zone, along with decreasing wellhead pressure. The water produced at the depletion stage of the reservoir is at a critical time because the costs of treating and disposing of this water is very high which can have a negative effect on oil production. The water breakthrough time can be determined from the cumulative water production. The values of water breakthrough can be seen in Table 3. Water breakthrough time can be helpful in determining the perforation layers needed to maintain a stable production rate. It can be said that perforation layers 7, 8, 9, 10, and 11 will have stable production rates, shown in Table 3. For perforation layers 9, 10, and 11, at a production rate 500 bbl/day, water breakthrough is at approximately 6210 days. For perforation layers 7, 8, and 9, with a production rate 500 bbl/day, water breakthrough is at approximately 5996 days. As it can be seen in Table 3, perforation layers 12, 13, and 14 have really low water breakthrough times because the OWC is at layer 14. Therefore, if the well is perforated any closer to the OWC, the well will have excess water production. Furthermore, perforating in layers 12, 13, and 14 may result in water coning. Water coning happens when the bottom water layer infiltrates the perforation zone resulting in a reduction of oil production.

Results—Alison and Mengbo

Scenario 1, Figure 4, shows that if the production rate is 500 bbl/day the reservoir produces the most oil over time. If however the production rate is 1000 bbl/day then the wells will produce the least amount of oil over time. At this rate, the production rate will level out for the remainder of the reservoir's life. For this scenario, the best recovery factor (RF) comes from a production rate of 500 bbl/day. The RF's are as follows: 1.53% after 5 years, 3.06% after 10 years, 4.59% after 15 years, and 9.15% after 30 years. For this scenario, water breakthrough occurs at 6.17 years. The RF's and water breakthrough for production rates of 100 bbl/day and 1000 bbl/day can be found in Table 3. When the production rate is 1000 bbl/day, the reservoir is being produced too quickly for the formation and pressure drops below the minimum bottom hole pressure causing the wells to be shut in at about 1986-5-1. Figures 14-16 show how the different production scenarios affect the oil saturation

Figure 5 shows the cumulative oil production for scenario 2. For this scenario, there is a production and injection ratio, which are 1, 0.5, and 0.1. The production rate is 500 bbl/day. This scenario shows a constant cumulative rate up until 1999. At this point the different rates of the injectors cause the wells to act differently within the reservoir. With a higher water injection rate there is more cumulative oil production. This is because the injection water in this scenario helps to slow down the decreasing of bottom hole pressure, so that the wells will produce longer. For this scenario, the RF doesn't change when the injection rates are changed before 1999-1-1, which is the shut in time for an injector with a rate of 50 bbl/day. The best RF occurs after 30 years when there is a one to one ratio. The RF's for this ratio are 1.53% after 5 years, 3.06% after 10 years, 4.59% after 15 years, and 6.04% after 30 years. The RF's for ratios 0.1 and 0.5 can be found in Table 3. How the oil production affects the saturation in the reservoir can be seen in Figures 17-19.

For the third scenario there is a production rate of 1000 bbl/day and the injection well rate is varied. The injection well is varied based on the ratio of 1, 0.5, and 0.1. For scenario 3 the injectors start to change the reservoir in 1986. The best injection rate is 1000 bbl/day after 30 years of production. The RF's are as follows: 3.06% after 5 years, 4.03% after 10 years, 4.03% after 15 years, and 4.03% after 30 years. The RF's for an injection rate of 100 bbl/day and 500 bbl/day can be found in Table 3. At around 1986-5-1, which is the shut in time for an injector with a rate of 100 bbl/day, the cumulative oil production levels off at different points based on the rate of the water injector. The reasoning for this is the same as for scenario 2. The cumulative oil production for this scenario can be seen in Figure 6. The final oil saturation in the reservoir can be seen in Figures 20-22 for this scenario.

The production rate for scenario 4 is 100 bbl/day. The rate of the injection well is varied following a ratio 1, 0.5, and 0.1. Figure 7 shows the oil production for scenario 4. This figure shows that for a production rate of 100 bbl/day the reservoir will continue to produce past 2010 because the cumulative oil production hasn't leveled off, which means the well did not reach the minimum bottom hole pressure during the production time. The RF is the same for all the injection rates because the production rate is too low for the reservoir to reach minimum bottom hole pressure. The RF's are 0.31% after 5 years, 0.61% after 10 years, 0.92% after 15 years, and 1.84% after 30 years. Figures 23-25 show how oil production affects the oil saturation in this reservoir.

Comparing the first 4 scenarios

Changing the production rate has a greater effect on the cumulative oil production than the injection and production ratios. For the same injection and production ratios, different production rates have a huge effect on the reservoir pressure drop. A drop in reservoir pressure can also influence the well shut in time.

Figure 8 shows how changes in the perforation layers will change the production. For scenario 5 an optimization of the perforations was done. By optimizing the layers that were perforated, some of the wells were able to produce for a longer period of time. For one of the perforation scenarios the well starts producing at a stagnant rate in 1981 versus 1985 for another perforation scenario. The production rate for these wells is 1000 bbl/day. Three different perforation scenarios were done to see which one gave the best oil production. One scenario perforated layers 12, 13, and 14. Another perforation scenario was when layers 4, 5, and 6 were perforated. However, the best scenario was when layers 7, 8, and 9 were perforated. The RF's for this scenario are 3.06% after 5 years and 3.26% after 10, 15, and 30 years. The RF's for the other two perforation scenarios can be found in Table 3. The sweep of the oil can be seen in Figures 26-28 for this scenario.

Scenario 6, shown in Figure 9, is again optimizing the perforations. An optimized layer will produce the most oil out of the reservoir. The production rate for these wells is 500 bbl/day. Three different perforation scenarios were done to see which one gave the best oil production. The first perforation scenario perforated layers 12, 13, and 14. Another scenario perforated layers 4, 5, and 6. The best scenario however, occurred when layers 7, 8, and 9 were perforated. For this scenario the RF's are as follows: 1.53% after 5 years, 3.06% after 10 years, 4.59% after 15 years, and 5.12% after 30 years. The RF's for the other perforated layers can be found in Table 3. Figures 29-31 show how the oil production affects the sweep in this reservoir.

Figure 10 shows the cumulative oil production for scenario 7. This scenario has a production rate of 100 bbl/day. The production was optimized by varying the perforated layers for three different scenarios. One of the perforation scenarios perforated layers 12, 13, and 14. Another scenario perforated layers 4, 5, and 6. The third scenario perforated layers 7, 8, and 9. The RF for the second and third perforation scenarios are the same. There RF's are 0.31% after 5 years, 0.61% after 10, 0.92% after 15 years, and 1.84% after 30 years. The RF for the first scenario can be found in Table 3. How the oil is produced from a formation affects how the reservoir is swept, which can be seen in Figures 32-34.

Comparing scenarios 5-7

The oil production rate decreases when layers 12, 13, and 14 are perforated. This is because water starts to be produced from the production wells. The cumulative oil curve of layers 12, 13, and 14 started to deviate from the cumulative oil curves of layer 4, 5, and 6 and 7, 8, and 9, which is where water breakthrough started to happen. This phenomenon is called water coning. Coning is a production problem in which gas cap gas or bottom water infiltrates the perforation zone in the near-wellbore area and reduces oil production, Figure 44. Coning is a rate-sensitive phenomenon generally associated with high producing rates. A lower pressure zone that is caused by high flow rates, leads to the coning of water. This is strictly a near-wellbore phenomenon. It only develops once the pressure forces drawing fluids toward the wellbore and overcomes the natural buoyancy forces that segregate gas and water from oil.

Several strategies may apply to wells with the potential to cone. One strategy is to try to predict the rate at which a well will start coning and produce at a lower rate for as long as possible. This rate is also called the critical rate. However, optimal economics may result by producing at a much higher rate, causing the well to cone. This could also cause an increase in the cumulative hydrocarbon volume produced (and net present value) at any future date. This rate is also called an economic rate. The critical rate is usually very low, so a limited coning is typically accepted to get a higher oil production rate.

So when the perforation layers were chosen they couldn't be near the OWC. It can also be seen, in Table 3, which the water breakthrough happens at an earlier time when the production rate is increased. So in some situations water coning can't be avoided. Therefore, an economic production rate was found to balance the recovery factor and water oil production ratio.

For scenarios 8-10

For the following three scenarios, layers 4, 5, 7, and 8 were combined to make a simpler reservoir model. After the layers were combined, layers 7, 8, and 9 were chosen as the perforation layers. These layers were chosen because they are in the middle area of the reservoir and they have the highest permeability, shown in Table 2. Since they are in the middle, they are not as greatly affected by the water and gas coning.

Figure 11 shows the cumulative oil production for scenario 8. This scenario has a production rate of 500 bbl/day with a varying injection rate. The injection rates are 50 bbl/day, 250 bbl/day, and 500 bbl/day, which correspond to an injection/production ratio of 0.1, 0.5, and 1. For this scenario, the production continues to produce even after the stop date. The best scenario is for a production rate of 500 bbl/day and an injection rate of 500 bbl/day. The RF's for this scenario are 1.53% after 5 years, 3.06% after 10 years, 4.58% after 15 years, and 5.31% after 30 years. The RF's for an injection rate of 50 bbl/day and 250 bbl/day can be found in Table 3. Figures 35-37 show how these scenarios affect the sweep of the reservoir.

Scenario 9 has a production rate of 1000 bbl/day. The cumulative oil production for this scenario can be seen in Figure 12. The injection rates are 100 bbl/day, 500 bbl/day, and 1000 bbl/day. The best scenario occurs when the injection rate is 1000 bbl/day. The RF's for this scenario are 3.06% after 5 years, 3.26% after 10, 15, and 30 years. The water breakthrough occurs after 12.93 years. The wells are then shut in due to a low bottom hole pressure after water breakthrough. The other two scenarios can be found in Table 3. Oil production can affect the oil saturation in a reservoir, which can be seen in Figures 38-40.

Scenario 10 has a production rate of 100 bbl/day. The injection rates are 10 bbl/day, 50 bbl/day, and 100 bbl/day. The cumulative oil production can be seen in Figure 13. From this graph it can be seen that the wells are still producing at a cumulative rate even after the stop date, for the same reason talked about in scenario 4. For this scenario, the injection rate doesn't matter. The RF's are constant and are 0.31% after 5 years, 0.61% after 10 years, 0.92% after 15 years, and 1.83% after 30 years. The oil saturation sweep can be seen in Figures 41-43 for this scenario.

Conclusion—Shivani

Overall this reservoir shouldn't be produced for the short term. The recovery factors are much too small to make a return on investment. The RF's range from 0.2% to 9.15%. 9.15% is the highest RF for the reservoir scenario after 30 years of production. After 5 years, the best RF is only 3.06%. After 10 years, the best is 4.03%. Out of all the different scenarios, there is a minimum RF of 0.2%. Scenario 2 will give the best oil production after 15 years and the injection rate doesn't matter. When it comes to water breakthrough time and perforation layers, layers 7, 8, and 9 would be the best to work with since it results in a stable production.

Reflection—Shivani

This project helped us understand how a reservoir changes once injection and production wells are installed, and up running. The concepts, such as water coning and maintaining a stable production rate by recognizing the water breakthrough time, helped us with understanding the overall idea of determining OOIP, OGIP, GOC, and OWC. Recovery factor is another huge concept that helps in the prediction of the production rate. This can help with making an important decision on whether it is worth it to run the well and produce from the formation. Overall, reservoir simulation software is important and plays a vital role in understanding the changes occurring in the reservoir and helps us predict the flow of fluids.

Appendix of Figures

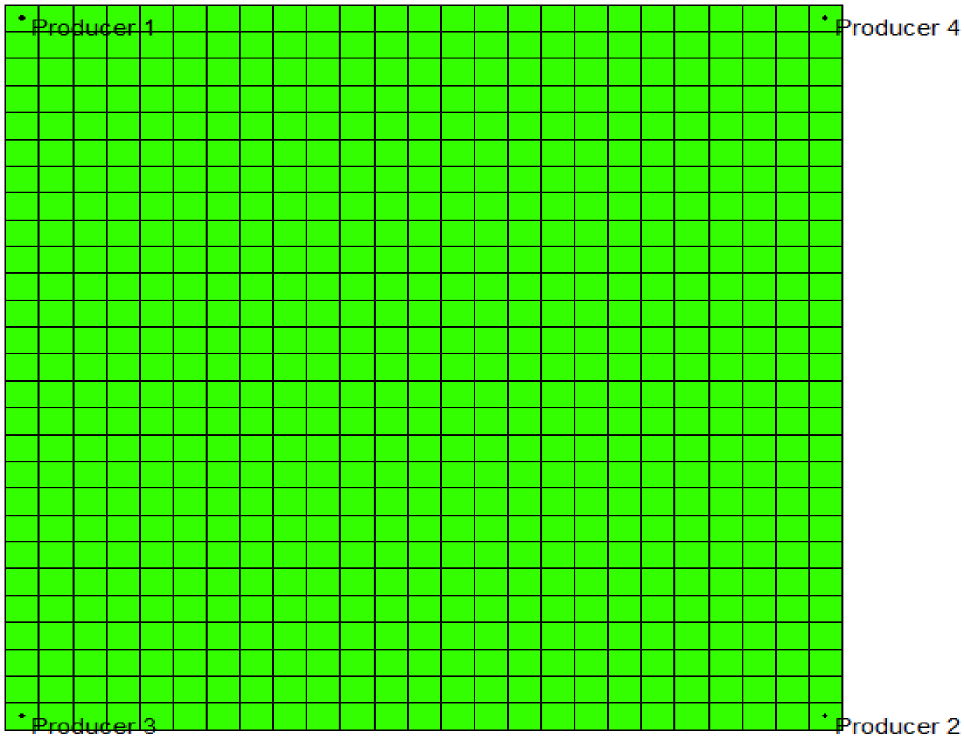

Figure 1: An aerial view of scenario 1

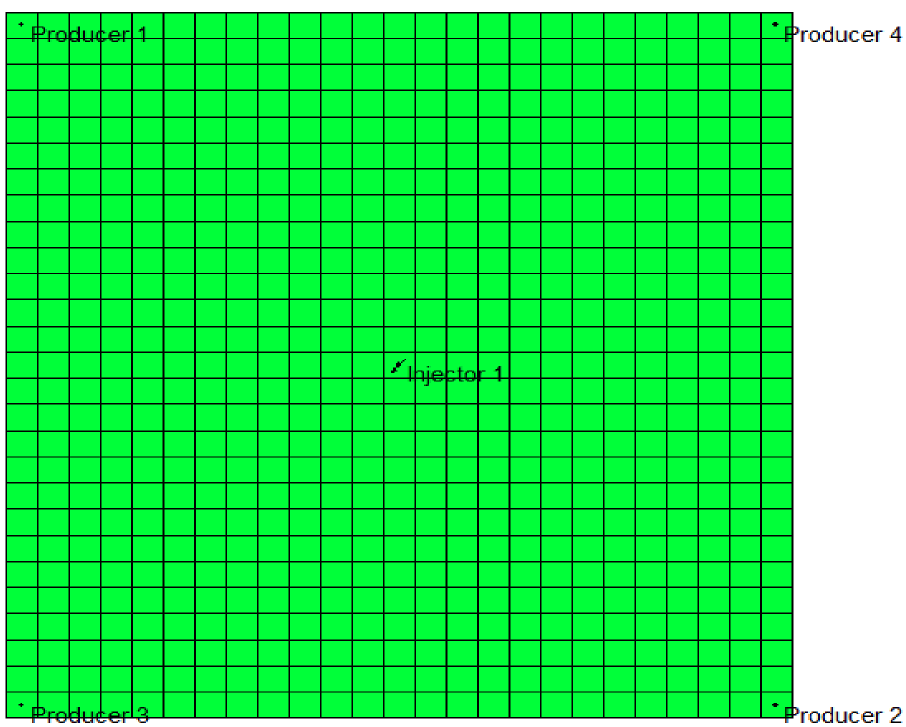

Figure 2: This is an overview of the reservoir

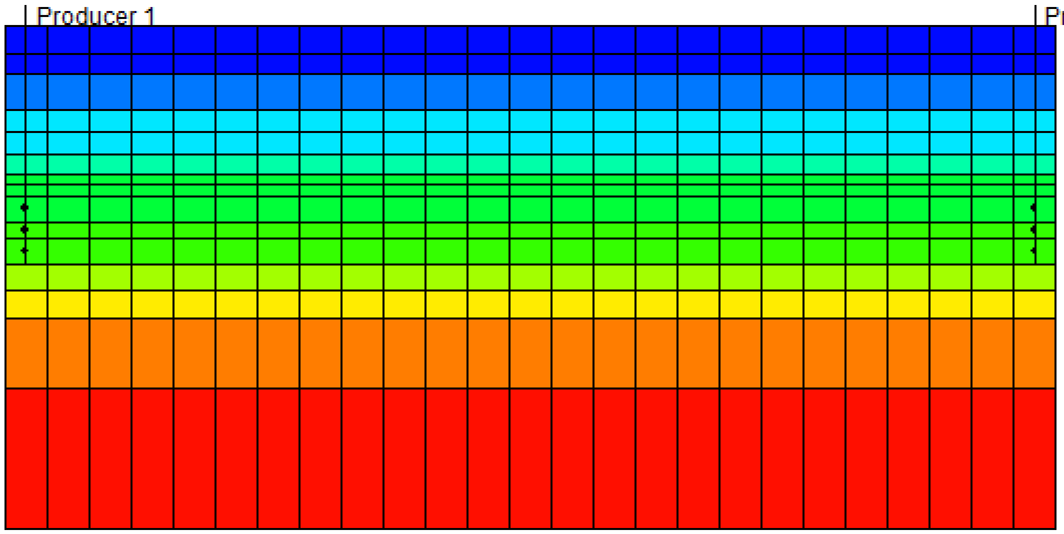

Figure 3: A side view showing layer distribution

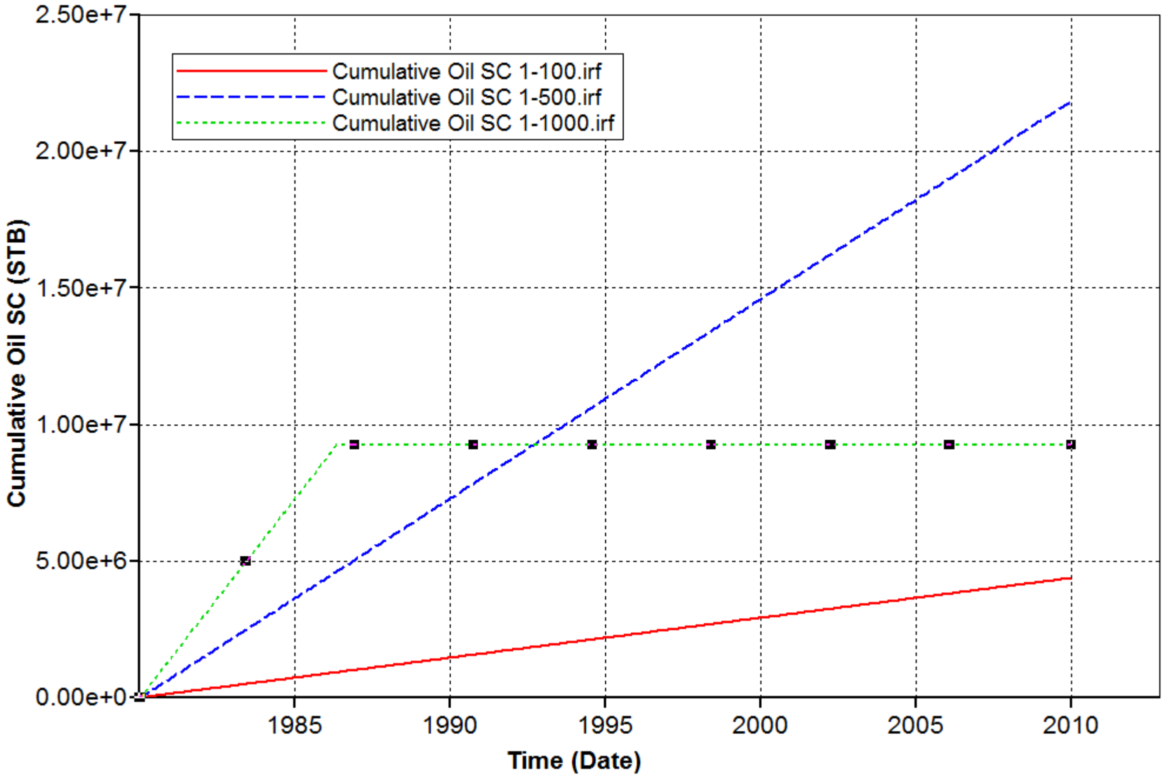

Figure 4: Cumulative Oil production for scenario 1

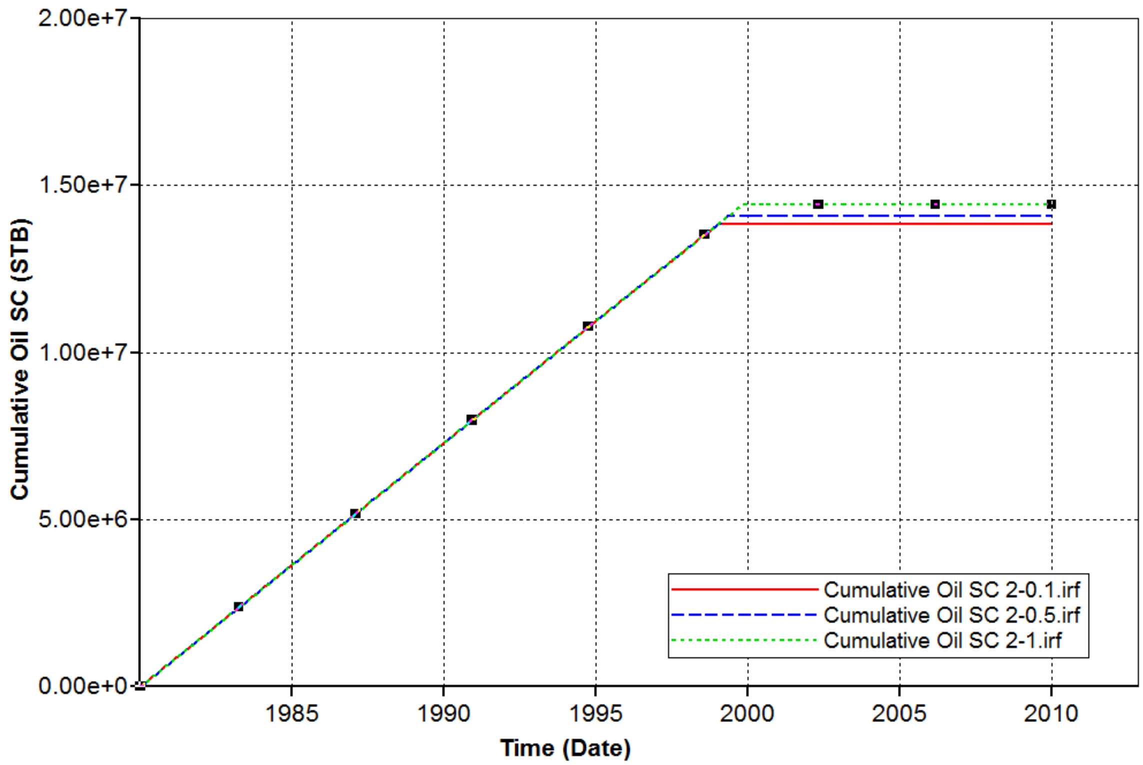

Figure 5: Cumulative oil production for scenario 2

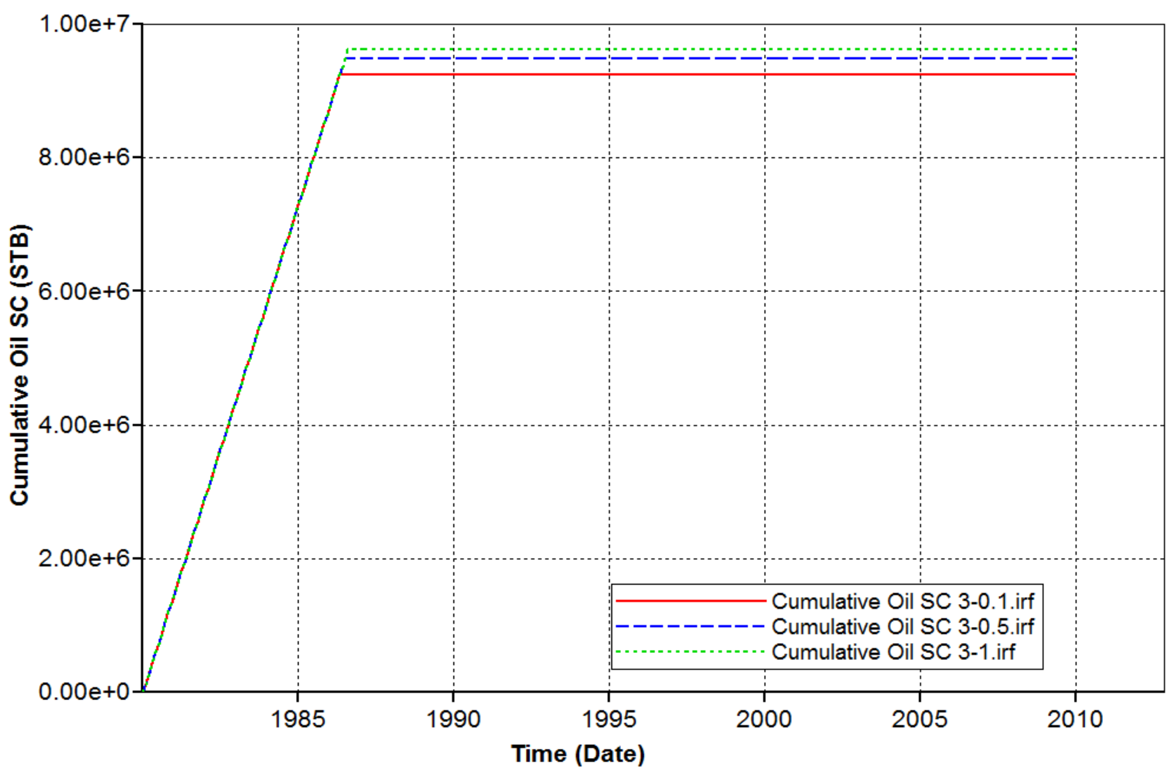

Figure 6: Cumulative oil production for scenario 3

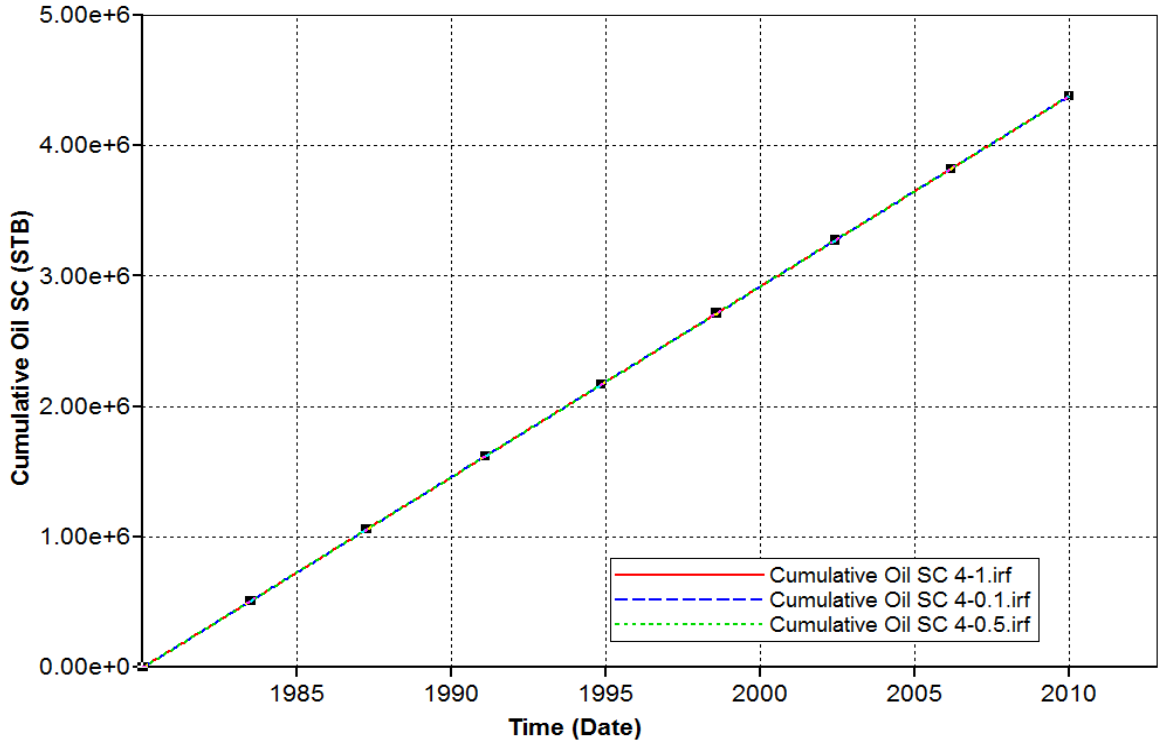

Figure 7: Cumulative oil production for scenario 4

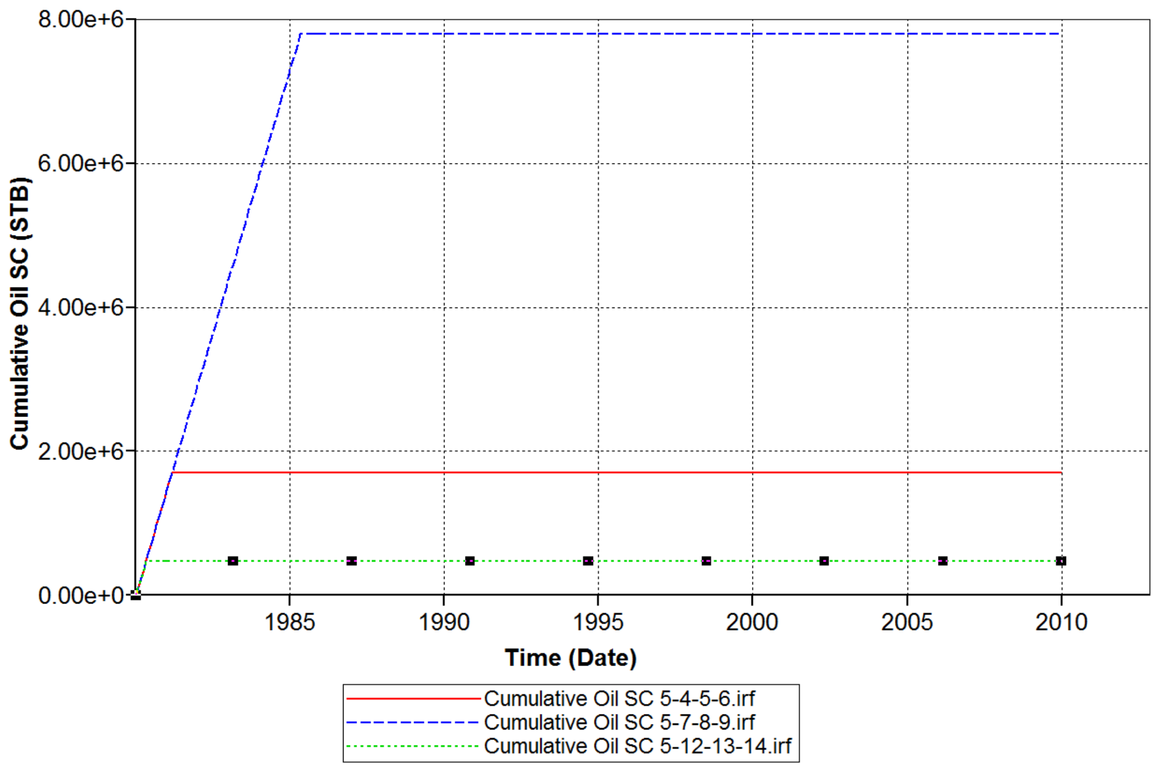

Figure 8: Cumulative oil production for option 5

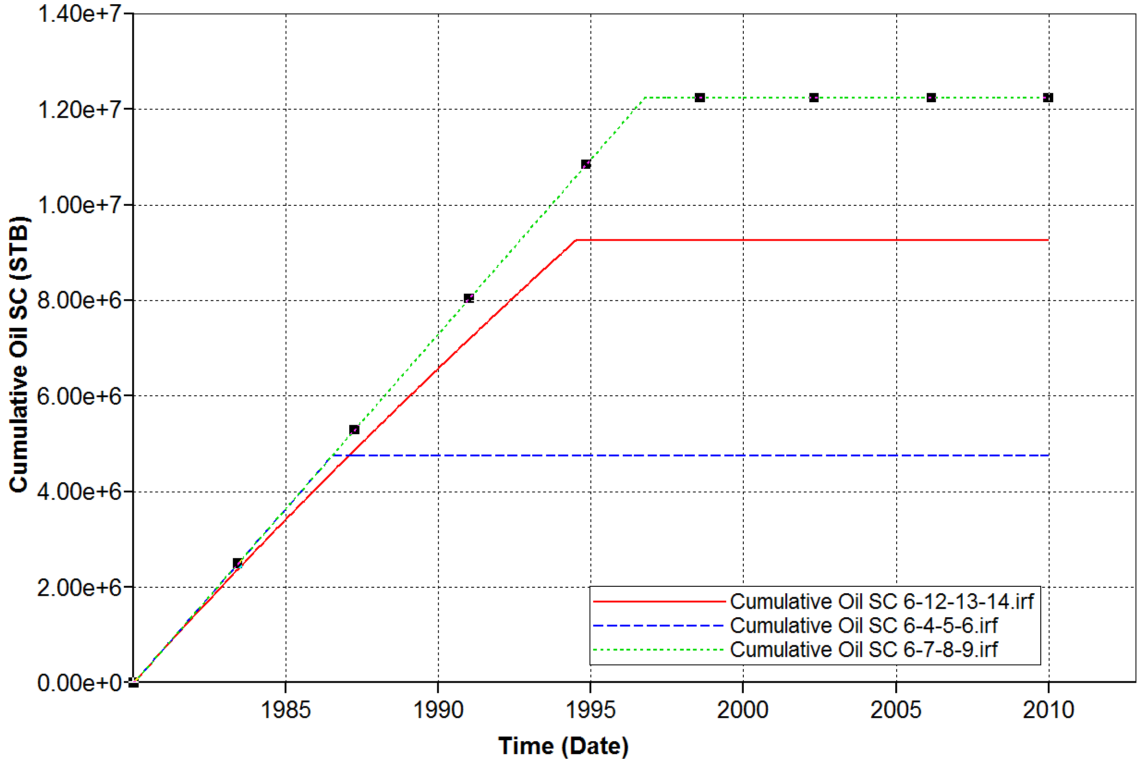

Figure 9: Cumulative oil production for scenario 6

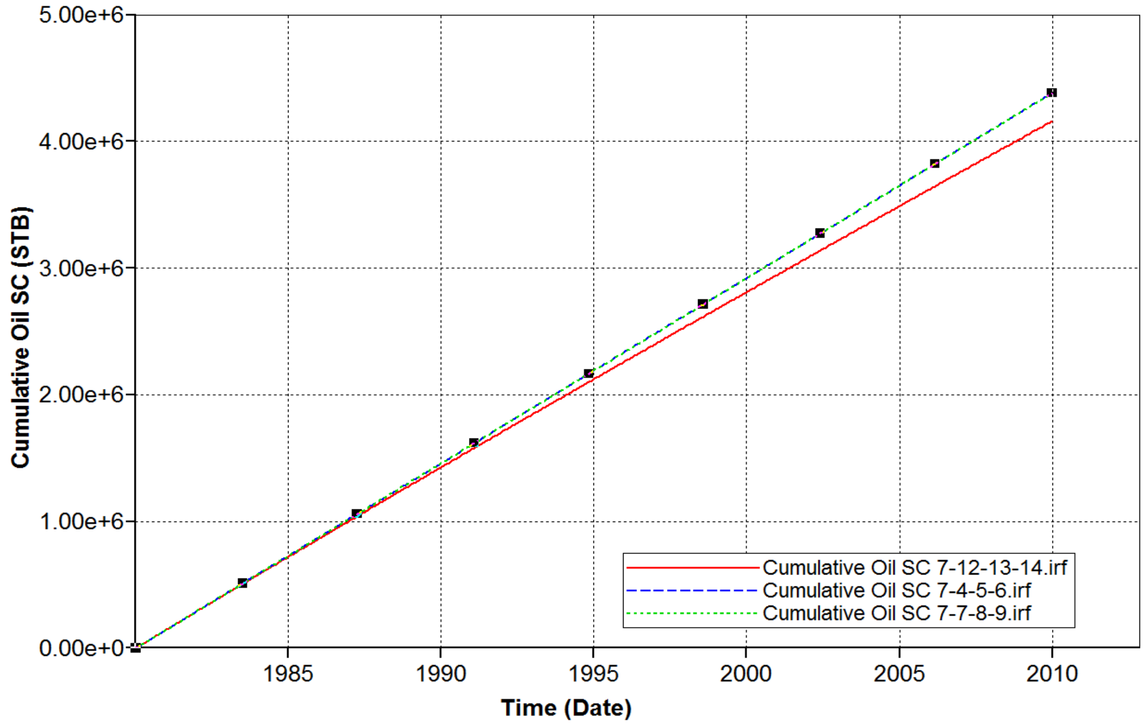

Figure 10: Cumulative oil production for scenario 7

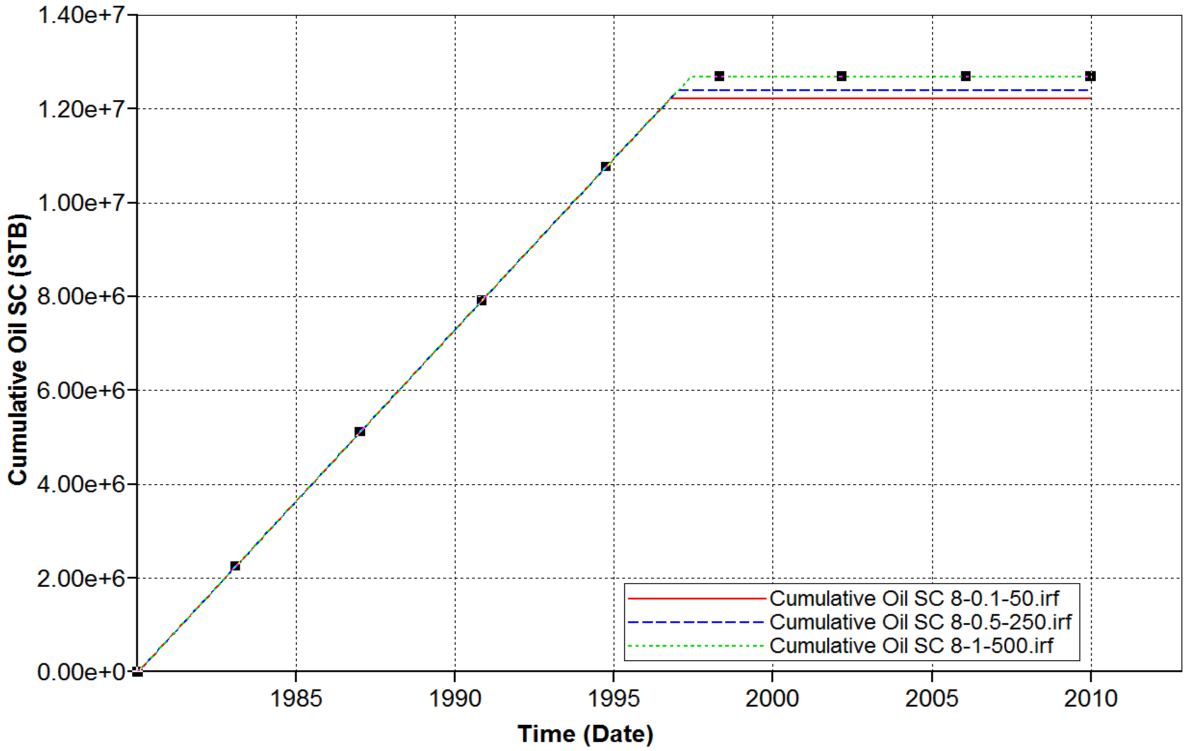

Figure 11: Cumulative oil production for scenario 8

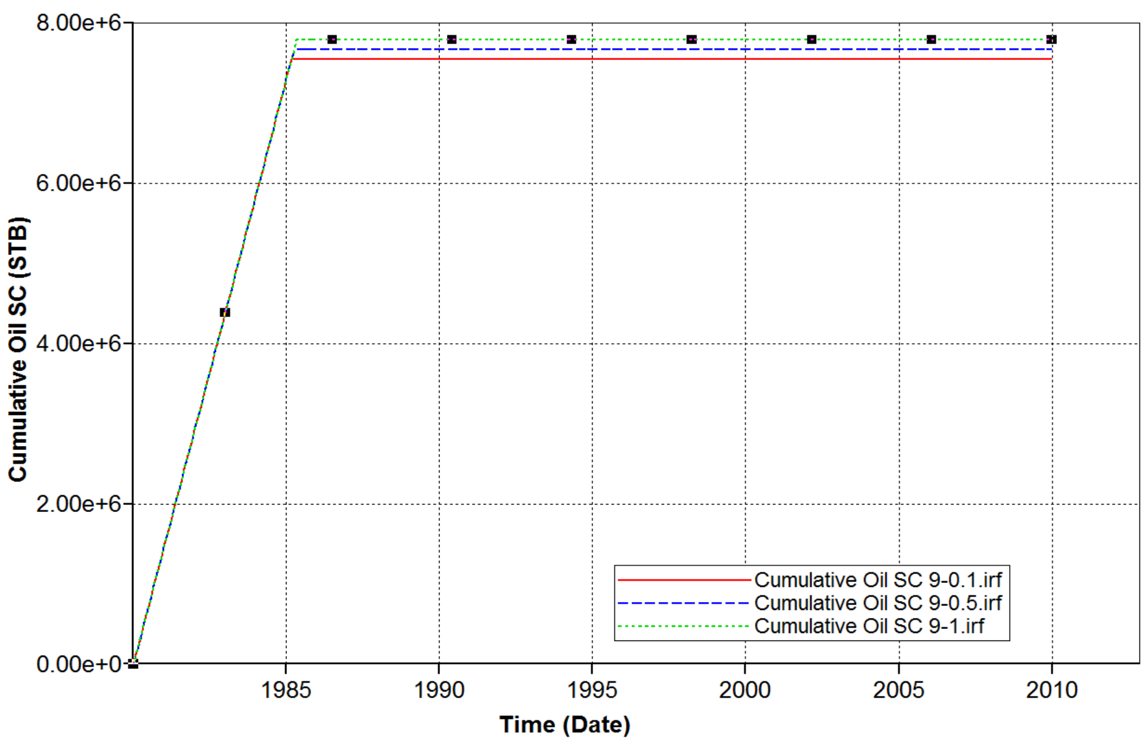

Figure 12: Cumulative oil production for scenario 9

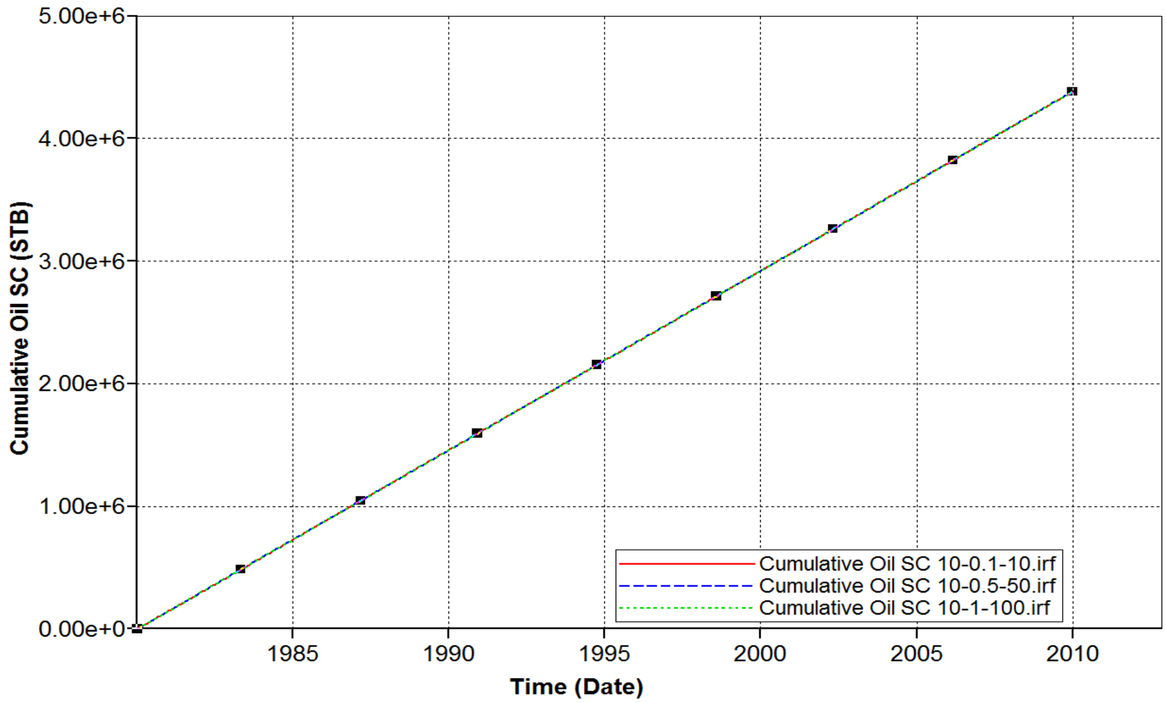

Figure 13: Cumulative oil production for scenario 10

Oil Saturation of Scenarios

Scenario 1

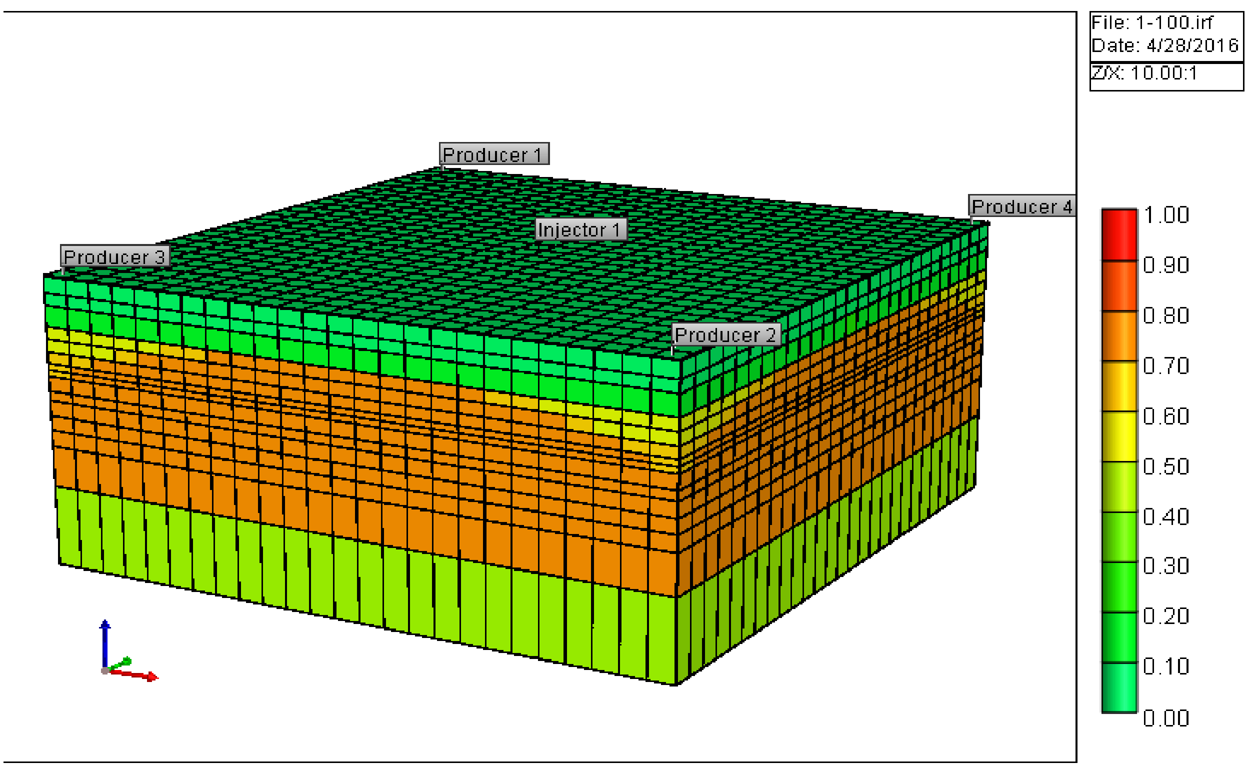

Figure 14: Production is 100 bbl/day

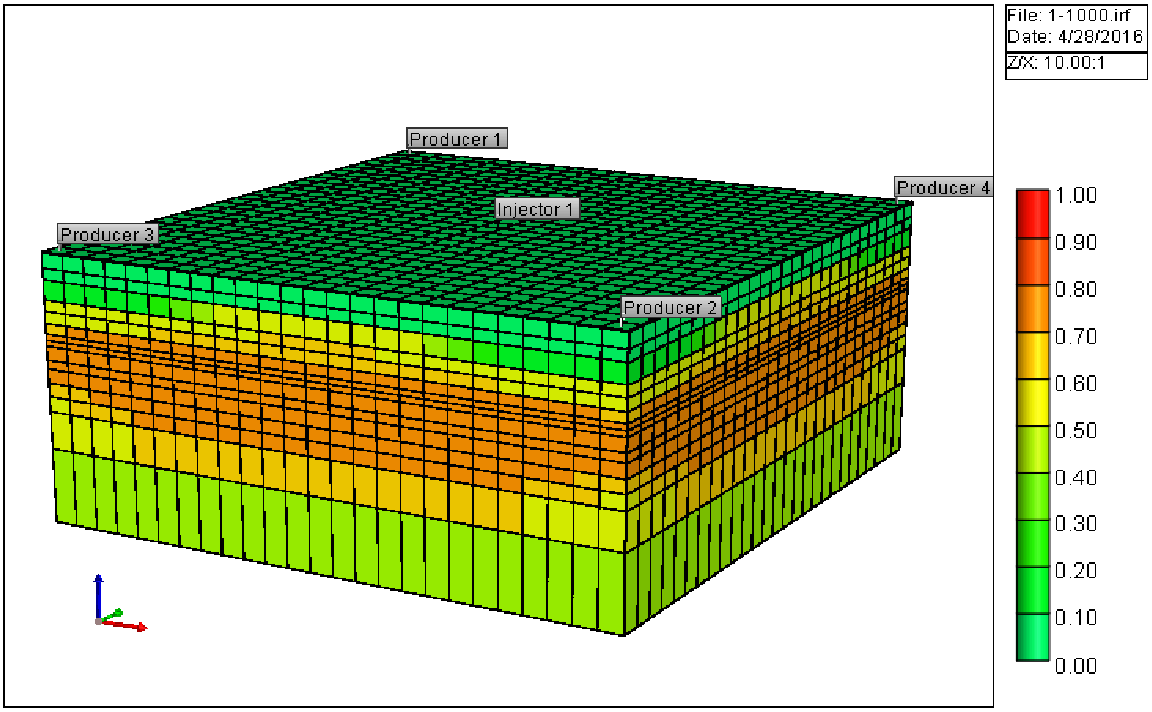

Figure 15: Production is 1000 bbl/day

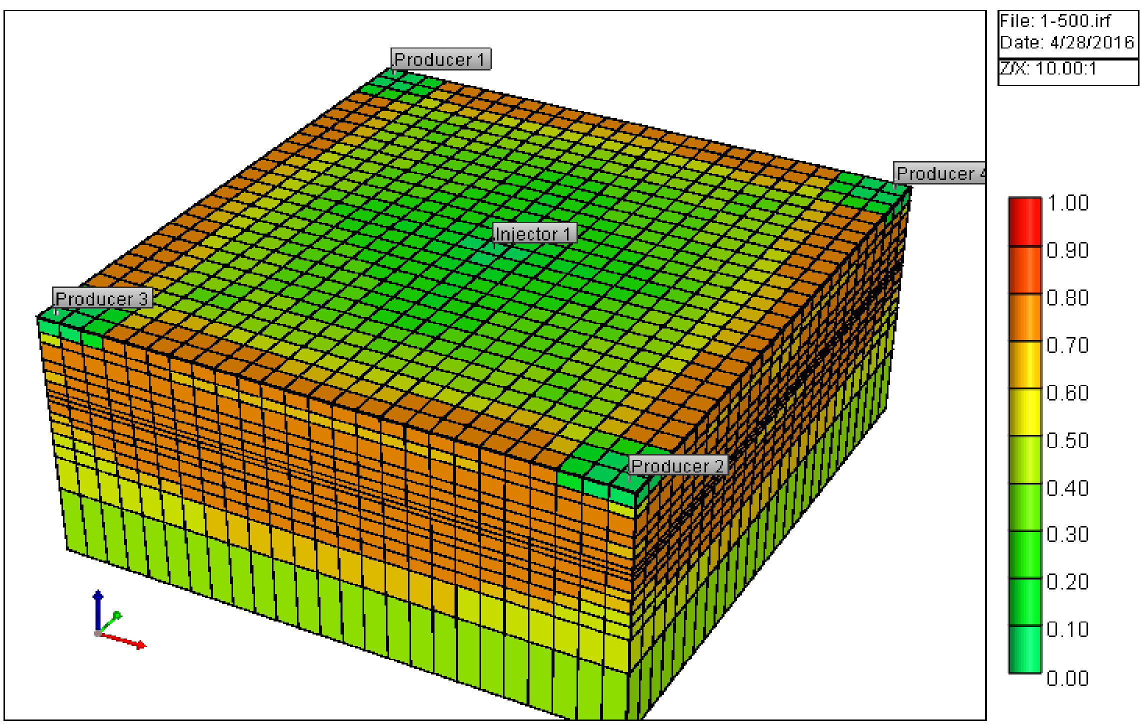

Figure 16: Production is 500 bbl/day

Scenario 2

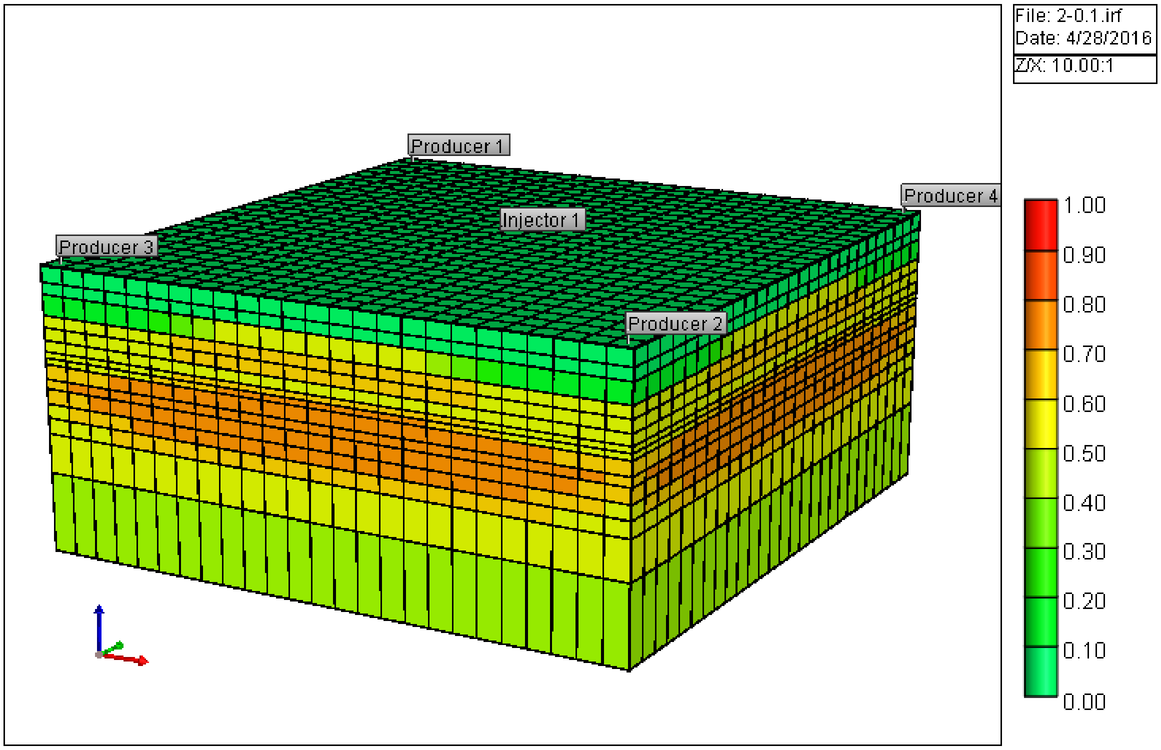

Figure 17: Injection ratio is 0.1

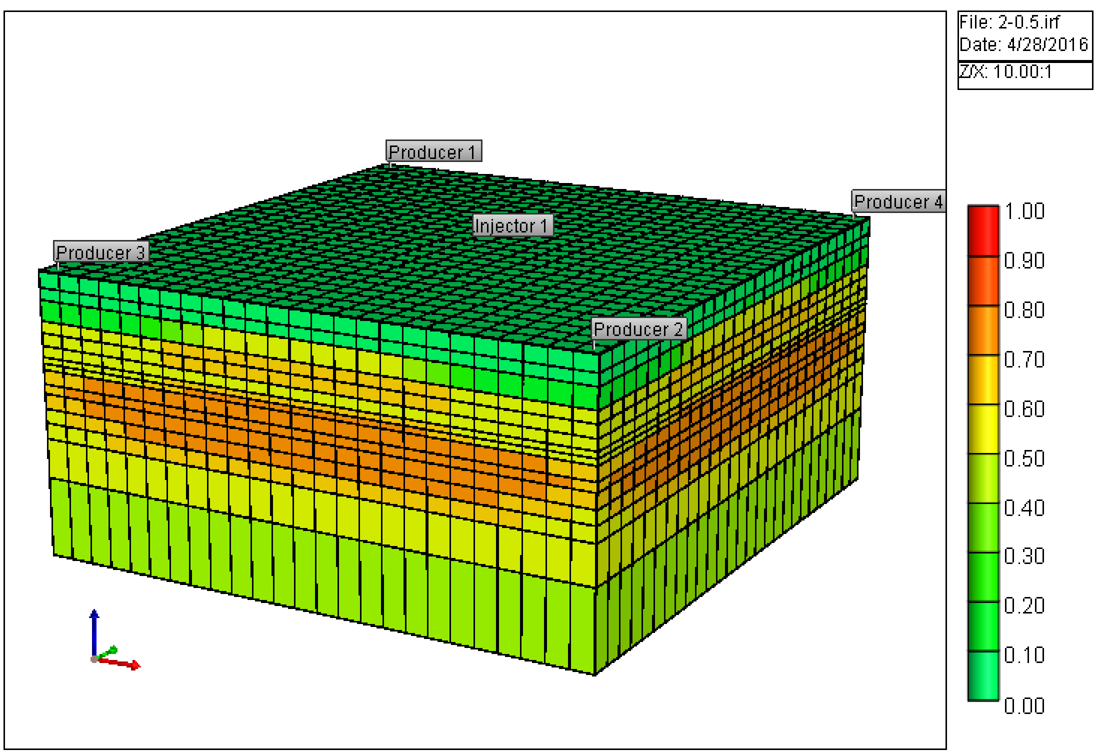

Figure 18: Oil: Injection ratio is 0.5

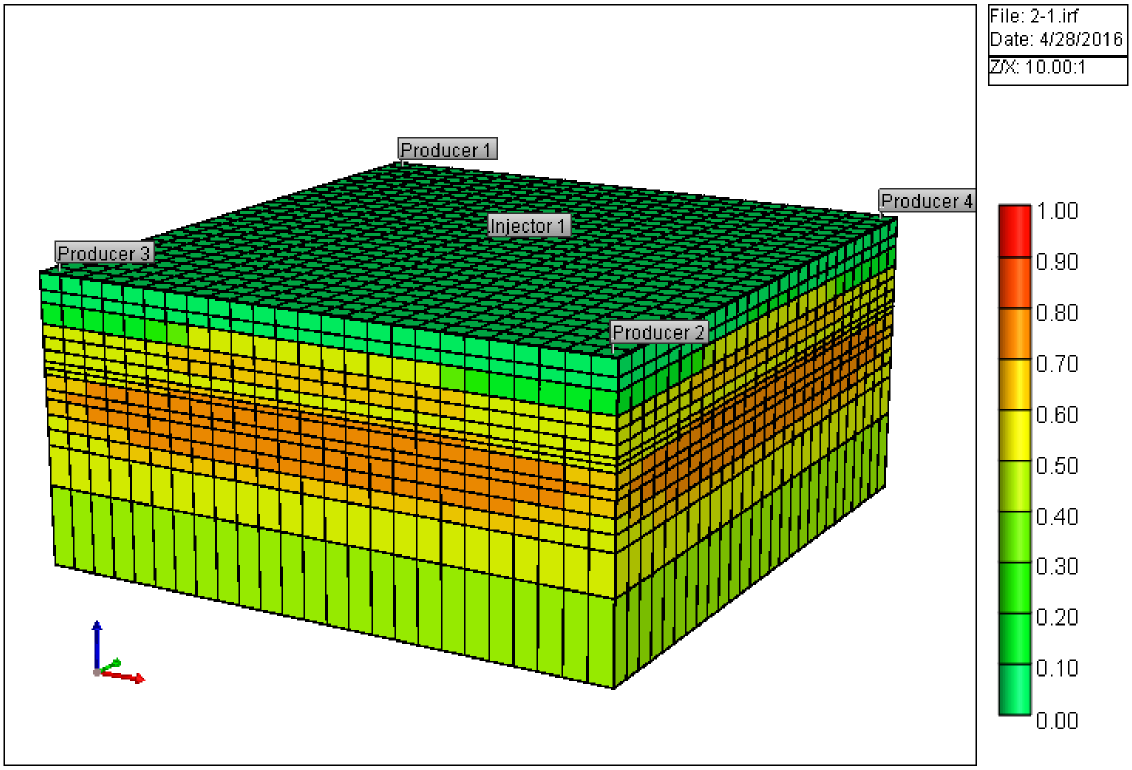

Figure 19: Injection ratio is 1

Scenario 3

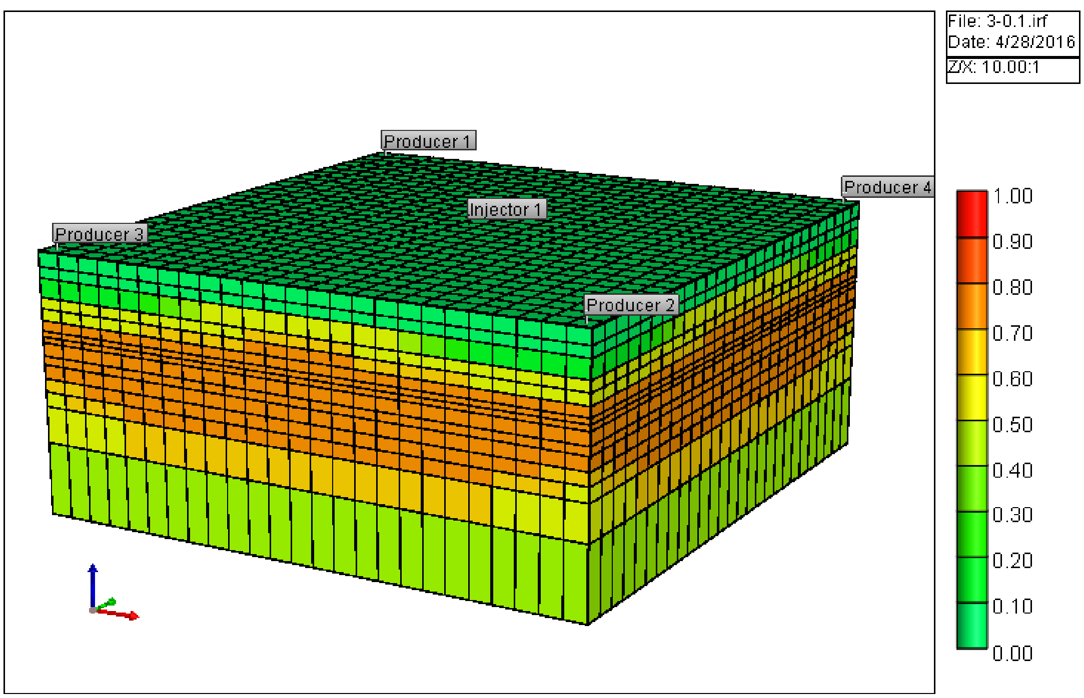

Figure 20: Injection ratio is 0.1

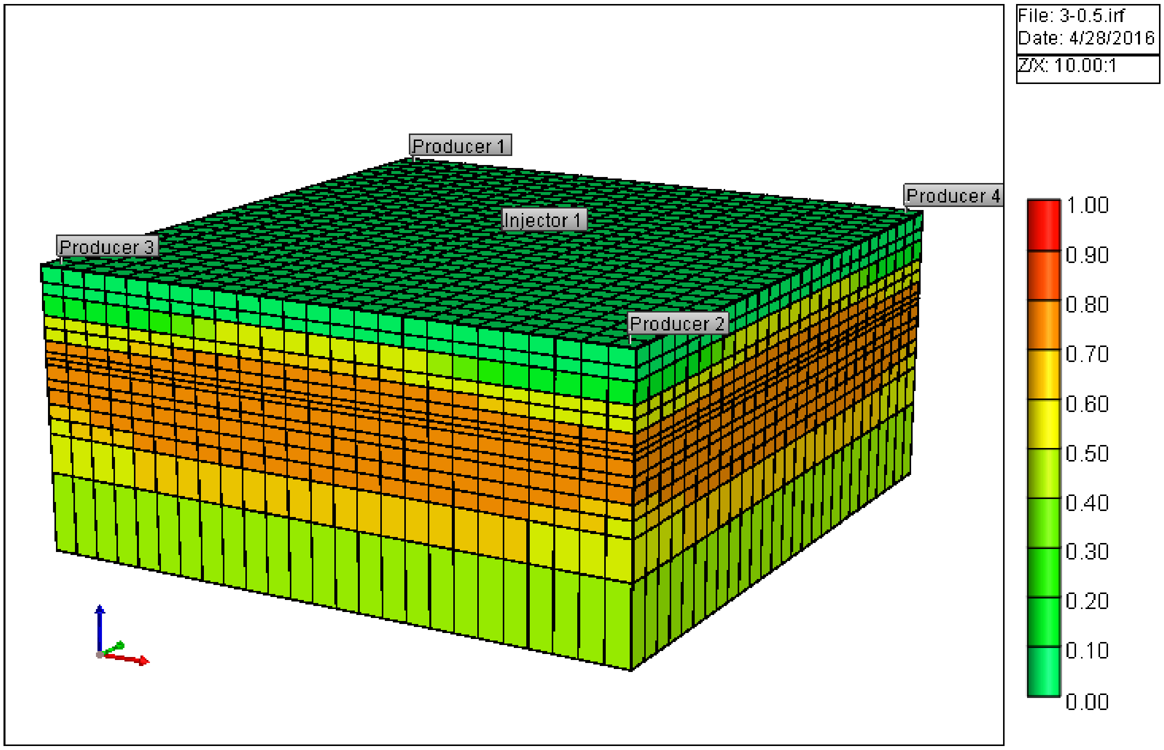

Figure 21: Injection ratio is 0.5

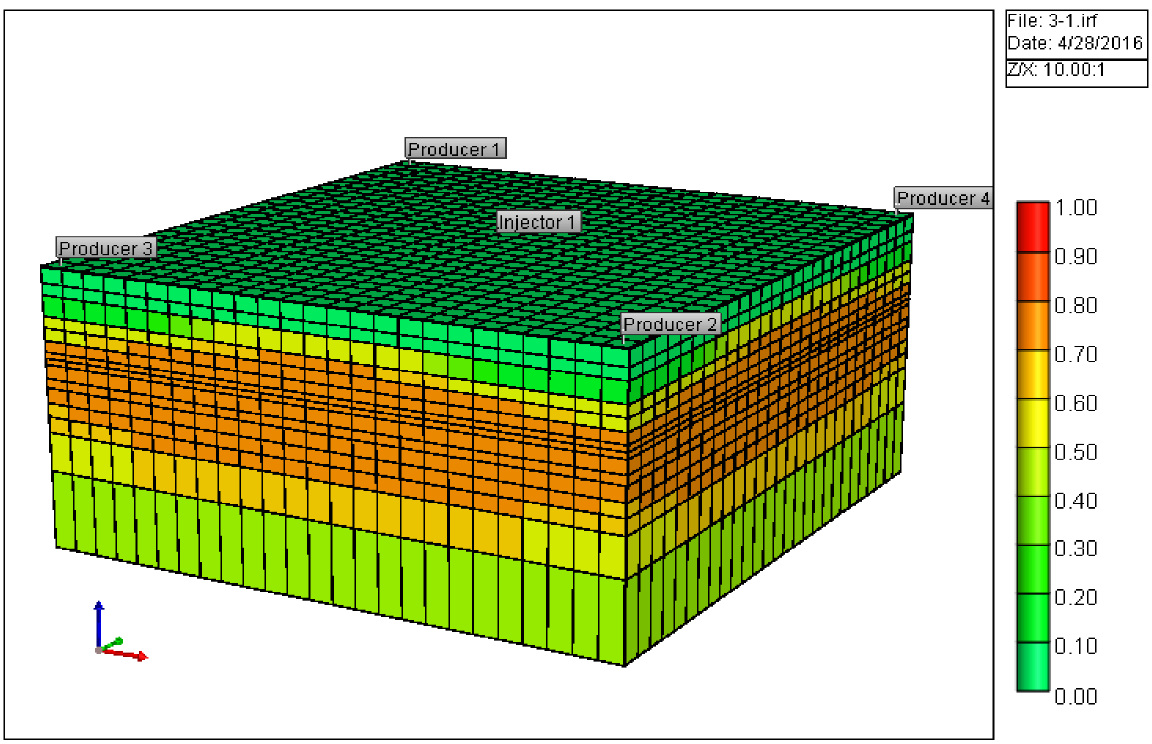

Figure 22: Injection ratio is 1

Scenario 4

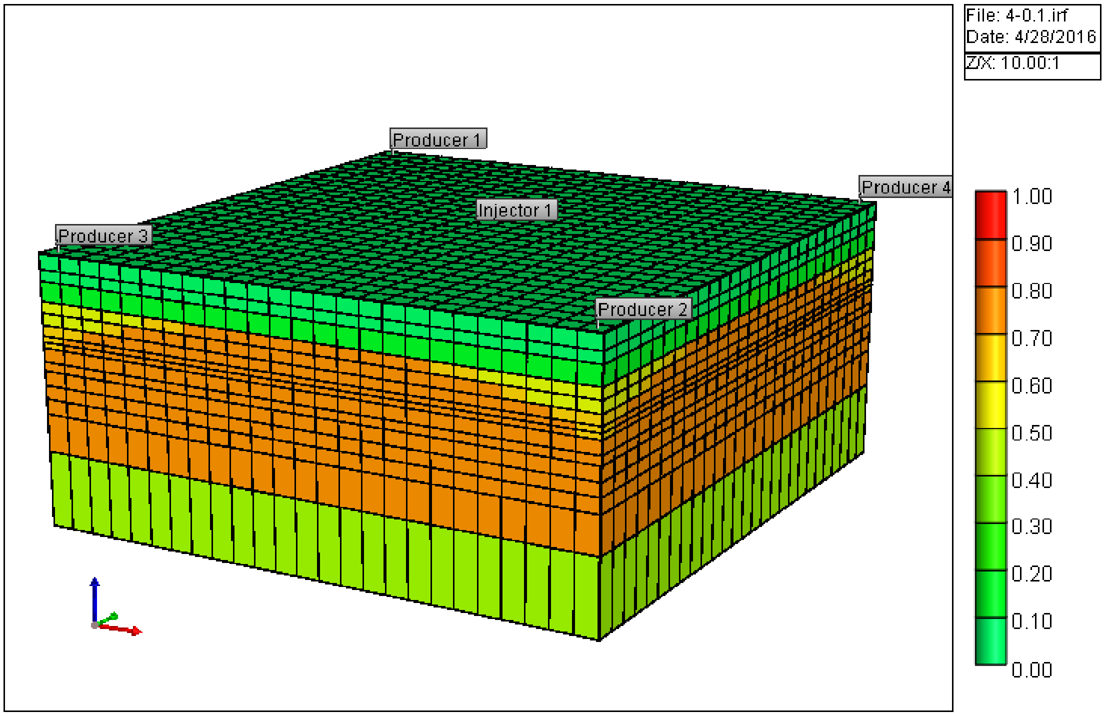

Figure 23: Injection ratio is 0.1

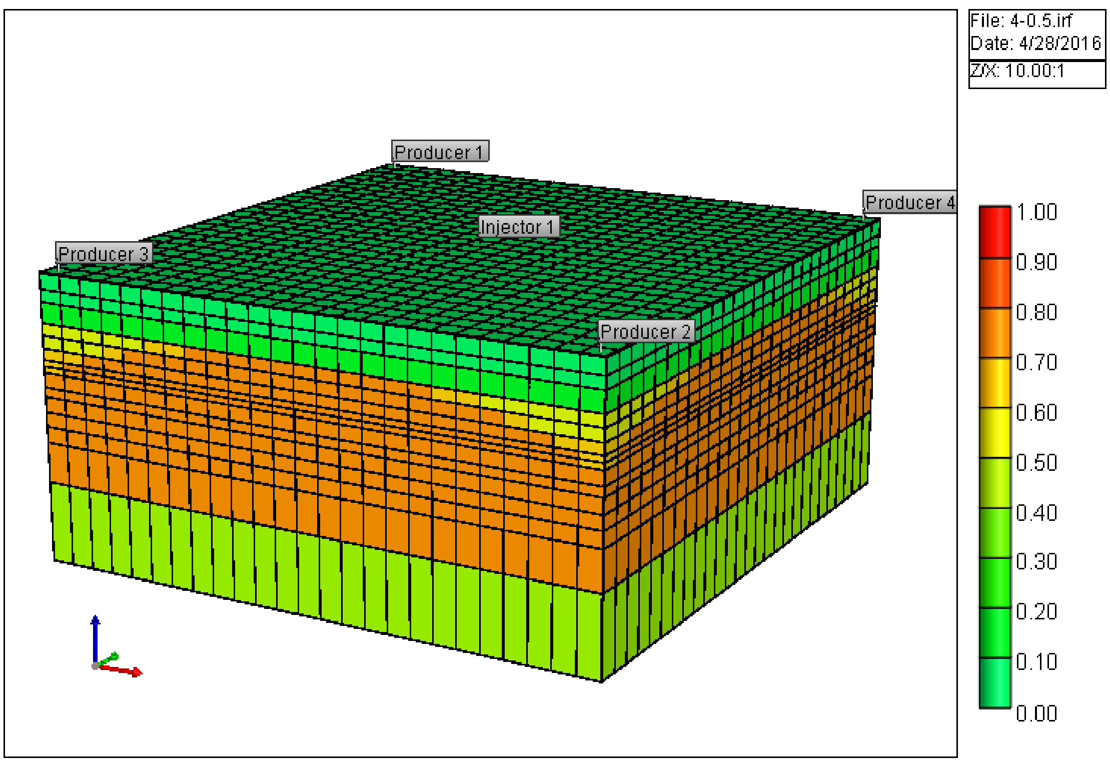

Figure 24: Injection ratio is 0.5

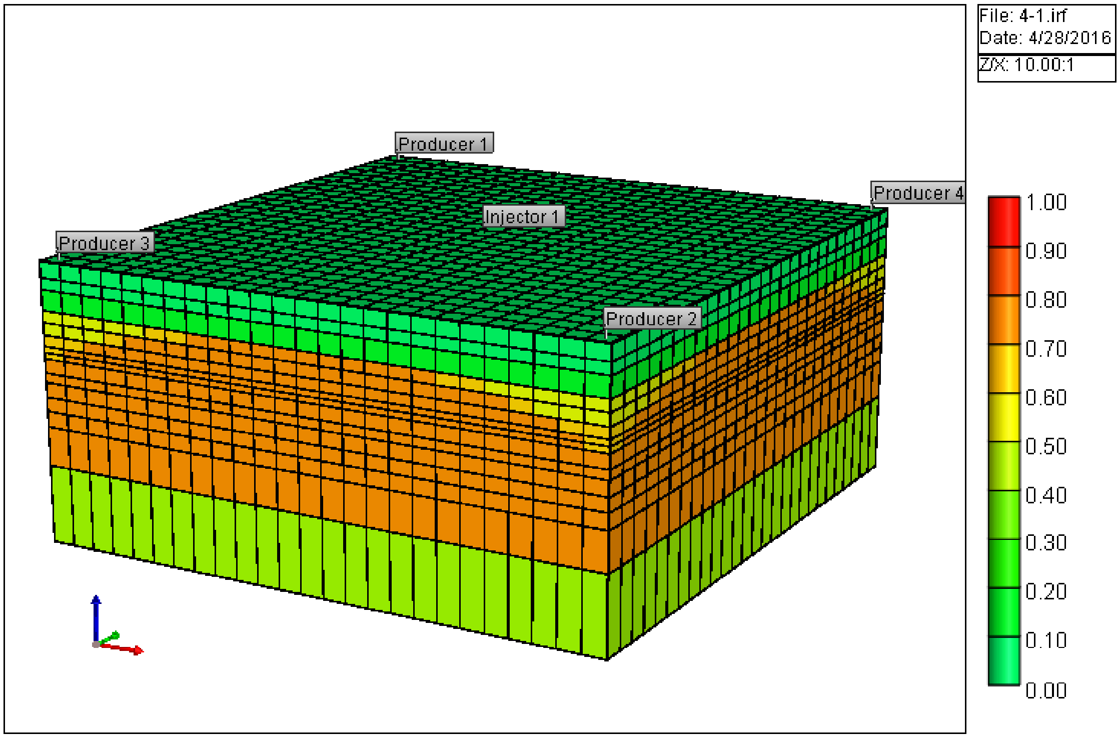

Figure 25: Injection ratio is 1

Scenario 5

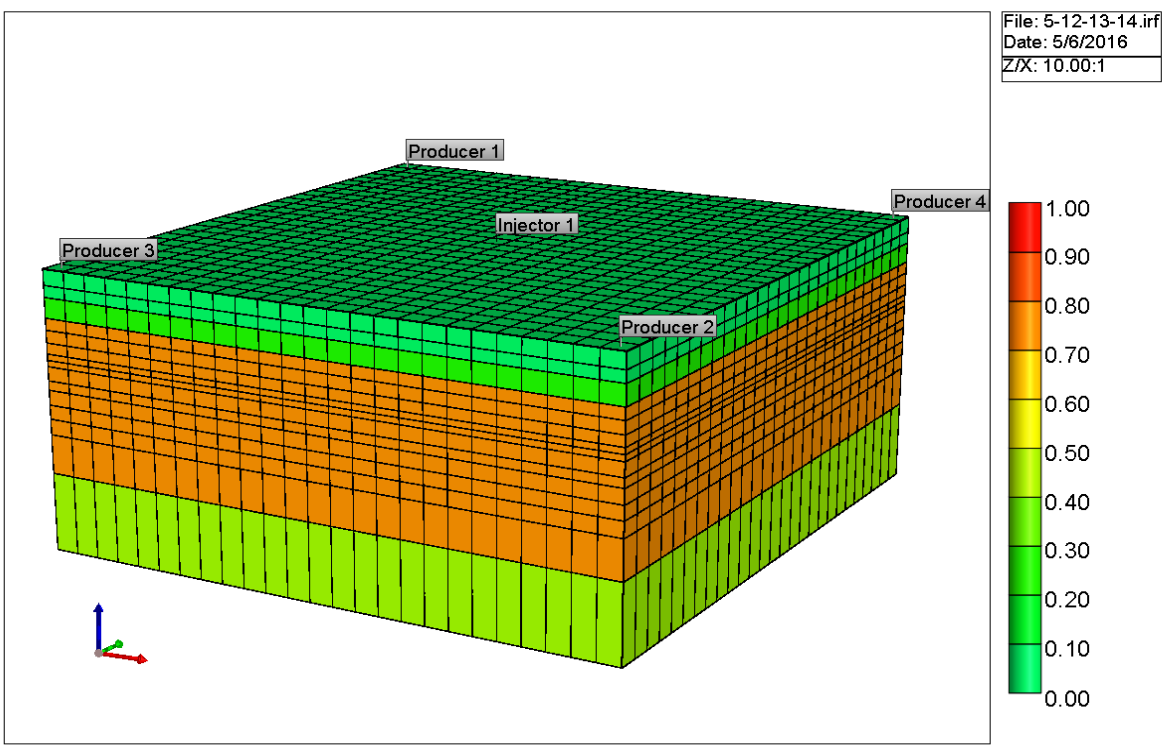

Figure 26: Perforated layers are 12, 13, and 14

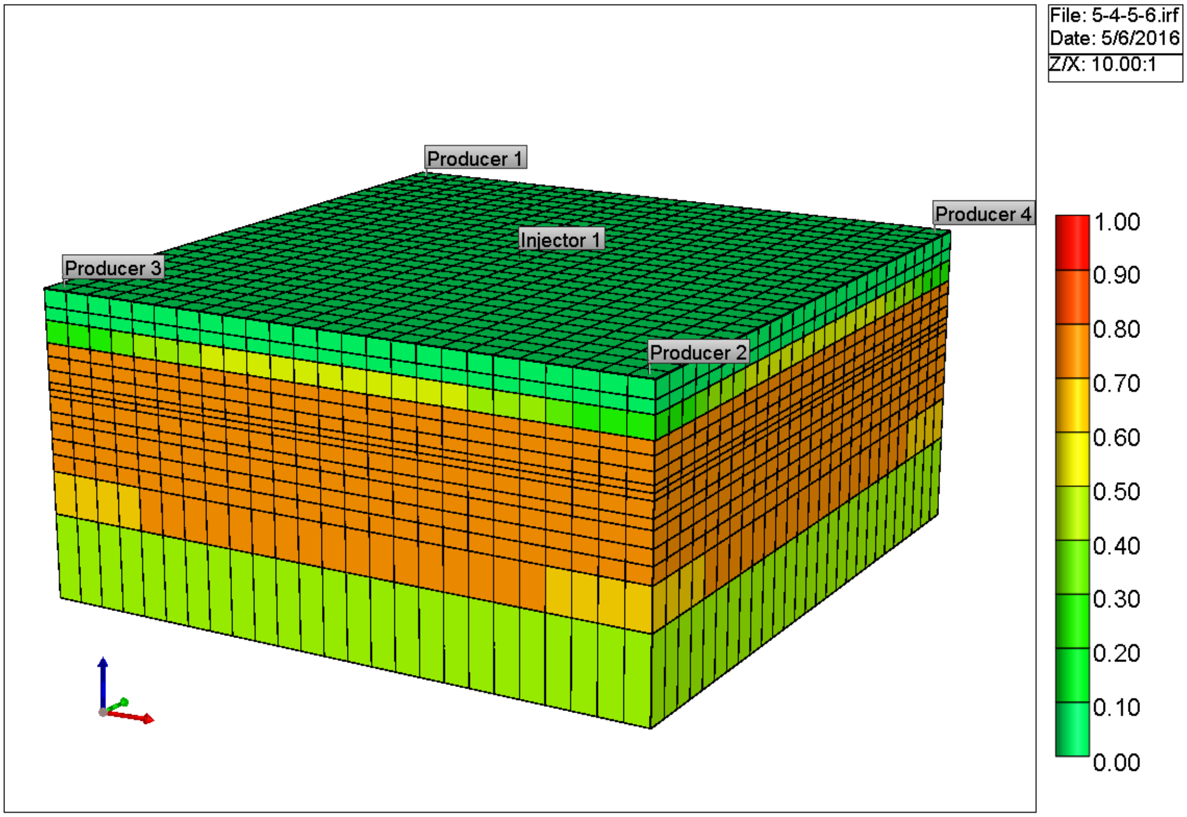

Figure 27: Perforated layers are 4, 5, and 6

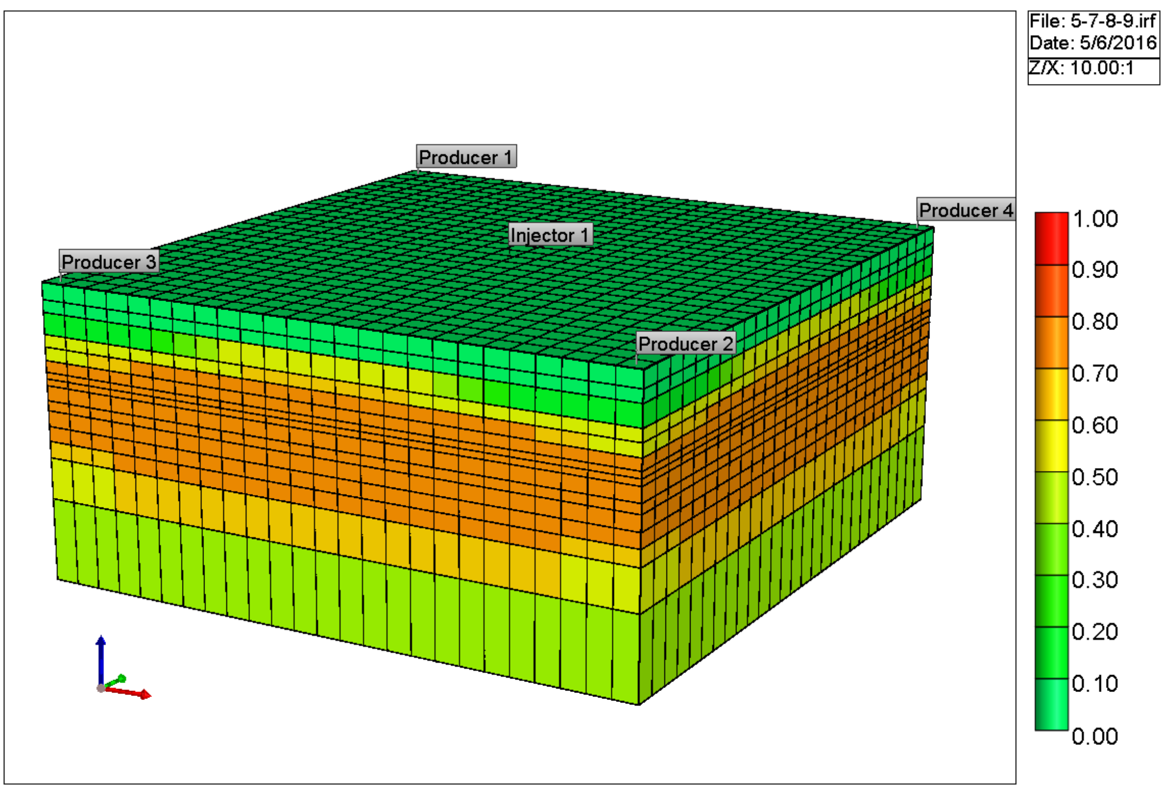

Figure 28: Perforated layers are 7, 8, and 9

Scenario 6

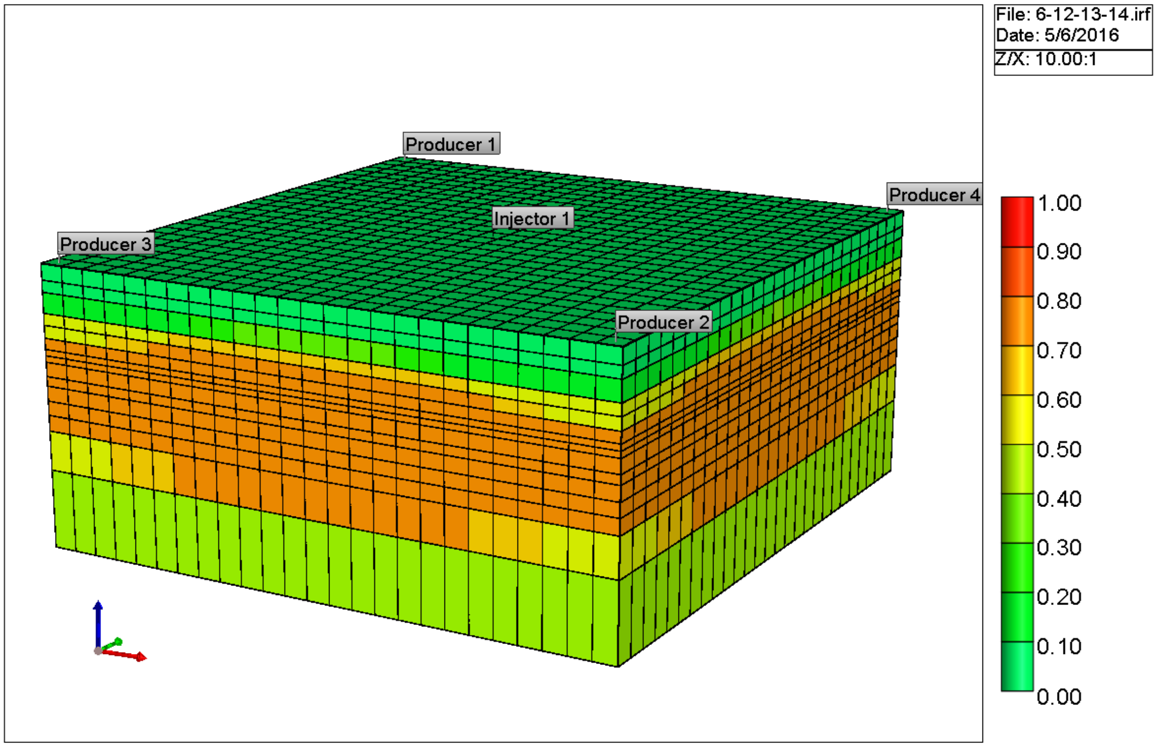

Figure 29: Perforated layers are 12, 13, and 14

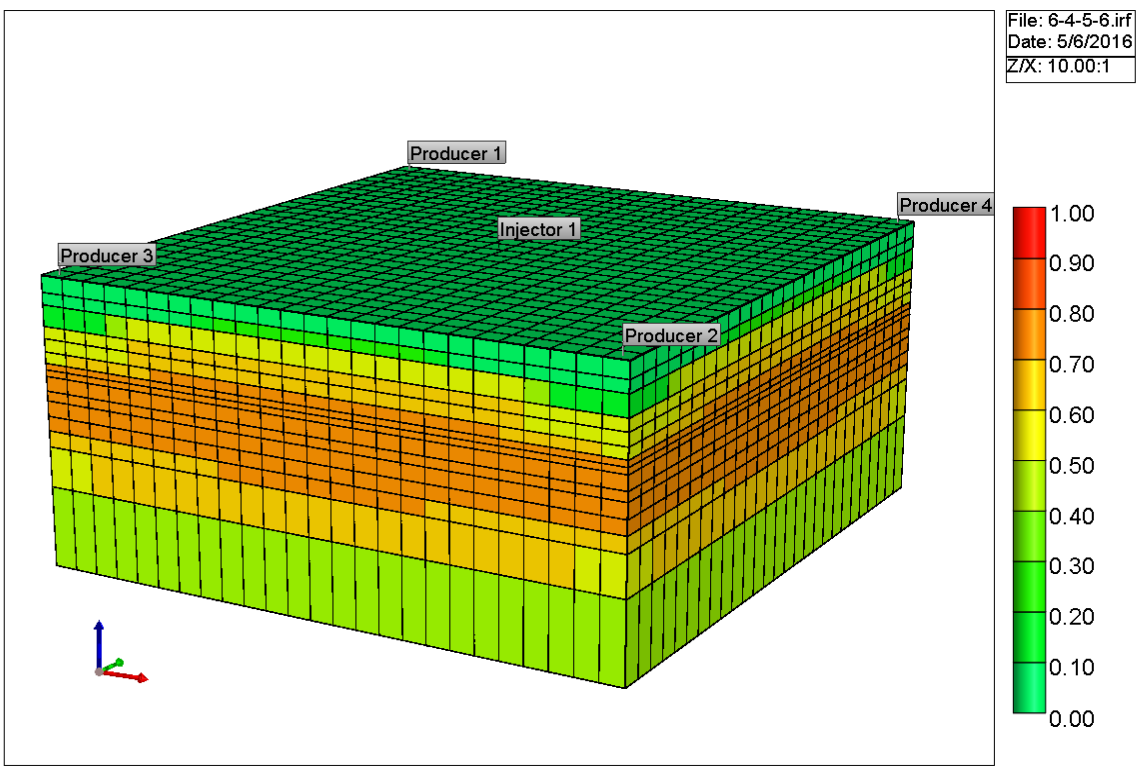

Figure 30: Perforated layers are 4, 5, and 6

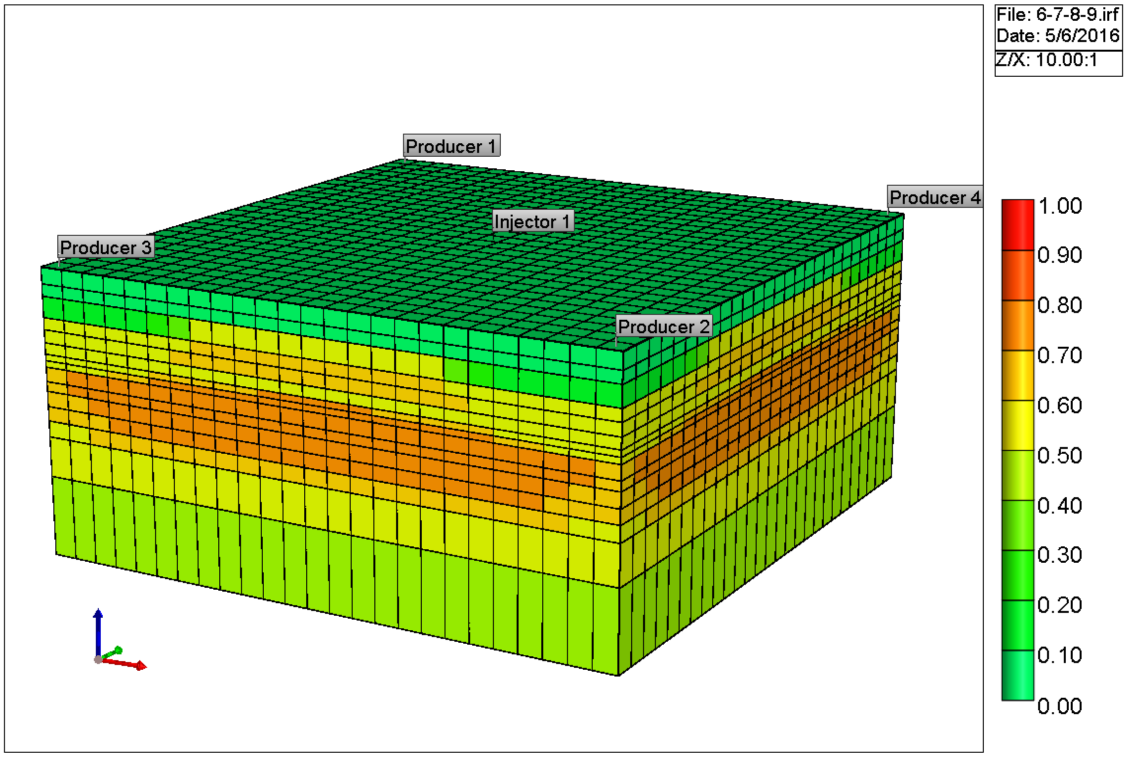

Figure 31: Perforated layers are 7, 8, and 9

Scenario 7

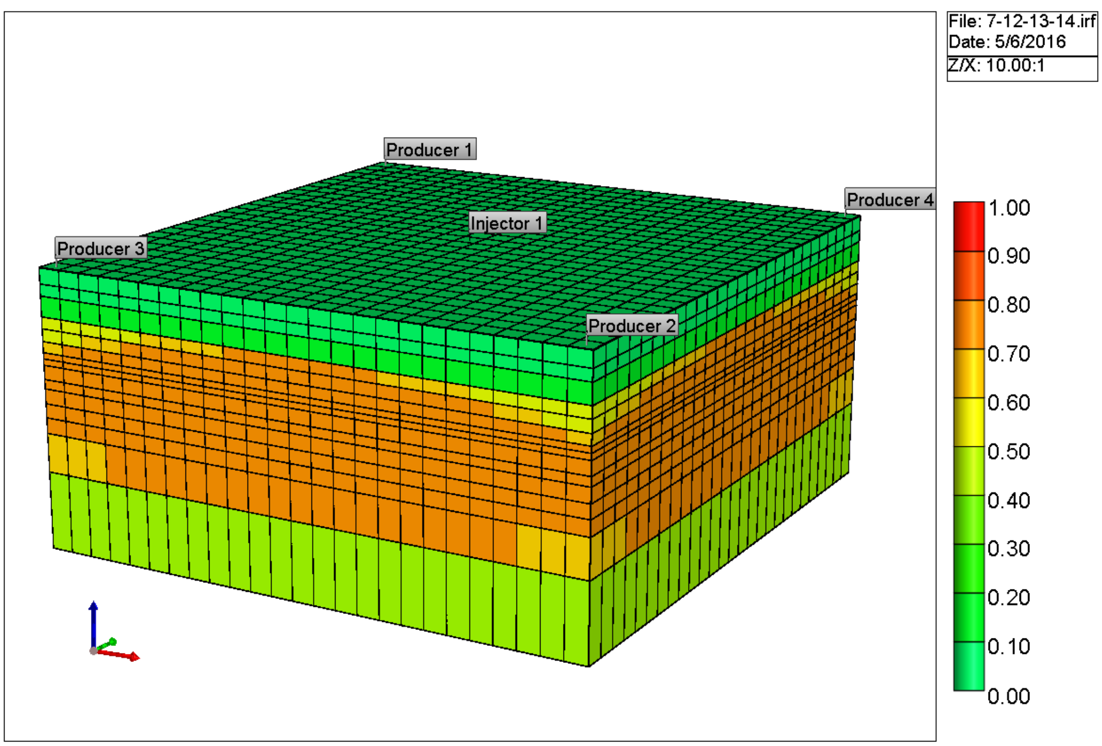

Figure 32: Perforated layers are 12, 13, and 14

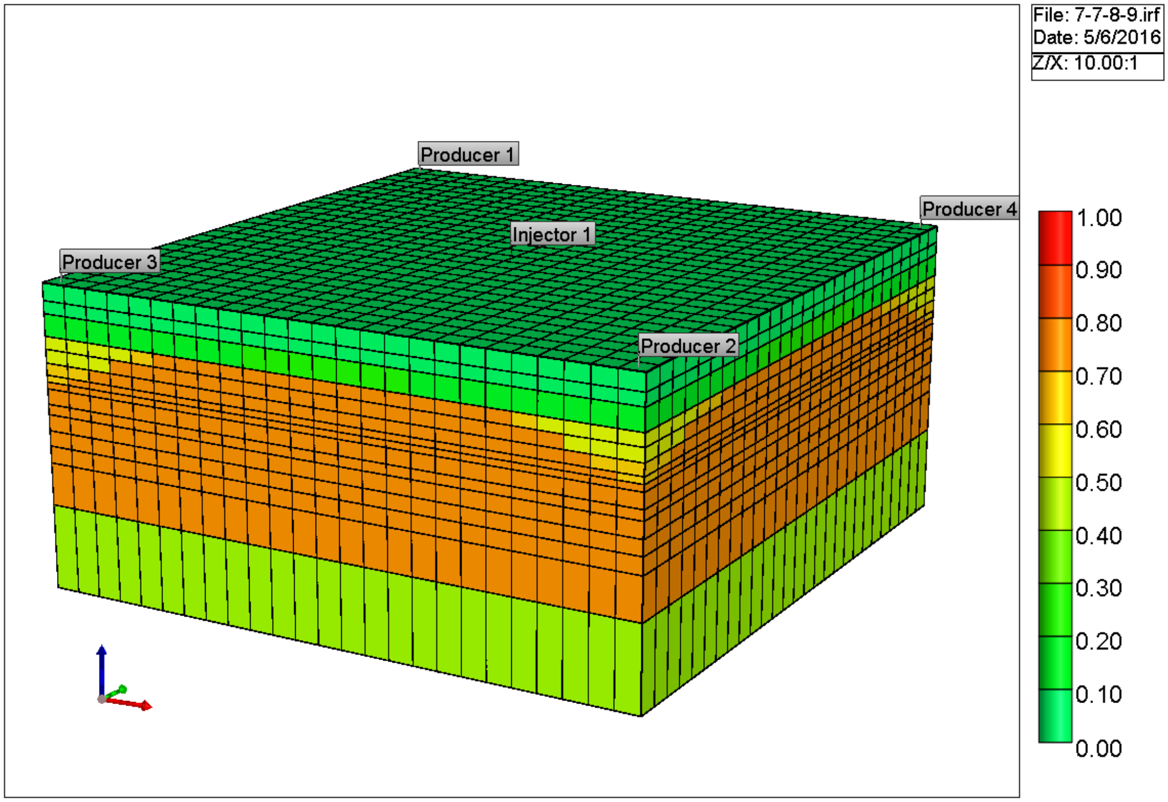

Figure 33: Perforated layers are 7, 8, and 9

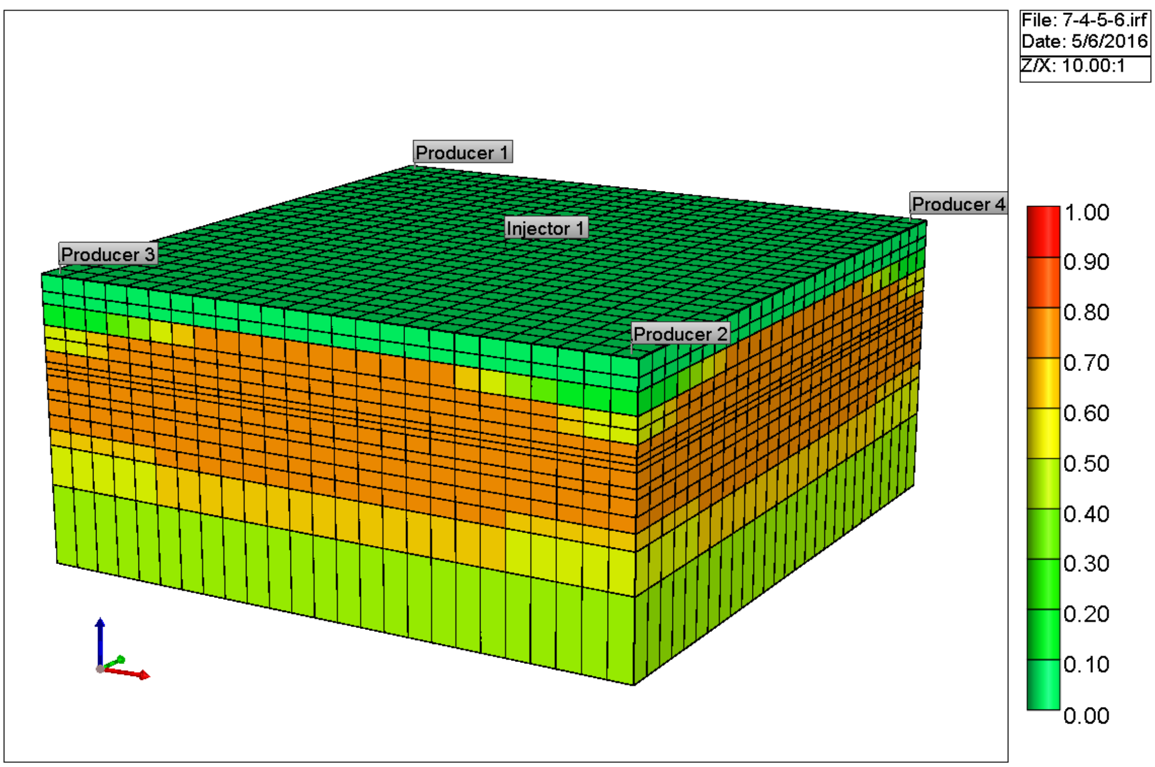

Figure 34: Perforated layers are 4, 5, and 6

Scenario 8

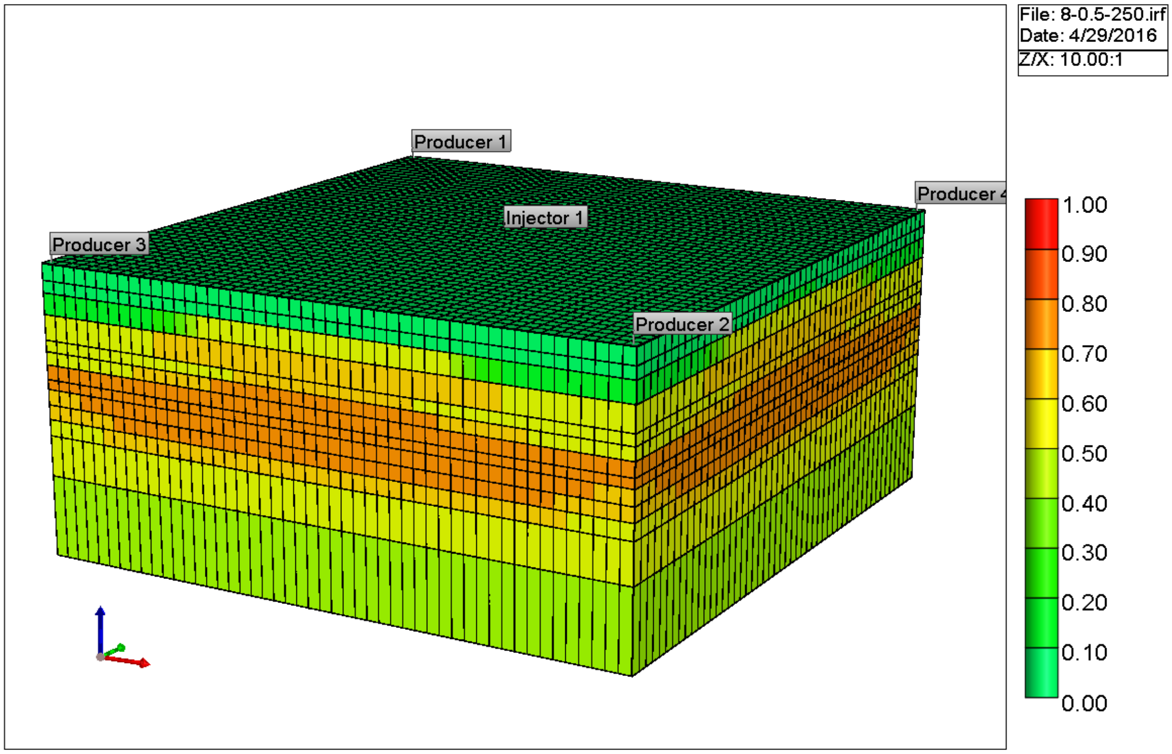

Figure 35: Injection rate is 250 bbl/day

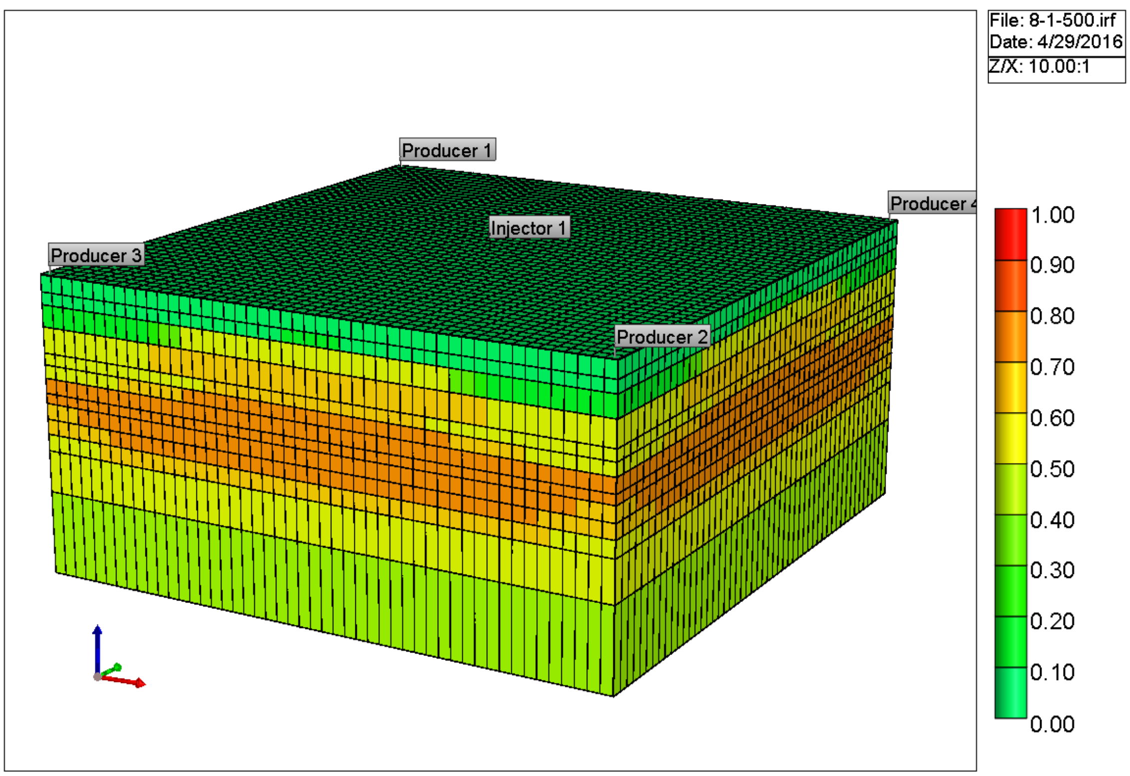

Figure 36: Injection rate is 500 bbl/day

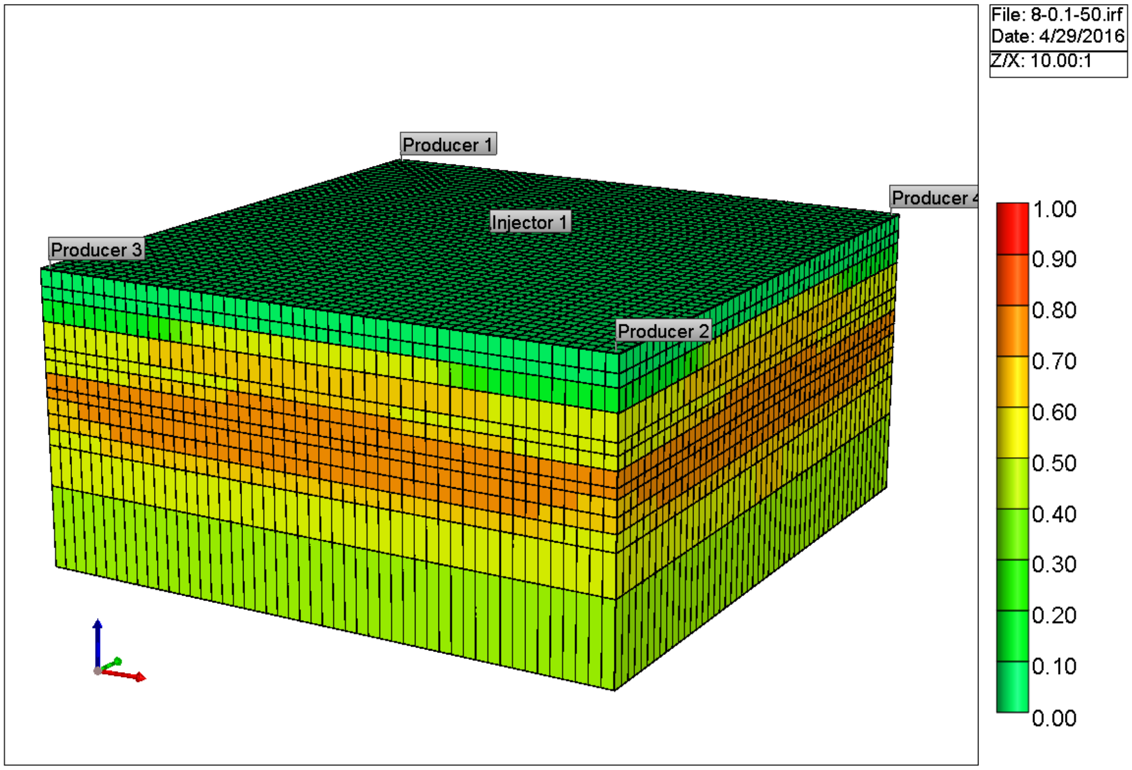

Figure 37: Injection rate is 50 bbl/day

Scenario 9

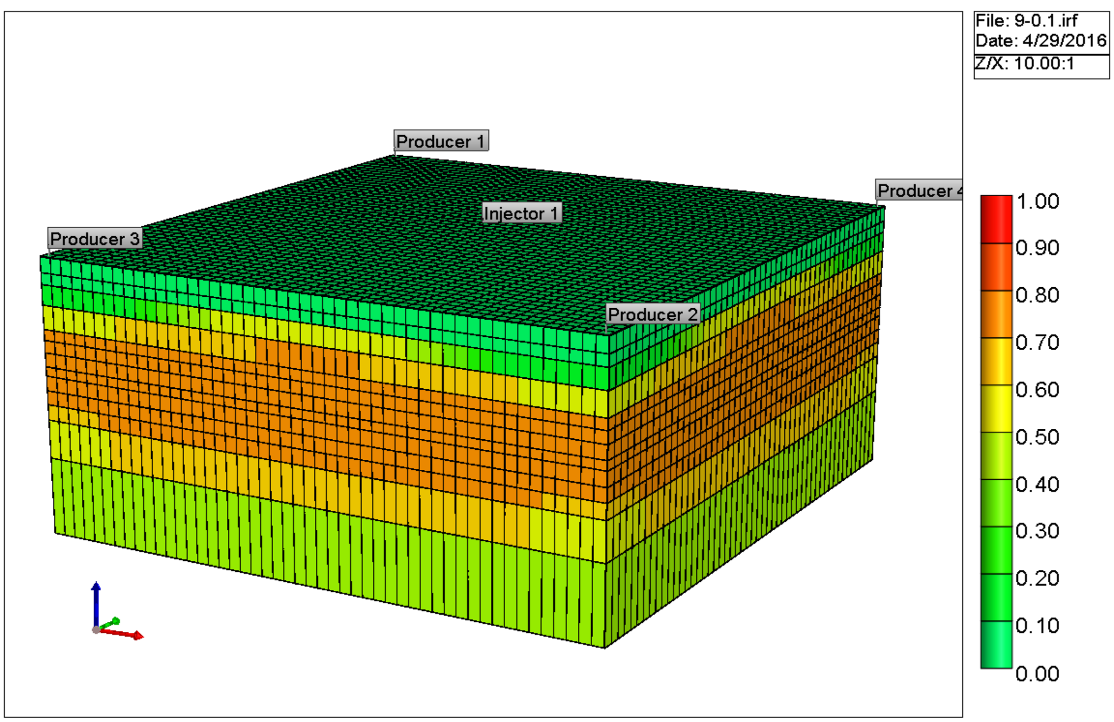

Figure 38: Injection rate is 100 bbl/day

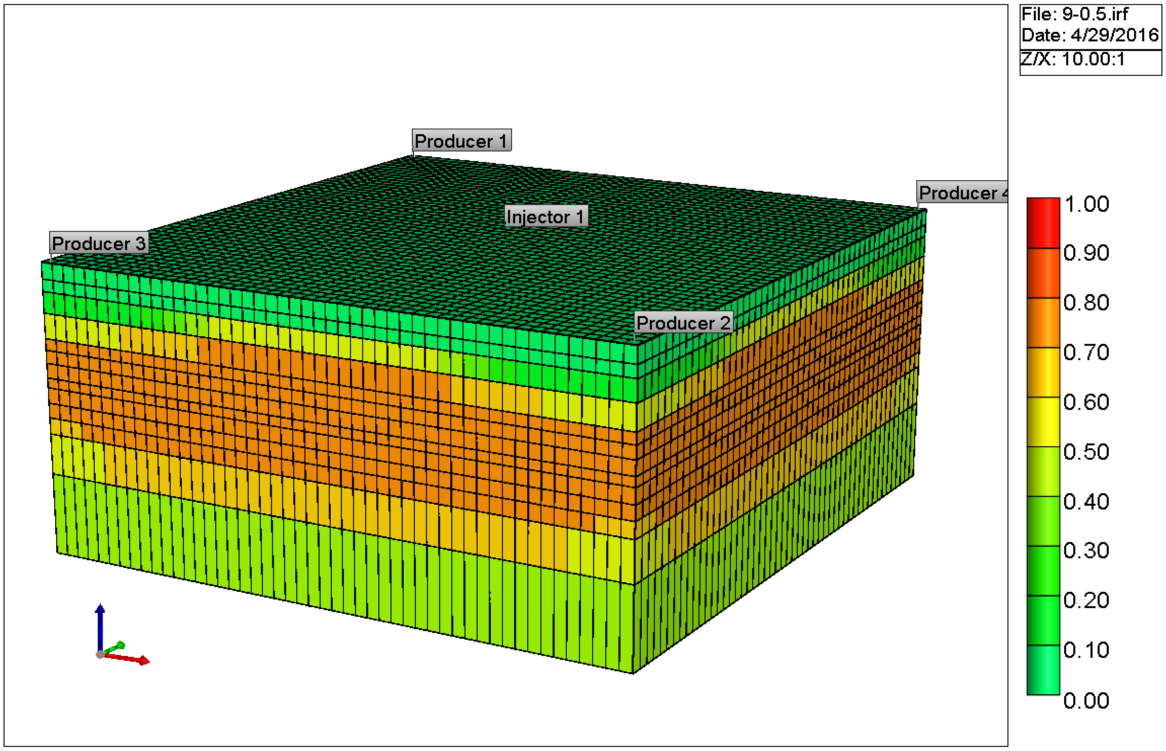

Figure 39: Injection rate is 500 bbl/day

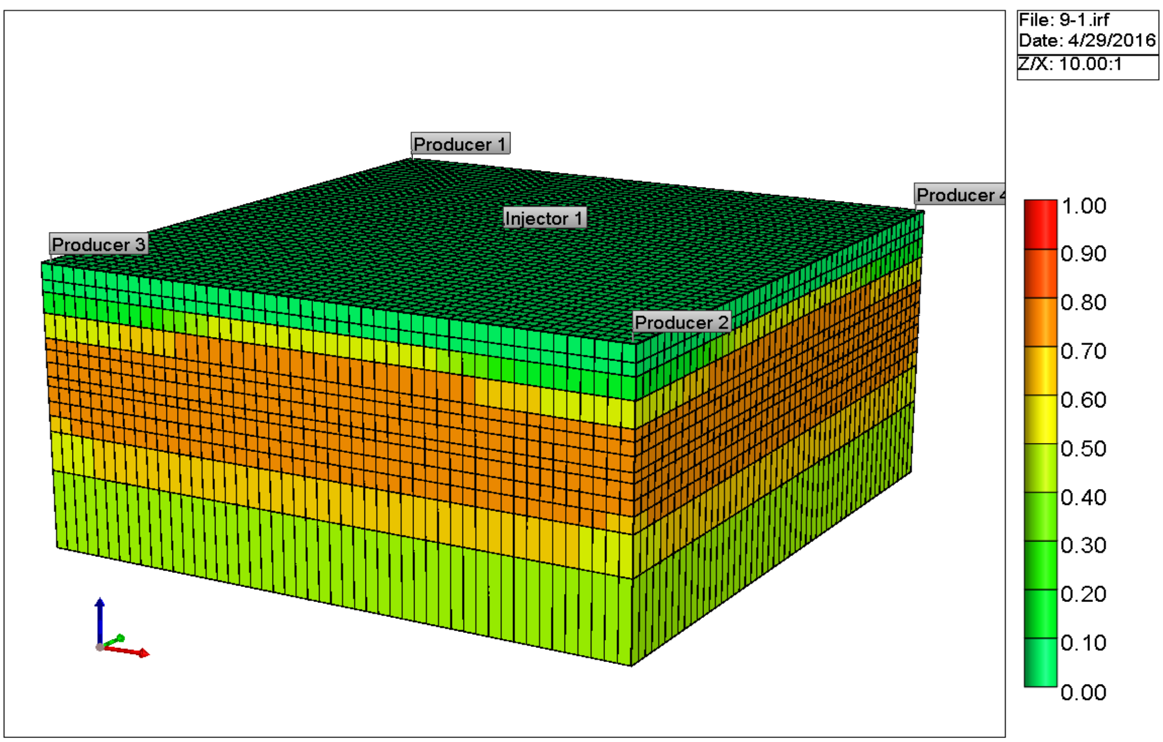

Figure 40: Injection rate is 1000 bbl/day

Scenario 10

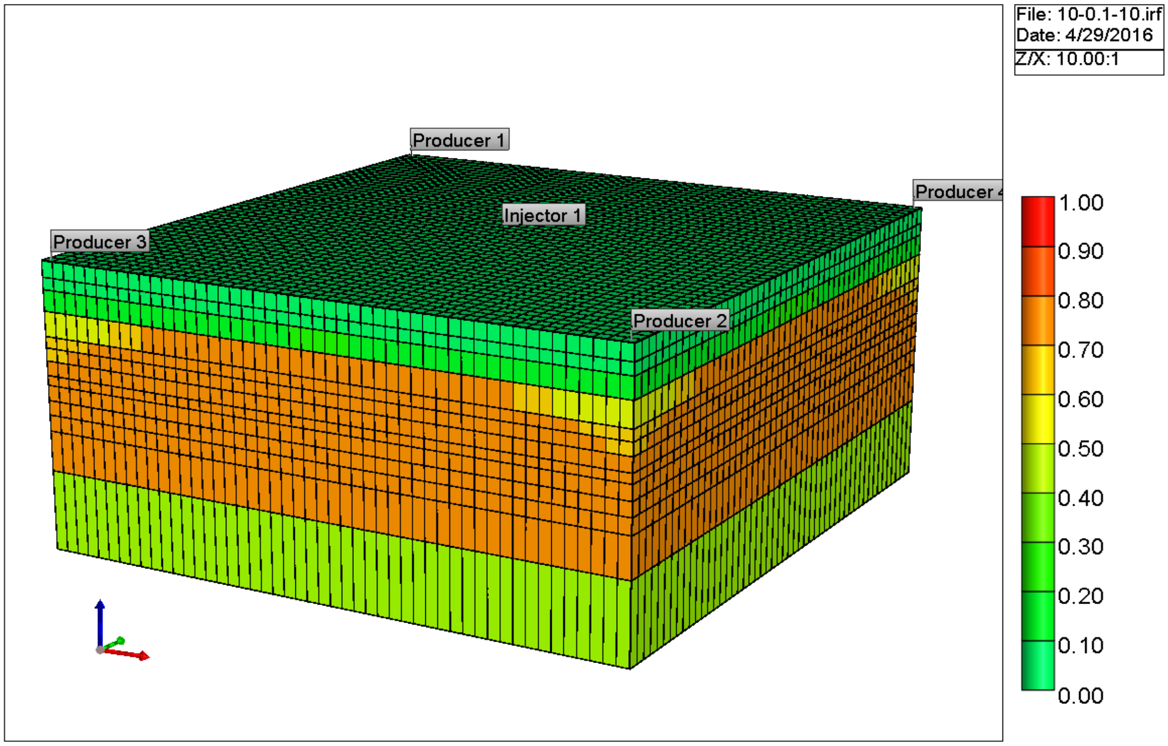

Figure 41: Injection rate is 10 bbl/day

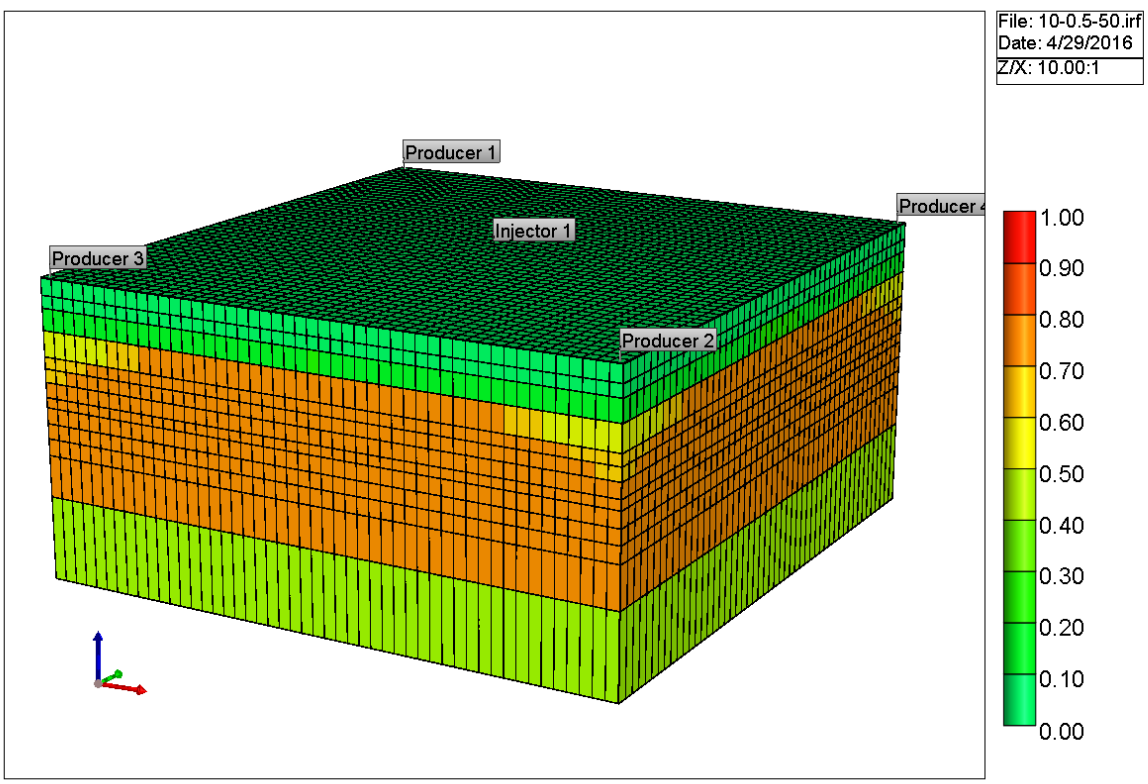

Figure 42: Injection rate is 50 bbl/day

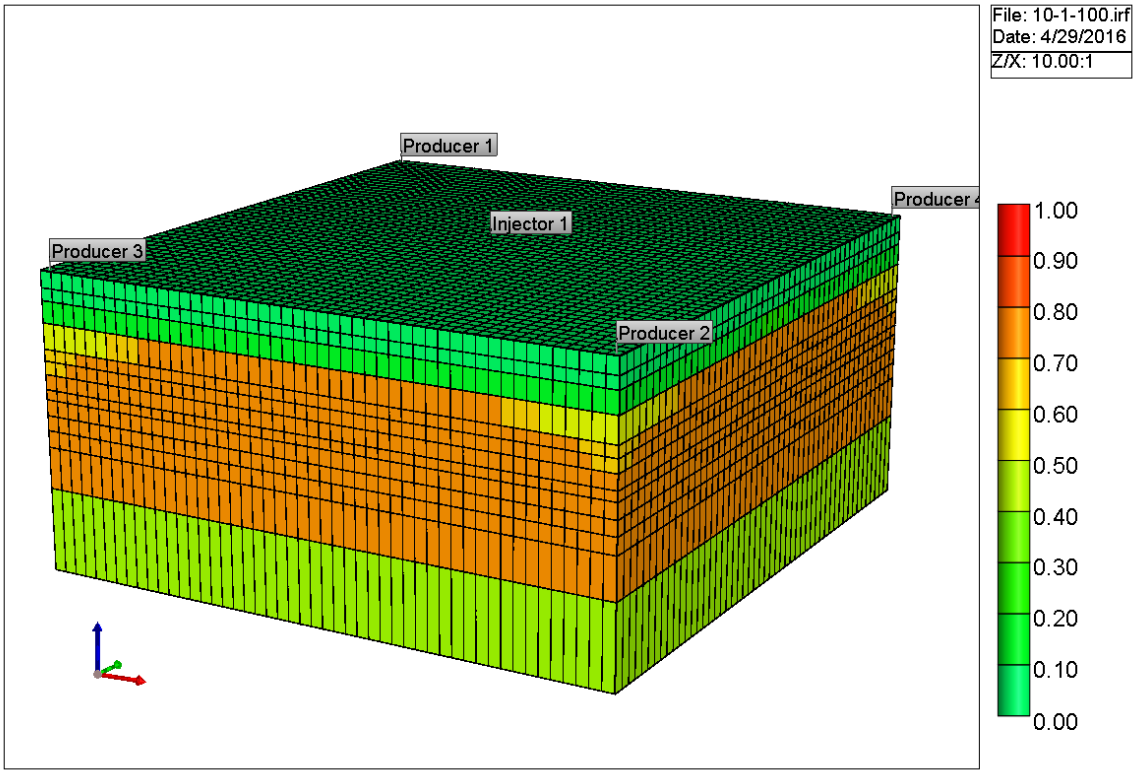

Figure 43: Injection rate is 100 bbl/day

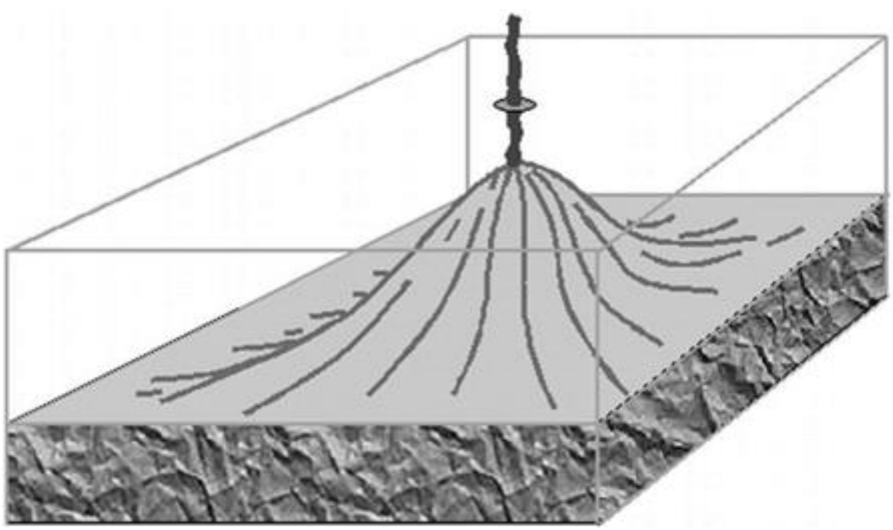

Figure 44: Coning for vertical well (Petrowiki. 2015. Water and gas coning)

Appendix of Tables

Table 1: Reservoir Properties

Layer sequence	Top depth (ft)	Permeability x direction (md)	Porosity	Thickness (ft)
1	9000	66	0.087	20
2		473	0.097	15
3		238	0.111	26
4		25	0.16	15
5		20	0.13	16
6		163	0.17	14
7		71	0.17	8
8		61	0.08	8
9		180	0.14	18
10		113	0.13	12
11		63	0.12	19
12		28	0.105	18
13		20	0.12	20
14		24	0.116	50
15		71	0.157	100

Table 2: The reservoir properties after the layers were combined

Layer sequence	Top depth (ft)	Permeability x direction (md)	Porosity	Thickness (ft)
1	9000	66	0.087	20
2		473	0.097	15
3		238	0.111	26
4		22.42	0.145	31
5		163	0.17	14
6		66	0.125	16
7		180	0.14	18
8		113	0.13	12
9		63	0.12	19
10		28	0.105	18
11		20	0.12	20
12		24	0.116	50
13		71	0.157	100

Table 3: All CMG inputs

Senario	# of grids in x direction	# of grids in y direction	# of grids between P and I in x direction	# of grids between P and I in y direction	distance between P and I	OOIP MSTB	OGIP MMSCF	OWIP MSTB
	25	27	23	25	4998.39	238770	394256	146822
	production rate/well	injection rate bbl/day	water breakthrough (yrs)	perforation layers	RF in 5 years 1985-1-1	RF by 10 years 1990-1-1	RF by 15 years 1995-1-1	RF by 30 years 2010-1-1
1-100	100	0	6.09	9,10,11	0.31%	0.61%	0.92%	1.84%
1-1000	1000	0	6.09	9,10,11	3.06%	3.87%	3.87%	3.87%
1-500	500	0	6.17	9,10,11	1.53%	3.06%	4.59%	9.15%
2-0.1	500	50	6.09	9,10,11	1.53%	3.06%	4.59%	5.79%
2-0.5	500	250	0.00	9,10,11	1.53%	3.06%	4.59%	5.89%
2-1	500	500	0.00	9,10,11	1.53%	3.06%	4.59%	6.04%
3-0.1	1000	100	0.00	7,8,9	3.06%	3.87%	3.87%	3.87%
3-0.5	1000	500	0.00	7,8,9	3.06%	3.97%	3.97%	3.97%
3-1	1000	1000	0.00	7,8,9	3.06%	4.03%	4.03%	4.03%
4-0.1	100	10	0.00	7,8,9	0.31%	0.61%	0.92%	1.84%
4-0.5	100	50	12.01	7,8,9	0.31%	0.61%	0.92%	1.84%
4-1	100	100	11.92	7,8,9	0.31%	0.61%	0.92%	1.84%
5-1	1000	0	11.76	12,13,14	0.20%	0.20%	0.20%	0.20%
5-2	1000	0	0.00	4,5,6	0.71%	0.71%	0.71%	0.71%
5-3	1000	0	0.00	7,8,9	3.06%	3.26%	3.26%	3.26%
6-1	500	0	1.09	12,13,14	1.44%	2.76%	3.88%	3.88%
6-2	500	0	16.43	4,5,6	1.53%	1.99%	1.99%	1.99%
6-3	500	0	0.00	7,8,9	1.53%	3.06%	4.59%	5.12%
7-1	100	0	0.16	12,13,14	0.30%	0.60%	0.89%	1.74%
7-2	100	0	0.00	4,5,6	0.31%	0.61%	0.92%	1.84%
7-3	100	0	0.00	7,8,9	0.31%	0.61%	0.92%	1.84%
8-0.1-50	500	50	0.08	7,8,9	1.53%	3.06%	4.58%	5.11%
8-0.5-250	500	250	0.00	7,8,9	1.53%	3.06%	4.58%	5.19%
8-1-500	500	500	0.00	7,8,9	1.53%	3.06%	4.58%	5.31%
9-0.1	1000	100	0.00	7,8,9	3.06%	3.16%	3.16%	3.16%
9-0.5	1000	500	12.68	7,8,9	3.06%	3.21%	3.21%	3.21%
9-1	1000	1000	12.93	7,8,9	3.06%	3.26%	3.26%	3.26%
10-0.1-10	100	10	13.17	7,8,9	0.31%	0.61%	0.92%	1.83%
10-0.5-50	100	50	17.01	7,8,9	0.31%	0.61%	0.92%	1.83%
10-1-100	100	100	0.00	7,8,9	0.31%	0.61%	0.92%	1.83%