# Research on the Controlling Conditions of Supercritical $CO_2$ Injection

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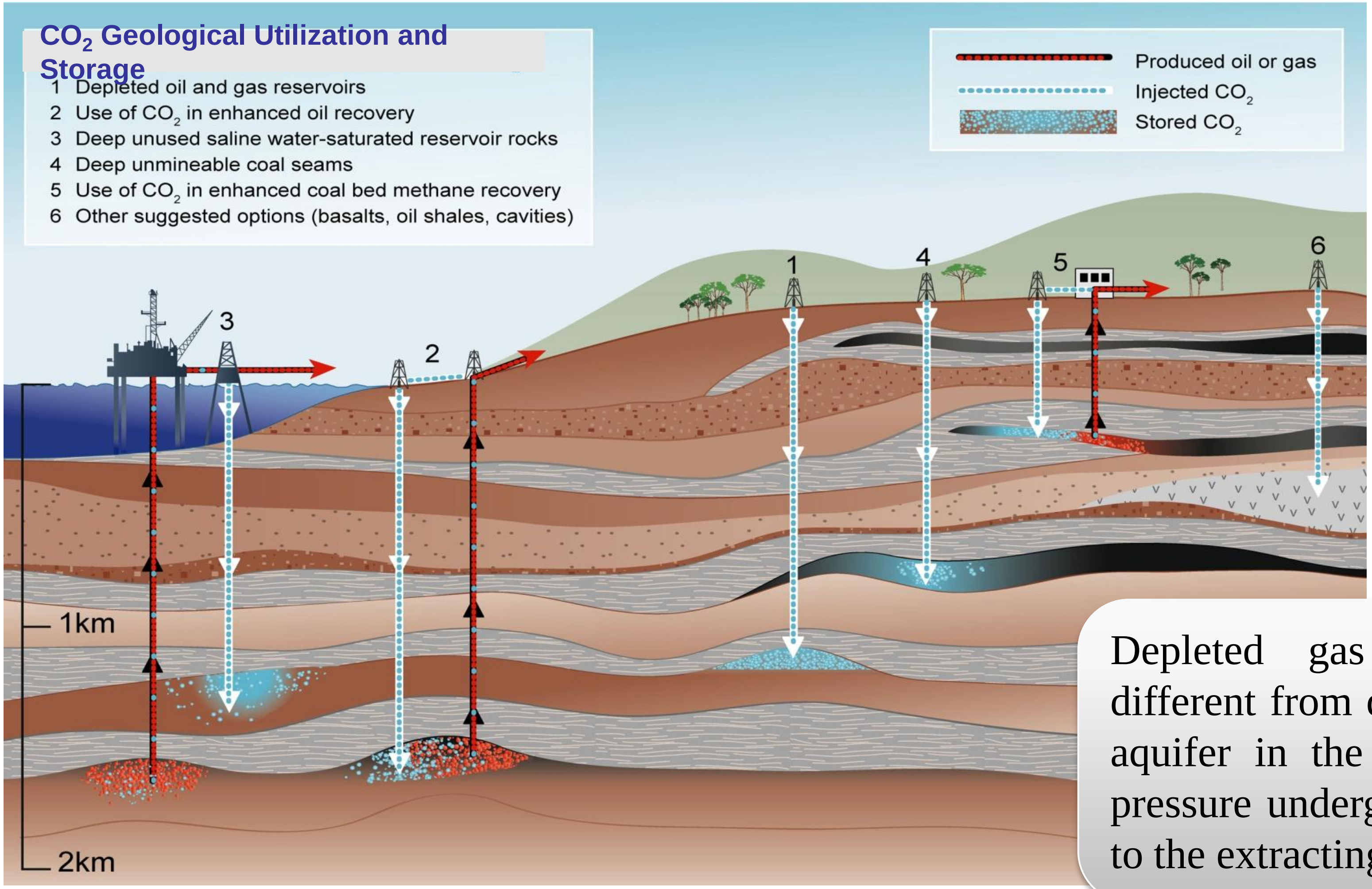
# Presentation Outline

1. Goal and status of the research
2. Research contents and method
3. Model building and parameter setting
4. Results analysis
5. Conclusions

## 1 Goal and status of the research

# Goal and status of the research



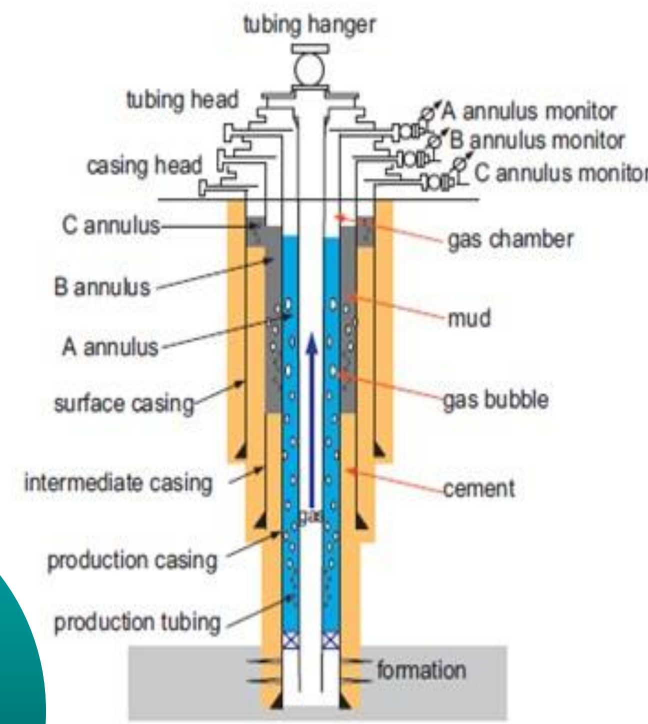

Depleted gas field is different from deep saline aquifer in the profile of pressure underground due to the extracting of gas.

# Goal and status of the research

Many projects are on operating or on building around the world recent years.

| stage | Projects | Start time | location | Capture amount/(Mt/a) | Sequestration type |
|---|---|---|---|---|---|
| Operation phase | Val Verde natural gas industry | 1972 | USA | 1.3 | EOR |
| | Shute Creek processing equipment | 1986 | USA | 7 | EOR |
| | Sleipner $CO_2$ injecting project | 1996 | Norway | 1 | Deep saline aquifer |
| | Great Plains synfuel plant and Weyburn-Midale project | 2000 | USA/Canada | 3 | EOR and MMV |
| | Snφhvit $CO_2$ injecting project | 2008 | Norway | 0.7 | Deep saline aquifer |
| | Century Plant project | 2010 | USA | 5（another 3.5Mt is in building | EOR |
| | Shenghua group $CO_2$ capture and sequestration demonstration project | 2011 | China | 0.1 | Deep saline aquifer |
| building | Lost Cabin gas plant | 2012 | USA | 1 | EOR |
| | Shengli oil field $CO_2$ capture and sequestration demonstration project | 2013-2014 | China | 1 | EOR |
| | Gorgon $CO_2$ injecting project | 2015 | Australia | 3.4~4 | Deep saline aquifer |
| | CNPC Jilin oil field $CO_2$-EOR project | 2015 | China | 1.2 | EOR |

# Goal and status of the research

# Goal and status of the research

**Wellbore pressure and temperature profile**

- **Analytical method**
  - *Wanghaizhu 2011*, Hongjun Zhu *2012*, Jacques *2005*, P.K. Chadha *1993*
    - baseed on Ramay model, carry out different analytical method to calculate wellbore pressure and temperature profile
    - the effect factors of wellbore pressure and temperate profile are various, such as CO2 density, viscosity, heat conductivity
    - Injecting velocity plays a vital role in affecting the injecting temperature of the reservoir
    - In the wellbore, high injecting temperature , low pressure and big injecting velocity can induce the rapid decrease of temperature and less heat loss
- **Numerical simulation**
  - Mireault 2010, Meng Lu *2008*, A.R. Hasan *2012*, Lehua Pan *2011*, P. Pourafshary 2009
    - Different from water injecting well, enhance the injecting velocity can not increase injecting pressure dramatically
    - implement different numerical simulation method to evaluate the change of pressure and temperature in the wellbore

**Wellbore stability and safety**

- *Theresa 2009*, *Rajesh 2008*, *Litang Hu 2012*
  - Risk assessment of the gas or CO2 leakage during CCS.
  - Numercial study of different site CO2 leakage mechanicals with T2well or other simulation tools to provide theoretical support for real projects

# Goal and status of the research

## Research goal

•Research on the supercritical $CO_2$ injecting conditions with **numerical simulation** to optimize the wellhead injecting parameters,

• Meanwhile, carry out sensitivity analysis on the injecting parameters such as temperature, pressure, $CO_2$ saturation,

• **Providing theoretical support for safety and efficient sequestration.**

## 2 Research contents and method

# Contents of the research

## Research contents

### Depleted gas field

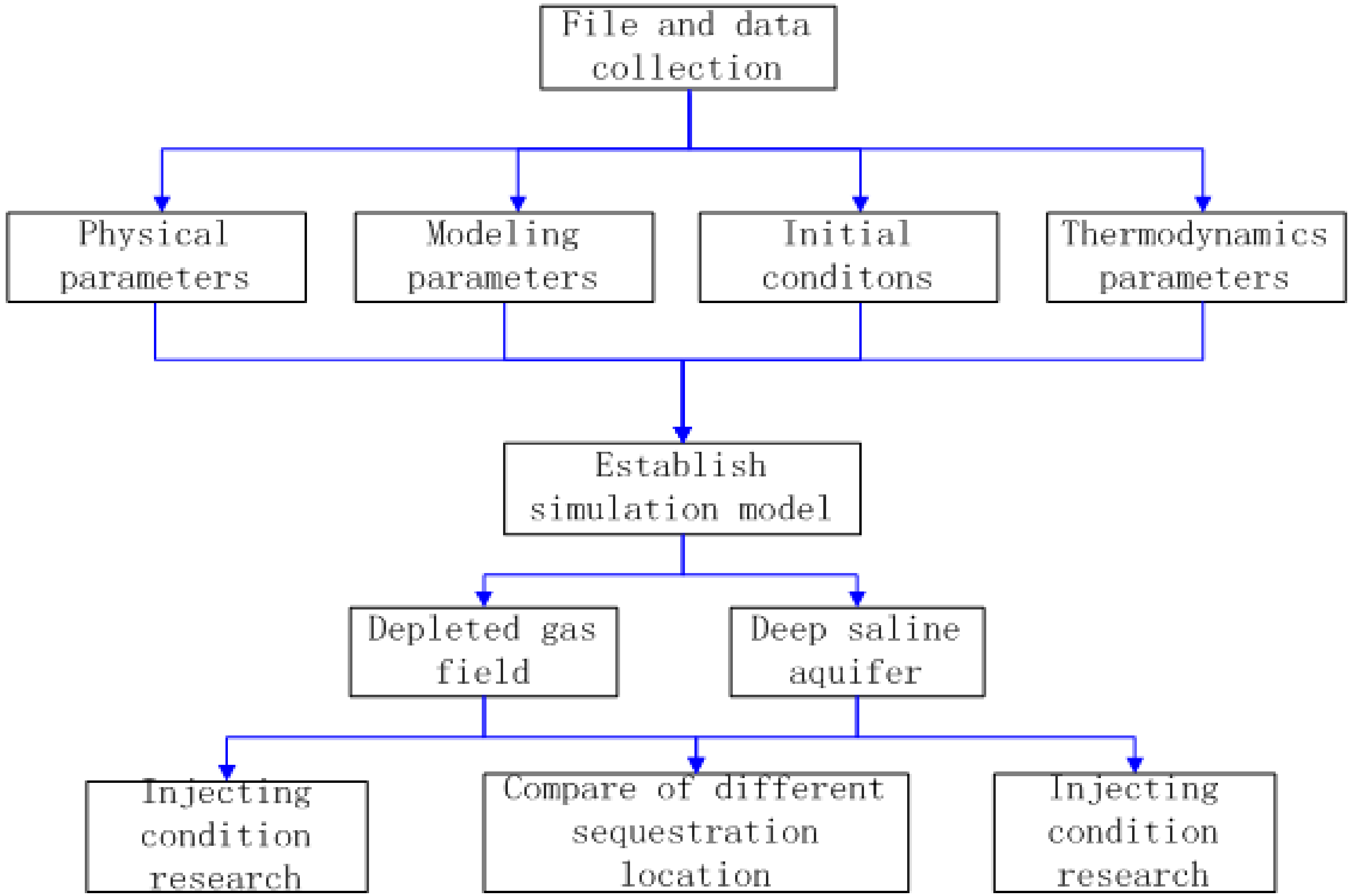
Simulating the correlations between wellhead injecting parameters(pressure, temperature, $CO_2$ saturation) and the actual injecting parameter(pressure, temperature and $CO_2$ flow rate) of the reservoir and study on the influence factors of well bottom conditions.

Research on the impact of different sequestration site type to the supercritical CO2 injecting condition.

### Deep saline aquifer

Simulating the correlations between wellhead injecting parameters(pressure, temperature, $CO_2$ saturation) and the actual injecting parameter(pressure, temperature and $CO_2$ flow rate) of the reservoir and study on the influence factors of well bottom conditions.

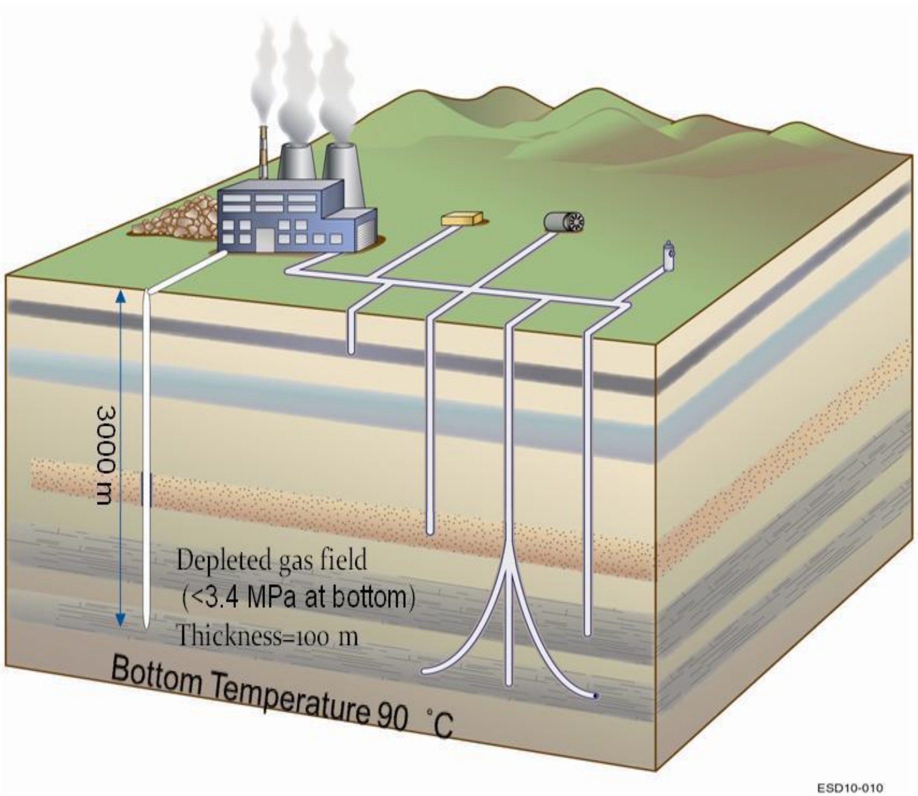
# Contents of the research

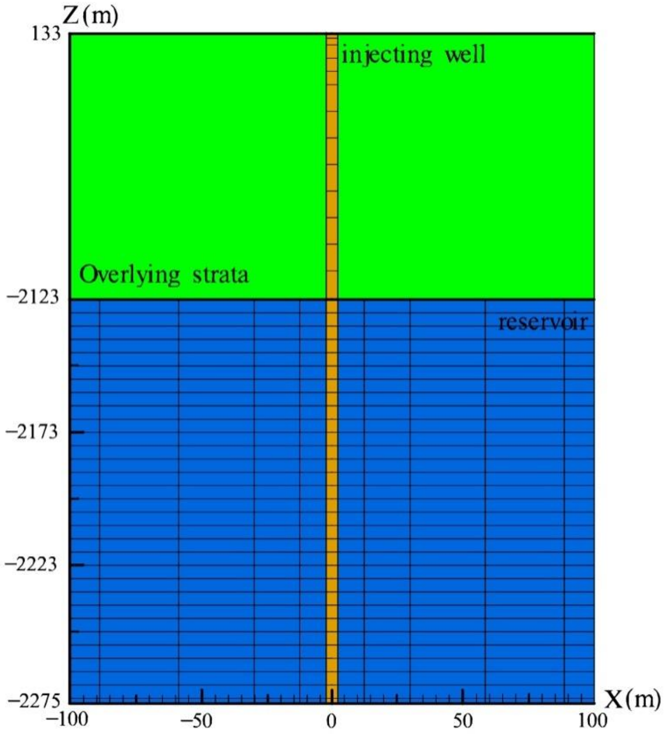



**Research technical road map**

## 3 Model building and parameter setting

# Model building and parameters setting




Depleted gas field injection scenario sketch

A 2D radially symmetry gird is used

# Model building and parameters setting

## Basic hydro-geological parameters

| parameter | Wellhead injecting element | wellbore | reservoir |
|---|---|---|---|
| Horizontal permeability（$m^2$） | $2\times10^{-7}$ | $2\times10^{-7}$ | $2.0\times10^{-13}$ |
| Vertical permeability（$m^2$） | $2\times10^{-8}$ | $2\times10^{-8}$ | $2.0\times10^{-14}$ |
| porosity（SI） | 50% | 100% | 28% |
| $CO_2$ saturation | 1 | 0 | 0 |
| Diffusion coefficient（$m^2/s$） | $1.0\times10^{-9}$ | | |
| Rock density（$kg/m^3$） | $2600\times10^3$ | | 2600 |
| Heat conductivity（W/m℃） | 2.51 | | |
| Rock particle specific enthalpy（J/kg℃） | $9.2\times10^{52}$ | | $9.2\times10^2$ |
| salinity（%） | 0 | | 0 |
| $k_{rl}$： liquid relative permeability | $k_{rl}=\sqrt{S^*}\left\{1-(1-\left[S^*\right]^{1/m})^m\right\}^2 \qquad S^*=(S_l-S_{lr})/(1-S_{lr})$ | | |
| $S_{lr}$： residual liquid saturation | $S_{lr}=0.30$ | | $S_{lr}=0.20$ |
| $k_{rg}$： gas relative permeability | $k_{rg}=(1-\hat{S})^2(1-\hat{S}^2) \qquad \hat{S}=(S_l-S_{lr})/(S_l-S_{lr}-S_{gr})$ | | |
| $S_{gr}$： residual gas saturation | $S_{gr}=0.05$ | | $S_{gr}=0.28$ |
| Pcap： pore pressure | | | $P_{cap}=-P_0(\left[S^*\right]^{-1/m}-1)^{1-m}$ $S^*=(S_l-S_{lr})/(1-S_{lr})$ |
| m： index | | | m =0.457 |
| Pmax (Pa) | | | $1.0\times10^7$ |
| $P_0$: pressure coefficient | | | $P_0$=19.61 KPa |

# Model building and parameters setting

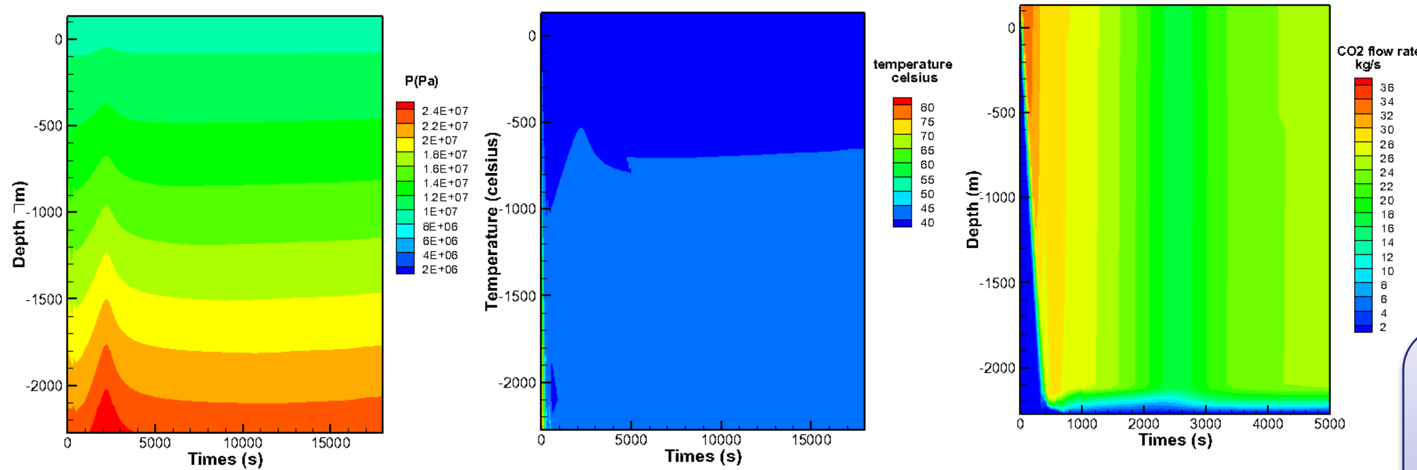
**Experimental level setting**

| | P/MPa | T/℃ | Sg |
|---|---|---|---|
| Base case | 8.5 | 35 | 1.0 |
| case1 | 7.5 | 35 | 1.0 |
| case2 | 12 | 35 | 1.0 |
| case3 | 16 | 35 | 1.0 |
| case4 | 25 | 35 | 1.0 |
| case5 | 40 | 35 | 1.0 |
| case6 | 50 | 35 | 1.0 |
| case7 | 8.5 | 25 | 1.0 |
| case8 | 8.5 | 42 | 1.0 |
| case9 | 8.5 | 50 | 1.0 |
| case10 | 8.5 | 60 | 1.0 |
| case11 | 8.5 | 70 | 1.0 |
| case12 | 8.5 | 80 | 1.0 |
| case13 | 8.5 | 35 | 0.9 |
| case14 | 8.5 | 35 | 0.7 |
| case15 | 8.5 | 35 | 0.5 |
| | Depleted gas feild | | Deep saline aquifer |
| Pressure ingredient/MPa/km | 9.75 | | 10 |
| Temperature ingredient/℃/100m | 0.3 | | 0.3 |

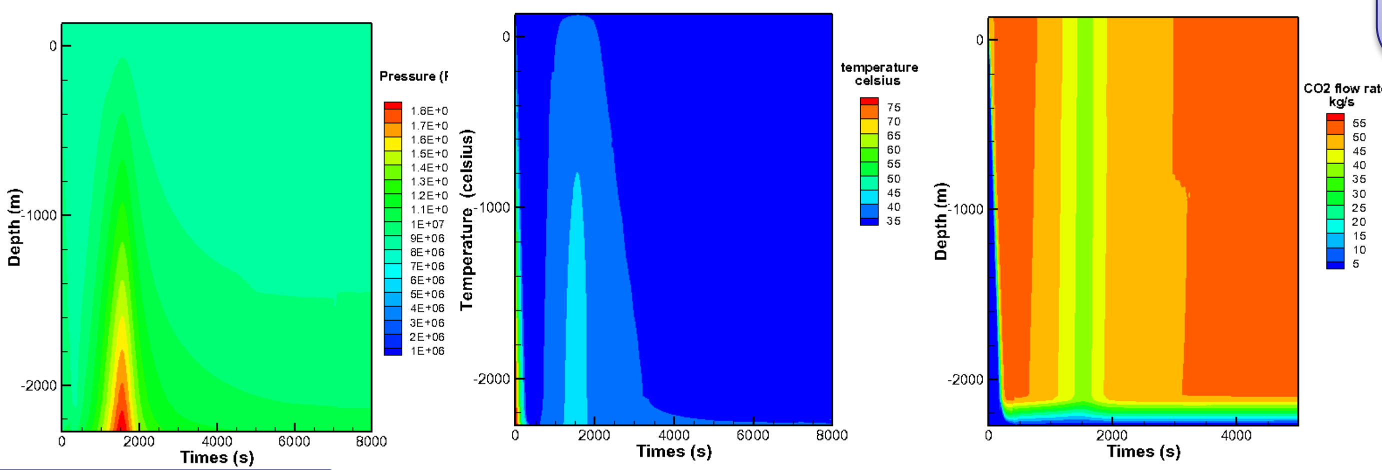
# 4 Results analysis

# Results analysis

Depleted gas field



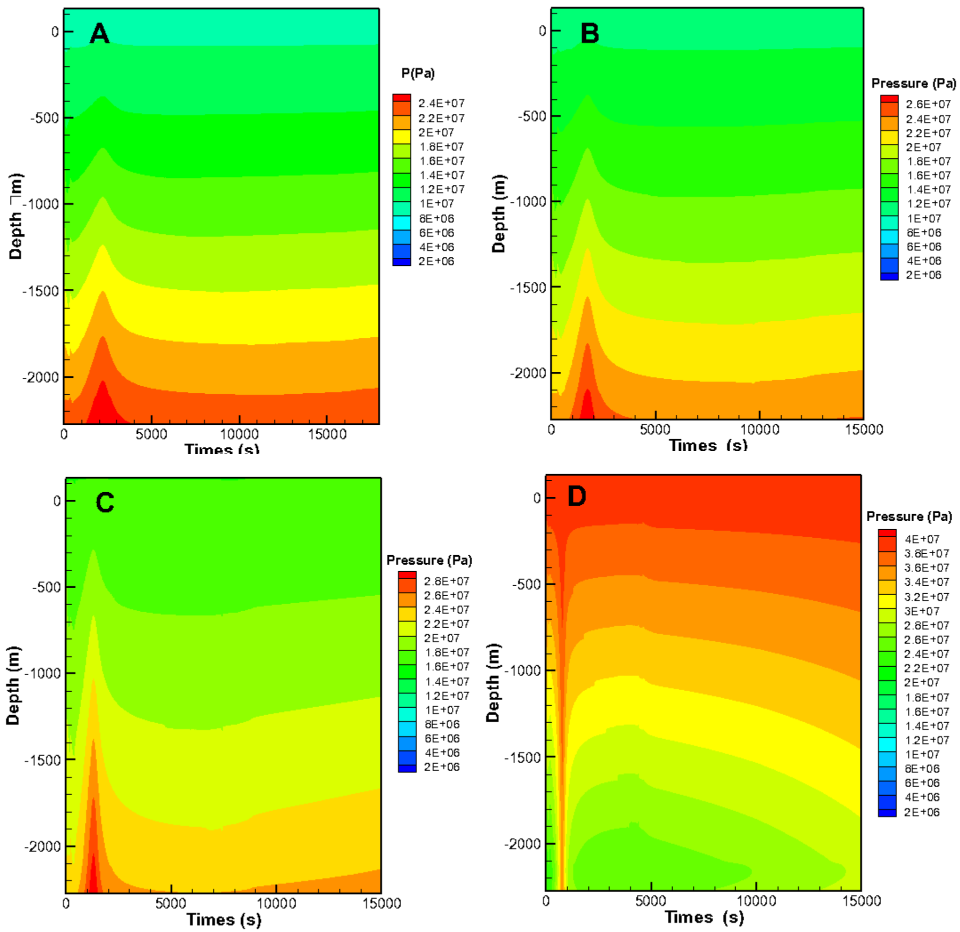

Both under the same injecting condition：
**Pressure**：8.5MPa
**Temperature**： 35℃
**$CO_2$ saturation**： 1.0



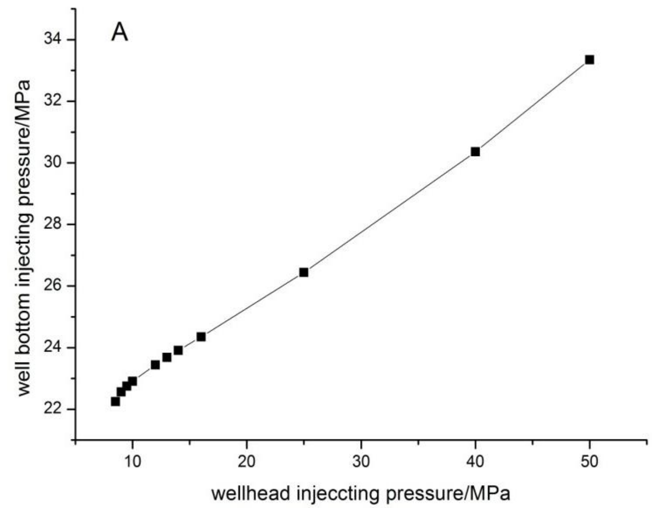

Deep saline aquifer

# Results analysis

## —— depleted gas field




Wellbore pressure change in different injecting pressure .A（8.5MPa）、B（11MPa）、C（16MPa）D（40MPa）

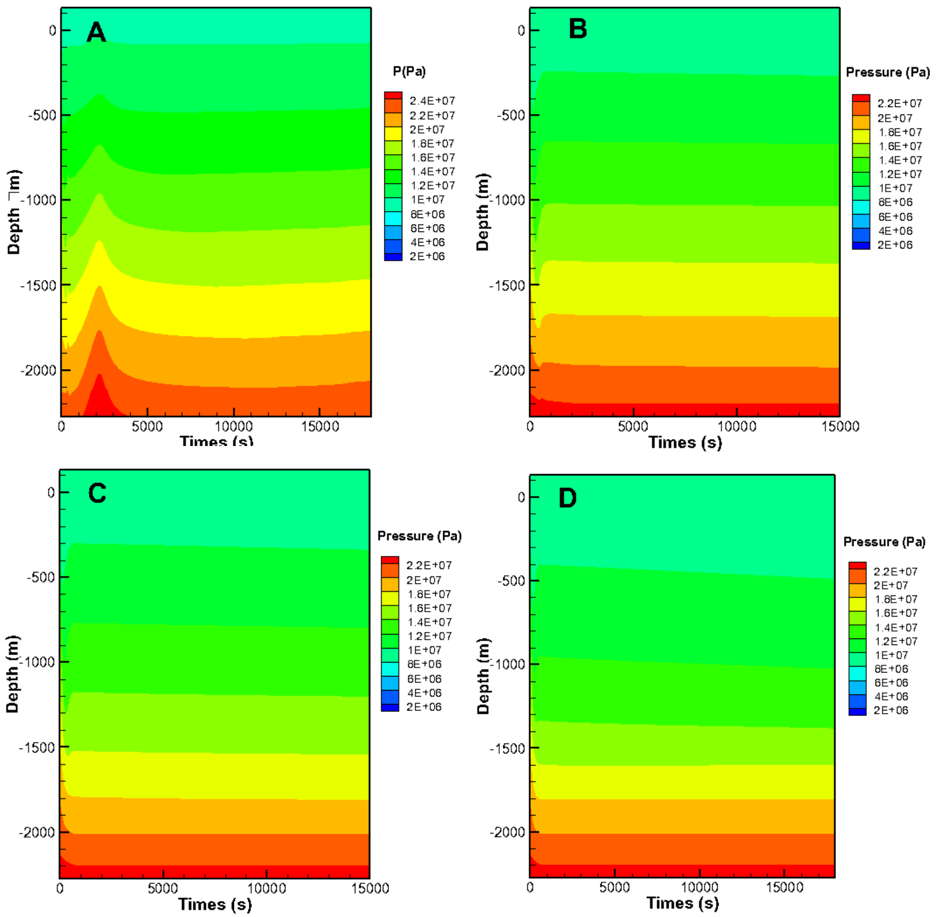



**Well bottom injecting pressure**

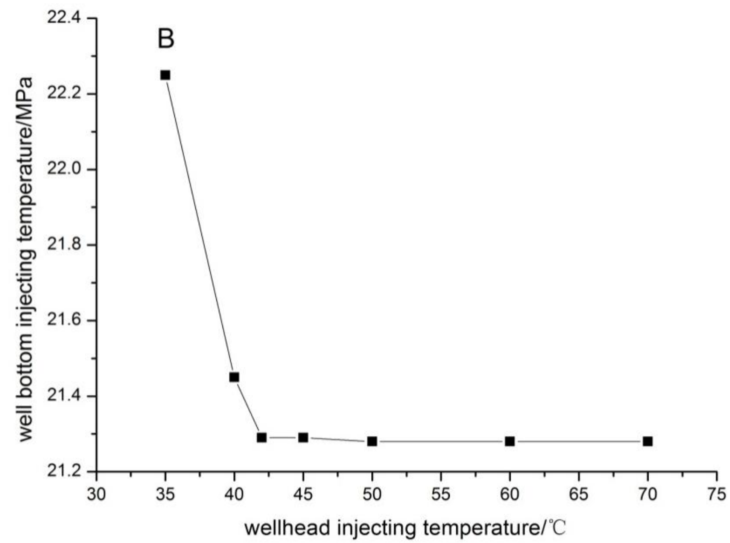
- Well bottom injection pressure is in positive correlation with the wellhead injecting pressure.
- The higher the injecting pressure is, the more drastically the pressure change in the wellbore.

# Results analysis

## —— depleted gas field




Wellbore pressure change in different injecting temperature.
A（35℃）、B（42℃）、C（50℃）D（80℃）




**Well bottom injecting pressure**

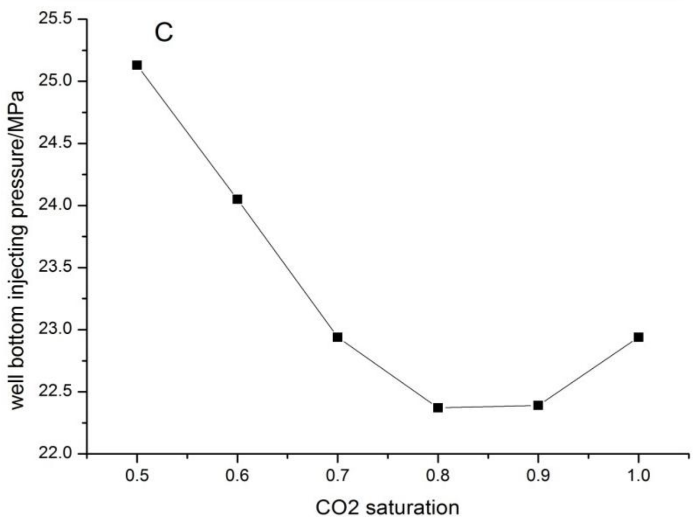
● With the increase of injecting temperature(＜45 ℃）, well bottom injection pressure declines, but when the injecting temperature exceeds 45℃， the well bottom injection pressure keeps stable.

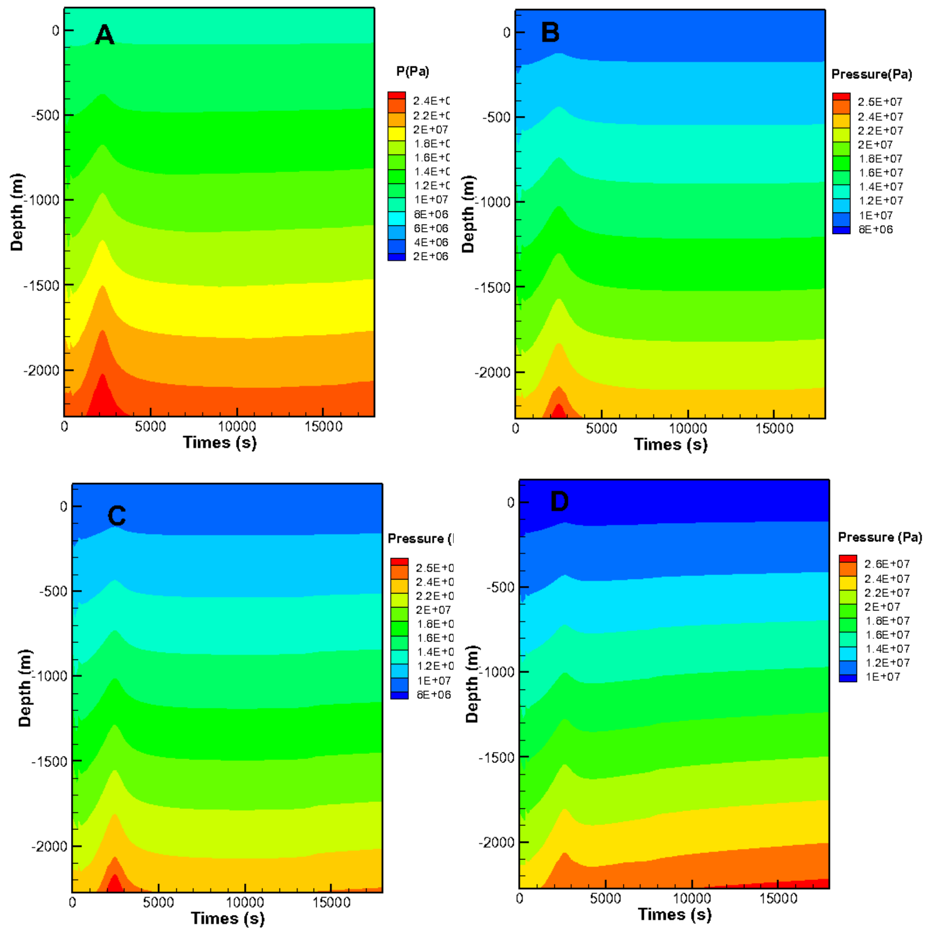
# Results analysis

## —— depleted gas field

**Well bottom injection pressure**

●there exists one critical Sg. When Sg＜0.8， the rising of Sg can lead to the decline of reservoir injecting pressure, while if Sg＞0.9， the increase of Sg may cause pressure uplifting. But when Sg=0.8,0.9, the pressure keeps the same.

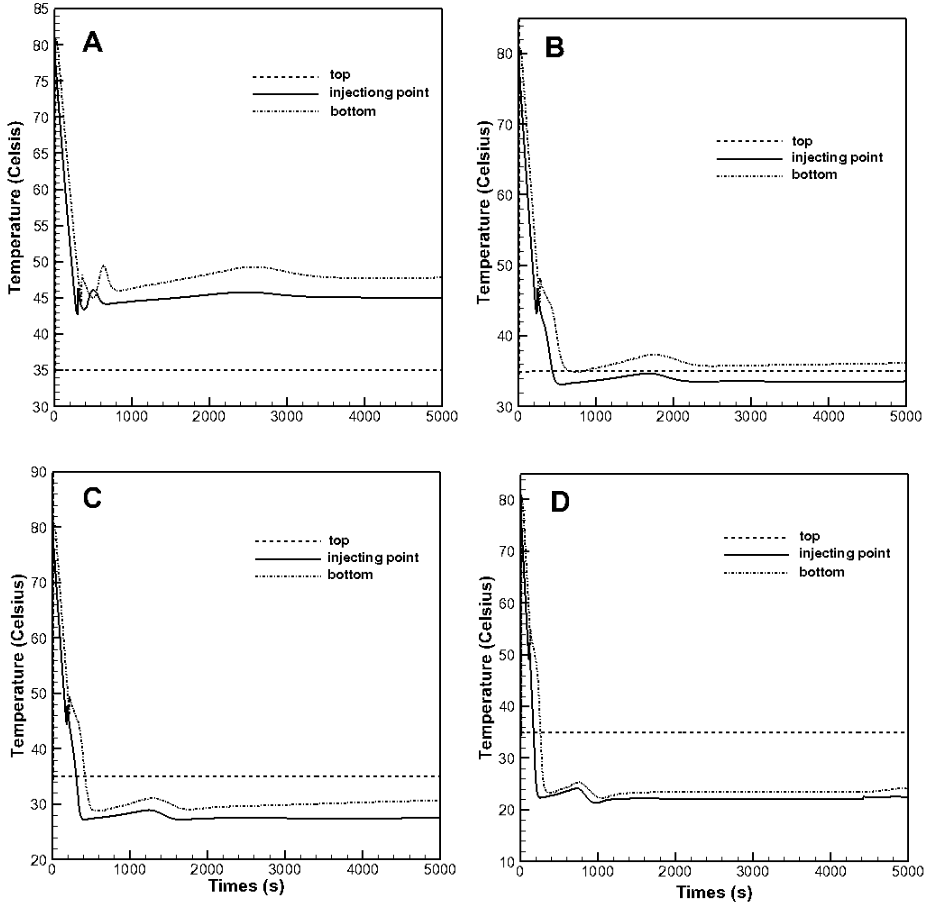


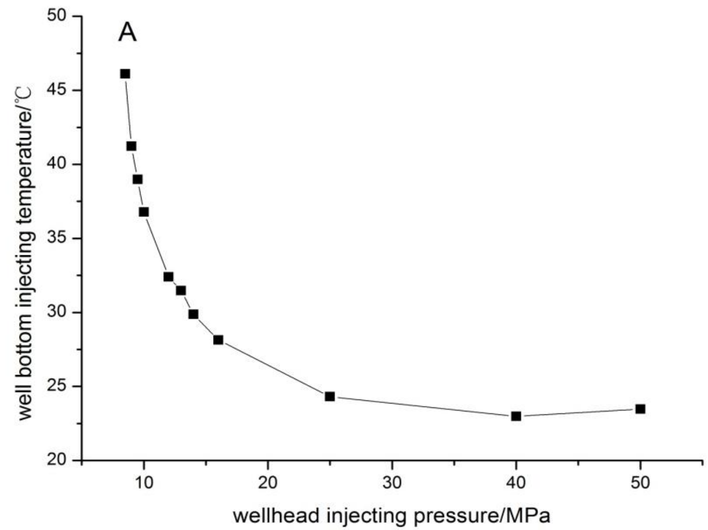

Wellbore pressure change in different $CO_2$ saturation. A（1.0）、B（0.9）、C（0.7）and D（0.5）

# Results analysis

## —— depleted gas field




Well bottom temperature in different injecting pressure .A（8.5MPa）、B（11MPa）、C（16MPa）D（40MPa）

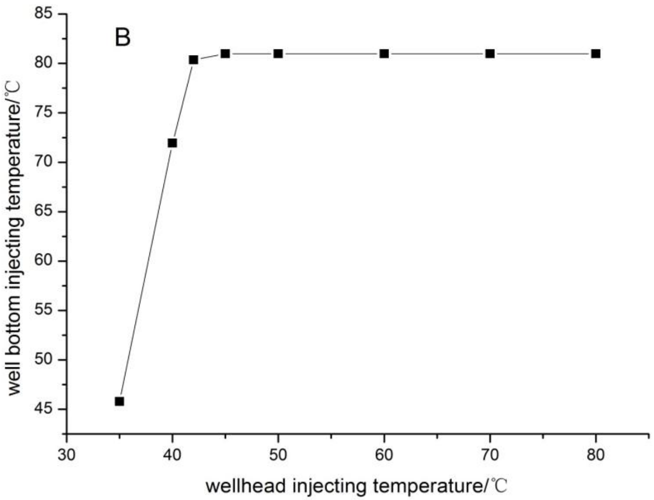


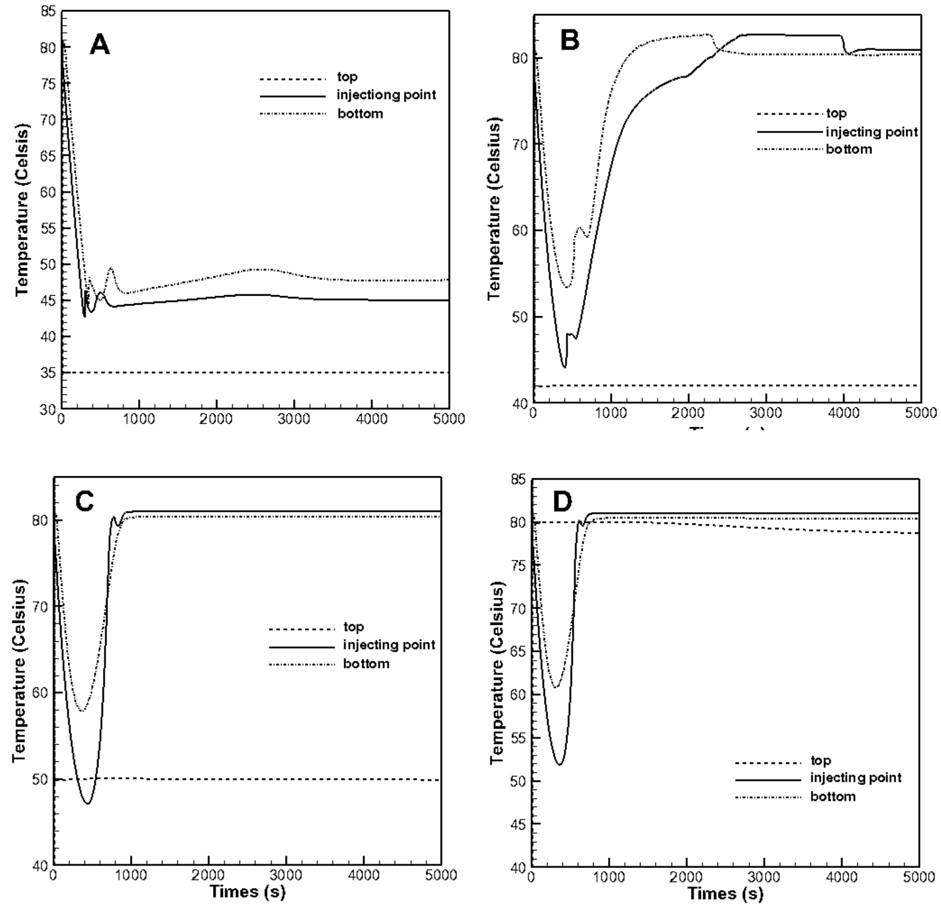

**Well bottom injection temperature**

● well bottom injection temperature is in negative correlation with the wellhead injecting pressure.

# Results analysis

## —— depleted gas field




**Well bottom injection temperature**

- Within 45 ℃, well bottom injection temperature increases with the enhance of wellhead injecting temperature.

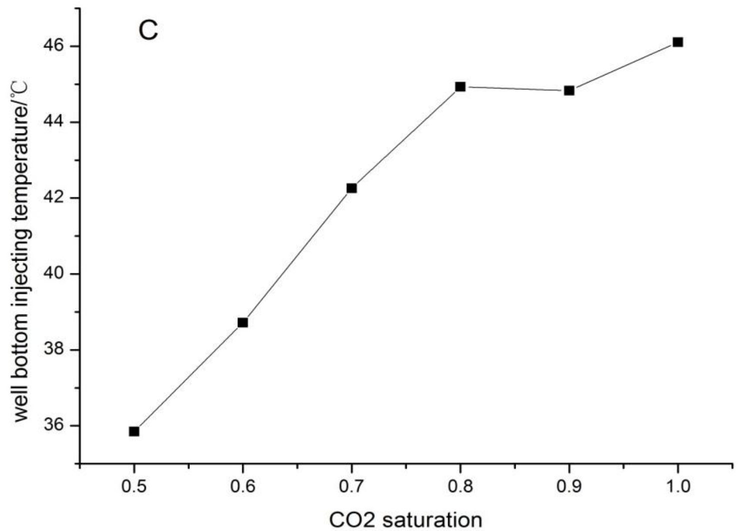
Well bottom temperature change in different injecting temperature. A（35℃）、B（42℃）、C（50℃）D（80℃）

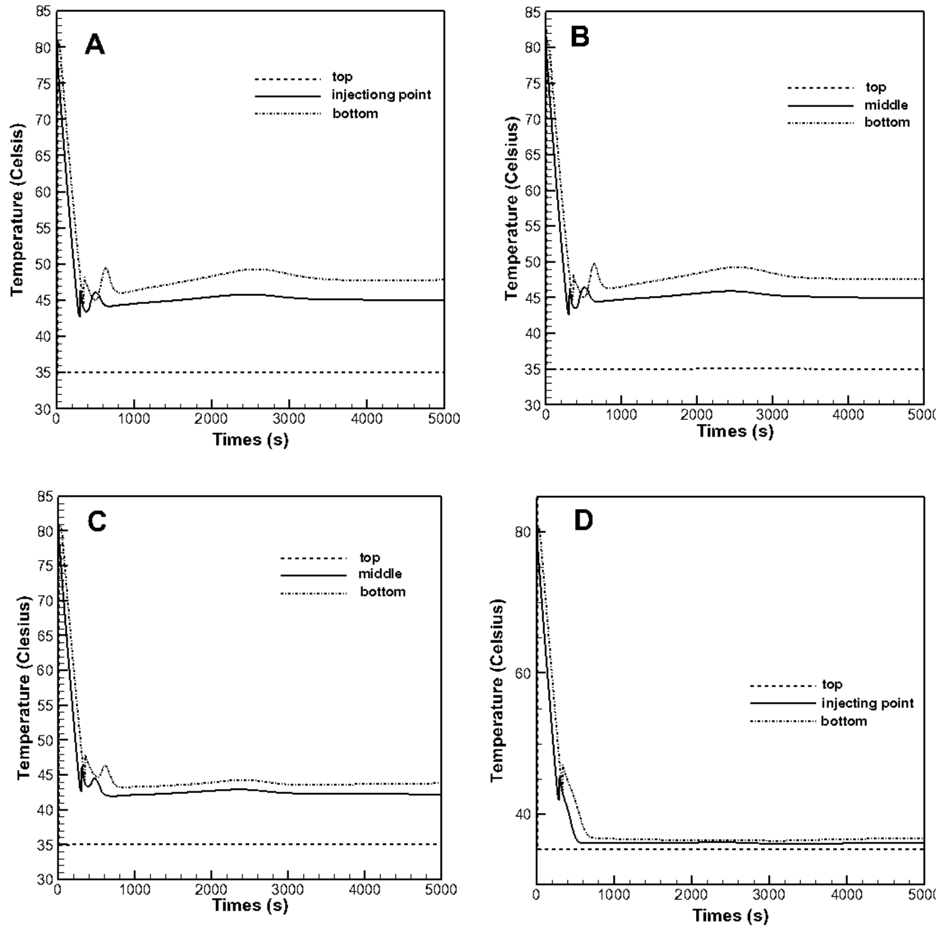
# Results analysis

## —— depleted gas field

### Well bottom injection temperature

●With the increase of $CO_2$ saturation, well bottom injection temperature ascends accordingly. But when Sg=0.8,0.9, the temperature keeps the same.

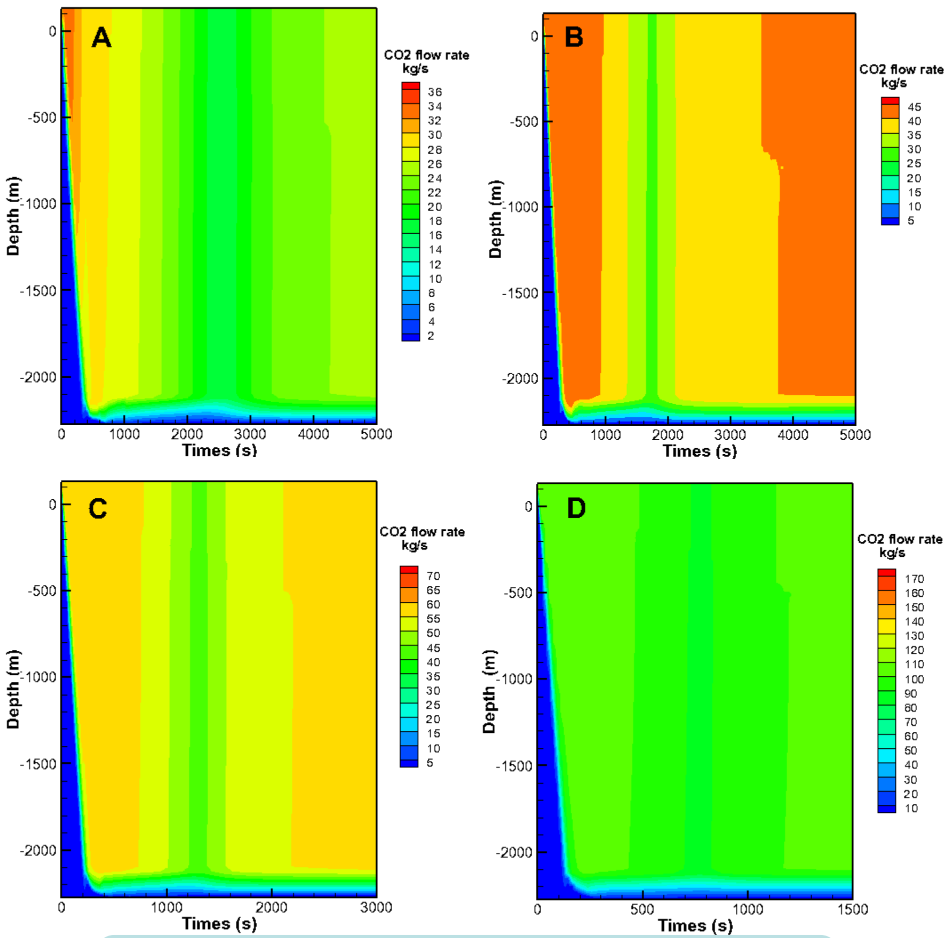


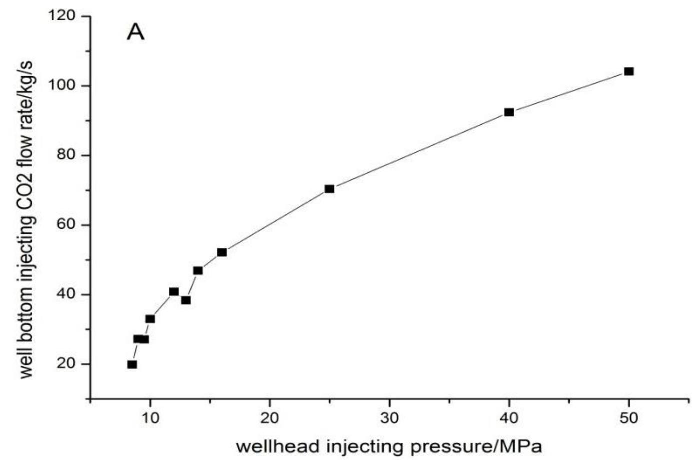

Well bottom temperature change in different $CO_2$ saturation. A（1.0）、B（0.9）、C（0.7）and D（0.5）

# Results analysis

## —— depleted gas field



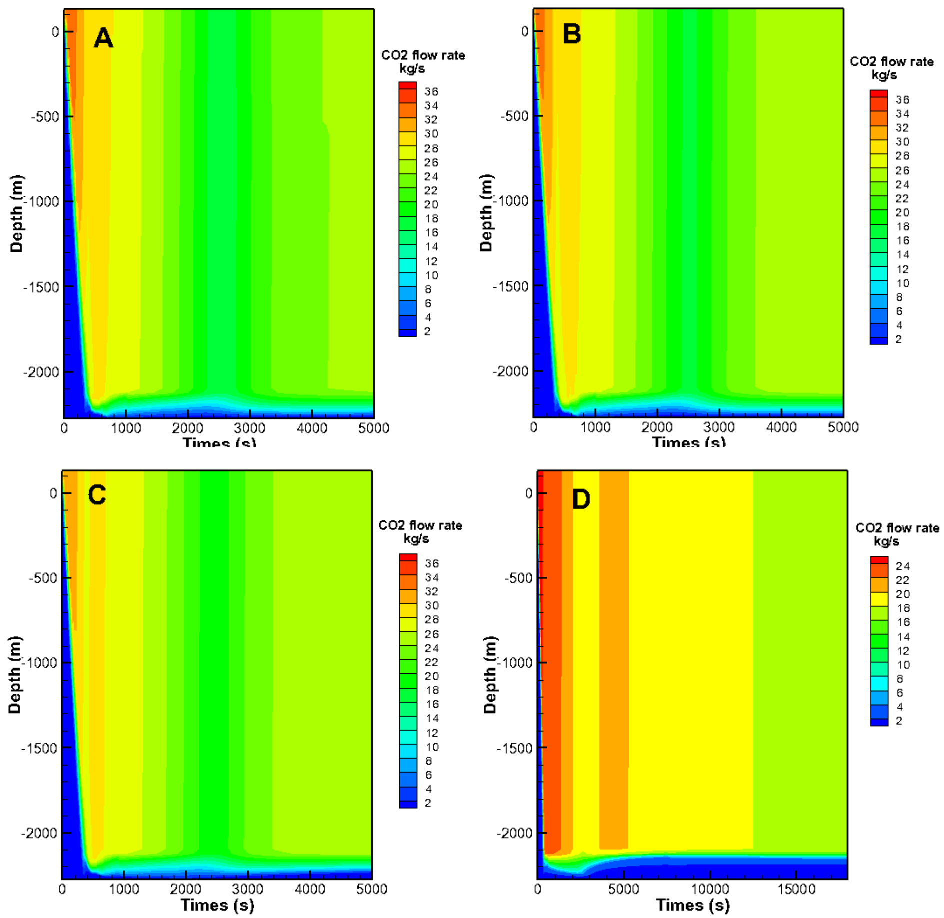

Wellbore $CO_2$ flow rate in different injecting pressure .
A（8.5MPa）、B（11MPa）、C（16MPa）D（40MPa）




**Well bottom injecting $CO_2$ flow rate**

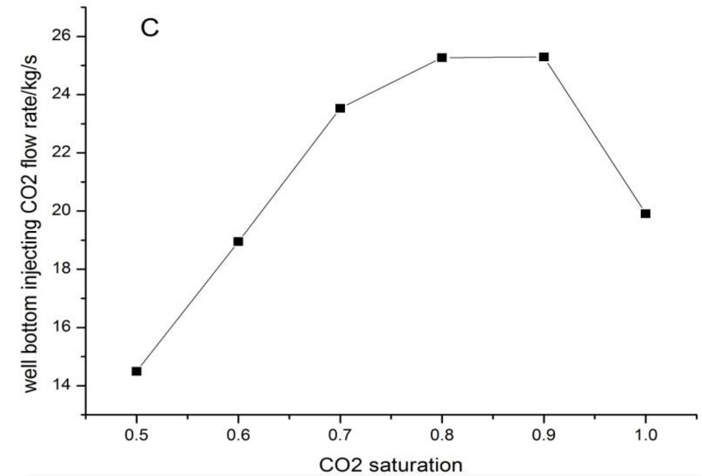
●The plot line shows that well bottom injecting $CO_2$ flow rate is increase with the uplift of wellhead injecting pressure, but the change amplitude declines during the process.

# Results analysis




Wellbore $CO_2$ flow rate in different injecting $CO_2$ saturation .A（1.0）、B（0.9）、C（0.7）D（0.5）

## —— depleted gas field

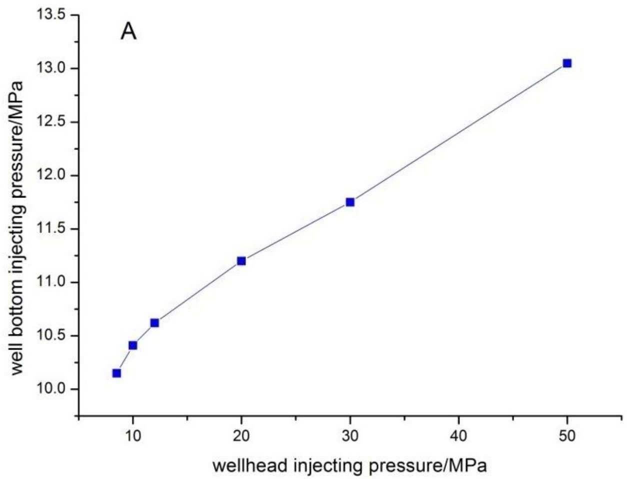


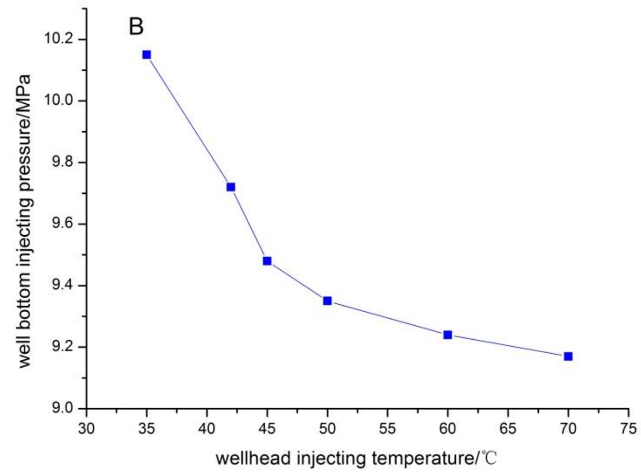

**Well bottom injecting $CO_2$ flow rate**

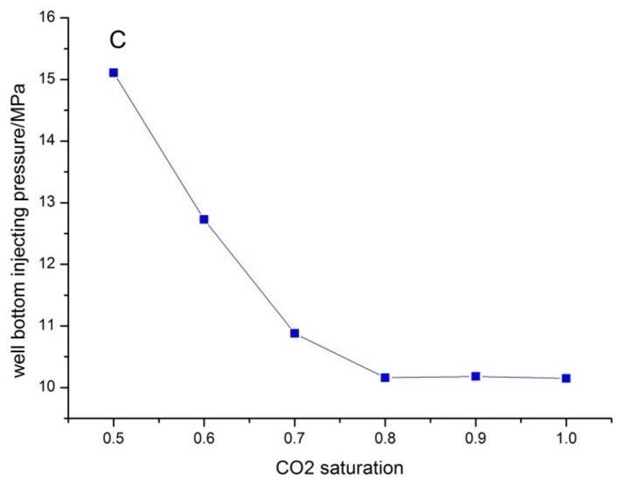
● The plot line shows that there exists one critical $CO_2$ saturation for well bottom injecting $CO_2$ flow rate. When the saturation is between 0.8~0.9, the well bottom injecting $CO_2$ flow rate is the biggest which is opposite to the change of Pressure.

# Results analysis

## —— deep saline aquifer



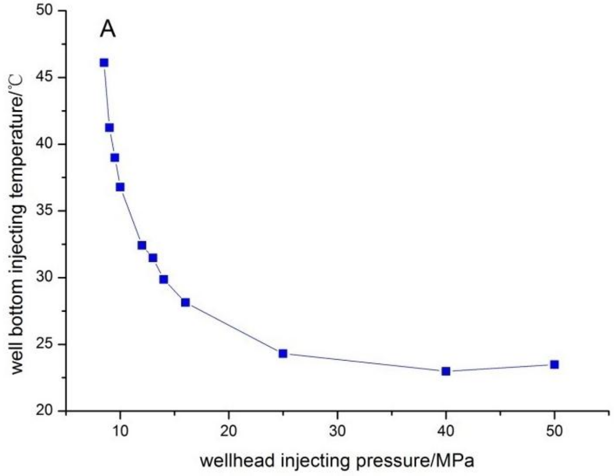



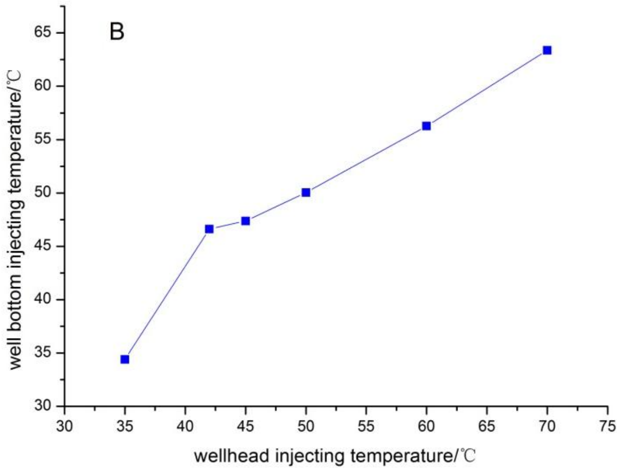

**Well bottom injection pressure**

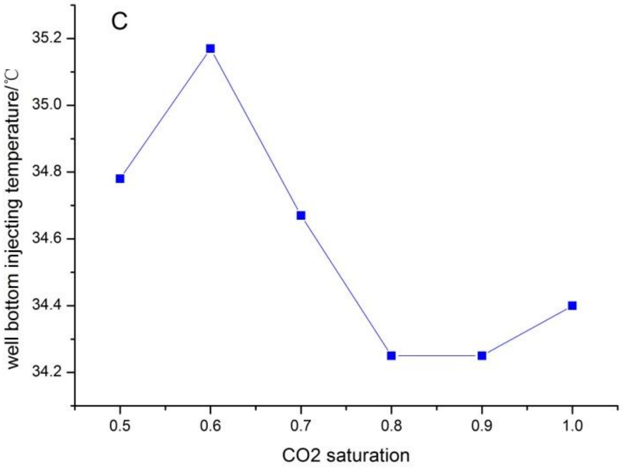
●Well bottom injection pressure increase with the uplift of wellbore injecting pressure but decrease with the ascending of $CO_2$ saturation and temperature. For those two factors, they all exert more important influence on well bottom injection pressure within small values.

# Results analysis

—— deep saline aquifer



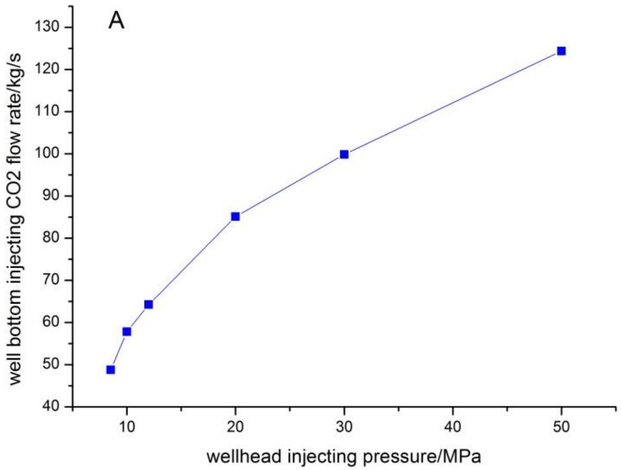



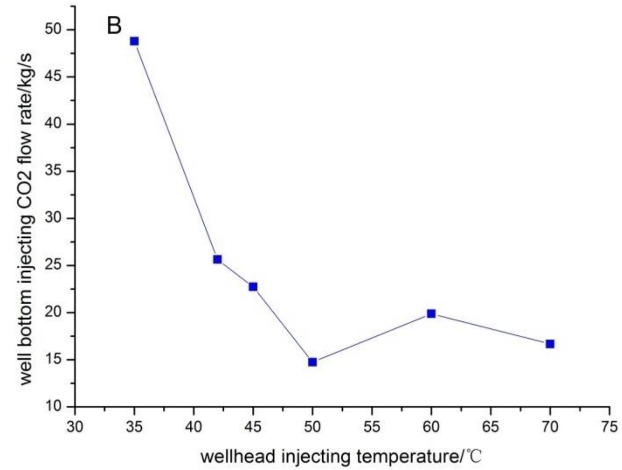

**Well bottom injection temperature**

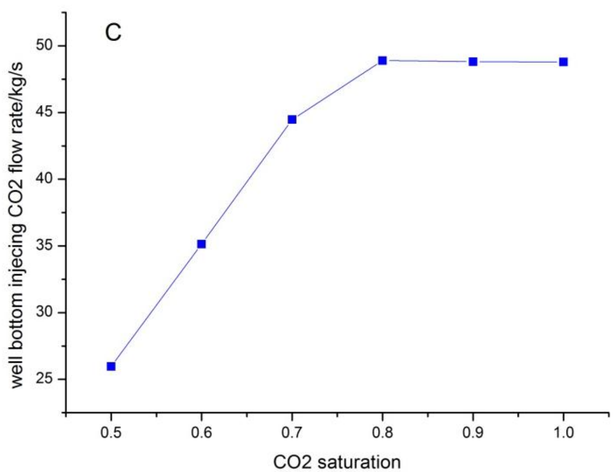
●Well bottom injection temperature is in negative correlation with the wellhead injecting pressure and in positive correlations with the wellhead injecting temperature and $CO_2$ saturation.

# Results analysis

## —— deep saline aquifer




### Well bottom injecting $CO_2$ flow rate

- ●Well bottom injecting $CO_2$ flow rate increases with the uplift of wellhead injecting pressure and Sg, but the increase amplitude declines during the process.
- ●The graph of $CO_2$ flow rate ‘s change to injecting temperature is opposite to pressure. Nevertheless, when injecting temperature is 50℃， the $CO_2$ flow rate acquires the minimum value.

# 5 Conclusions

# Conclusions

**Depleted gas field**

1. Well bottom injecting pressure increase with the uplift of injecting pressure, and decrease with the enhance of temperature with a limited range. The $CO_2$ saturation influence was separated into Two stage: Sg＜0.8， pressure decrease with saturation, Sg＞0.9， pressure increase with Sg.
2. Well bottom injection temperature increase with wellhead injecting pressure; in limited range, it is in a linear relationship with injecting temperature; before Sg＜0.8， it is in positive correlation with Sg.
3. Well bottom $CO_2$ flow rate increase with injecting pressure , and if P=8.5MPa, T=35℃， change the value of Sg, when Sg=0.8~0.9, the reservoir got the fattest $CO_2$ flow rate.

**Deep saline aquifer**

1. Well bottom injecting pressure increase with the uplift of injecting pressure, and decrease with the enhance of temperature and Sg. And bigger the value , smaller the change amplitude.
2. Well bottom injection temperature increase with wellhead injecting pressure and temperature; it exists one minimum Sg=0.8~0.9， and one maximum Sg=0.6.
3. Well bottom $CO_2$ flow rate increase with injecting pressure and Sg, but decrease with temperature.

# Conclusions

- For depleted gas field and deep saline aquifer, their evolution process of pressure, temperature and $CO_2$ flow rate are similar, all goes though a  perturbation.
- With the same injecting conditions, the well bottom injecting pressure, temperature of depleted gas field is higher than saline aquifer, but $CO_2$ flow rate is less which means that temperature and pressure may curb the increase of $CO_2$ flow rate.

# 中文简介

**研究目的**

利用数值模拟的方法对二氧化碳超临界灌注条件进行研究，优化井口灌注参数，同时对注入温度、压力、注入速率等因素进行敏感性分析，为灌注工程设计时安全注入及注入井设计提供理论依据。

# 中文简介

## 研究方法

（1）建立枯竭气田的超临界$CO_2$灌注模型，利用正演法，研究井口初始注入参数（压力、温度、$CO_2$饱和度）对井底实际需要注入参数的关系，并明确各个灌注参数的影响因素；

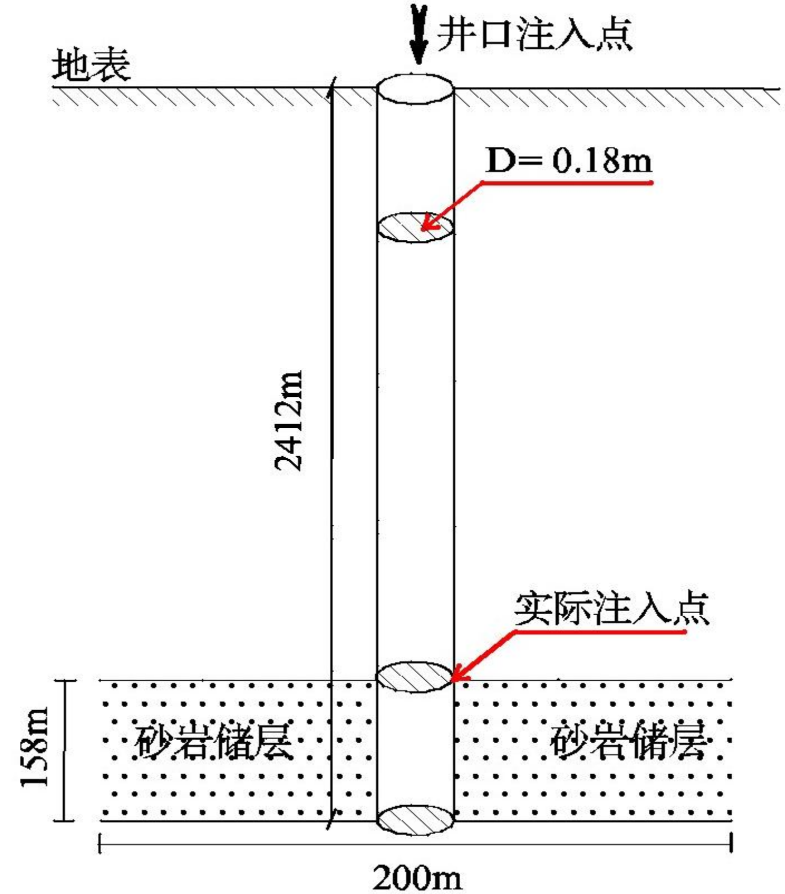
（2）建立深部咸水含水层的超临界$CO_2$灌注模型，利用正演法，研究井口初始注入参数（压力、温度、$CO_2$饱和度）对井底实际需要注入参数的关系，并明确各个灌注参数的影响因素；

（3）对比不同封存场地（枯竭气田和深部咸水含水层）的超临界灌注控制条件的差异。

# 中文简介

## 研究方法

枯竭气田由于天然气的开采，地层中压力很小，有别于一般深部咸水层。基于此，本研究使用先进的数值模拟软件T2WELL/ECO2N，建立二维放射状均质非等温模型，分别对枯竭气田和深部咸水含水层的灌注控制条件进行研究。利用单一变量法分别改变井口注入压力、温度、$CO_2$饱和度，研究不同注入参数对储层中实际注入参数的影响。



# 中文简介

## 结论

1. 不管是枯竭气田还是咸水含水层，随着$CO_2$的注入，井筒中温度、压力和$CO_2$流动速率初期均经历了扰动过程后才趋于稳定。

2. 相同井口灌注条件下，枯竭气田中稳定时实际注入点的温度、压力均高于咸水含水层，但是$CO_2$流速要小于咸水含水层。该现象说明温度与压力相互拮抗来影响井筒中$CO_2$的流速。

# 中文简介

## 枯竭气田灌注结论

1. 储层实际注入压力随着注入压力的增大而增大，注入温度的增大而减小；到$CO_2$饱和度小于0.8时，实际压力随饱和度的增加而减小，当饱和度大于0.9时，实际压力随饱和度的增加而增大。
2. 储层实际注入点温度随着井口注入压力的增大而增大，但是增大的程度随着压力的增大而减小；在温度影响范围内，储层实际注入点温度基本上与井口注入温度呈正比；储层实际注入点温度与$CO_2$饱和度呈正相关性，但当饱和度介于0.8 ～0.9之间变化时，饱和度的改变对储层实际注入温度没有影响。
3. 储层实际注入$CO_2$流速大小变化与井口注入压力变化呈正相关性，但随着压力的增大，其对储层实际注入$CO_2$流动速率的影响逐渐减小。在相同条件下，仅改变$CO_2$饱和度，则当其值为0.8~0.9时，储层注入点$CO_2$流速最大。

# 中文简介

## 深部咸水层灌注结论

1. 储层实际注入压力随着注入压力的增大而增大，注入温度和$CO_2$饱和的增大而减小，当注入温度和$CO_2$饱和度比较大时，对实际注入压力影响反而小。

2. 储层实际注入温度随着井口注入压力的增大降低，注入温度的增加而增加，注入参数值越大，则实际注入温度影响越小。 $CO_2$饱和度的影响比较复杂，存在最大值临界点和最小值临界点，分别为0.6和0.8~0.9。

3. 储层实际注入$CO_2$流速大小随井口注入压力和注入$CO_2$饱和度的增大而变大，随注入温度的增大而减小。但当三者的值增大到一定范围后，储层实际注入$CO_2$则逐渐不发生变化。

# Thank you!