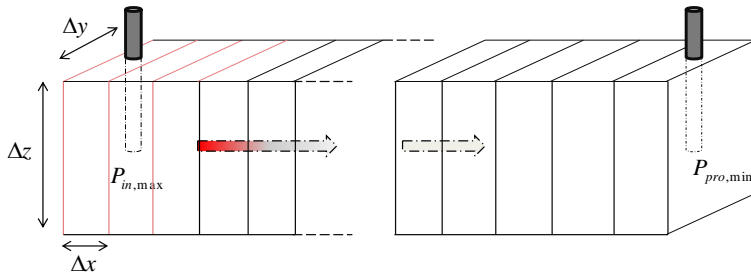


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Development of Thermal Recovery Simulator for Hot Water Flooding



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Outline

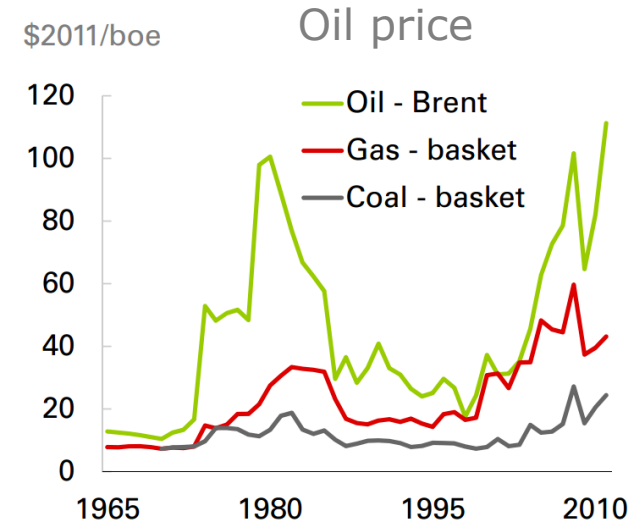
- **Background**
 - **EOR**
 - **Heavy oil**
- **Development of black oil reservoir simulator**
 - **Governing equations**
 - **Verification of 1-D and 2-Phase black oil simulator**
- **Development of Thermal recovery simulator**
 - **Conservation of Energy Equation**
 - **Constitutive equations**
- **Case studies of the thermal recovery simulator**
- **Conclusion and future work**
- **Acknowledgement**

Background

Global Oil Demand

We are faced with a massive increase in demand for oil. We will need to make better use of existing resources.

- Recovery factor by means of water flooding is only 33%.
- By increasing the global average recovery factors by just 1% up to 70bn bbl of reserves could be added to the global oil & gas reserves.

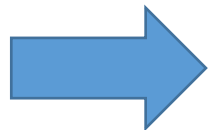


ref. Global Energy Systems Conference

ref. Jan. 2013 BP Energy Outlook 2030

- Unconventional oil meets about 10% of world oil demand in all scenarios by 2035 compared with less than 3% today.

ref. World Energy Outlook 2010



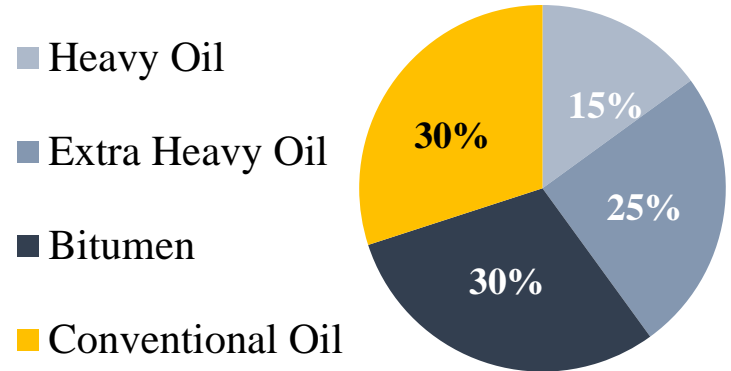
Enhanced Oil Recovery (EOR) techniques

The development of unconventional resources

Background

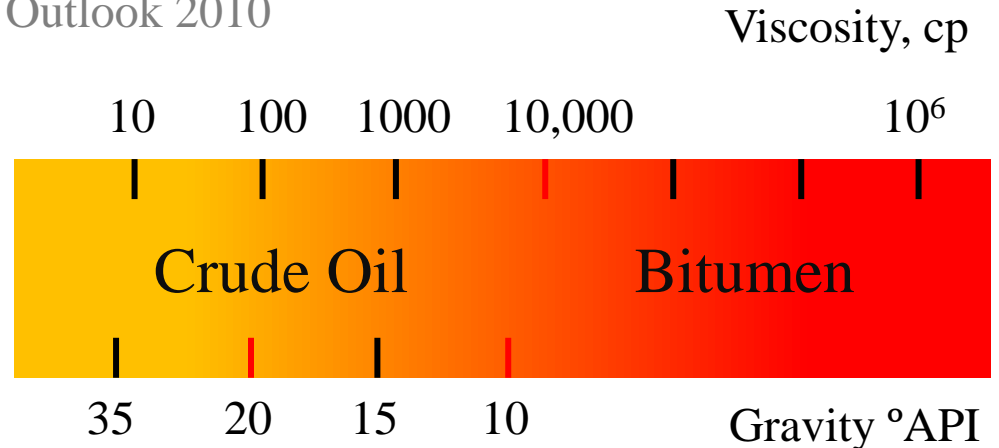
- The global heavy oil market will see production of 6.659 million barrels per day in 2013. This includes heavy/extra-heavy oil operations in Canada and Venezuela, but excludes oil sands projects where bitumen is the primary target. ref. visiongain
- **25% of the world's oil reserves are Heavy oil.** ref. BP
- Canadian oil sands and Venezuelan extra-heavy oil dominate the mix. ref. World Energy Outlook 2010

Total World Oil Reserves



Source. : Schlumberger
"Highlighting Heavy Oil" 2006

Mobility	
k	: Absolute permeability
$\frac{k k_{r\alpha}}{\mu_\alpha}$: Relative permeability
μ_α	: Phase viscosity



Source. UNITAR

Background

EORs for heavy oil fields

Mobility

$$\frac{k k_{ra}}{\mu_{\alpha}}$$

k : Absolute permeability

k_{ra} : Relative permeability

μ_{α} : Phase viscosity

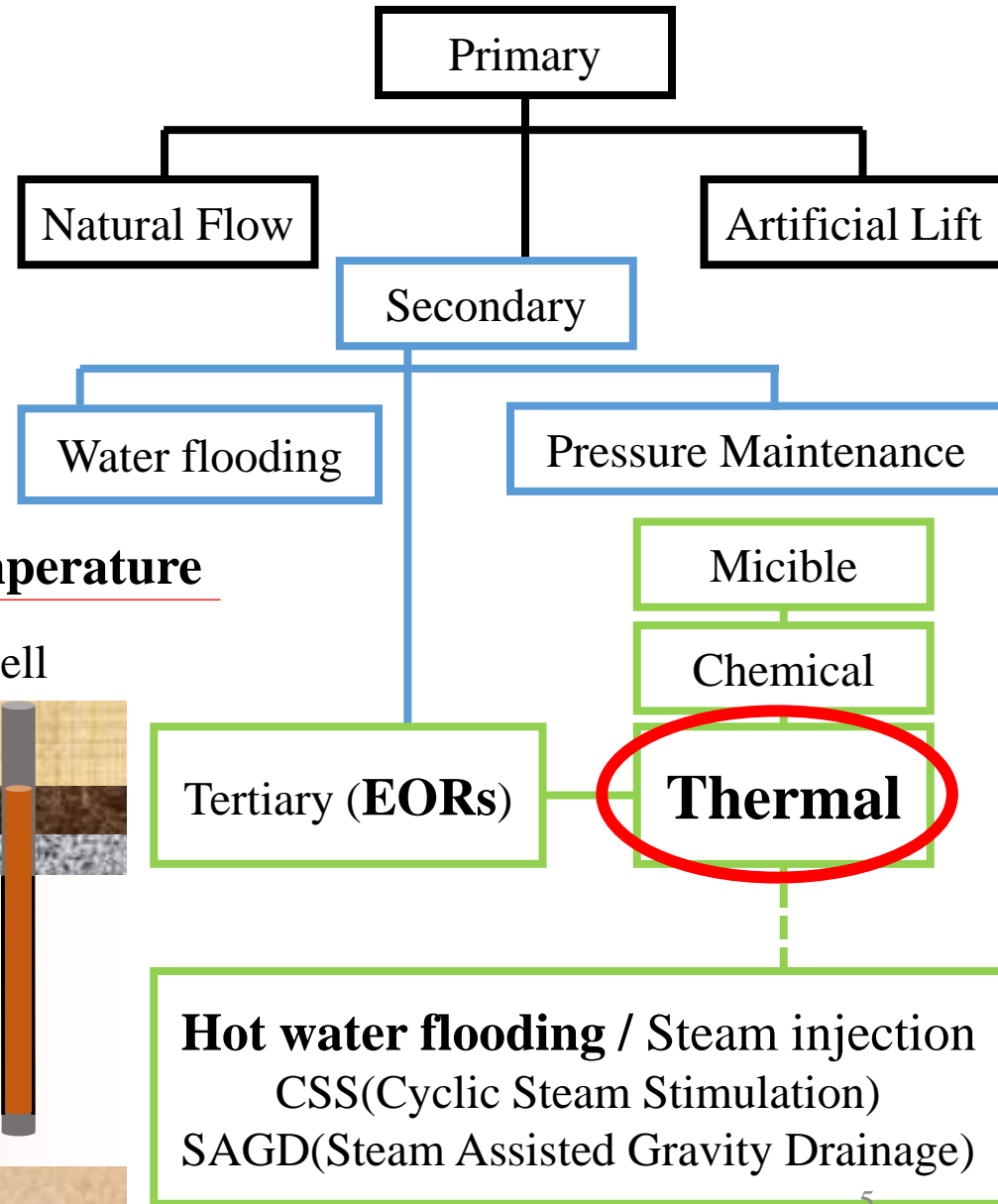
A function of the phase Temperature

Injection well

Production well



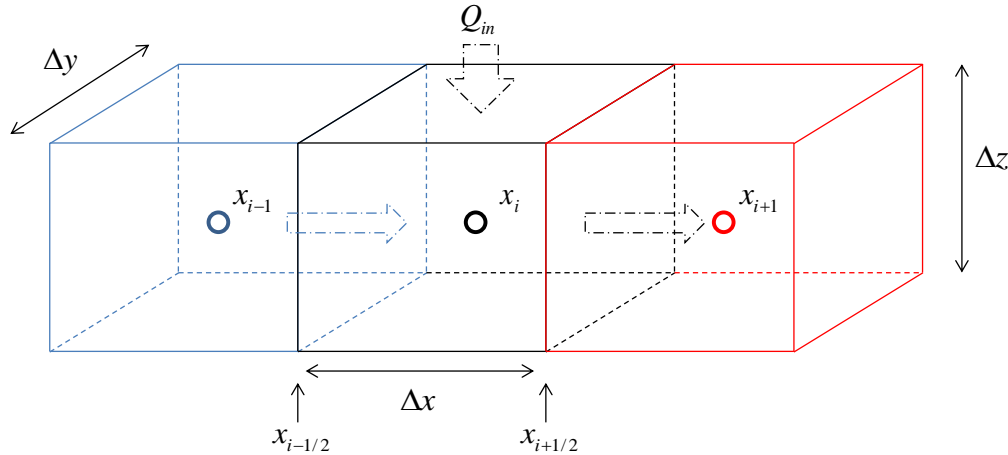
Hot water flooding



Black oil reservoir simulator

Buckley-Leverett Analysis (1 Dimension 2 Phases)

Consider displacement of oil by water in a system.



$$q = q_w + q_o, \quad f_w = \frac{q_w}{q}$$

$$f_w = \frac{1 + \frac{k k_{ro}}{q \mu_o} \left(\frac{\partial P_{cow}}{\partial x} - \Delta \rho g \sin \alpha \right)}{1 + \frac{k_{ro}}{\mu_o} \frac{\mu_w}{k_{rw}}}$$

Dominant equations

$$\frac{\partial}{\partial x} \left(\frac{k k_{rw}}{\mu_w} \rho_w \frac{\partial (P_w - \gamma_w D)}{\partial x} \right) + Q_w \rho_w = \frac{\partial}{\partial t} (\rho_w \phi S_w)$$

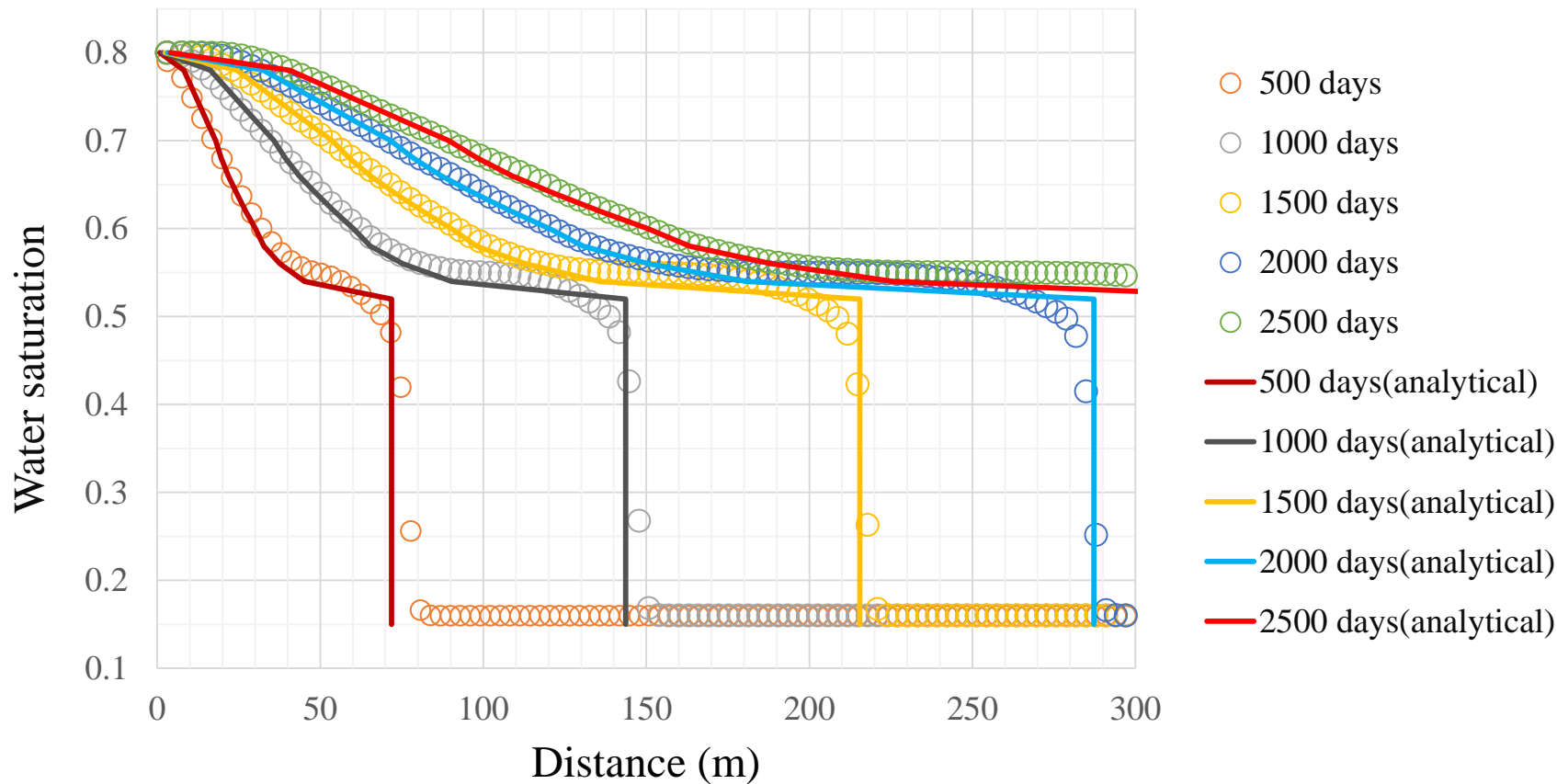
Two main variables

$$\frac{\partial}{\partial x} \left(\frac{k k_{ro}}{\mu_o} \rho_o \frac{\partial (P_o - \gamma_o D)}{\partial x} \right) + Q_o \rho_o = \frac{\partial}{\partial t} (\rho_o \phi S_o)$$

Mass flow in + Mass flow out = Mass accumulation

Black oil reservoir simulator

Verification of 1-D and 2-Phase black oil simulator



Energy equation

Net rate of energy equation into V

+ Rate of energy production in V

= Rate energy accumulation in V

Net rate of energy equation into V:

L.W. Lake (1989)

-Total internal energy, -Kinetic energy per unit bulk volume

$$\frac{\partial}{\partial t} \left(\phi \sum_{\alpha} \rho_{\alpha} S_{\alpha} U_{\alpha} + (1 - \phi) \rho_s C_s T + \frac{1}{2} \sum_{\alpha} \rho_{\alpha} |u_{\alpha}|^2 \right)$$

Rate of energy production in V:

-Energy flux (convective contributions from the flowing phases, conduction and radiation)

$$+ \nabla \cdot \left(\sum_{\alpha} \rho_{\alpha} u_{\alpha} \left(U_{\alpha} + \frac{1}{2} |u_{\alpha}|^2 \right) \right) - \nabla \cdot (k_T \nabla T) - \underline{q_r}, \quad U_{\alpha} = H_{\alpha} - \frac{P_{\alpha}}{\rho_{\alpha}}$$

-The rate of work done against the pressure field and gravity

$$+ \sum_{\alpha} \left(\nabla \cdot (P_{\alpha} u_{\alpha}) - \rho_{\alpha} u_{\alpha} \cdot g \nabla z \right), \quad g: \text{gravitational acceleration}$$

Neglect

Rate energy accumulation in V:

-Enthalpy source term per bulk volume, -Heat loss

$$q_H - q_L$$

Governing equations

To deal with changes in reservoir temperature

Energy conservation equation

$$\frac{\partial}{\partial x} \left(k_T \frac{\partial}{\partial x} T \right) + \frac{\partial}{\partial x} \left(\sum_{\alpha} \rho_{\alpha} u_{\alpha} H_{\alpha} \right) + \sum_{\alpha} Q_{\alpha, \text{in}} \rho'_{\alpha} H'_{\alpha} - q_L$$
$$= \frac{\partial}{\partial t} \left(\phi \sum_{\alpha} \rho_{\alpha} S_{\alpha} U_{\alpha} + (1 - \phi) \rho_s C_s T \right)$$

Three main variables

Mass balance equations

$$\frac{\partial}{\partial x} \left(\frac{k k_{rw}}{\mu_w} \rho_w \frac{\partial (P_w - \gamma_w D)}{\partial x} \right) + Q_w \rho_w = \frac{\partial}{\partial t} (\rho_w \phi S_w)$$
$$\frac{\partial}{\partial x} \left(\frac{k k_{ro}}{\mu_o} \rho_o \frac{\partial (P_o - \gamma_o D)}{\partial x} \right) + Q_o \rho_o = \frac{\partial}{\partial t} (\rho_o \phi S_o)$$

“Water saturation” “Pressure” “Temperature”
is the three main variables.

Constitutive equations

Viscosity

$$\mu_{\alpha} = a_{\text{vis}} \cdot \exp\left(\frac{b_{\text{vis}}}{T}\right)$$

R. C. Reid (1977)

T is a temperature, “ a_{vis} ” and “ b_{vis} ” denote first and second empirical parameters. These empirical parameters depend on the type of fluid.

For example, the value of these parameters for the water phase (10 cp at 373 K) is consistent with $a_{\text{vis}} = 0.0047352$ cp, $b_{\text{vis}} = 1515.7$ K .

Enthalpy

$$H_{\alpha} = H_{\text{g}} - H_{\text{vap}}$$

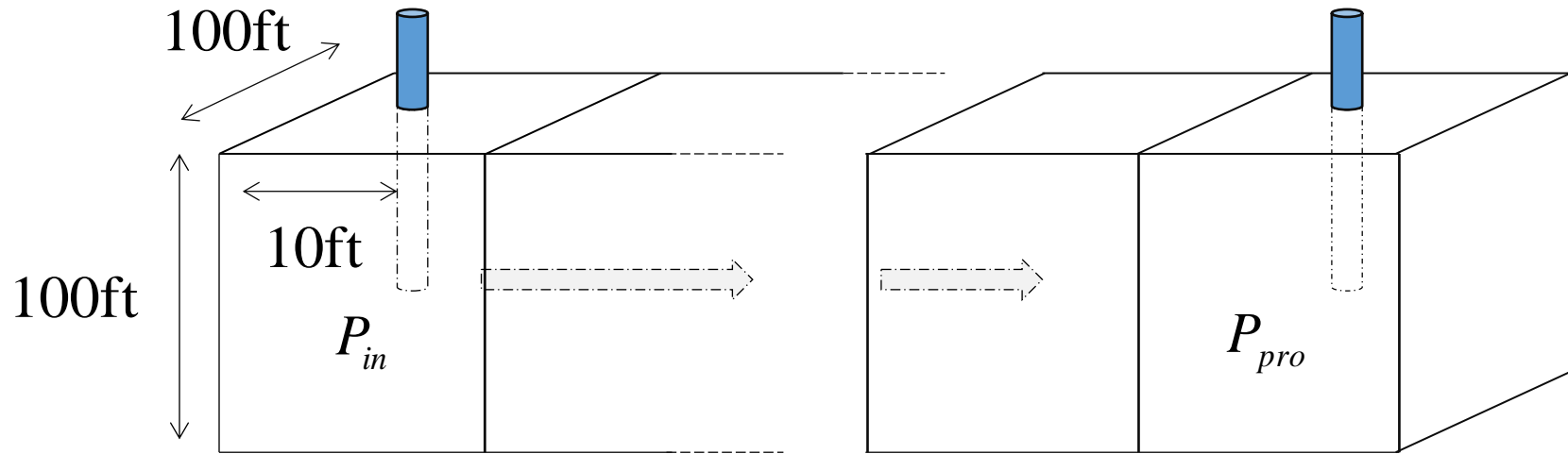
$$H_{\text{g}}(T) = \int_{T_{\text{ref}}}^T C_{\text{g}} dt, \quad H_{\text{vap}}(T) = \text{HVR} \cdot (T_{\text{c}} - T)^{\text{ev}}$$

$$C_{\text{g}} = C_{\text{pg1}} + C_{\text{pg2}} \cdot T + C_{\text{pg3}} T^2 + C_{\text{pg4}} T^3$$

	Oil	Water
C_{pg1}	-22.383	32.243
C_{pg2}	1.939	1.924e-3
C_{pg3}	-1.117e-3	1.055e-5
C_{pg4}	2.528e-7	-3.596e-9

-	Oil	Water
ev	0.38	0.38
HVR (J/mol-K)	8569	4820
T_{c}	373.2	617.0

Reservoir model



Initial / Operating Conditions

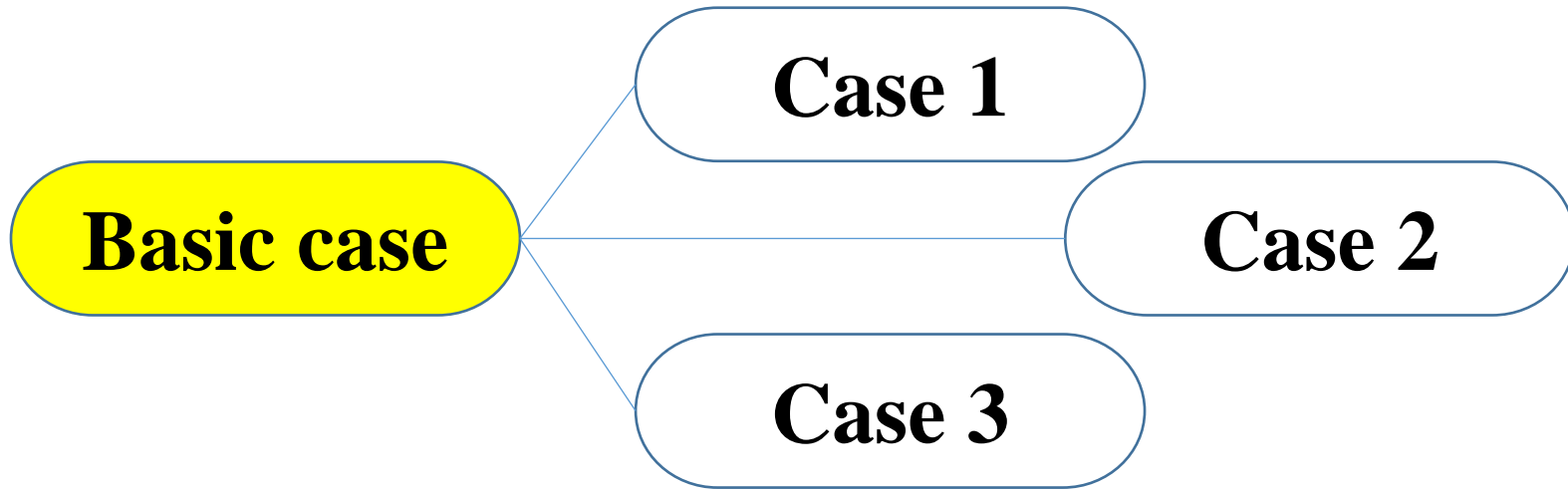
Grid size (x-direction)	100*3.048 m
Grid size (y-direction)	30.48 m
Grid size (z-direction)	30.48 m
Top Depth	3000 m
Temperature	100 °c
Reservoir pressure	30.33 MPa
Swir	0.16

Reservoir Properties

Permeability	300 mD
Porosity	0.33
B_o	1
B_w	1
Density (oil)	966 kg/m
Density (water)	998 kg/m
Viscosity (oil)	Oil A, Oil B, Oil C
Viscosity (water)	0.27 cp

Basic case

Basic case : the hot water of 200°C was injected into the reservoir containing the Oil A



Initial / Operating Conditions	
Injection	(1, 1)
Production	(100, 1)
Injection pressure	45.5 MPa
Production pressure	15.2 MPa
Injection temperature	200 °C

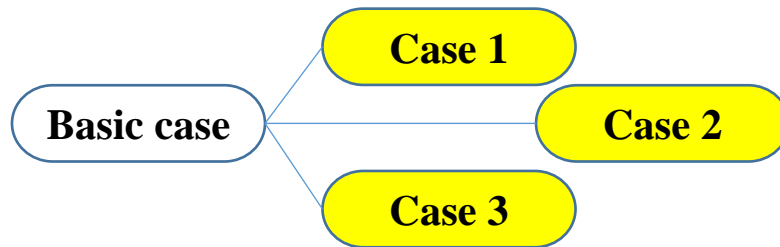
Reservoir oil properties		
Oil A	100 °C	100 cp
	150 °C	35.14 cp
	200 °C	15.41 cp

Case studies

Case 1: Temperature of injection water is different.
(100, 200 and 250°C)

Case 2: Reservoir oil is different. (Oil A, B and C)

Case 3: Well spacing is different. (0.5, 1.0 and 1.5 times)

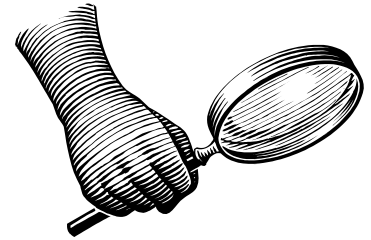


Well properties	
Injection	(1, 1)
Production	(100, 1)
Injection pressure	45.5 MPa
Production pressure	15.2 MPa
Injection temperature	100, 200, 250 °C
Well distance	*0.5 , *1.0, *1.5

Reservoir oil properties		
Oil A	100 °C	100 cp
	150 °C	35.14 cp
	200 °C	15.41 cp
Oil B	100 °C	1000 cp
	150 °C	351.42 cp
	200 °C	154.05 cp
Oil C	100 °C	10 cp
	150 °C	3.51 cp
	200 °C	1.54 cp

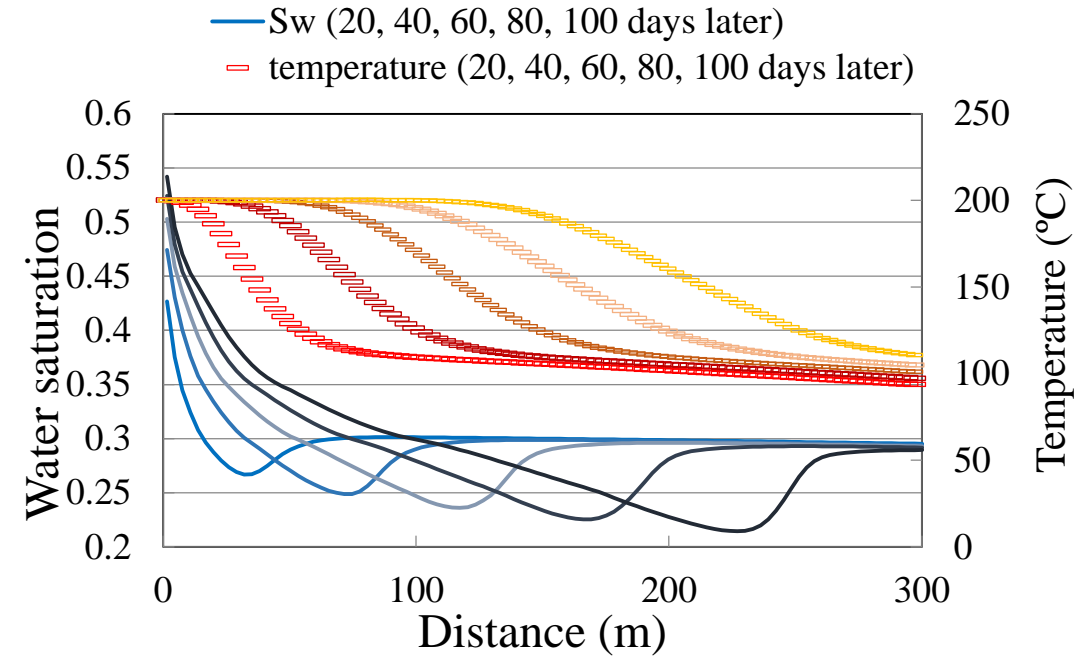
Verification

Basic case

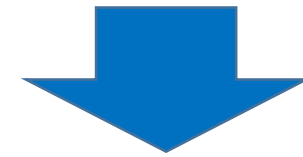


Verification of the basic study

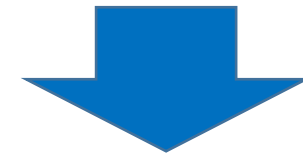
The simulated distributions of temperature and water saturation for different times



Temperature
increases gradually

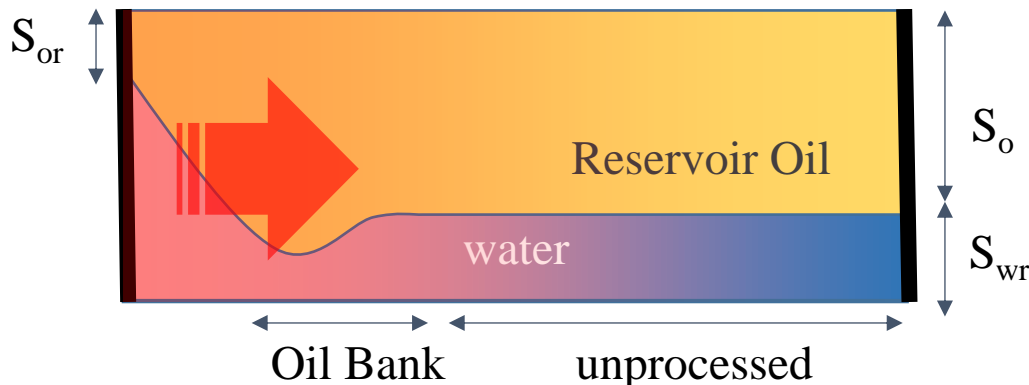


The mobility of oil phase is greater than
that of water phase.



The generation of
“oil bank”

Image of fluid distribution

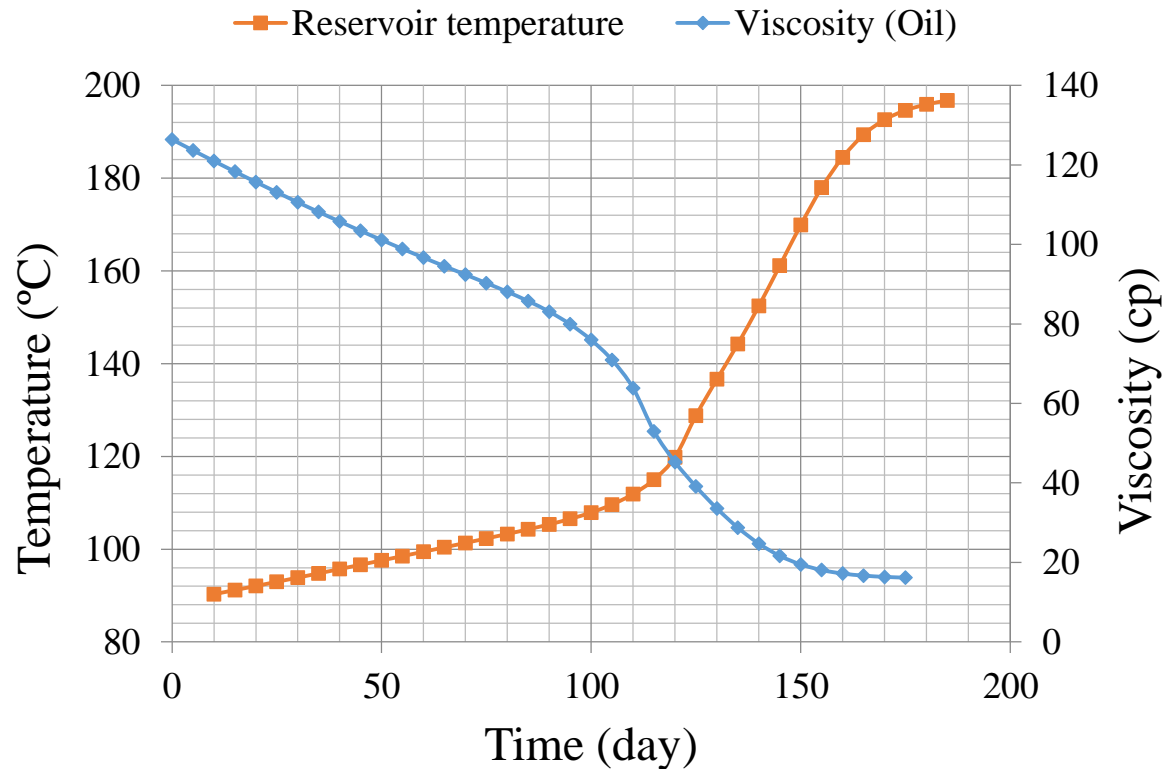


Verification of the basic study

The changes in the temperature and oil viscosity predicted for the grid block where the production well is located .

Viscosity correlation

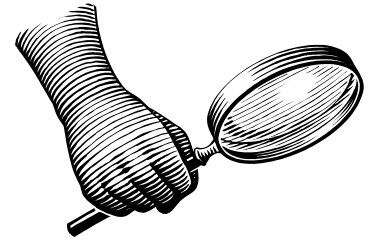
$$\mu_{\alpha} = a_{vis} \cdot \exp\left(\frac{b_{vis}}{T}\right)$$



These results seem to suggest that The simulator can appropriately predict the increase in the reservoir temperature, and hence the reduction of the oil viscosity along the hot water injection.

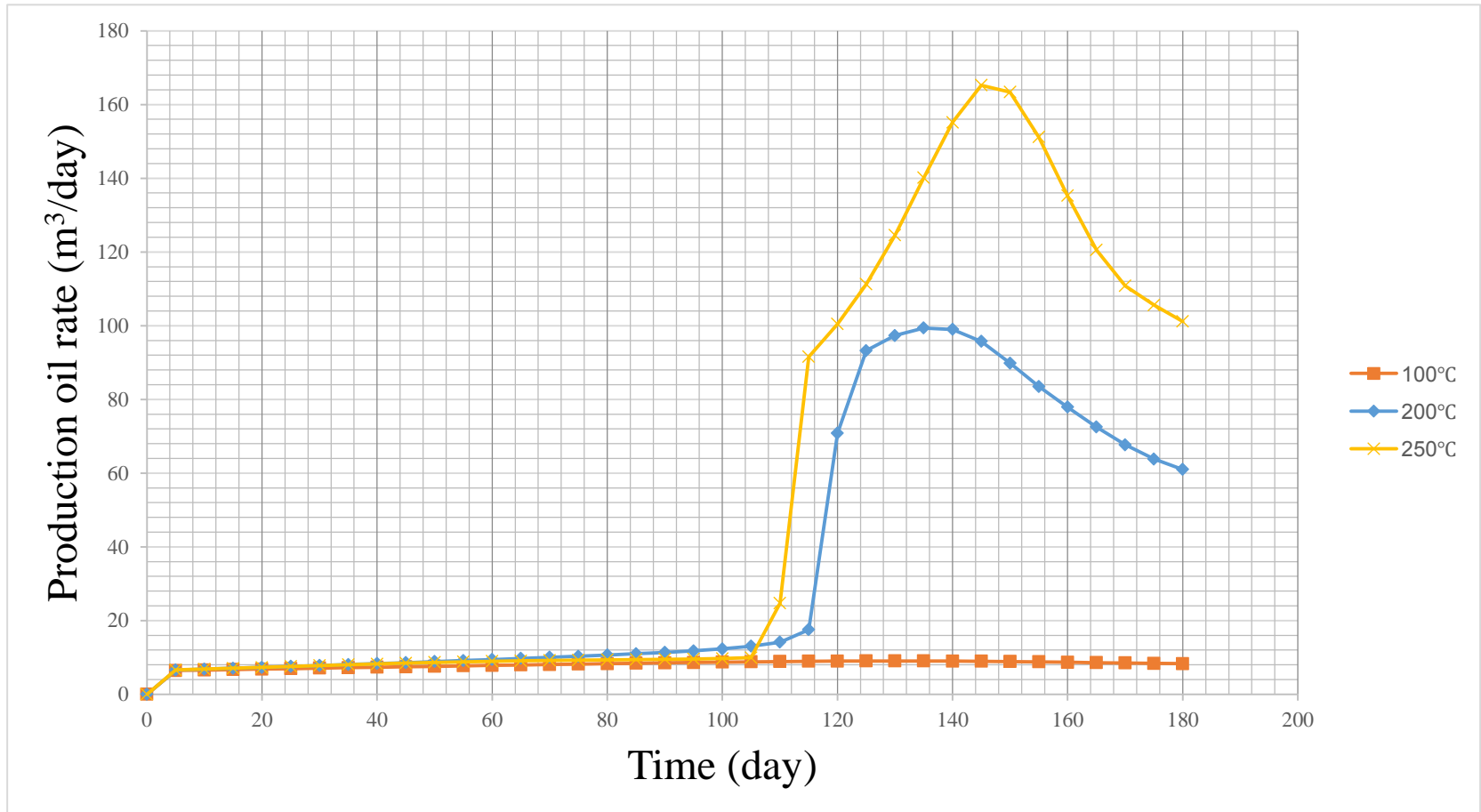
Verification of the case studies

Case1, Case2, Case3



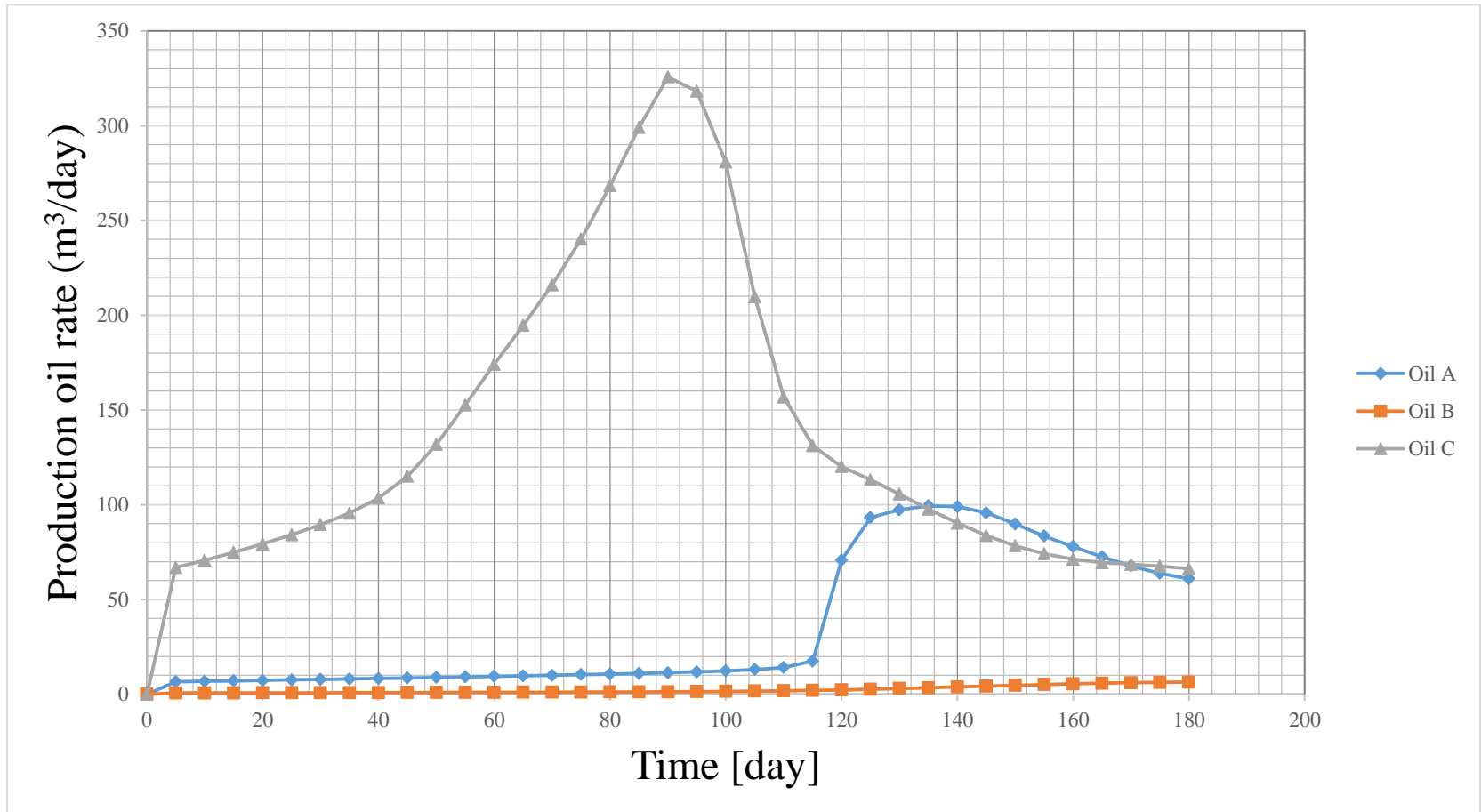
Case studies

Case1. Three different temperatures (100, 200 and 250°C) of the injection water.



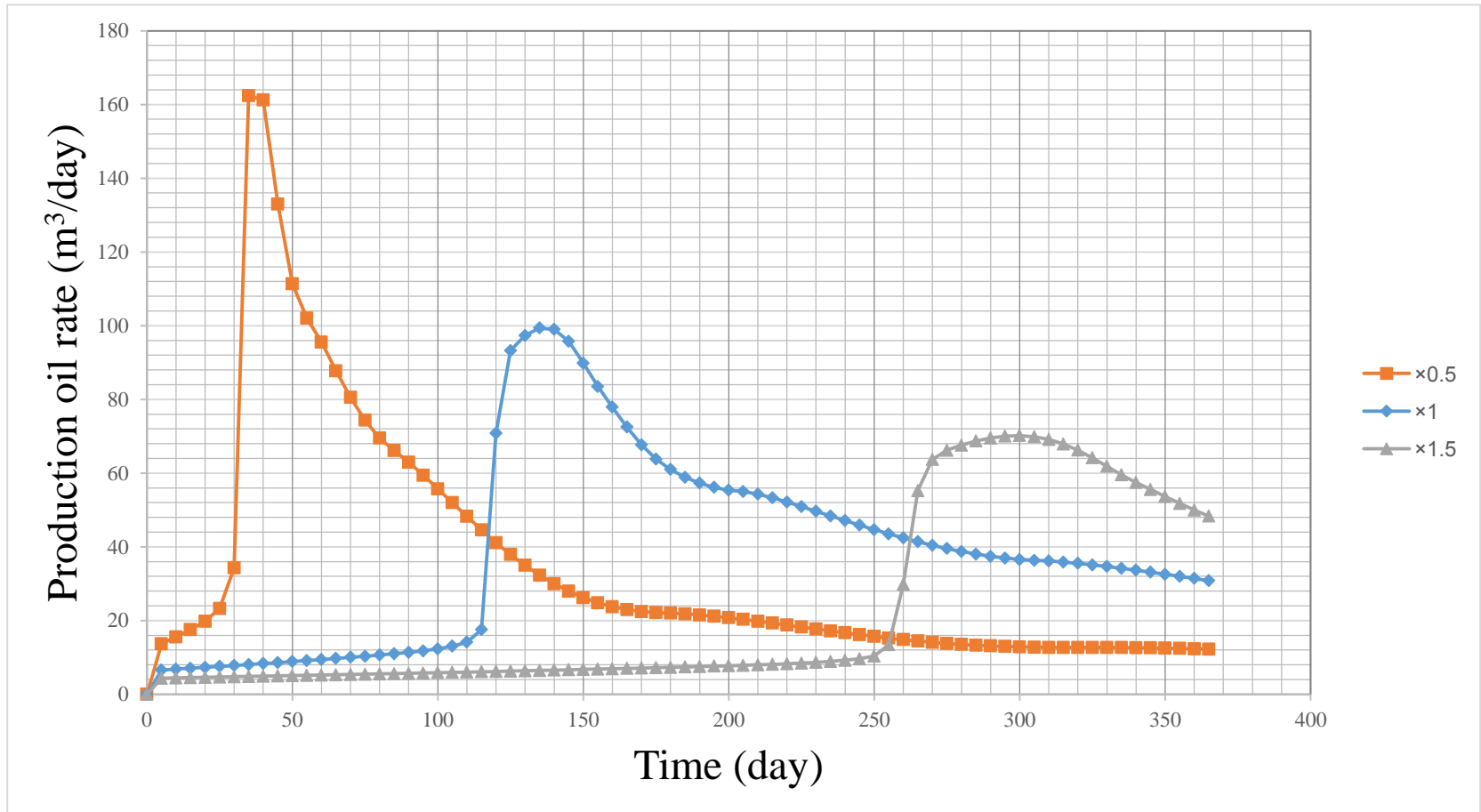
Case studies

Case2. Three different viscosities for Original oil viscosity and that the effect of the production oil rate.



Case studies

Case3. Well spacing (0.5, 1.0 and 1.5 times longer than that of the base case)



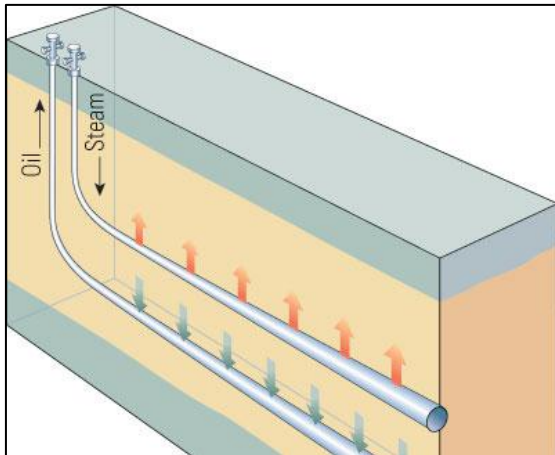
Conclusions

1. Oil viscosity decreases and **oil bank** is generated along with the advancement of hot water.
2. Oil recovery increase with increase in the temperature of injection water and with decrease in the original oil viscosity.
3. Shorter well spacing hasten the effect of hot water injection.

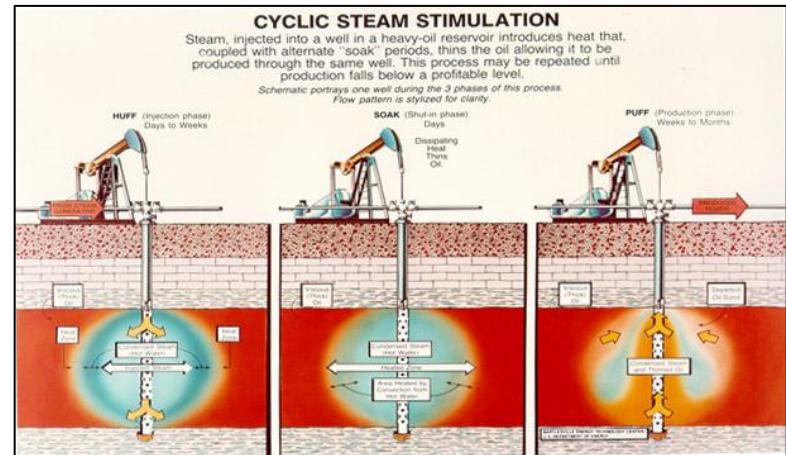
Future work

We are planning to further improve this simulator so that it can be applied to **2D- and 3D- problems** and can deal with **gaseous phase including steam**.

- Considering the gaseous phase
- Multidimensional expansion
- More effective constitutive equations



ref. Oilfield Glossary



ref. Regent energy group

Acknowledgement

I would like to express sincere gratitude to the colleague, Mr. Kaito, for his helpful guidance and advice.

ありがとうございました。

Thank you very much
for your attention.

ขอบอกคุณคุณ
terima kasih