Does injection sequence matter: A simulation study of chemical enhanced oil recovery processes

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Abstract

In this study, CMG STARS was employed to simulate the experimental results conducted by Surtek in the lab, specifically focusing on a linear core flooding using alkaline, surfactant, polymer, and their combinations in different sequences to enhance oil recovery in the Warner Field.

To begin with, experimental data, including essential core and reservoir information, oil and chemical properties, injection schemes, chemical adsorption data, interfacial tension (IFT) data, relative permeability data, and oil production data was extracted from the Surtek report.

Subsequently, a comprehensive step-by-step procedure detailing the construction of the simulation model in CMG was described. This paper then presented the simulation data, followed by a comparison with the experimental data. The oil cut based on simulation results was plotted as well. It was found that there was improvement in oil cut when the chemicals were applied. It is noteworthy that, to achieve a better match with the experimental data, it was necessary to modify the relative permeability curve and chemical adsorption data. After matching the experimental data, sensitivity analysis was conducted by using the tuned simulation model. Specifically, the order of the ASP injection was modified by placing the ASP slug 3 with a lower polymer concentration ahead of ASP slug 1. A notable decrease in the oil production was found in the early stage but a higher final recovery factor was achieved in this injection strategy.

This study reports a successful alignment between the simulation and experimental data. The sensitivity analysis using the predictions of the simulation model suggests the injection sequence is important in the chemical EOR processes. Depending on the priority of a high recovery rate or a high final recovery factor, a certain injection sequence may be selected for practical applications.

Keywords: Chemical EOR; ASP Flooding; Reservoir Simulation; CMG; History Matching; Injection strategy

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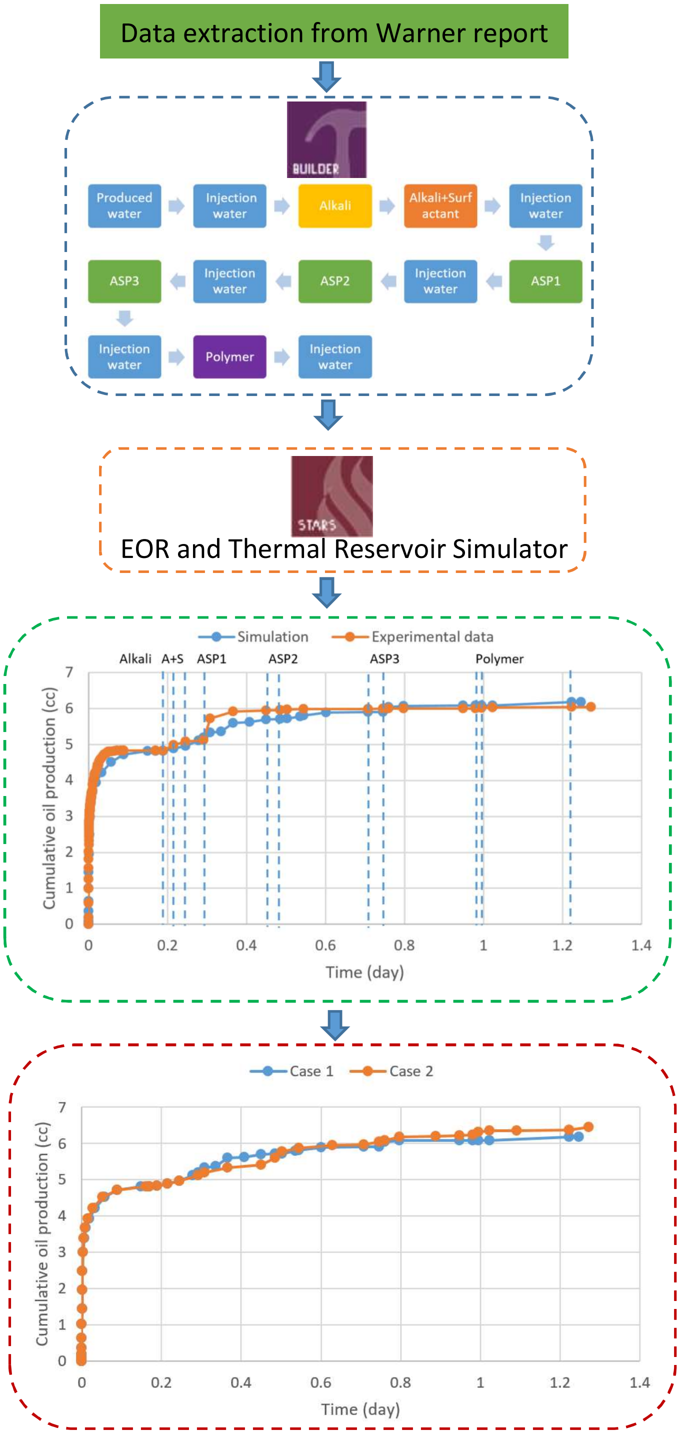
Graphical Abstract



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0. Problem statement

Surtek undertook comprehensive laboratory assessments of alkaline-surfactant-polymer (ASP) injection at the Warner Field in Alberta, encompassing 6 linear and 14 radial corefloods as detailed in the report. Our assignment entailed conducting a simulation study to match one of the experimental results with historical production data by tuning simulation parameters.

For this endeavor, I opted for the analysis of experiment 6L, a linear coreflood experiment. I meticulously extracted pertinent experimental data, incorporating reservoir and core details, reservoir fluid properties, injection schemes, and production data from the comprehensive report. Subsequently, utilizing CMG STARS, an advanced EOR and thermal simulator, I constructed a simulation model.

Through adjustments of the parameters, a commendable history match of the experimental results was achieved. Following this successful calibration, the model was leveraged to scrutinize the impact of the injection sequence for sensitivity analysis.

1. Data extraction from the Warner report

1.1 Reservoir information

1.1.1 Reservoir condition

The core was collected from well 00/16-20-007-16W4 in the Warner Field in Alberta. The reservoir temperature and experimental temperature were both 35°C. The pressure indicated in Table 1 is the experimental pressure, not the reservoir pressure.

Table 1. Well and reservoir condition.

Field	Pressure (kPa)	Temperature (°C)	Depth (ft)	Well #
Warner	100	35	3236.1	00/16-20-007-16W4

1.1.2 Core information

This was a linear core flooding experiment (6L) and core diameter was small (2.47cm). Other information of the core can be found in Table 2.

Table 2. Dimension and other information of the core used in the experiment.

Length (cm)	Diameter (cm)	Porosity	Permeability (Darcy)	Soi	OOIP (cc)
8.26	2.47	0.256	2.26	0.807	8.21

1.2 Reservoir fluids

1.2.1 Oil and water properties at 35°C

Warner reservoir crude oil was diluted with7.3% white gas and the viscosity after dilution was 52 cP. The viscosity of the produced water was the same (0.69 cP) as the injection water.

Table 3. Densities and viscosities of the oil and water.

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Fluid	Density (g/cc)	Viscosity (cP)
Oil	0.9238	52
Water	0.9972	0.69

1.2.2 Relative permeability

The oil-water relative permeability can be found in Table 5.1.1.6 in the Warner report and is presented in Table 4 in this report.

Table 4. Oil-water relative permeability.

Sw	Kro	Krw	Kw/Ko
0.193	1	0	0
0.209	0.844	0.001	0.002
0.422	0.168	0.024	0.139
0.472	0.103	0.033	0.319
0.543	0.045	0.045	1.004
0.582	0.033	0.055	1.645
0.622	0.019	0.076	4.012
0.658	0.005	0.116	24.933
0.668	0	0.151	---

1.2.3 Chemical properties

The surfactant used was a sulfonate ORS-97HF from OCT. Conventional alkali sodium hydroxide was used as the alkali. Flopaam 3630S, a partially hydrolysed polyacrylamide (HPAM) was used as the polymer. The viscosity of the polymer under different concentrations can be found in Table 6. The adsorption data of the chemicals are listed in Table 7.

Table 5. Properties of the chemicals used in the experiment.

Fluid	Chemical	Concentration (%)	MW
Surfactant	ORS-97HF	0.1	
Alkali	NaOH	1	
Polymer	Flopaam 3630S	0.05-0.15	19000

Table 6. Polymer viscosity with concentration

Concentration (%)	0.05	0.1	0.15
Viscosity (cP)	4.2	10.8	22.1

Table 7. Adsorption data of the chemicals.

Process	Time (days)	Alkali	Surfactant	Polymer
Polymer flooding	0			4
	1			2.6
	4			5.6
	7			6.1
	20			4.6

ASP flooding	0	36.9	72.8	
	1	41.4	73.2	
	4	53.2	77	
	7	64.5	77.6	
	20	76.4	79.2	

1.2.4 IFT

The IFT data of the surfactant and alkaline solutions can be found in Table 8. Note, polymer doesn't alter the IFT much so its effect is not considered.

Table 8. The IFT data of the surfactant and alkaline solutions.

	Weight % Alkaline	IFT, (dyne/cm)
Surfactant wt. % = 0	0	15
	0.3	0.241
	0.5	0.176
	0.75	0.432
	1	0.496
	1.25	0.566
	1.5	0.708
	1.75	0.729
Surfactant wt. % = 0.1	0	0.587
	0.3	0.014
	0.5	0.002
	0.75	0.01
	1	0.035

1.3 Injection scheme

The injection rate can be found in Table 5.3.1.6 in the report. The injection end time was determined from the produced volume data in this table. It should be mentioned that the unit of the produced volume was PV instead of cc. After the calculation, the injected fluid, rate and injection end time are presented in Table 9.

Table 9. The injected fluid, rate and injection end time.

Injected fluid	Rate (ft/d)	Injection end time (day)
Produced water	18.03	0.089446951
	10.48	0.169645905
Injection water	10.48	0.189247141
Alkali	10.48	0.215359973
AS	10.48	0.245525942
Injection water	10.48	0.291970904
ASP1	10.48	0.307651893
	3.74	0.366673411
	1.12	0.449985781
Injection water	10.48	0.485135115

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ASP2	10.48	0.503407453
	3.74	0.544368759
	1.12	0.708506563
Injection water	10.48	0.746247247
ASP3	10.48	0.759602666
	3.74	0.797957343
	1.12	0.948416997
Injection water	10.48	0.980576312
Polymer	10.48	0.994928403
	3.74	1.02341513
	1.12	1.222991778
Injection water	10.48	1.272360313

1.3.1 Alkali injection

The alkali (1 wt% NaOH) was injected after the initial water flooding. Because mole fraction is needed in STARS and we only have the weight percentage data in the report, a conversion is needed. The excel file provided by Dr. Trivedi was used for the conversion.

Table 10. Conversion of the alkali mole fraction.

Name	Mw	Lab. Inj. Composition	Units	STARS Inj. Composition
'Water'	0.018015	99.000	Wt%	0.995471359
'Polymer'	19000	0.0	PPM	0
'Surfact'	0.29941	0.000	Wt%	0
'Alkaline'	0.04	1.000	Wt%	0.004528641
'Dead_Oil'	0.4	0.000	Wt%	0

1.3.2 Alkali+Surfactant injection

Alkali (1 wt% NaOH) and Surfactant (0.1 wt% ORS-97HF) mixture was injected after the alkali injection.

Table 11. Conversion of the Alkali+Surfactant from weight fraction to mole fraction.

Name	Mw	Lab. Inj. Composition	Units	STARS Inj. Composition
'Water'	0.018015	98.900	Wt%	0.995406518
'Polymer'	19000	0.0	PPM	0
'Surfact'	0.29941	0.100	Wt%	6.05581E-05
'Alkaline'	0.04	1.000	Wt%	0.004532924
'Dead_Oil'	0.4	0.000	Wt%	0

1.3.3 ASP slug 1 injection

Water flooding was conducted after Alkali+Surfactant injection, and an ASP slug was followed. The ASP slug 1 includes 1.0 wt% NaOH, 0.1 wt% ORS-97HF and 1500 mg/L Flopaam 3630S.

Table 12. Conversion of the ASP slug 1 from weight fraction to mole fraction.

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Name	Mw	Lab. Inj. Composition	Units	STARS Inj. Composition
'Water'	0.018015	98.750	Wt%	0.995399571
'Polymer'	19000	1500.0	PPM	1.43361E-09
'Surfact'	0.29941	0.100	Wt%	6.06497E-05
'Alkaline'	0.04	1.000	Wt%	0.004539778
'Dead_Oil'	0.4	0.000	Wt%	0

1.3.4 ASP slug 2 injection

This ASP slug includes 1.0 wt% NaOH, 0.1 wt% ORS-97HF and 1000 mg/L Flopaam 3630S. The only difference is the concentration of the polymer.

Table 13. Conversion of the ASP slug 2 from weight fraction to mole fraction.

Name	Mw	Lab. Inj. Composition	Units	STARS Inj. Composition
'Water'	0.018015	98.800	Wt%	0.995401889
'Polymer'	19000	1000.0	PPM	9.55261E-10
'Surfact'	0.29941	0.100	Wt%	6.06191E-05
'Alkaline'	0.04	1.000	Wt%	0.004537491
'Dead_Oil'	0.4	0.000	Wt%	0

1.3.5 ASP slug 3 injection

A lower concentration of polymer (500 mg/L Flopaam 3630S) was used in this slug.

Table 14. Conversion of the ASP slug 3 from weight fraction to mole fraction.

Name	Mw	Lab. Inj. Composition	Units	STARS Inj. Composition
'Water'	0.018015	98.850	Wt%	0.995404204
'Polymer'	19000	500.0	PPM	4.7739E-10
'Surfact'	0.29941	0.100	Wt%	6.05886E-05
'Alkaline'	0.04	1.000	Wt%	0.004537491
'Dead_Oil'	0.4	0.000	Wt%	0

1.3.6 Polymer injection

Polymer injection (1000 mg/L Flopaam 3630S) was conducted to further improve the oil recovery.

Table 15. Conversion of the polymer slug from weight fraction to mole fraction.

Name	Mw	Lab. Inj. Composition	Units	STARS Inj. Composition
'Water'	0.018015	99.900	Wt%	0.999999999
'Polymer'	19000	1000.0	PPM	9.49107E-10
'Surfact'	0.29941	0.000	Wt%	0
'Alkaline'	0.04	0.000	Wt%	0
'Dead_Oil'	0.4	0.000	Wt%	0

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1.4 Production data

The production data include two parts. The water flooding data can be found in Table 5.1.3.6 and the chemical flooding data can be determined from Table 5.3.1.6 in the Warner report. The oil production during chemical flooding was calculated from the oil saturation data with the injection rate.

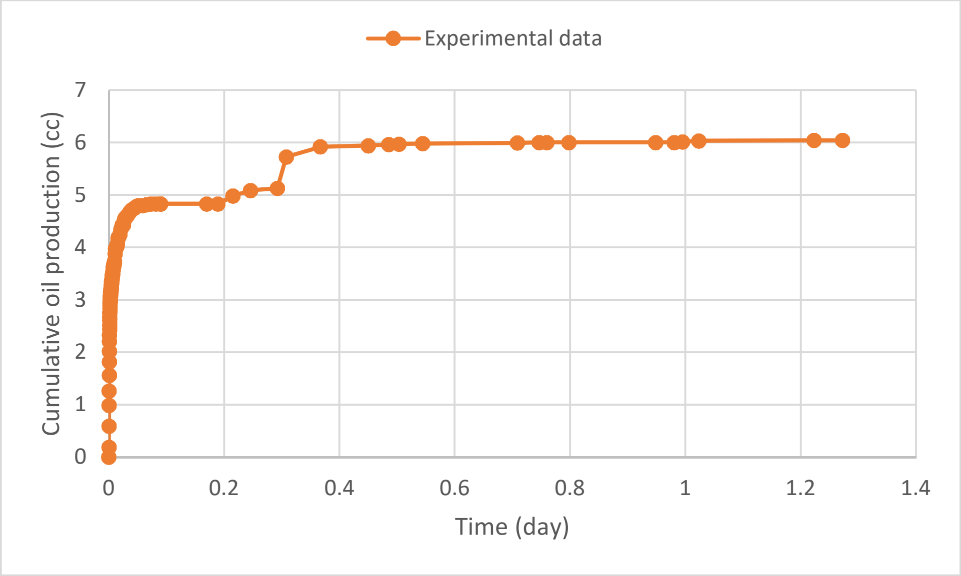
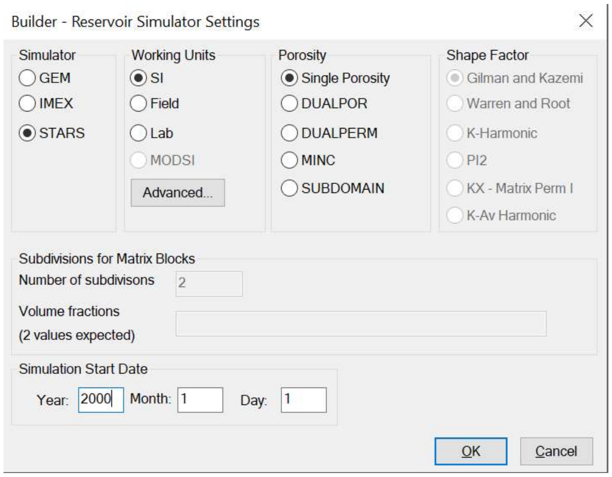


Figure 1. The cumulative oil production in the experiment.

2. Simulation model in CMG STARS

Reservoir Simulator Settings

I used the STARS model as this was a chemical EOR process. SI unit was selected and the unit used in the experiment (such as cm) should be converted into SI unit.



Builder - Reservoir Simulator Settings

Simulator
○ GEM
○ IMEX
● STARS

Working Units
● SI
○ Field
○ Lab
○ MODSI

Porosity
● Single Porosity
○ DUALPOR
○ DUALPERM
○ MINC
○ SUBDOMAIN

Shape Factor
● Gilman and Kazemi
○ Warren and Root
○ K-Harmonic
○ PI2
○ KX - Matrix Perm I
○ K-Av Harmonic

Subdivisions for Matrix Blocks
Number of subdivisons: 2
Volume fractions (2 values expected):

Simulation Start Date
Year: 2000 Month: 1 Day: 1

Figure 2. Reservoir simulator settings.

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Grid Properties

Because the Cartesian coordinate was selected and the core is cylindrical, we need to obtain an equivalent length in the j direction for which the cross sectional areas are equal.

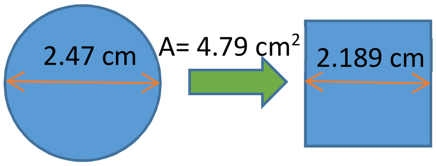
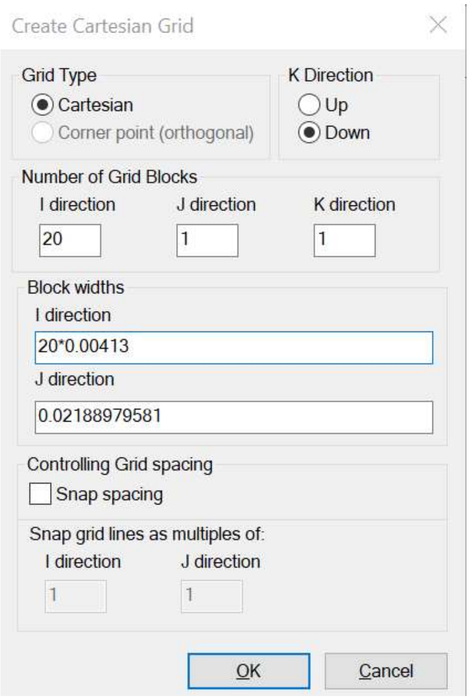


Figure 3. Illustration of the equivalent length.

In the horizontal direction, 20 equally divided grids were created to simulate the linear flooding.



Grid Type
● Cartesian
○ Corner point (orthogonal)

K Direction
○ Up
● Down

Number of Grid Blocks

I direction	J direction	K direction
20	1	1

Block widths
I direction: 20*0.00413
J direction: 0.02188979581

Controlling Grid spacing
☐ Snap spacing

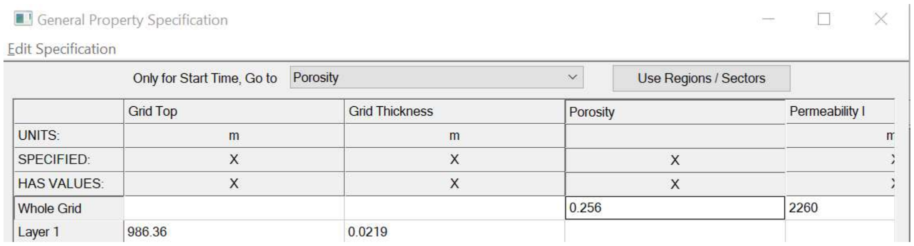
Snap grid lines as multiples of:

I direction	J direction
1	1

Figure 4. Grid created for the simulation.

Reservoir Properties

The reservoir properties, such as grid top, porosity, permeability, were specified using the data collected. Grid thickness was the equivalent length.



Only for Start Time, Go to: Porosity

	Grid Top	Grid Thickness	Porosity	Permeability I
UNITS:	m	m		m
SPECIFIED:	X	X	X	X
HAS VALUES:	X	X	X	X
Whole Grid			0.256	2260
Layer 1	986.36	0.0219		

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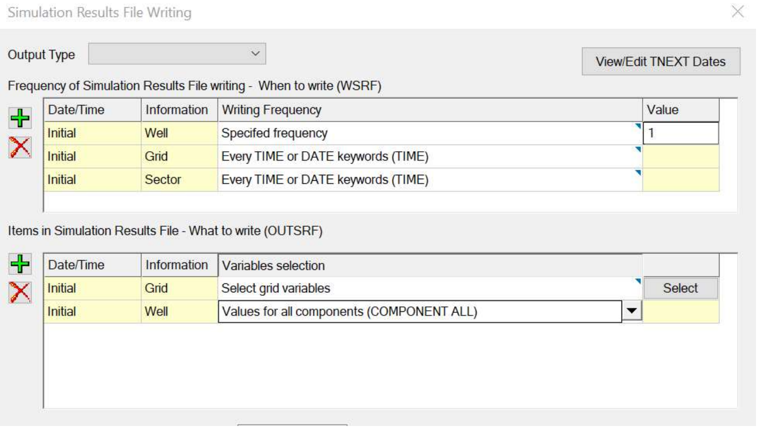
Figure 5. Reservoir properties for the simulation.

I/O Control



Output Type

Frequency of Simulation Results File writing - When to write (WSRF)

Date/Time	Information	Writing Frequency	Value
Initial	Well	Specifed frequency	1
Initial	Grid	Every TIME or DATE keywords (TIME)	
Initial	Sector	Every TIME or DATE keywords (TIME)	

Items in Simulation Results File - What to write (OUTSRF)

Date/Time	Information	Variables selection	
Initial	Grid	Select grid variables	Select
Initial	Well	Values for all components (COMPONENT ALL)	

Figure 6. I/O control for the simulation.

3D view of the Grid Top

After specifying the reservoir properties, a 3D view of the reservoir properties, such as the grip top can be found in Figure 7.

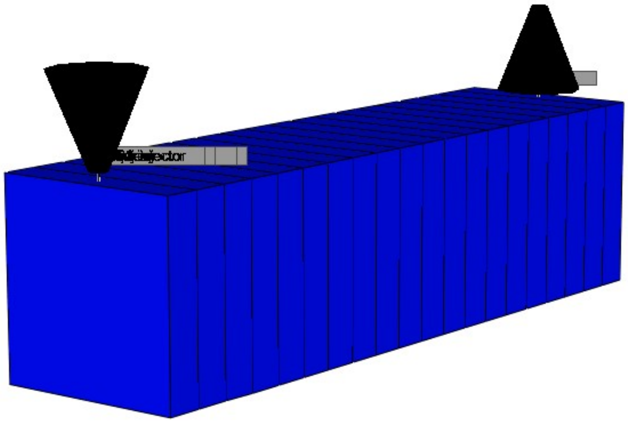


Figure 7. 3D view of the Grid Top.

Component

An aqueous phase and an oleic phase were added in the component section. The densities and viscosities of the two phases were specified in Figures 8 and 9.

The experimental conditions were entered in the General tab in the component section as shown in Figure 10.

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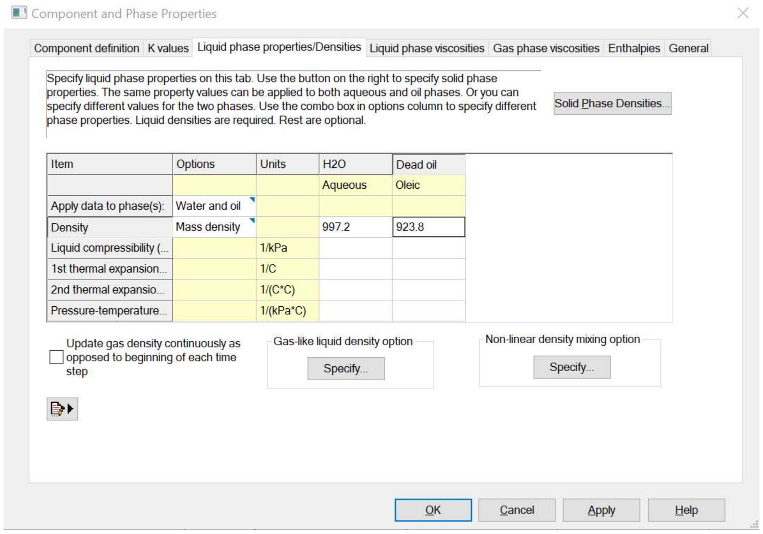
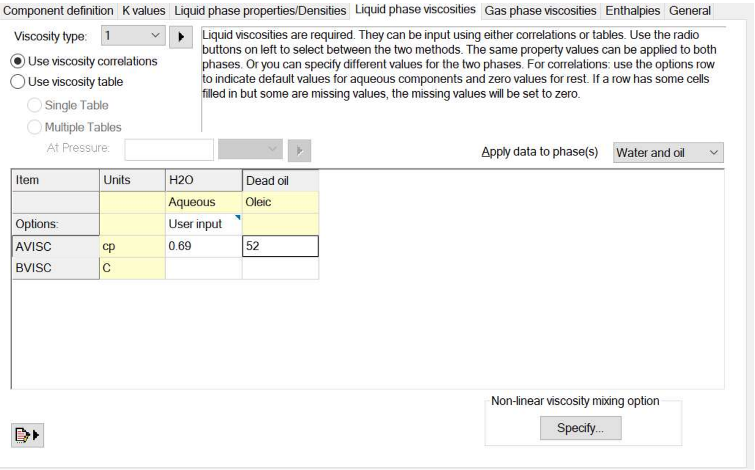


Specify liquid phase properties on this tab. Use the button on the right to specify solid phase properties. The same property values can be applied to both aqueous and oil phases. Or you can specify different values for the two phases. Use the combo box in options column to specify different phase properties. Liquid densities are required. Rest are optional.

Item	Options	Units	H2O	Dead oil
			Aqueous	Oleic
Apply data to phase(s):	Water and oil			
Density	Mass density		997.2	923.8
Liquid compressibility (...		1/kPa		
1st thermal expansion...		1/C		
2nd thermal expansio...		1/(C*C)		
Pressure-temperature...		1/(kPa*C)		

☐ Update gas density continuously as opposed to beginning of each time step

Figure 8. The densities of the two phases.



Viscosity type: 1

● Use viscosity correlations

○ Use viscosity table

○ Single Table

○ Multiple Tables

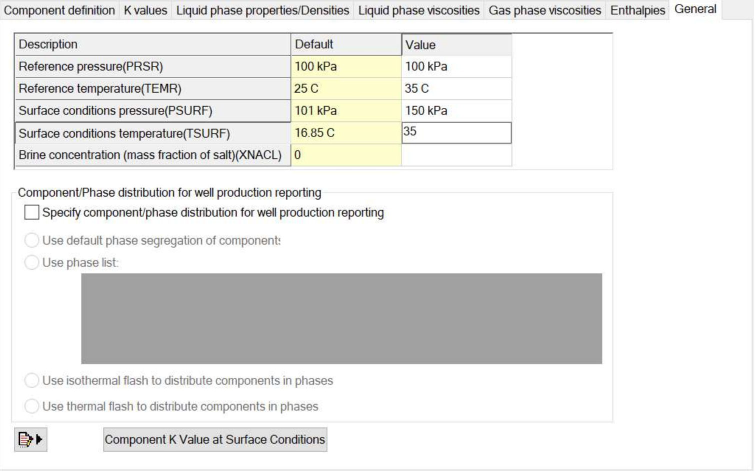
At Pressure:

Liquid viscosities are required. They can be input using either correlations or tables. Use the radio buttons on left to select between the two methods. The same property values can be applied to both phases. Or you can specify different values for the two phases. For correlations: use the options row to indicate default values for aqueous components and zero values for rest. If a row has some cells filled in but some are missing values, the missing values will be set to zero.

Apply data to phase(s) Water and oil

Item	Units	H2O	Dead oil
		Aqueous	Oleic
Options:		User input	
AVISC	cp	0.69	52
BVISC	C		

Figure 9. The viscosities of the two phases.



Description	Default	Value
Reference pressure(PRSR)	100 kPa	100 kPa
Reference temperature(TEMR)	25 C	35 C
Surface conditions pressure(PSURF)	101 kPa	150 kPa
Surface conditions temperature(TSURF)	16.85 C	35
Brine concentration (mass fraction of salt)(XNACL)	0	

Component/Phase distribution for well production reporting

☐ Specify component/phase distribution for well production reporting

○ Use default phase segregation of component:

○ Use phase list:

○ Use isothermal flash to distribute components in phases

○ Use thermal flash to distribute components in phases

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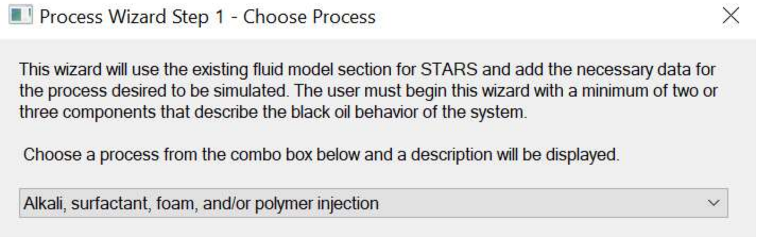
Figure 10. Experimental conditions in the simulator.

Process wizard was used for ASP injection. There were 9 steps for the process wizard. First step was the selection of the process which was “Alkali, surfactant, foam, and/or polymer injection” in our case (Figure 11).



Process Wizard Step 1 - Choose Process

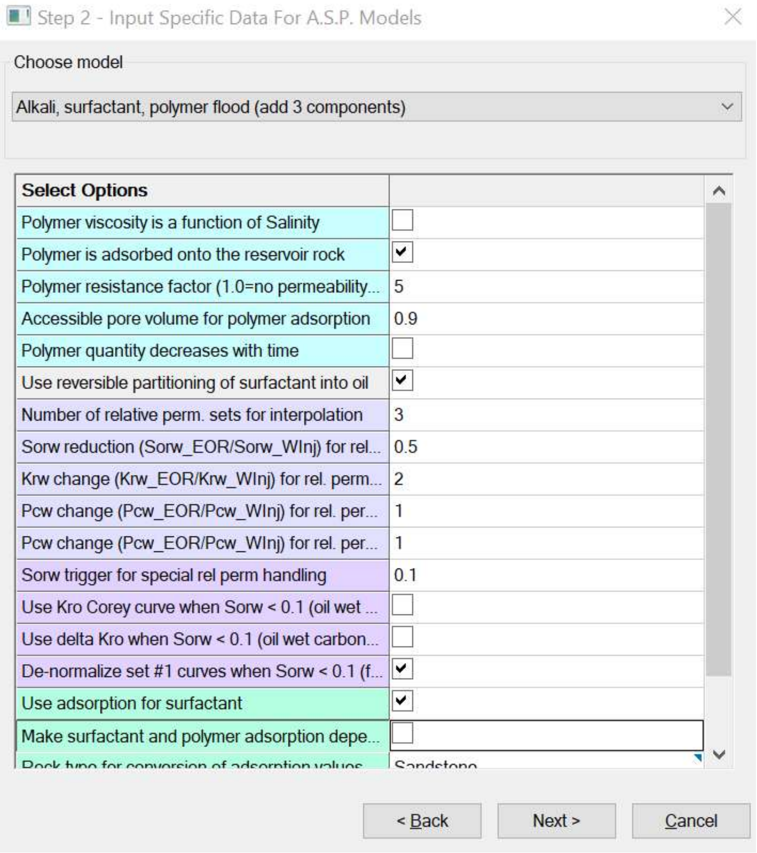
This wizard will use the existing fluid model section for STARS and add the necessary data for the process desired to be simulated. The user must begin this wizard with a minimum of two or three components that describe the black oil behavior of the system.

Choose a process from the combo box below and a description will be displayed.

Alkali, surfactant, foam, and/or polymer injection

Figure 11. Process selection in the Process Wizard.

3 components (Alkali, surfactant and polymer) were added in steps 2 and 3 where polymer and surfactant adsorptions were selected (Figures 12 and 13).



Step 2 - Input Specific Data For A.S.P. Models

Choose model

Alkali, surfactant, polymer flood (add 3 components)

Select Options	
Polymer viscosity is a function of Salinity	☐
Polymer is adsorbed onto the reservoir rock	☑
Polymer resistance factor (1.0=no permeability...	5
Accessible pore volume for polymer adsorption	0.9
Polymer quantity decreases with time	☐
Use reversible partitioning of surfactant into oil	☑
Number of relative perm. sets for interpolation	3
Sorw reduction (Sorw_EOR/Sorw_WInj) for rel...	0.5
Krw change (Krw_EOR/Krw_WInj) for rel. perm...	2
Pcw change (Pcw_EOR/Pcw_WInj) for rel. per...	1
Pcw change (Pcw_EOR/Pcw_WInj) for rel. per...	1
Sorw trigger for special rel perm handling	0.1
Use Kro Corey curve when Sorw < 0.1 (oil wet ...	☐
Use delta Kro when Sorw < 0.1 (oil wet carbon...	☐
De-normalize set #1 curves when Sorw < 0.1 (f...	☑
Use adsorption for surfactant	☑
Make surfactant and polymer adsorption depe...	☐
Rock type for conversion of adsorption values	Sandstone

Figure 12. Adding three components in the Process Wizard.

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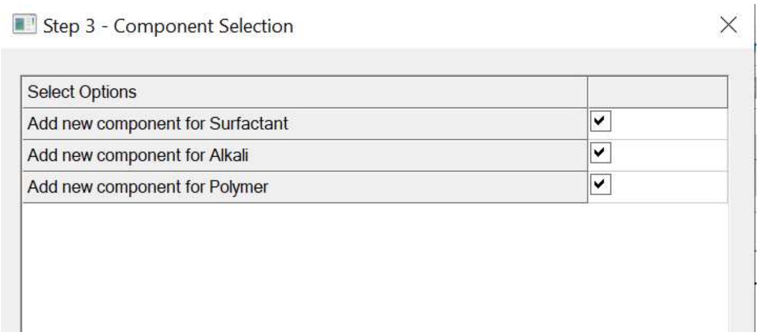
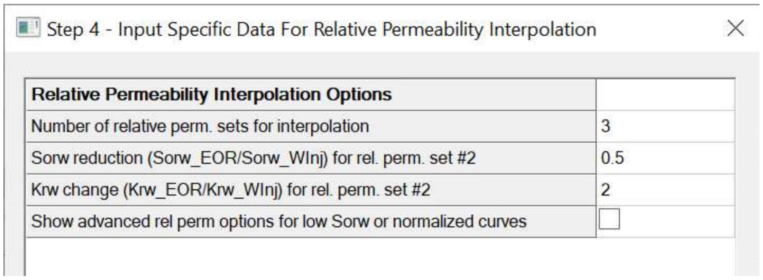


Select Options	
Add new component for Surfactant	☑
Add new component for Alkali	☑
Add new component for Polymer	☑

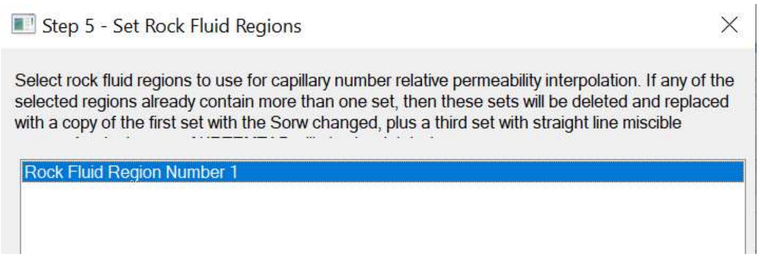
Figure 13. Adding three components in the Process Wizard.

Default values were used for relative permeability interpolation and rock fluid regions in Steps 4 and 5 (Figure 14).



Relative Permeability Interpolation Options	
Number of relative perm. sets for interpolation	3
Sorw reduction (Sorw_EOR/Sorw_WInj) for rel. perm. set #2	0.5
Krw change (Krw_EOR/Krw_WInj) for rel. perm. set #2	2
Show advanced rel perm options for low Sorw or normalized curves	☐

Figure 14. Relative permeability interpolation in the Process Wizard.

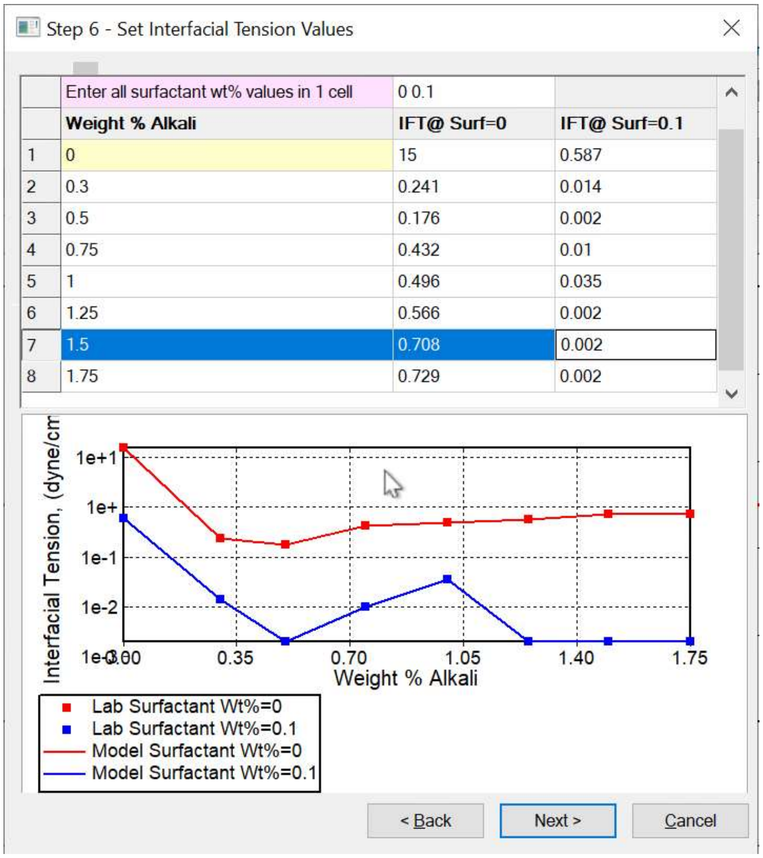


Select rock fluid regions to use for capillary number relative permeability interpolation. If any of the selected regions already contain more than one set, then these sets will be deleted and replaced with a copy of the first set with the Sorw changed, plus a third set with straight line miscible

Rock Fluid Region Number 1

Figure 15. Rock fluid regions in the Process Wizard.

Interfacial tension data were entered in Step 6 (Figure 16). The data can be found in Table 8 in this report.

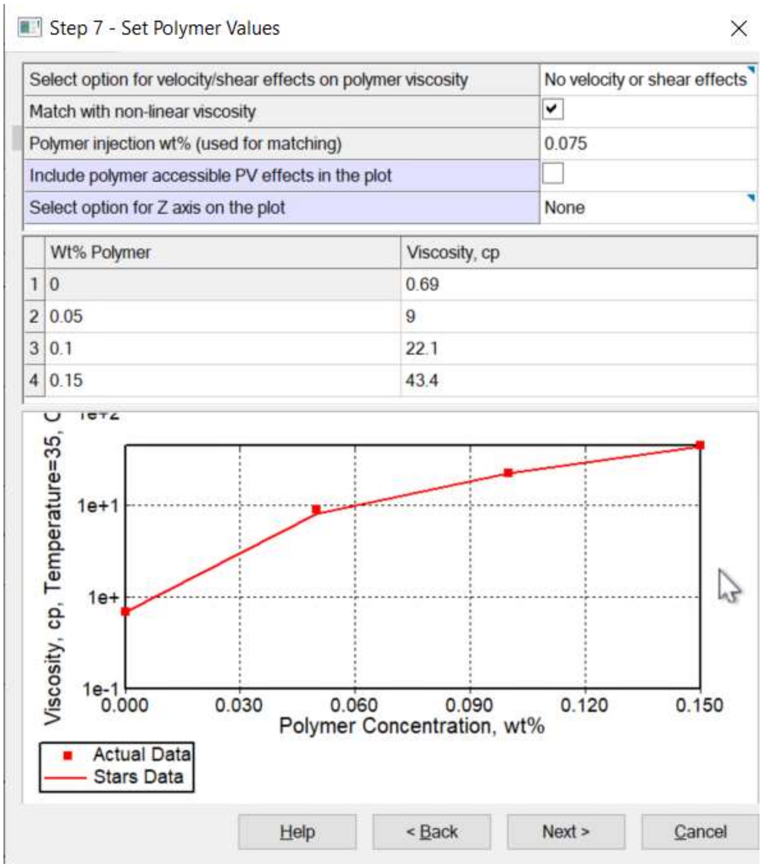


	Enter all surfactant wt% values in 1 cell	0 0.1	
	Weight % Alkali	**IFT@ Surf=0**	**IFT@ Surf=0.1**
1	0	15	0.587
2	0.3	0.241	0.014
3	0.5	0.176	0.002
4	0.75	0.432	0.01
5	1	0.496	0.035
6	1.25	0.566	0.002
7	1.5	0.708	0.002
8	1.75	0.729	0.002

- ■ Lab Surfactant Wt%=0
- ■ Lab Surfactant Wt%=0.1
- — Model Surfactant Wt%=0
- — Model Surfactant Wt%=0.1

Figure 16. IFT data in the Process Wizard.

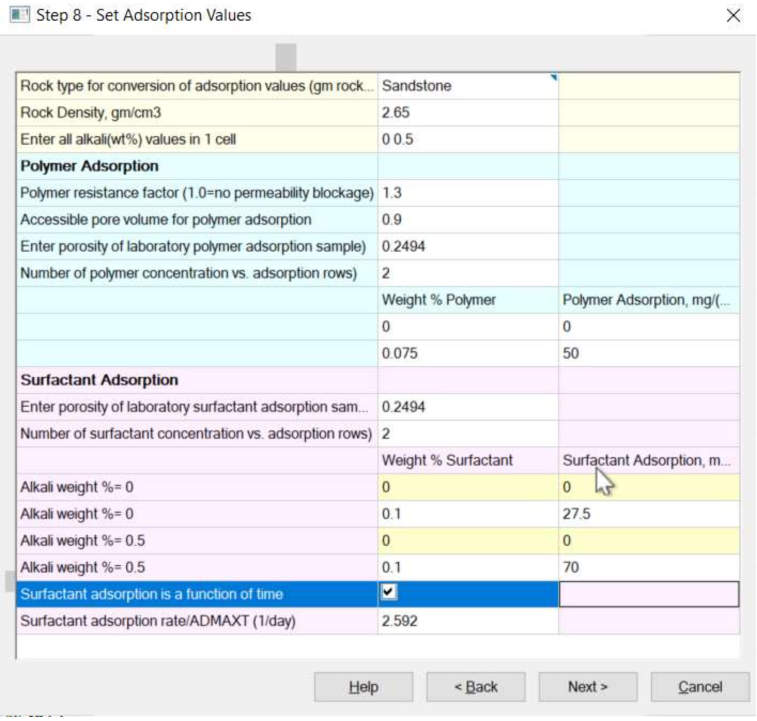
Viscosities of the polymer under different concentrations were added in Step 7 as shown in Figure 17. The viscosity data can be found in Table 6 in this report. The surfactant and polymer adsorption data were entered in the Step 8 as shown in Figure 18. Finally, the concentrations of the chemicals were added in the last step (Figure 19).


Step 7 - Set Polymer Values

Select option for velocity/shear effects on polymer viscosity	No velocity or shear effects
Match with non-linear viscosity	☑
Polymer injection wt% (used for matching)	0.075
Include polymer accessible PV effects in the plot	☐
Select option for Z axis on the plot	None

	Wt% Polymer	Viscosity, cp
1	0	0.69
2	0.05	9
3	0.1	22.1
4	0.15	43.4

Figure 17. Viscosity of the polymer data in the Process Wizard.


Step 8 - Set Adsorption Values

Rock type for conversion of adsorption values (gm rock...	Sandstone	
Rock Density, gm/cm3	2.65	
Enter all alkali(wt%) values in 1 cell	0 0.5	
Polymer Adsorption		
Polymer resistance factor (1.0=no permeability blockage)	1.3	
Accessible pore volume for polymer adsorption	0.9	
Enter porosity of laboratory polymer adsorption sample)	0.2494	
Number of polymer concentration vs. adsorption rows)	2	
	Weight % Polymer	Polymer Adsorption, mg/(...
	0	0
	0.075	50
Surfactant Adsorption		
Enter porosity of laboratory surfactant adsorption sam...	0.2494	
Number of surfactant concentration vs. adsorption rows)	2	
	Weight % Surfactant	Surfactant Adsorption, m...
Alkali weight %= 0	0	0
Alkali weight %= 0	0.1	27.5
Alkali weight %= 0.5	0	0
Alkali weight %= 0.5	0.1	70
Surfactant adsorption is a function of time	☑	
Surfactant adsorption rate/ADMAXT (1/day)	2.592	

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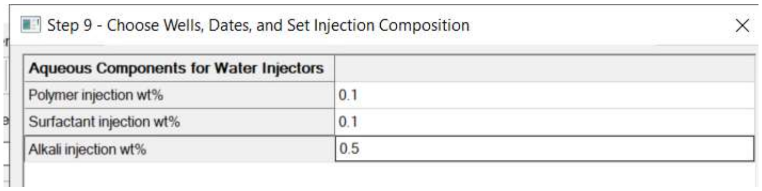
Figure 18. Surfactant and polymer adsorptions data in the Process Wizard.

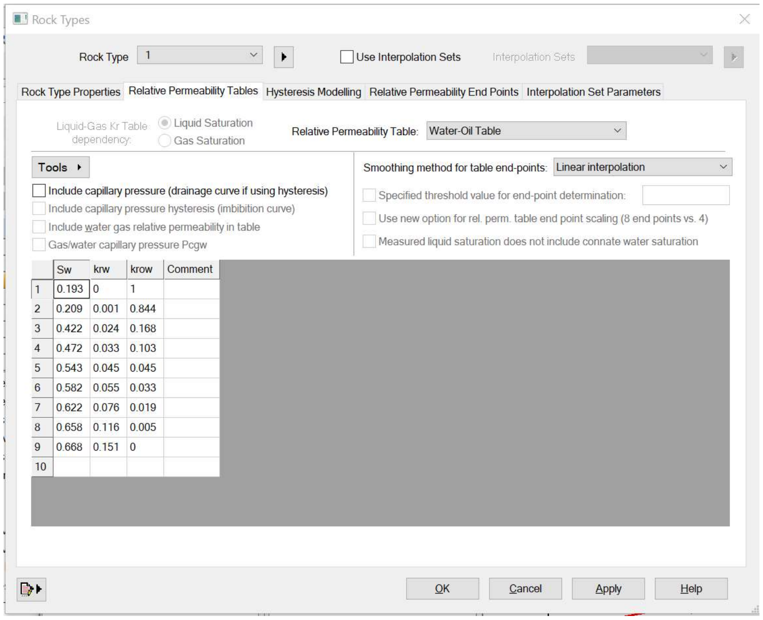


Aqueous Components for Water Injectors	
Polymer injection wt%	0.1
Surfactant injection wt%	0.1
Alkali injection wt%	0.5

Figure 19. Chemical concentration in the Process Wizard.

Rock-fluid properties

A new rock type was added and the water-oil relative permeability was specified using Table 4 in this report.



Rock Type: 1

☐ Use Interpolation Sets

Liquid-Gas Kr Table dependency: ● Liquid Saturation ○ Gas Saturation

Relative Permeability Table: Water-Oil Table

Smoothing method for table end-points: Linear interpolation

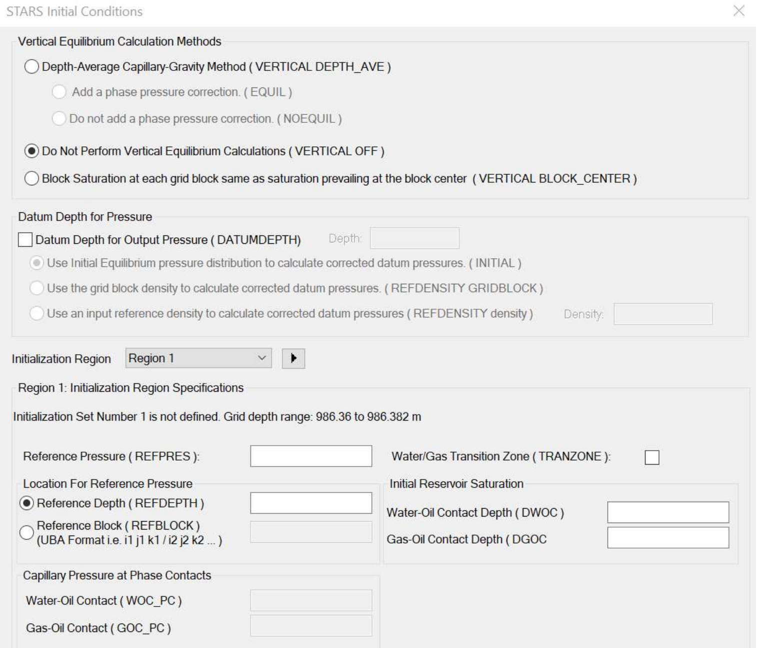
☐ Include capillary pressure (drainage curve if using hysteresis)
☐ Include capillary pressure hysteresis (imbibition curve)
☐ Include water gas relative permeability in table
☐ Gas/water capillary pressure Pcgw
☐ Specified threshold value for end-point determination:
☐ Use new option for rel. perm. table end point scaling (8 end points vs. 4)
☐ Measured liquid saturation does not include connate water saturation

	Sw	krw	krow	Comment
1	0.193	0	1	
2	0.209	0.001	0.844	
3	0.422	0.024	0.168	
4	0.472	0.033	0.103	
5	0.543	0.045	0.045	
6	0.582	0.055	0.033	
7	0.622	0.076	0.019	
8	0.658	0.116	0.005	
9	0.668	0.151	0	
10				

Figure 20. Water-oil relative permeability.

Initial conditions

Because this was a linear core flooding and no gravity effect was taken into consideration, we don’t need to perform vertical equilibrium calculation (Figure 21).



STARS Initial Conditions

Vertical Equilibrium Calculation Methods

○ Depth-Average Capillary-Gravity Method (VERTICAL DEPTH_AVE)
○ Add a phase pressure correction. (EQUIL)
○ Do not add a phase pressure correction. (NOEQUIL)
● Do Not Perform Vertical Equilibrium Calculations (VERTICAL OFF)
○ Block Saturation at each grid block same as saturation prevailing at the block center (VERTICAL BLOCK_CENTER)

Datum Depth for Pressure

☐ Datum Depth for Output Pressure (DATUMDEPTH) Depth:
● Use Initial Equilibrium pressure distribution to calculate corrected datum pressures. (INITIAL)
○ Use the grid block density to calculate corrected datum pressures. (REFDENSITY GRIDBLOCK)
○ Use an input reference density to calculate corrected datum pressures (REFDENSITY density) Density:

Initialization Region: Region 1

Region 1: Initialization Region Specifications

Initialization Set Number 1 is not defined. Grid depth range: 986.36 to 986.382 m

Reference Pressure (REFPRES):
Water/Gas Transition Zone (TRANZONE): ☐

Location For Reference Pressure
● Reference Depth (REFDEPTH)
○ Reference Block (REFBLOCK) (UBA Format i.e. i1 j1 k1 / i2 j2 k2 ...)

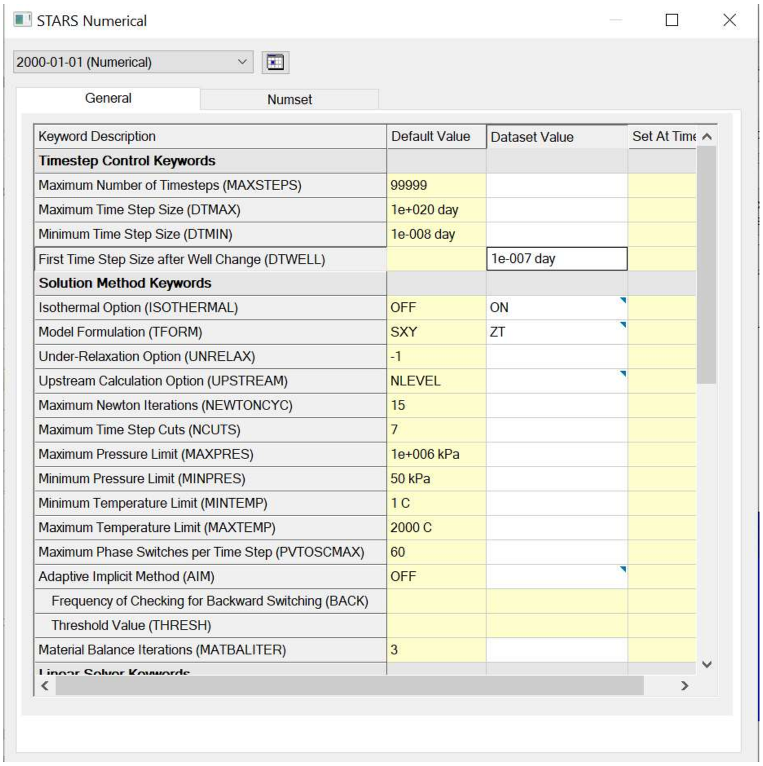
Initial Reservoir Saturation
Water-Oil Contact Depth (DWOC)
Gas-Oil Contact Depth (DGOC)

Capillary Pressure at Phase Contacts
Water-Oil Contact (WOC_PC)
Gas-Oil Contact (GOC_PC)

Figure 21. Initial condition for the simulation.

Numerical

First time step size was set to 1e-07 day in the numerical section. Also, the isothermal option was set to ON as the experiment was conducted at a constant temperature of 35°C.



STARS Numerical

2000-01-01 (Numerical)

Keyword Description	Default Value	Dataset Value	Set At Time
Timestep Control Keywords			
Maximum Number of Timesteps (MAXSTEPS)	99999		
Maximum Time Step Size (DTMAX)	1e+020 day		
Minimum Time Step Size (DTMIN)	1e-008 day		
First Time Step Size after Well Change (DTWELL)		1e-007 day	
Solution Method Keywords			
Isothermal Option (ISOTHERMAL)	OFF	ON	
Model Formulation (TFORM)	SXY	ZT	
Under-Relaxation Option (UNRELAX)	-1		
Upstream Calculation Option (UPSTREAM)	NLEVEL		
Maximum Newton Iterations (NEWTONCYC)	15		
Maximum Time Step Cuts (NCUTS)	7		
Maximum Pressure Limit (MAXPRES)	1e+006 kPa		
Minimum Pressure Limit (MINPRES)	50 kPa		
Minimum Temperature Limit (MINTEMP)	1 C		
Maximum Temperature Limit (MAXTEMP)	2000 C		
Maximum Phase Switches per Time Step (PVTOSCMAX)	60		
Adaptive Implicit Method (AIM)	OFF		
Frequency of Checking for Backward Switching (BACK)			
Threshold Value (THRESH)			
Material Balance Iterations (MATBALITER)	3		
Linear Solver Keywords			

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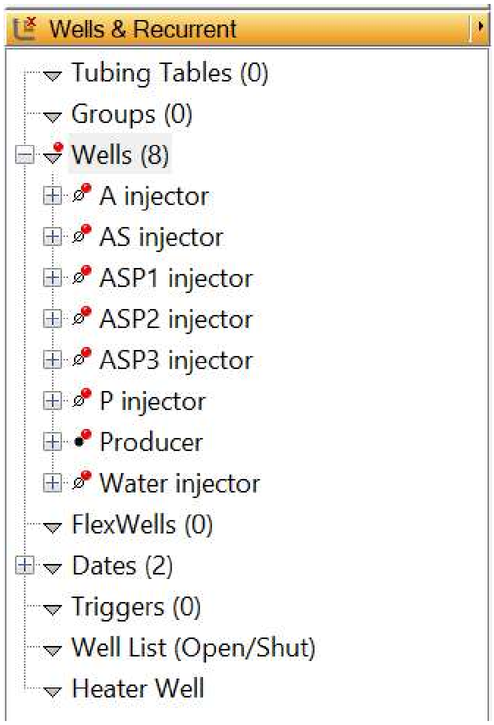
Figure 22. Numerical setting in the simulator.

Well and Recurrent

I created one production well and 7 injection wells at the same location for water, alkali, alkali+surfactant, ASP 1, ASP 2, ASP 3, and polymer injections.



Wells & Recurrent

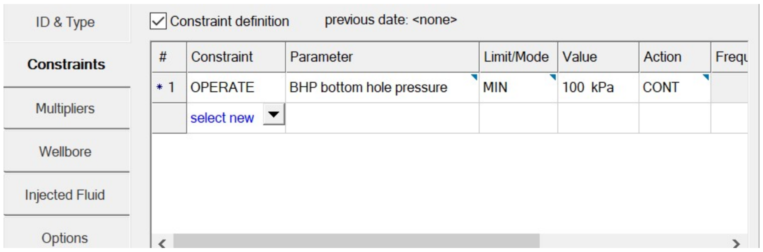
- Tubing Tables (0)
- Groups (0)
- Wells (8)
  - A injector
  - AS injector
  - ASP1 injector
  - ASP2 injector
  - ASP3 injector
  - P injector
  - Producer
  - Water injector
- FlexWells (0)
- Dates (2)
- Triggers (0)
- Well List (Open/Shut)
- Heater Well

Figure 23. One production well and 7 injection wells in the Well section.

<u>Producer</u>

The producer has one constrain:

- Operate – BHP Bottom hole pressure – MIN – 100 kPa



☑ Constraint definition previous date: <none>

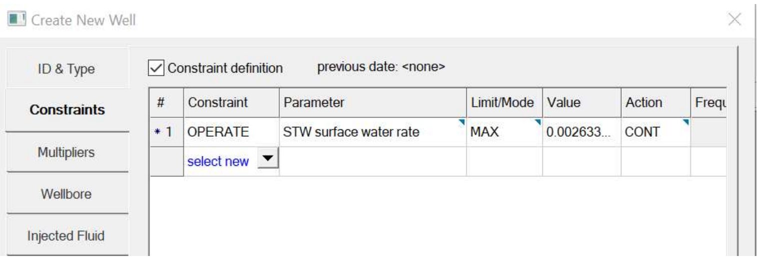
#	Constraint	Parameter	Limit/Mode	Value	Action	Frequ
* 1	OPERATE	BHP bottom hole pressure	MIN	100 kPa	CONT	
	select new					

Figure 24. Constraint definition of the producer.

<u>Water injector and chemical injectors</u>

For the first run time, there was one constrain. The max injection rate of 0.002633 m^3/day was corresponding to the injection velocity of 18.03 ft/day.

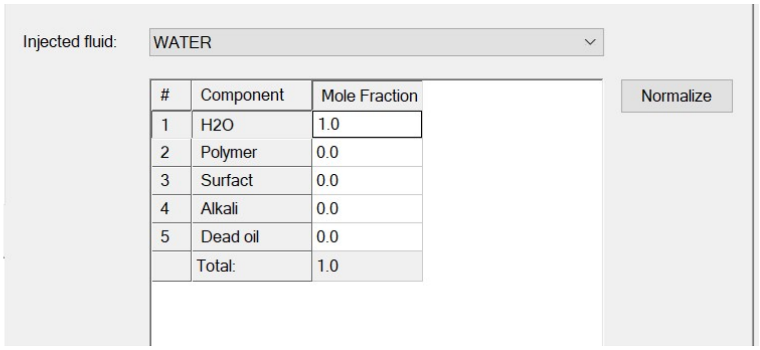
- Operate – STW Surface water rate – Max –0.002633 m^3/day



☑ Constraint definition previous date: <none>

#	Constraint	Parameter	Limit/Mode	Value	Action	Frequ
• 1	OPERATE	STW surface water rate	MAX	0.002633...	CONT	
	select new					

Figure 25. Constraint definition of the water injector.

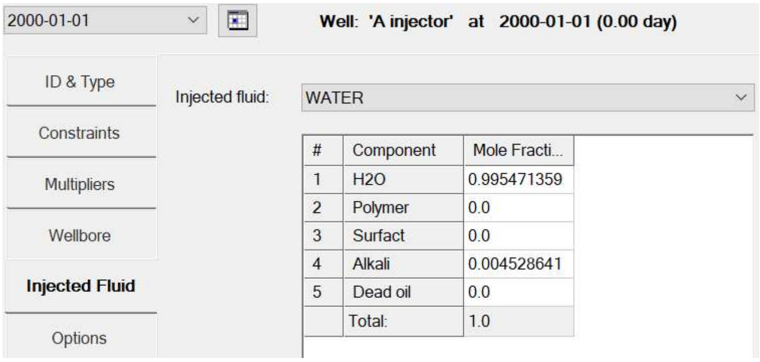


Injected fluid: WATER

#	Component	Mole Fraction
1	H2O	1.0
2	Polymer	0.0
3	Surfact	0.0
4	Alkali	0.0
5	Dead oil	0.0
	Total:	1.0

Figure 26. The injected fluid of the water injector.

Other 6 injectors were created for injection of different chemicals. Figures 27-34 show the injected fluid of each injector.



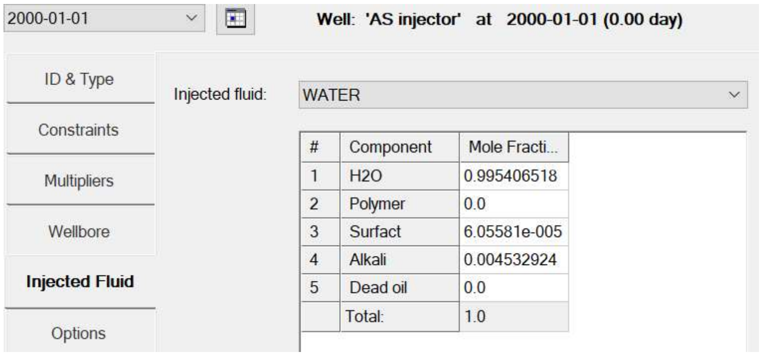
2000-01-01

Well: 'A injector' at 2000-01-01 (0.00 day)

Injected fluid: WATER

#	Component	Mole Fracti...
1	H2O	0.995471359
2	Polymer	0.0
3	Surfact	0.0
4	Alkali	0.004528641
5	Dead oil	0.0
	Total:	1.0

Figure 27. The injected fluid of the alkali injector.

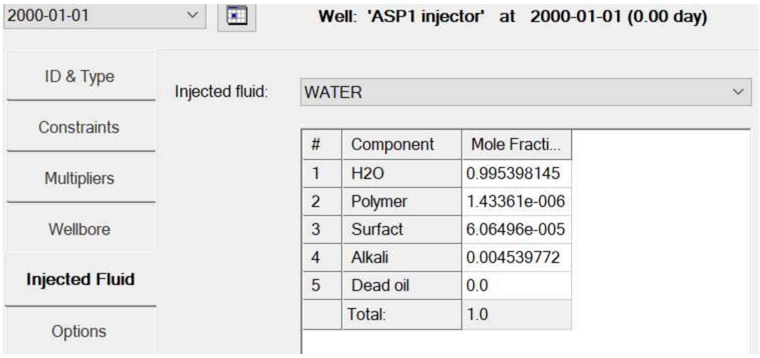


Well: 'AS injector' at 2000-01-01 (0.00 day)

Injected fluid: WATER

#	Component	Mole Fracti...
1	H2O	0.995406518
2	Polymer	0.0
3	Surfact	6.05581e-005
4	Alkali	0.004532924
5	Dead oil	0.0
	Total:	1.0

Figure 28. The injected fluid of the alkali and surfactant injector.

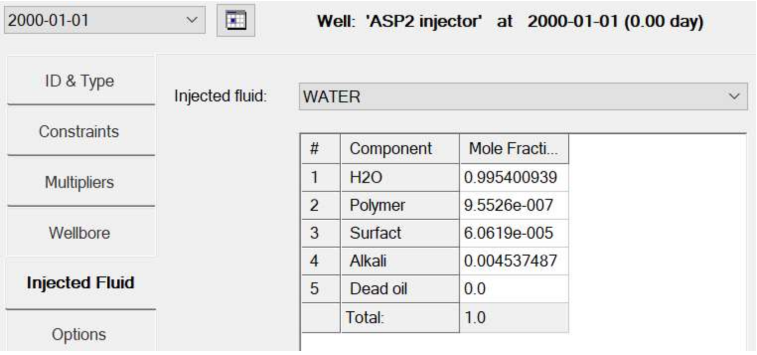


Well: 'ASP1 injector' at 2000-01-01 (0.00 day)

Injected fluid: WATER

#	Component	Mole Fracti...
1	H2O	0.995398145
2	Polymer	1.43361e-006
3	Surfact	6.06496e-005
4	Alkali	0.004539772
5	Dead oil	0.0
	Total:	1.0

Figure 29. The injected fluid of the ASP slug 1 injector.

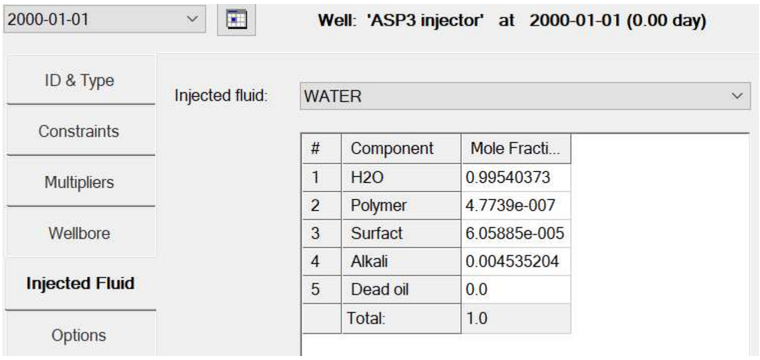


Well: 'ASP2 injector' at 2000-01-01 (0.00 day)

Injected fluid: WATER

#	Component	Mole Fracti...
1	H2O	0.995400939
2	Polymer	9.5526e-007
3	Surfact	6.0619e-005
4	Alkali	0.004537487
5	Dead oil	0.0
	Total:	1.0

Figure 30. The injected fluid of the ASP slug 2 injector.

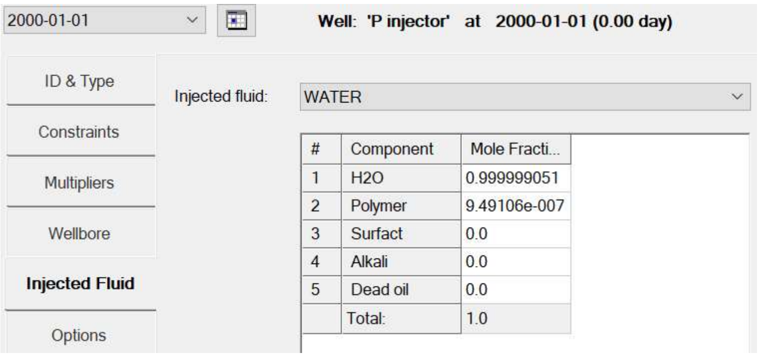


Well: 'ASP3 injector' at 2000-01-01 (0.00 day)

Injected fluid: WATER

#	Component	Mole Fracti...
1	H2O	0.99540373
2	Polymer	4.7739e-007
3	Surfact	6.05885e-005
4	Alkali	0.004535204
5	Dead oil	0.0
	Total:	1.0

Figure 31. The injected fluid of the ASP slug 3 injector.



Well: 'P injector' at 2000-01-01 (0.00 day)

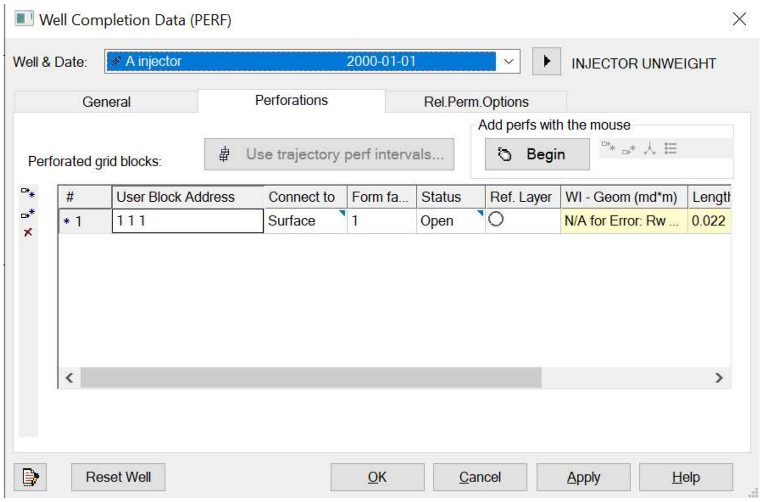
Injected fluid: WATER

#	Component	Mole Fracti...
1	H2O	0.999999051
2	Polymer	9.49106e-007
3	Surfact	0.0
4	Alkali	0.0
5	Dead oil	0.0
	Total:	1.0

Figure 32. The injected fluid of the polymer injector.

Perforations:

All injectors were perforated in Block (1, 1, 1) which was the left most block and the producer was perforated in Block (20, 1, 1) which was the right most block.



Well & Date: A injector 2000-01-01

INJECTOR UNWEIGHT

Perforated grid blocks:

#	User Block Address	Connect to	Form fa...	Status	Ref. Layer	WI - Geom (md*m)	Lengtl
1	1 1 1	Surface	1	Open	○	N/A for Error: Rw ...	0.022

Figure 33. Perforation of the injection wells.

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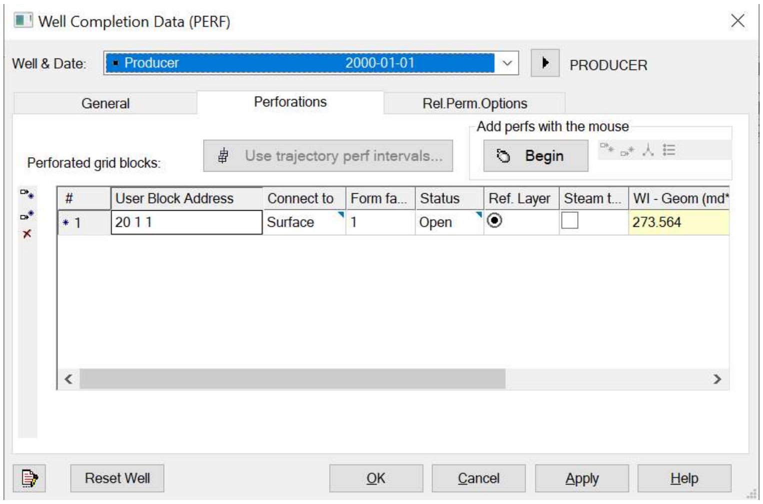


Well & Date: Producer 2000-01-01 PRODUCER

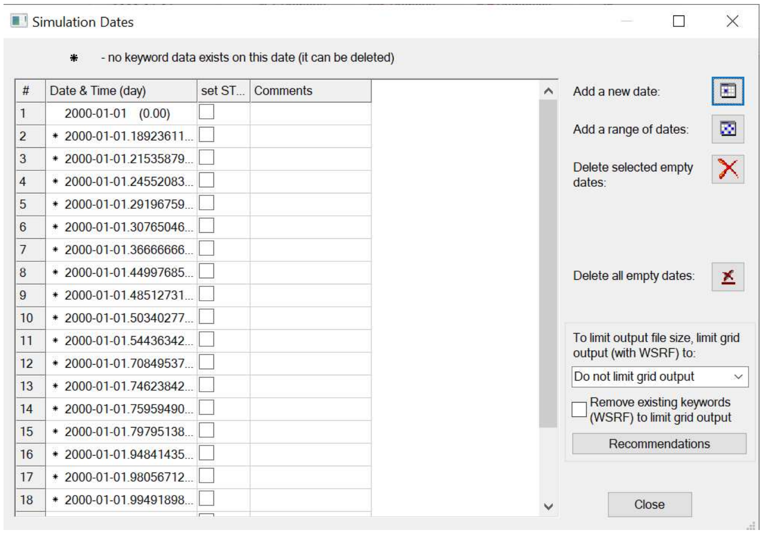
Perforated grid blocks:

#	User Block Address	Connect to	Form fa...	Status	Ref. Layer	Steam t...	WI - Geom (md*
* 1	20 1 1	Surface	1	Open	●	☐	273.564

Figure 34. Perforation of the production well.

Dates

All the dates in the experiment were added. For example, the first date (0.08944 days) was the time when the produced water injection with an injection velocity of 18.03 ft/day was finished.



* - no keyword data exists on this date (it can be deleted)

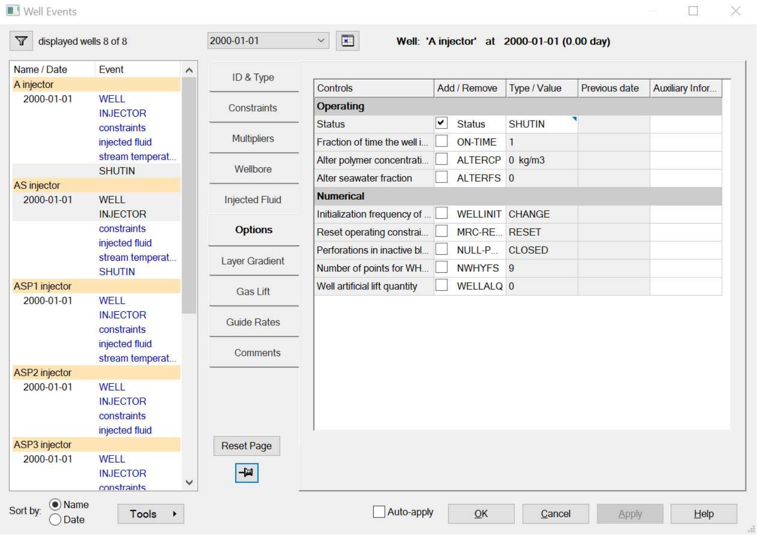
#	Date & Time (day)	set ST...	Comments
1	2000-01-01 (0.00)	☐	
2	* 2000-01-01.18923611...	☐	
3	* 2000-01-01.21535879...	☐	
4	* 2000-01-01.24552083...	☐	
5	* 2000-01-01.29196759...	☐	
6	* 2000-01-01.30765046...	☐	
7	* 2000-01-01.36666666...	☐	
8	* 2000-01-01.44997685...	☐	
9	* 2000-01-01.48512731...	☐	
10	* 2000-01-01.50340277...	☐	
11	* 2000-01-01.54436342...	☐	
12	* 2000-01-01.70849537...	☐	
13	* 2000-01-01.74623842...	☐	
14	* 2000-01-01.75959490...	☐	
15	* 2000-01-01.79795138...	☐	
16	* 2000-01-01.94841435...	☐	
17	* 2000-01-01.98056712...	☐	
18	* 2000-01-01.99491898...	☐	

To limit output file size, limit grid output (with WSRF) to: Do not limit grid output

☐ Remove existing keywords (WSRF) to limit grid output

Figure 35. Adding dates in the simulation.

At the beginning, all chemical injectors need to be shut-in.



2000-01-01

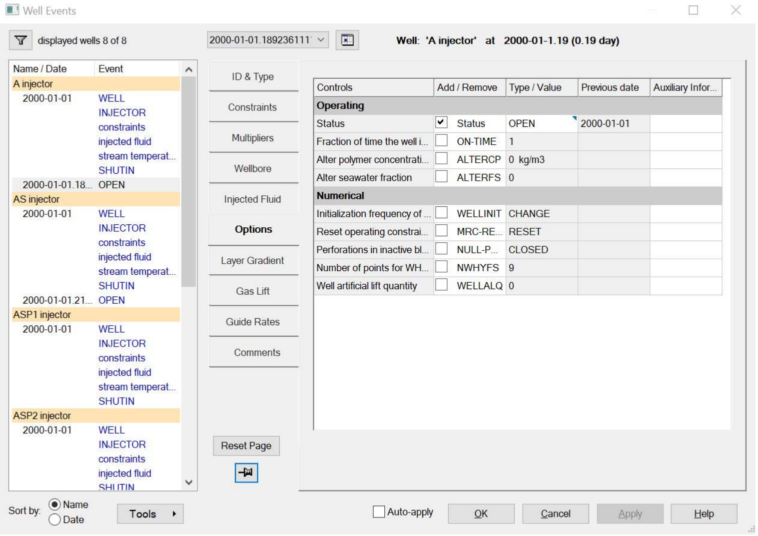
Well: 'A injector' at 2000-01-01 (0.00 day)

Name / Date	Event
A injector	
2000-01-01	WELL INJECTOR constraints injected fluid stream temperat... SHUTIN
AS injector	
2000-01-01	WELL INJECTOR constraints injected fluid stream temperat... SHUTIN
ASP1 injector	
2000-01-01	WELL INJECTOR constraints injected fluid stream temperat...
ASP2 injector	
2000-01-01	WELL INJECTOR constraints injected fluid
ASP3 injector	
2000-01-01	WELL INJECTOR constraints

Controls	Add / Remove		Type / Value	Previous date	Auxiliary Infor...
Operating					
Status	☑	Status	SHUTIN		
Fraction of time the well i...	☐	ON-TIME	1		
Alter polymer concentrati...	☐	ALTERCP	0 kg/m3		
Alter seawater fraction	☐	ALTERFS	0		
Numerical					
Initialization frequency of ...	☐	WELLINIT	CHANGE		
Reset operating constrai...	☐	MRC-RE...	RESET		
Perforations in inactive bl...	☐	NULL-P...	CLOSED		
Number of points for WH...	☐	NWHYFS	9		
Well artificial lift quantity	☐	WELLALQ	0		

Figure 36. All chemical injectors were set to SHUTIN at the beginning.

At different injection times, we need to change the constraints and switch the well between "SHUTIN" and "OPEN". For example, at 0.189 day, the water injector was changed to SHUTIN and Alkali injector was change to OPEN. Because the injection rate of the alkali injector was different from the water injector, it was important to change the constraint of the alkali injector with specified injection rate. At this time, the max injection rate was 0.00153 m3/day which was corresponding to 10.48 ft/day.



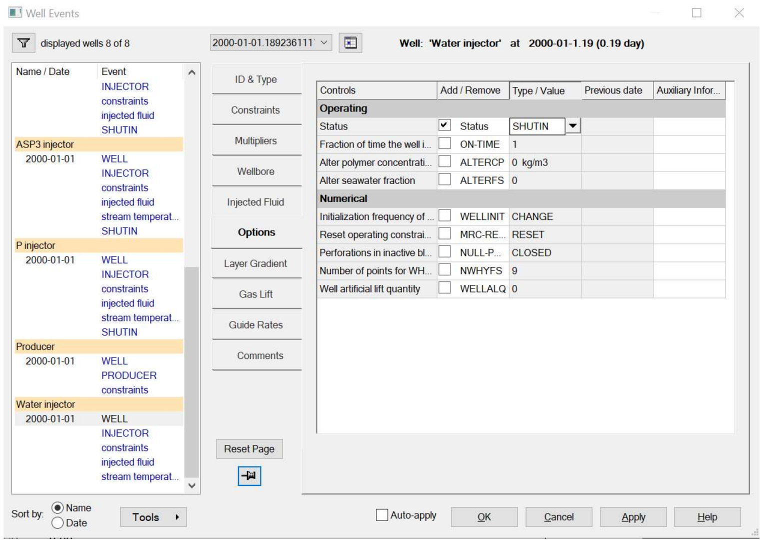
2000-01-01.189236111

Well: 'A injector' at 2000-01-1.19 (0.19 day)

Name / Date	Event
A injector	
2000-01-01	WELL INJECTOR constraints injected fluid stream temperat... SHUTIN
2000-01-01.18...	OPEN
AS injector	
2000-01-01	WELL INJECTOR constraints injected fluid stream temperat... SHUTIN
2000-01-01.21...	OPEN
ASP1 injector	
2000-01-01	WELL INJECTOR constraints injected fluid stream temperat... SHUTIN
ASP2 injector	
2000-01-01	WELL INJECTOR constraints injected fluid SHUTIN

Controls	Add / Remove		Type / Value	Previous date	Auxiliary Infor...
Operating					
Status	☑	Status	OPEN	2000-01-01	
Fraction of time the well i...	☐	ON-TIME	1		
Alter polymer concentrati...	☐	ALTERCP	0 kg/m3		
Alter seawater fraction	☐	ALTERFS	0		
Numerical					
Initialization frequency of ...	☐	WELLINIT	CHANGE		
Reset operating constrai...	☐	MRC-RE...	RESET		
Perforations in inactive bl...	☐	NULL-P...	CLOSED		
Number of points for WH...	☐	NWHYFS	9		
Well artificial lift quantity	☐	WELLALQ	0		

Figure 37. Status of the alkali injector was changed to OPEN at 0.189 days.



displayed wells 8 of 8

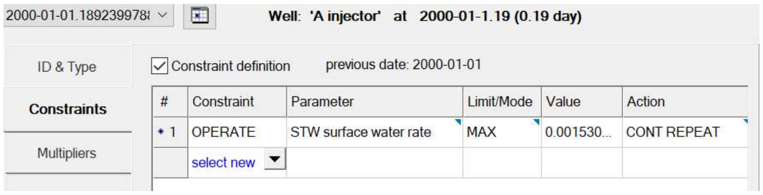
2000-01-01.189236111

Well: 'Water injector' at 2000-01-1.19 (0.19 day)

Name / Date	Event
	INJECTOR constraints injected fluid SHUTIN
ASP3 injector	
2000-01-01	WELL INJECTOR constraints injected fluid stream temperat... SHUTIN
P injector	
2000-01-01	WELL INJECTOR constraints injected fluid stream temperat... SHUTIN
Producer	
2000-01-01	WELL PRODUCER constraints
Water injector	
2000-01-01	WELL INJECTOR constraints injected fluid stream temperat...

Controls	Add / Remove		Type / Value	Previous date	Auxiliary Infor...
Operating					
Status	☑	Status	SHUTIN		
Fraction of time the well i...	☐	ON-TIME	1		
Alter polymer concentrati...	☐	ALTERCP	0 kg/m3		
Alter seawater fraction	☐	ALTERFS	0		
Numerical					
Initialization frequency of ...	☐	WELLINIT	CHANGE		
Reset operating constrai...	☐	MRC-RE...	RESET		
Perforations in inactive bl...	☐	NULL-P...	CLOSED		
Number of points for WH...	☐	NWHYFS	9		
Well artificial lift quantity	☐	WELLALQ	0		

Figure 38. Status of the water injector was changed to SHUTIN at 0.189 days.



2000-01-01.189239978

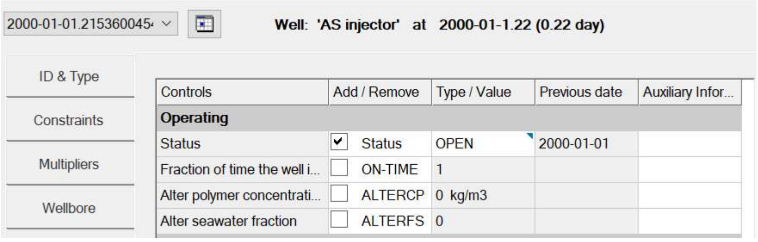
Well: 'A injector' at 2000-01-1.19 (0.19 day)

☑ Constraint definition previous date: 2000-01-01

#	Constraint	Parameter	Limit/Mode	Value	Action
* 1	OPERATE	STW surface water rate	MAX	0.001530...	CONT REPEAT
	select new				

Figure 39. Constraint of the alkali injector.

At 0.215 days, the status of the alkali and surfactant injector was changed to OPEN and the status of the alkali injector was changed to SHUTIN.

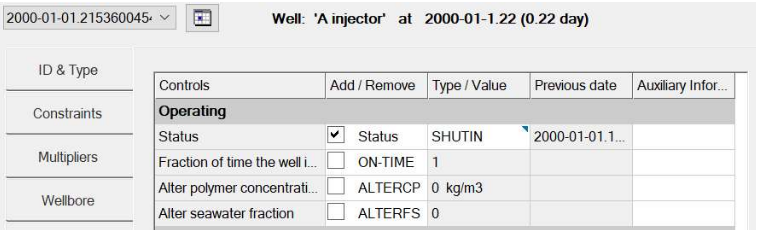


2000-01-01.215360045

Well: 'AS injector' at 2000-01-1.22 (0.22 day)

Controls	Add / Remove		Type / Value	Previous date	Auxiliary Infor...
Operating					
Status	☑	Status	OPEN	2000-01-01	
Fraction of time the well i...	☐	ON-TIME	1		
Alter polymer concentrati...	☐	ALTERCP	0 kg/m3		
Alter seawater fraction	☐	ALTERFS	0		

Figure 40. The status of the alkali and surfactant injector was changed to OPEN at 0.215 days.



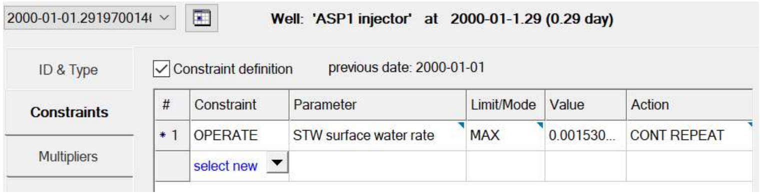
2000-01-01.215360045

Well: 'A injector' at 2000-01-1.22 (0.22 day)

Controls	Add / Remove		Type / Value	Previous date	Auxiliary Infor...
Operating					
Status	☑	Status	SHUTIN	2000-01-01.1...	
Fraction of time the well i...	☐	ON-TIME	1		
Alter polymer concentrati...	☐	ALTERCP	0 kg/m3		
Alter seawater fraction	☐	ALTERFS	0		

Figure 41. The status of the alkali injector was changed to SHUTIN at 0.215 days.

After the alkali and surfactant injection, water was injected again and the water injector turned into OPEN. This procedure was repeated until all the injection was completed at 1.27 days. To save time and limit the page number of this report, the screenshots were not taken and the detailed injection scheme can be found in the Builder in CMG. It was important to point out that there were 3 injection rates for each chemical injection process and the constraints should be modified accordingly. Take ASP slug 1 injection as an example, the injection rate was 0.00153 m^3/day at 0.29 days, 0.000546 m^3/day at 0.31 days and 0.000163 m^3/day at 0.37 days.



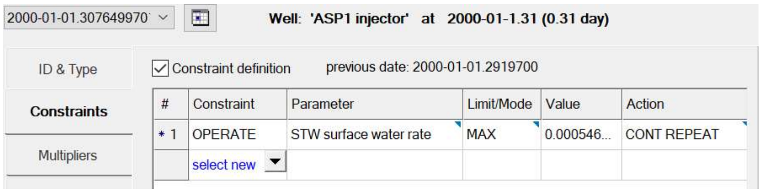
2000-01-01.291970014

Well: 'ASP1 injector' at 2000-01-1.29 (0.29 day)

☑ Constraint definition previous date: 2000-01-01

#	Constraint	Parameter	Limit/Mode	Value	Action
* 1	OPERATE	STW surface water rate	MAX	0.001530...	CONT REPEAT
	select new				

Figure 42. Constraint of the ASP1 injector at 0.29 days.



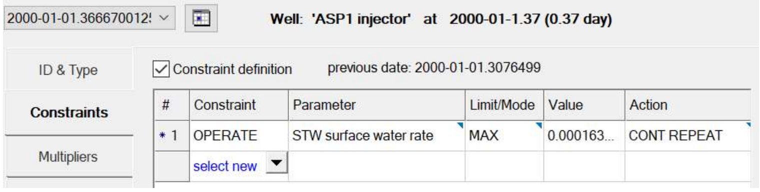
2000-01-01.307649970

Well: 'ASP1 injector' at 2000-01-1.31 (0.31 day)

☑ Constraint definition previous date: 2000-01-01.2919700

#	Constraint	Parameter	Limit/Mode	Value	Action
* 1	OPERATE	STW surface water rate	MAX	0.000546...	CONT REPEAT
	select new				

Figure 43. Constraint of the ASP1 injector at 0.31 days.



2000-01-01.366670012

Well: 'ASP1 injector' at 2000-01-1.37 (0.37 day)

☑ Constraint definition previous date: 2000-01-01.3076499

#	Constraint	Parameter	Limit/Mode	Value	Action
* 1	OPERATE	STW surface water rate	MAX	0.000163...	CONT REPEAT
	select new				

Figure 44. Constraint of the ASP1 injector at 0.37 days.

3. Results and discussion

3.1 Results without modification

The cumulative oil after running the simulation is shown in Figure 45. There was a good match for the initial water flooding between the simulation and experimental data, but the simulation result overestimated the oil production at the later stage (i.e. during chemical injection). This might be caused by the low adsorption data entered in the simulation. Therefore, it was decided to increase the surfactant adsorption amount in the simulation.

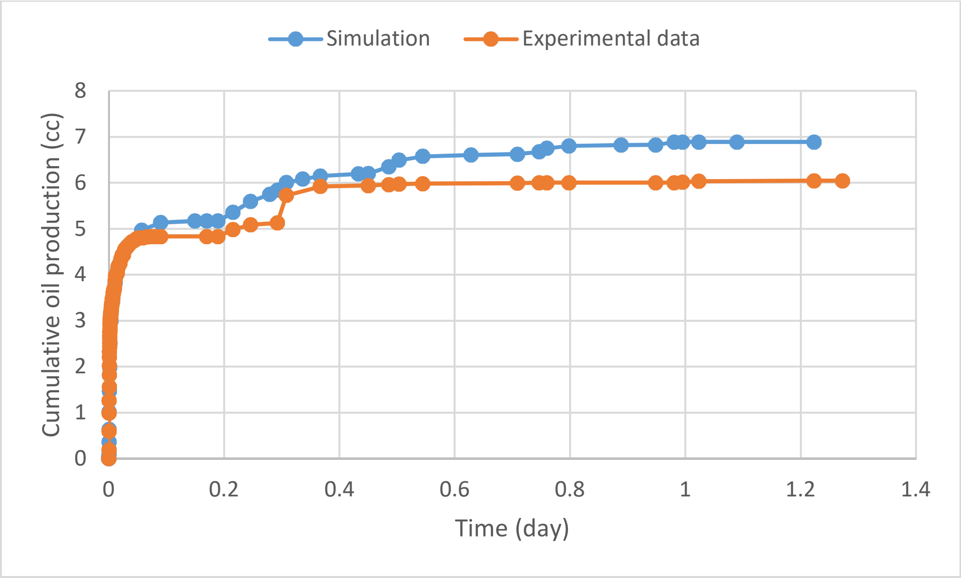
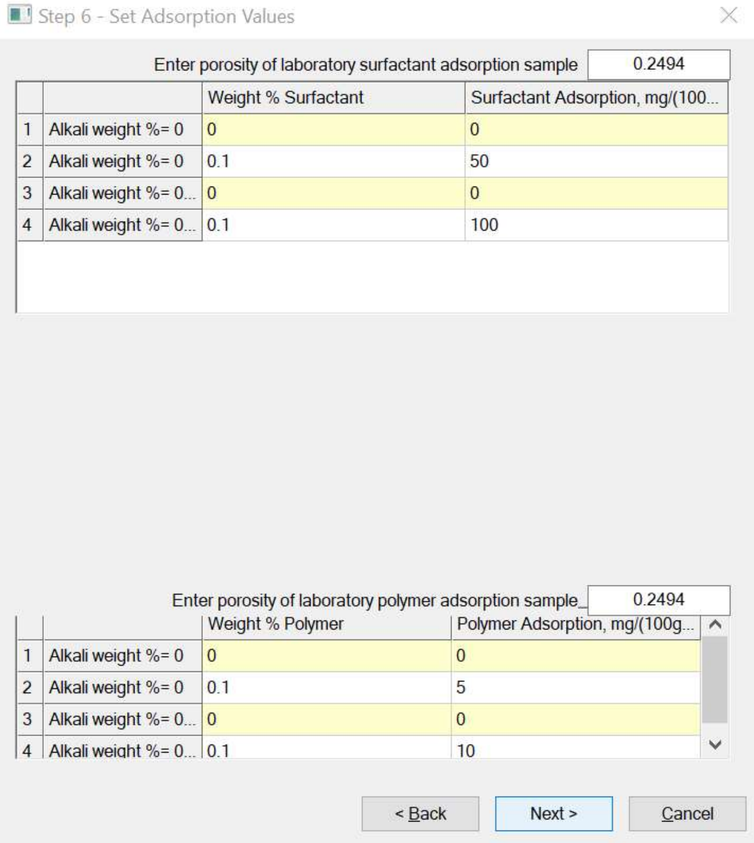


Figure 45. Cumulative oil production results from the simulation and the experimental data.

3.2 Results with modification to the adsorption

The adsorption data can be modified through the Process Wizard. The surfactant adsorption was increased to 50 and 100 mg/g rock when the alkali weight percentage was 0 and 0.1%.



Enter porosity of laboratory surfactant adsorption sample 0.2494

		Weight % Surfactant	Surfactant Adsorption, mg/(100...
1	Alkali weight %= 0	0	0
2	Alkali weight %= 0	0.1	50
3	Alkali weight %= 0...	0	0
4	Alkali weight %= 0...	0.1	100

Enter porosity of laboratory polymer adsorption sample 0.2494

		Weight % Polymer	Polymer Adsorption, mg/(100g...
1	Alkali weight %= 0	0	0
2	Alkali weight %= 0	0.1	5
3	Alkali weight %= 0...	0	0
4	Alkali weight %= 0...	0.1	10

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Figure 46. Modified adsorption data.

A better match was achieved between the simulation and experimental data as shown in Figure 47. However, there was still some mismatch during the ASP injection period. Our next step was to modify the relative permeability.

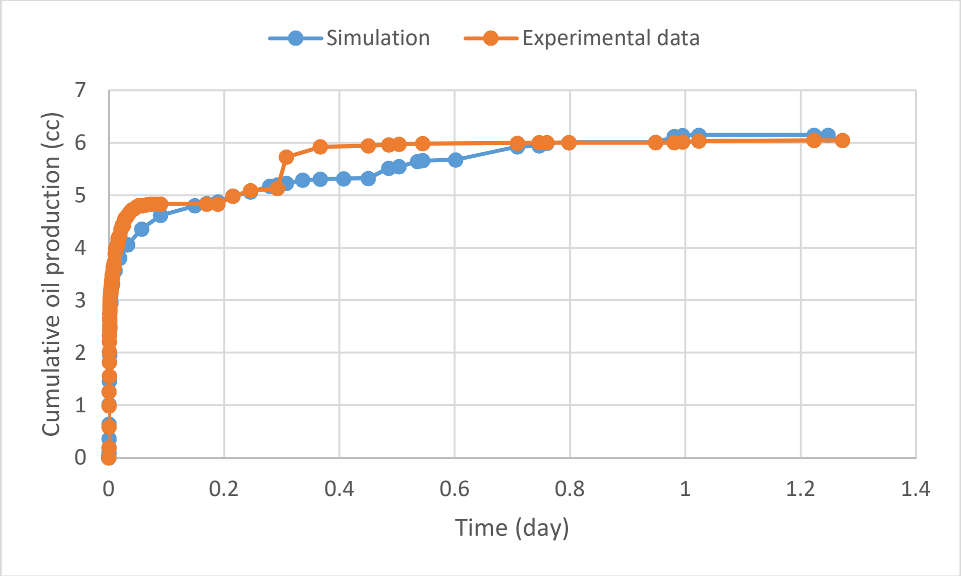

Figure 47. Cumulative oil production results from the simulation and the experimental data after modifying the adsorption data.

3.3 Results with modification to the relative permeability

The original and modified water-oil relative permeabilities are shown in Figures 4 and 5. In this modification, we increased the oil and water relative permeabilities.

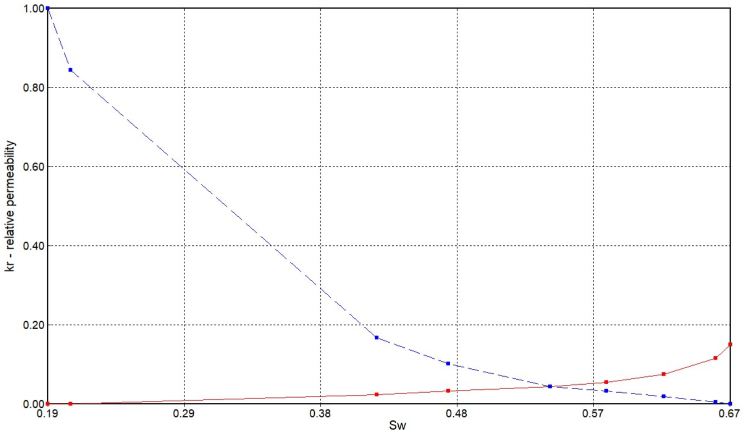

Figure 48. Original water-oil relative permeability.

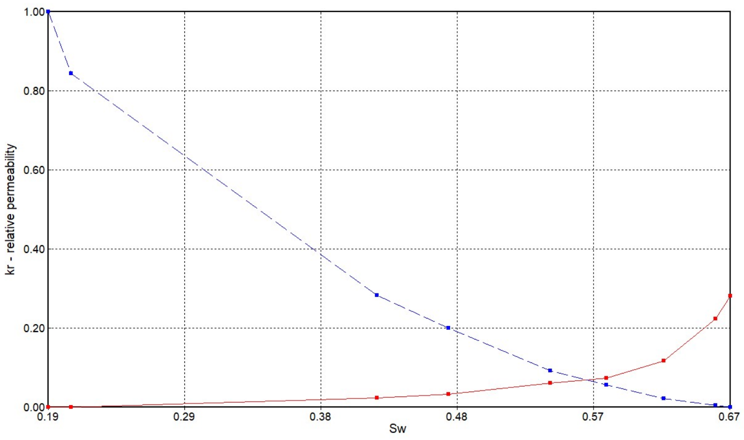

Figure 49. Modified water-oil relative permeability.

The cumulative oil production results from the simulation and the experimental data after modifying the adsorption data and the relative permeability are presented in Figure 50. The recovery factor at different injection times are also plotted in Figure 51. A much better match was achieved after the modifications. The recovery factor at the end of the first water flooding cycle from the simulation was 58.9% which was exactly the same with the experimental data. The final recovery factor from the simulation was 75.2% which was slightly higher than that in the experiment (73.6%).

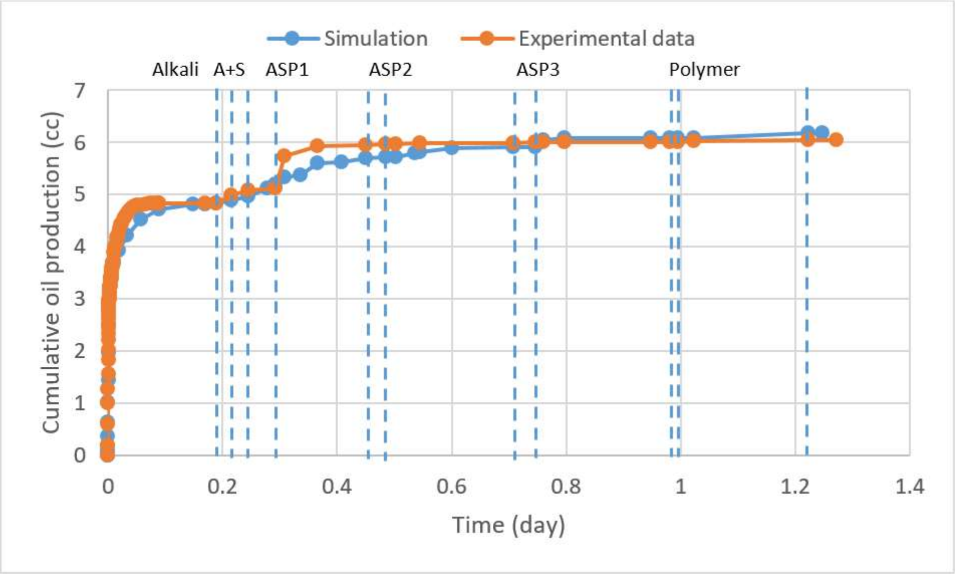

Figure 50. Cumulative oil production results from the simulation and the experimental data after modifying the adsorption data and the relative permeability.

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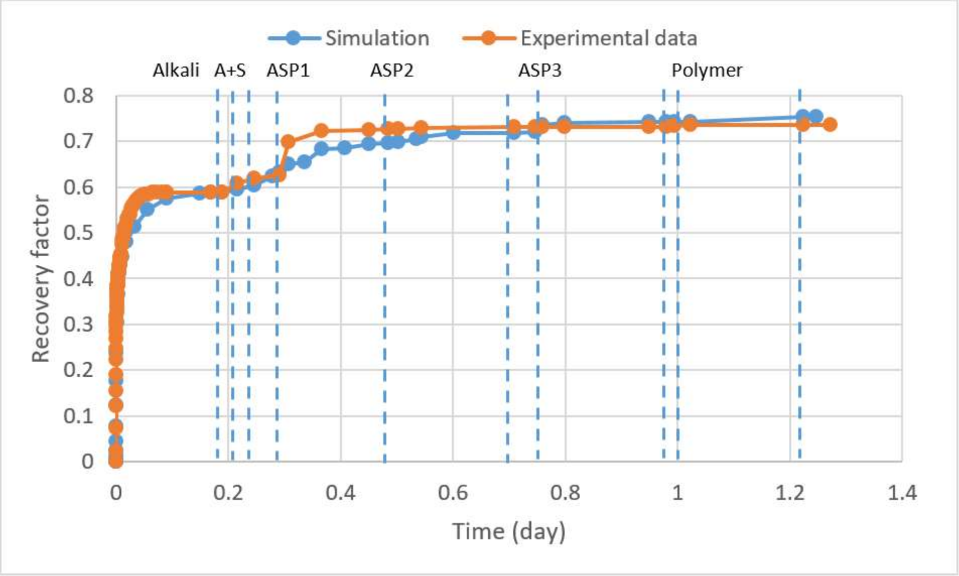

Figure 51. Recovery factor at different times from the simulation and the experimental data after modifying the adsorption data and the relative permeability.

The oil cut at different injection times from the simulation results is plotted in Figure 52. At the end of the first water injection period, the oil cut was almost 0%. The oil cut slowly picked up after the alkali, alkali+surfactant and ASP injections reaching 0.45% which indicates the effectiveness of chemical injections. The last cycle of polymer injection didn't improve the oil cut as the water saturation was too high at this late stage.

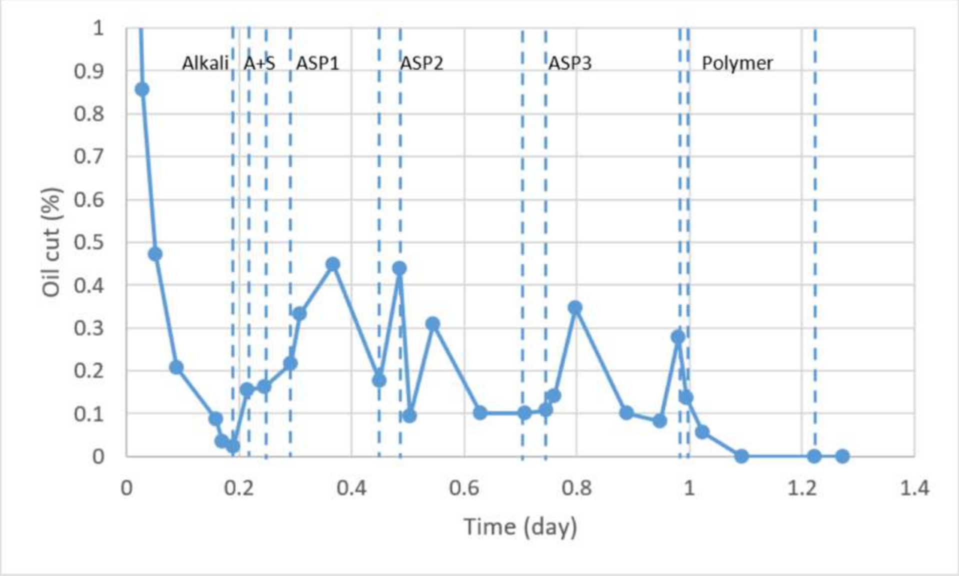

Figure 52. Oil cut at different injection times.

3.4 Sensitivity analysis: Effect of the injection sequence

After the simulation model was well established by matching the experimental data, it was used for sensitivity analysis. There were two cases for sensitivity analysis with the established model being case 1. In case 2, I changed the order of the ASP injection by switching ASP slug 3 and ASP slug 1. Note that ASP slug 3 had a lower polymer concentration of 500 ppm while the polymer concentration in ASP slug 1 was 1500 ppm.

The cumulative oil productions for these two cases were plotted in Figure 53. It can be seen from the figure that the oil production in case 2 was lower at 0.3-0.4 days where ASP injection started. Because lower concentration of polymer (500 ppm) was used in case 2 at 0.3 days, it was reasonable to have a lower oil production. However, the oil production in case 2 climbed up and reached a higher final recovery. This can be explained by the fact that there was more oil production at the later stage because a higher concentration of polymer (1500 ppm) was used at the later stage. The oil cuts in Figure 54 confirmed that the oil cut at the later stage in case 2 was higher than that in case 1.

The results suggest that the chemical injection sequence is important in the enhanced oil recovery process. In order to achieve a higher final recovery factor, a lower polymer concentration at the early stage is preferred. However, a higher polymer concentration is ideal if a higher production rate in the early stage is a priority.

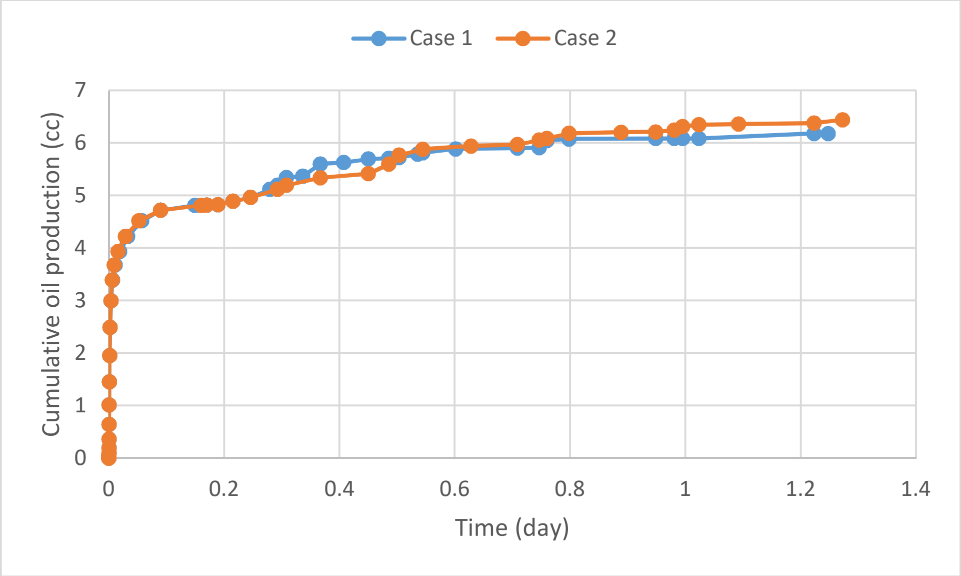

Figure 53. The cumulative oil productions for two cases.

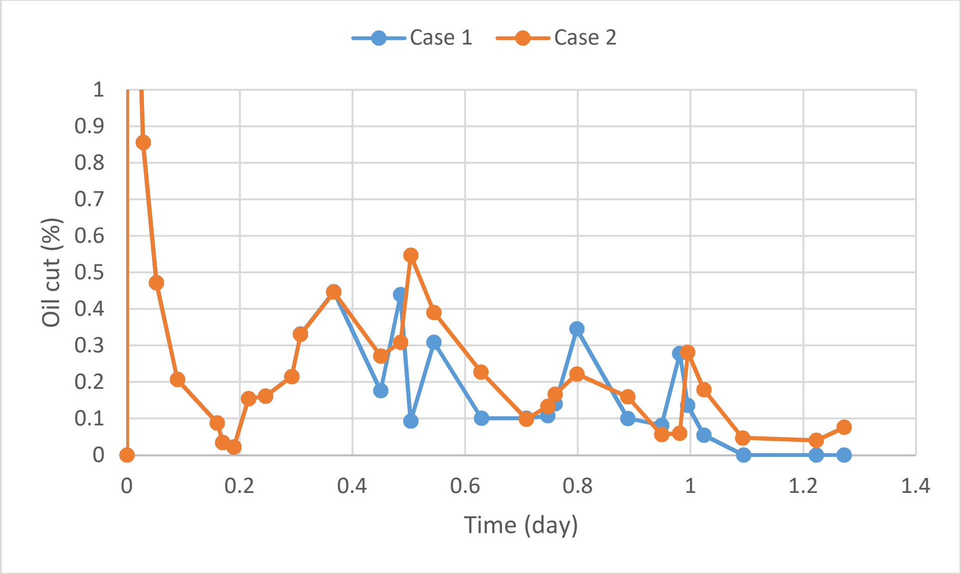

Figure 54. Oil cuts for two cases.

4. Conclusions

By employing the chemical EOR simulator STARS from CMG, a chemical EOR process conducted in the lab was modeled. This involved the injection of alkaline, surfactant, polymer, and their synergistic combinations. The simulation results demonstrated the potential of chemical injection to enhance oil recovery and augment the oil cut subsequent to water flooding.

In order to attain a more precise alignment with the data obtained from the experiment, it became imperative to fine-tune certain parameters in the simulation. Notably, adjustments were made to the relative permeability curve and chemical adsorption data. After adjusting these two parameters, a very good match between the simulation results and the experimental data was achieved. The modification of the relative permeability curve and chemical adsorption data served as a crucial calibration step, facilitating a more accurate representation of the dynamic interplay between injected chemicals and the reservoir rock.

The findings underscore the pivotal role of the chemical injection sequence in optimizing the enhanced oil recovery (EOR) process. To attain a superior final recovery factor, it is advisable to employ a lower polymer concentration during the initial stages. Nevertheless, in scenarios where prioritizing a high production rate in the early stages is paramount, a contrasting strategy emerges. Here, opting for a higher polymer concentration in the early stages proves to be more advantageous. The simulation outcomes conducted in this assignment not only align with laboratory observations but also provide valuable insights for optimizing future operations.