Assessing Heat and Fluid Flow in Doublet Enhanced Geothermal System (EGS)

UTAH FORGE MODELING & SIMULATION FORUM #6

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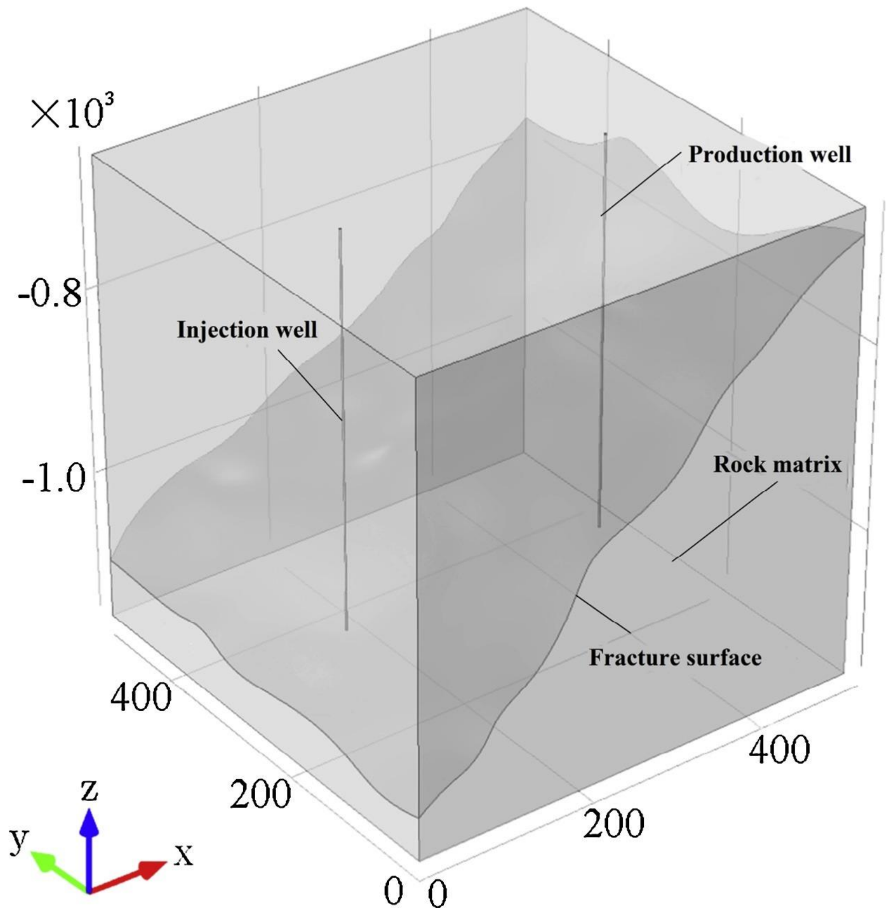
Objective

- Literature Review
- Optimization of EGS Doublet model based of various parameters
- Addressing the flow distribution assumption
- Introduction to wellbore dynamic model coupled with Falcon-Moose (FEM)
- Summary

Literature Review

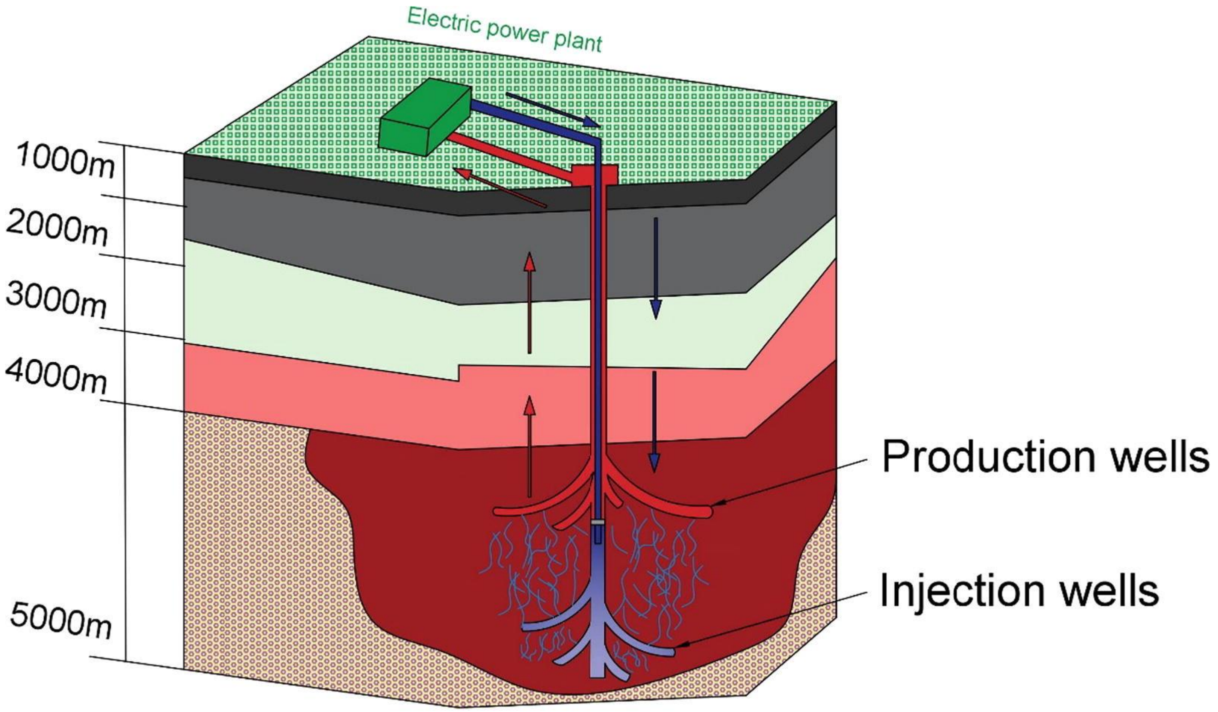


- **Study by Yao et al (2018)**
  - Vertical well models.
  - Flow through a natural fracture/fault
  - Easy to control and good performance if the size of the reservoir is sufficiently large.
  - Difficult to find such naturally existing systems with right conditions

Ref: https://doi.org/10.1016/j.geothermics.2017.12.005

Literature Review

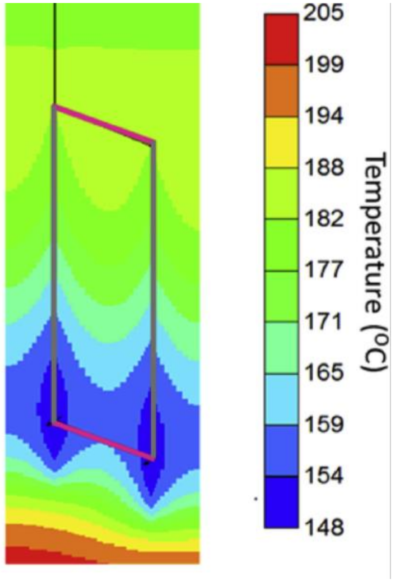
- **Study by Zhang et al (2019)**
  - They used a tree-shaped well model
  - Production well is placed above
  - Highly dependent on the rock matrix permeability and porosity
  - Requires high permeability and porosity
  - Reduced heat capacity of the reservoir.

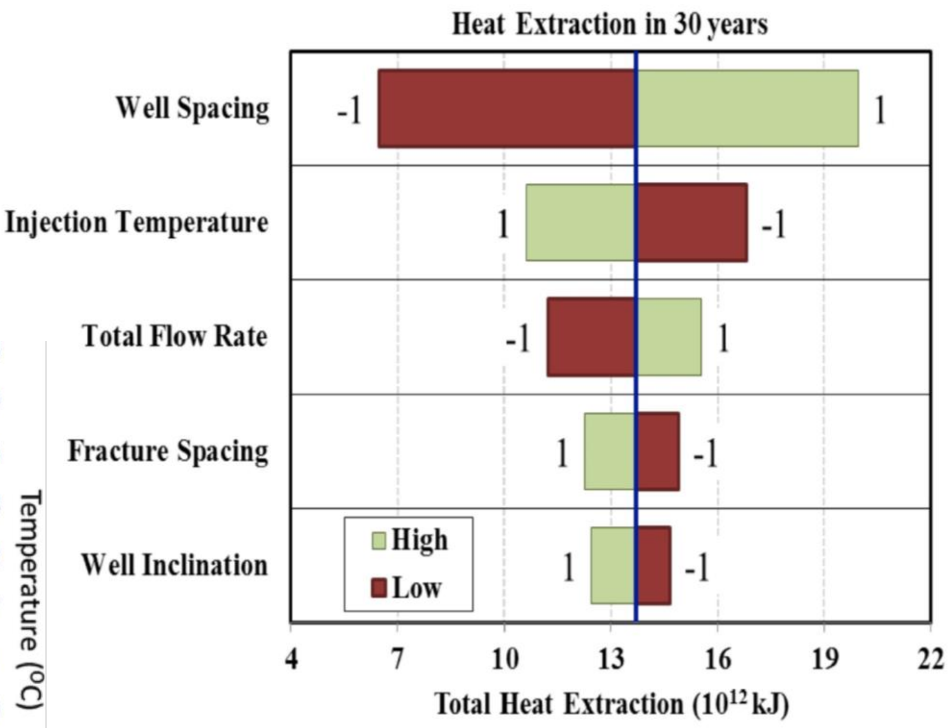


Ref: https://doi.org/10.1016/j.ijheatmasstransfer.2018.12.171

Literature Review

- **Study by Asai et al (2018 & 2019)**
  - Multi-fractured EGS model (TH)
  - Studied the effect of five different parameters
    - Well Spacing
    - Injection Temperature
    - Flow rate
    - Fracture Spacing
    - Well inclination
  - Ranked the parameters as per their effect on the total heat extraction

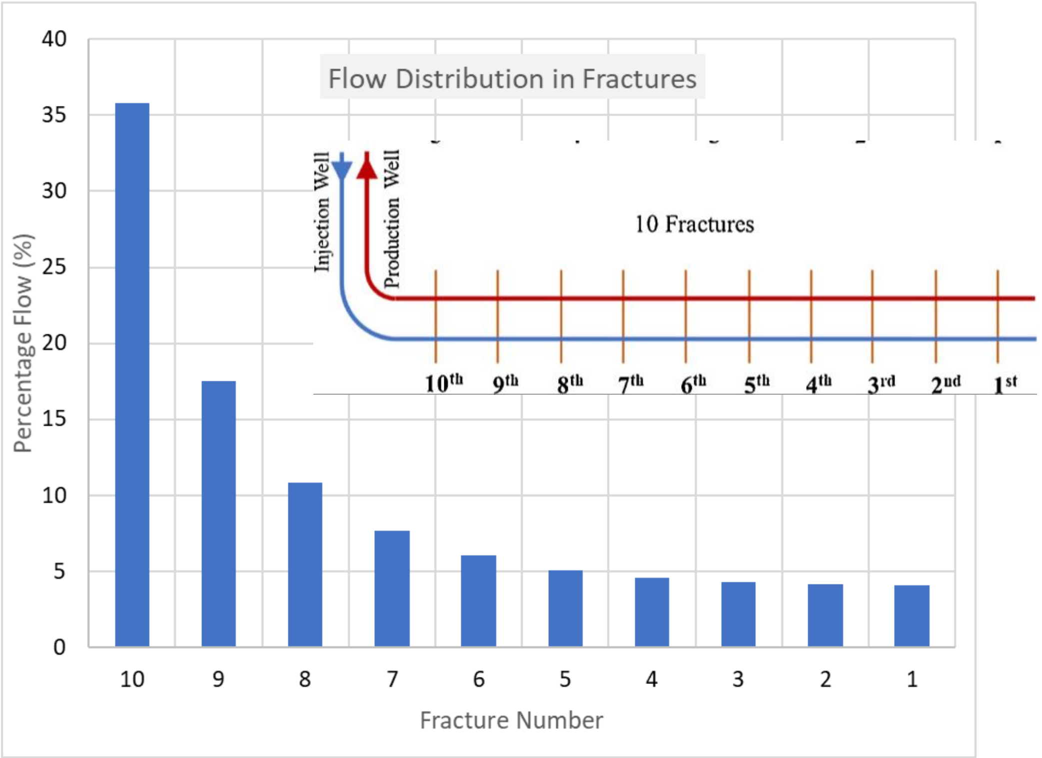




Ref: https://doi.org/10.1016/j.renene.2018.01.098
Ref: https://doi.org/10.1016/j.renene.2018.07.074

Literature Review

- **Study by Asai et al (2018)**
  - Analytical model analogous to Kirchhoff's law
  - Studied how fluid is distributed in a multi-fractured EGS
  - Effect of well diameter, number of fractures, flow rate
  - Does not include perforations or different well configurations



Ref: https://doi.org/10.1016/j.geothermics.2018.05.005

Optimization of Doublet EGS

Optimizations for an EGS

- **Reservoir Parameters (Site selection)**

- **Completion Parameters (Design of EGS)**
  - Heat transfer based optimization
  - Hydrodynamics based optimization

- **Operational Parameters (Heat extraction)**

Three level optimizations for EGS

- **Reservoir Parameters (Site selection)**

These parameters determine the total heat content available at a selected location.

  - Target depth (@FORGE 2000m/6562ft)
  - Temperature Gradient (65°C/km)
  - Size of the reservoir
  - Density/Heat Capacity
  - Thermal Conductivity

Note: These parameters are the least flexible and are solely dependent on the site.

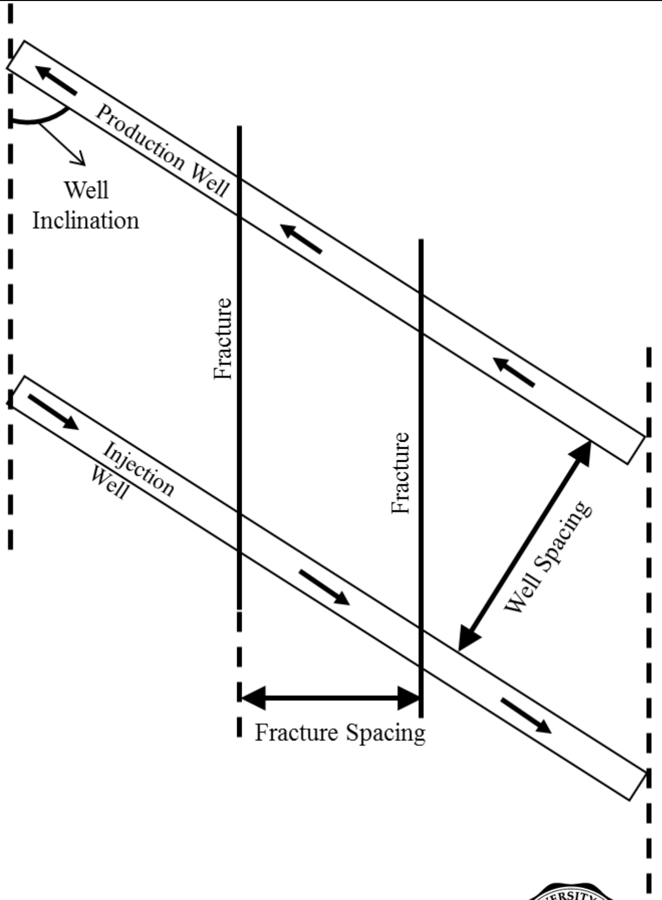
Three level optimizations for EGS

- **Completion Parameters (Design of EGS)**

These parameters determine the total heat content that is available to extract at a selected location.

  - Number of wells (@FORGE 2: Doublet system)
  - Length of the wells (1000m/3280ft)
  - Orientation/position of wells (65° from vertical)
  - Well spacing (200m/650ft)
  - Number of fractures / fractures spacing (TBD)

Note: These parameters have some flexibility before the system is drilled into the place.



Three level optimizations for EGS

- **Operational Parameters (Design of EGS)**

These parameters determine the rate of heat extraction at a selected location.

  - Type of fluid (@FORGE 2: Water)
  - Flow rates/schemes (TBD)
  - Injection temperature (TBD)

Note: These are the most flexible parameters.

Challenges/Concerns in EGS

- The production temperature of the fluid must be maintained at a targeted temperature (usually above 150°C)

- Prevent short circuiting or thermal breakdown.

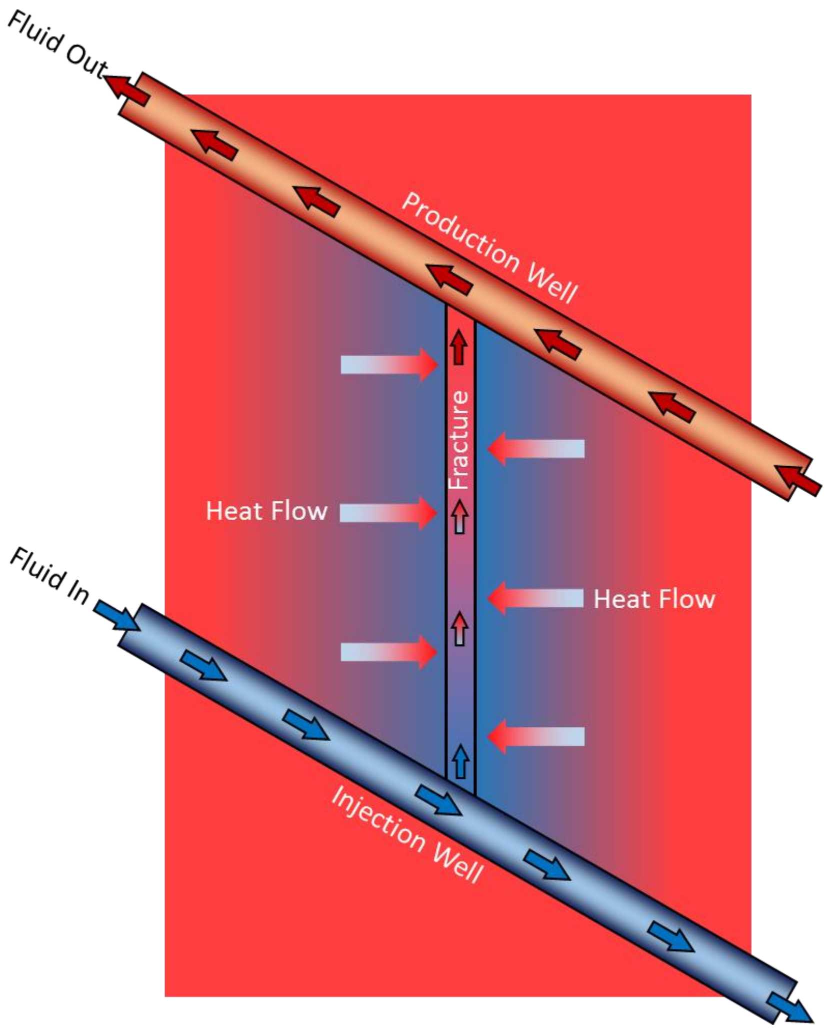
- Thermal interference between two fractures.

- To ensure that all the fractures are contributing equally towards heat extraction.

Optimization based on Heat Transfer

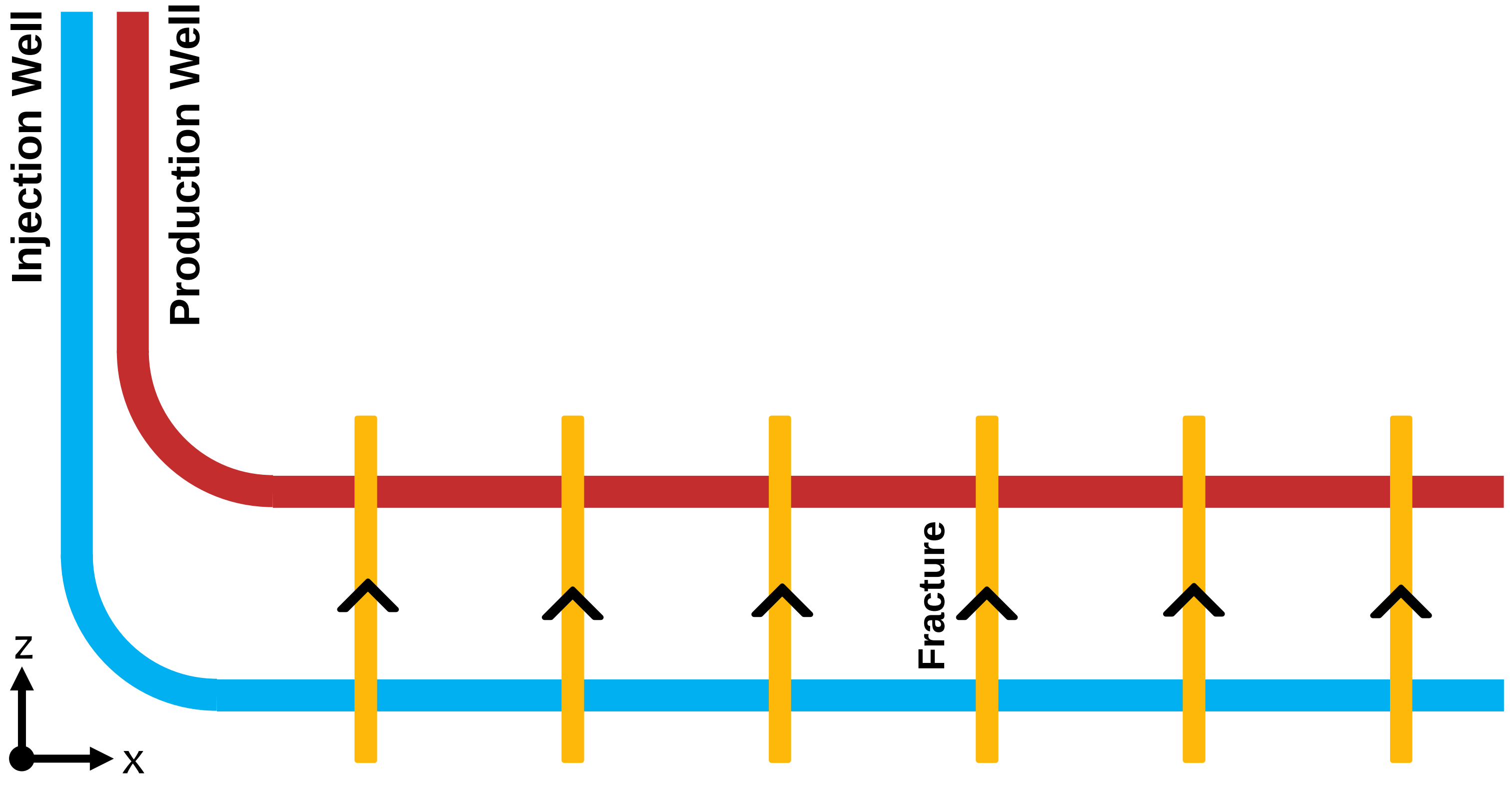
EGS Designs based on Heat transfer

- **Heat Extraction in EGS**
  - The heat is carried away by water as it flows though the fractures.
  - Heat transfer primarily occurs through convection inside the fracture
  - In the reservoir the heat is transferred thorough conduction.



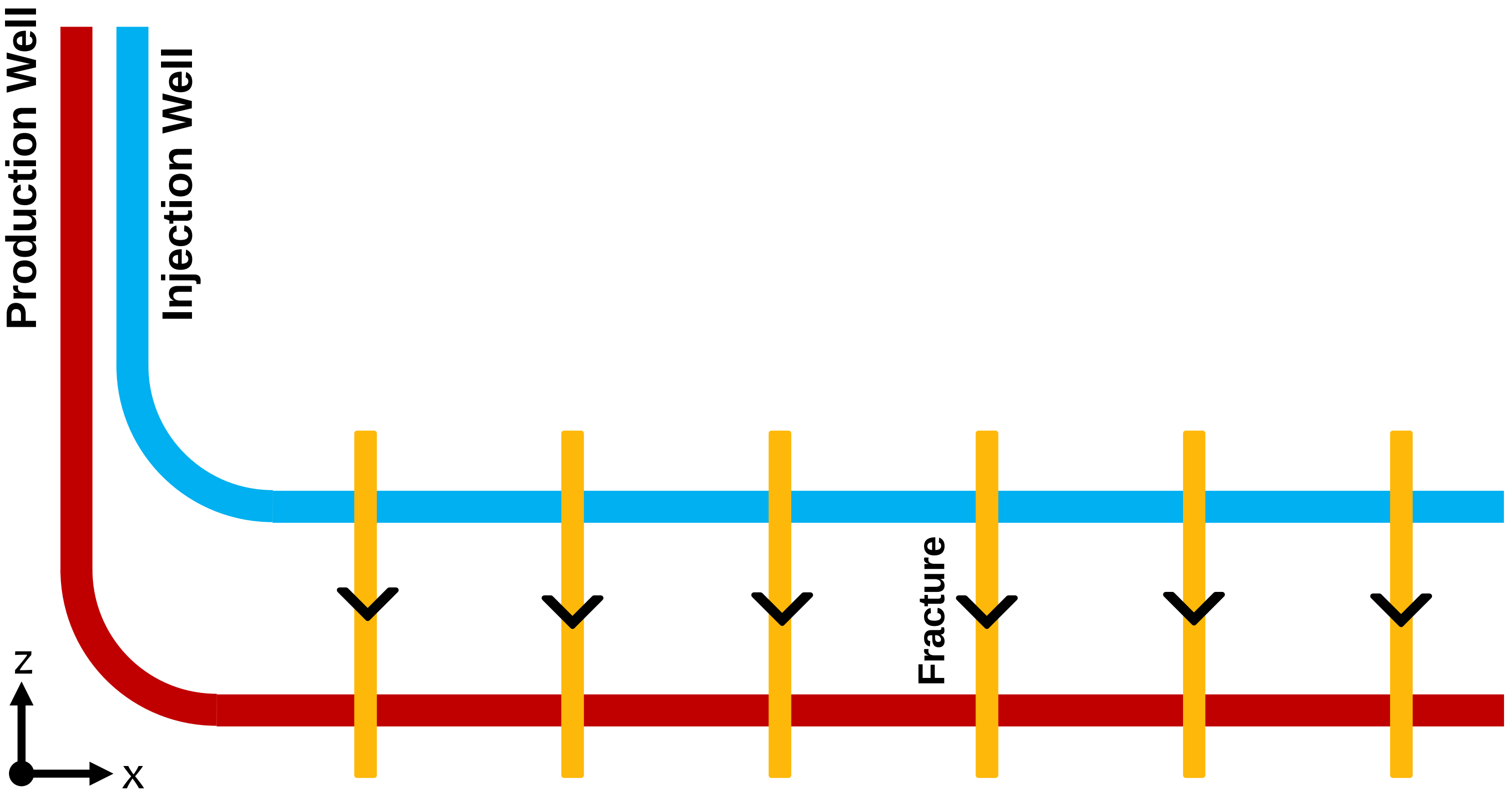
Conventional Design for a Doublet EGS

- Wells drilled in xz-plane
- Connected by multiple fractures.
- Production well is placed above the injection well.
- To exploit the density drive of the fluid.



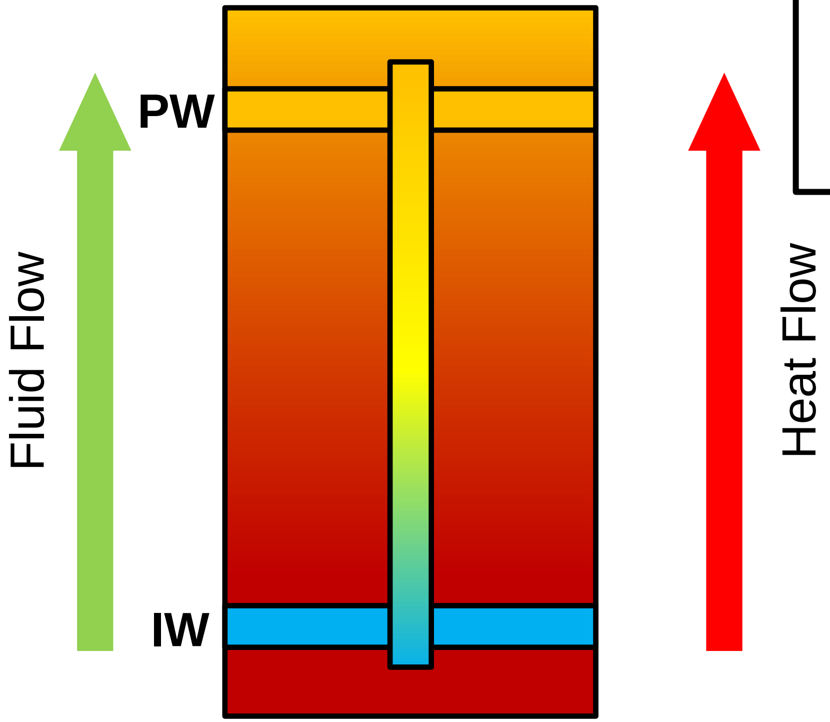
Modified Design for a Doublet EGS - 1

- Injection well is placed above the production well.
- This system produces 10% more energy (assuming rest all parameters remain constant)



Heat Extraction in EGS

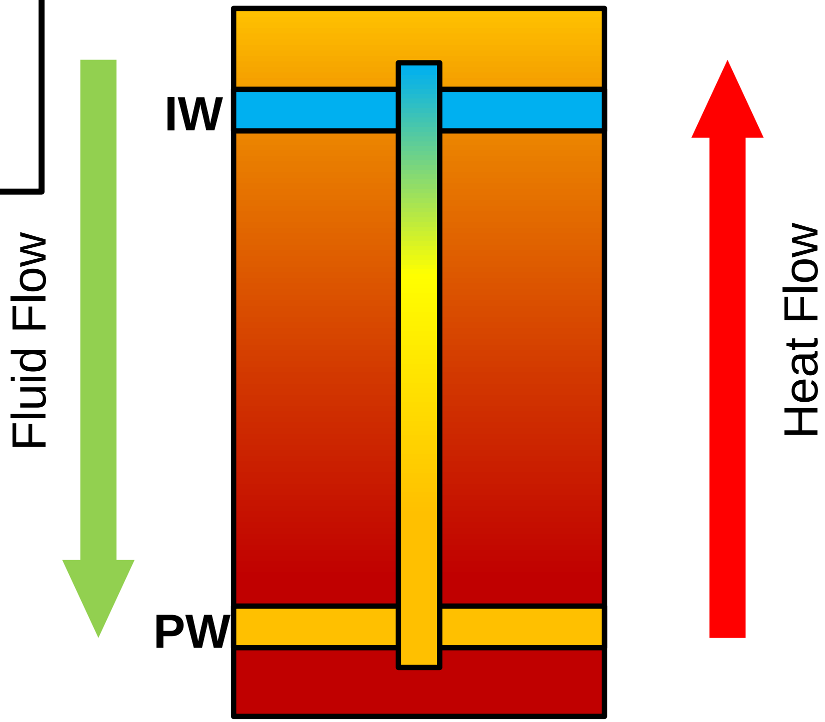
Conventional Doublet



Co-current Heat Transfer

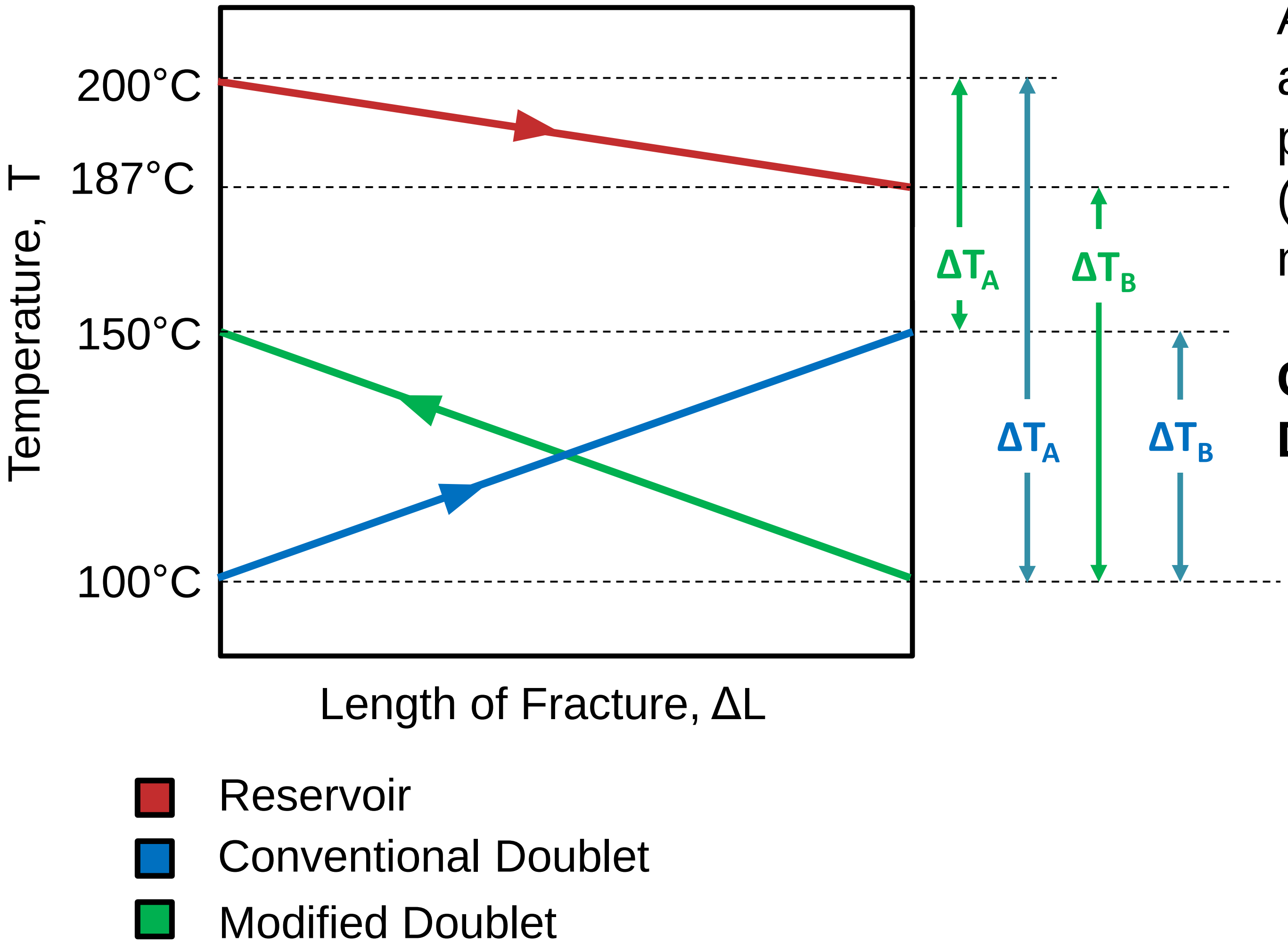
Assuming 200m well spacing (gradient:65 °C /km)
There would be about 13°C temperature difference between two wells at the fracture.

Modified Doublet



Counter-current Heat Transfer

Heat Extraction in EGS



Assuming the flow rates of two systems are adjusted in such a way that both systems produce the fluid at 150°C.
(i.e, the flow rate of the modified system needs to be reduced)

Calculating Log Mean Temperature Difference (LMTD)

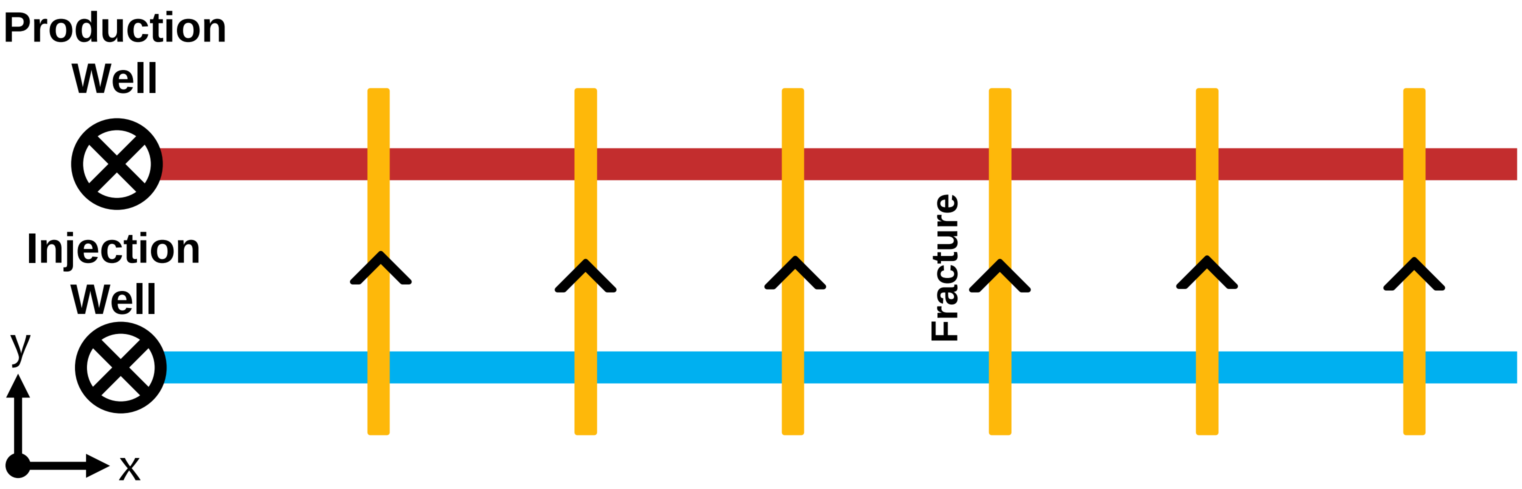
$$LMTD = \frac{\Delta T_A - \Delta T_B}{\ln\left(\frac{\Delta T_A}{\Delta T_B}\right)} = \frac{100 - 37}{ln\left(\frac{100}{37}\right)} = 63.36$$

$$LMTD = \frac{\Delta T_A - \Delta T_B}{\ln\left(\frac{\Delta T_A}{\Delta T_B}\right)} = \frac{50 - 87}{ln\left(\frac{50}{87}\right)} = 66.8 \equiv (\mathbf{5.4\%})$$

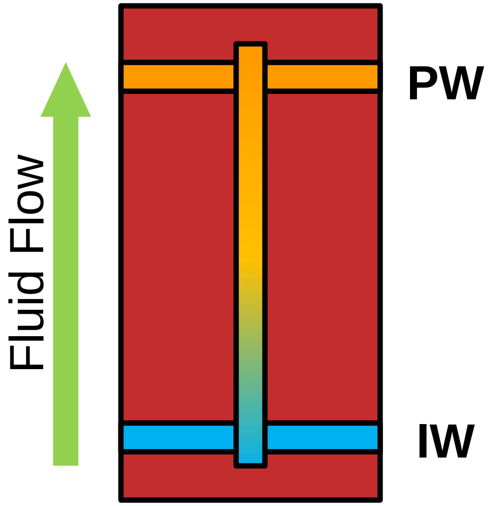
$$\boldsymbol{Q \propto LMTD}$$

Modified Design for a Doublet EGS - 2

- Change the plane of wells to xy
- Both the wells are in the same temperature plane



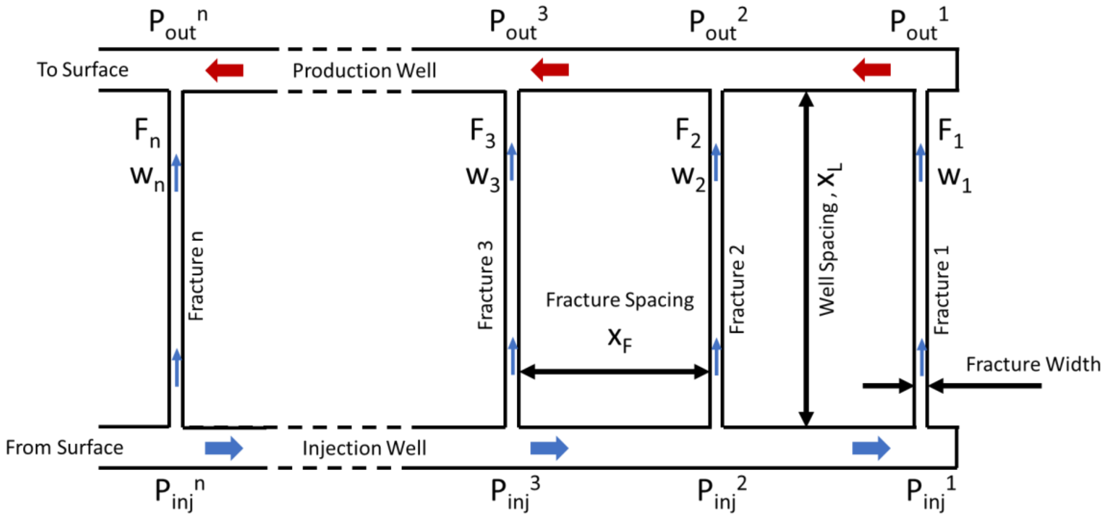
$$LMTD = \frac{\Delta T_A - \Delta T_B}{\ln\left(\frac{\Delta T_A}{\Delta T_B}\right)} = \frac{50 - 100}{ln\left(\frac{50}{100}\right)} = 72.13 \equiv (\mathbf{13.8\%})$$



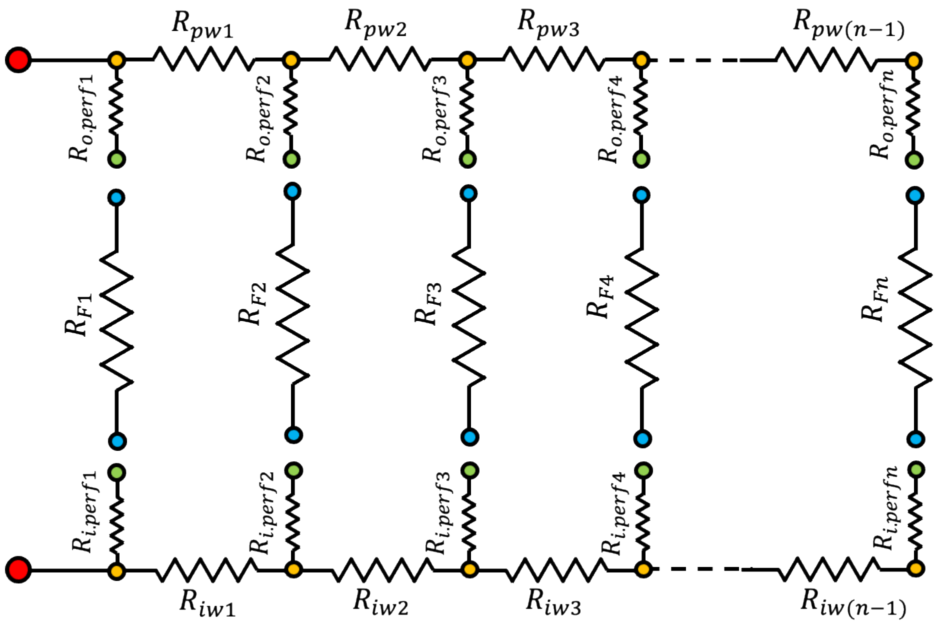
Optimization based on Hydrodynamics

EGS Designs based on Hydrodynamics

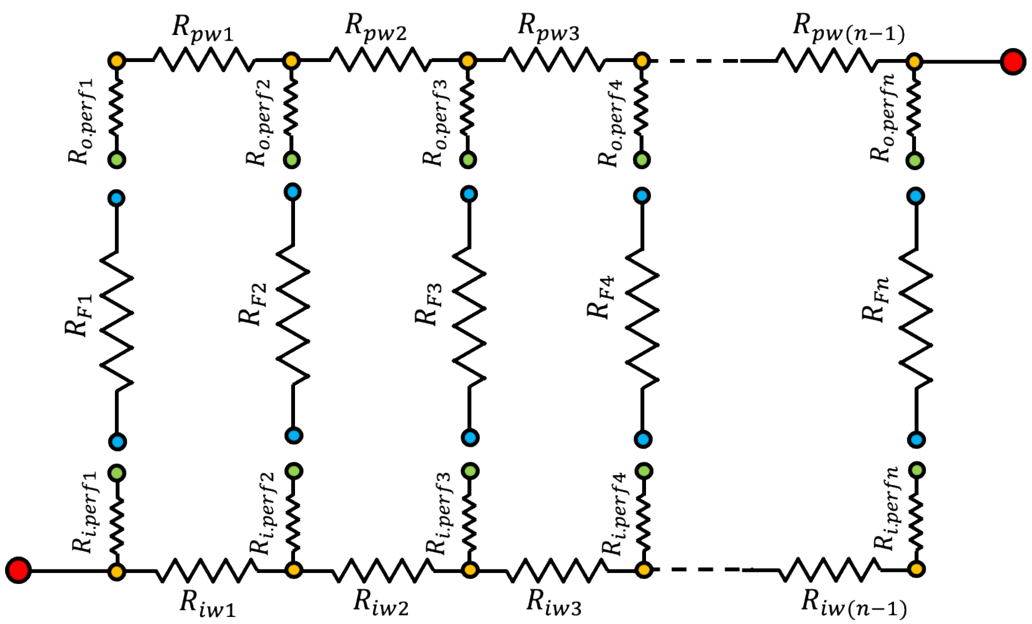
- **Fluid Flow**
  - The fluid flow distribution in any EGS is dependent on various factors
  - Fluid in a closed loop with multiple path would always choose a path of least resistance
  - If a EGS is not designed properly, all the fracture would not contribute towards heat production
  - Leading to short circuiting or early thermal breakdown



Analytical Fluid distribution Model



Parallel Wells



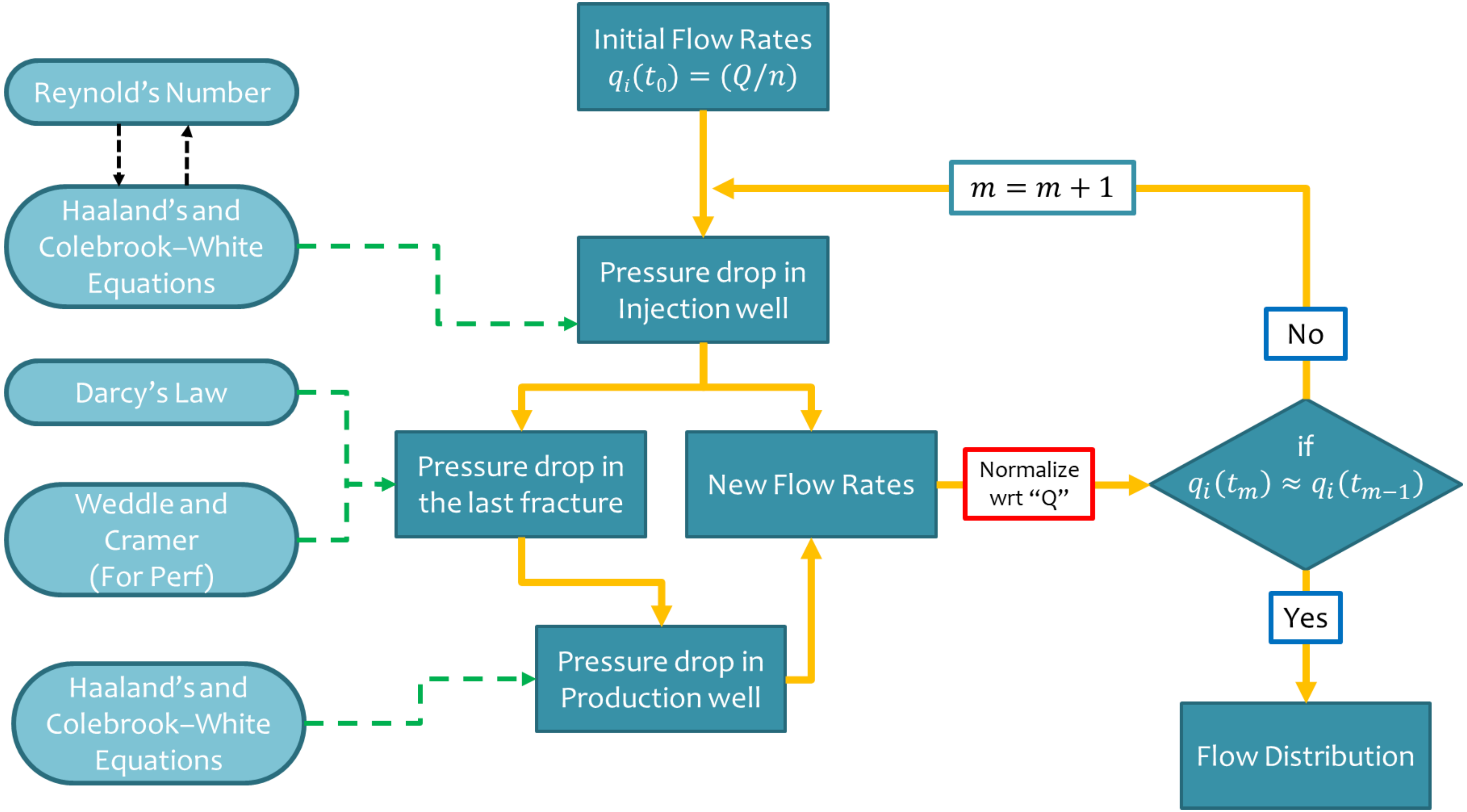
Counter-Parallel Wells

- Fluid flow is analogous to current flow in a closed circuit
- Pressure at each point/node is congruent to Voltage
- Flow rate is congruent to Current flow
- Friction for flow is congruent to resistors

Analytical Fluid distribution Model

- Rules/Assumptions:
  - Fluid flows from high pressure zone to low pressure zone
  - Gravity is not included
  - Constant density and viscosity are used
  - The system is isothermal i.e., no heating/cooling effect are considered
  - Frictional pressure drop is calculated using various flow equations depending on the Reynolds number.
  - Pressure drop in the fractures is calculated using the Darcy's Law
  - Fluid losses are negligible or zero

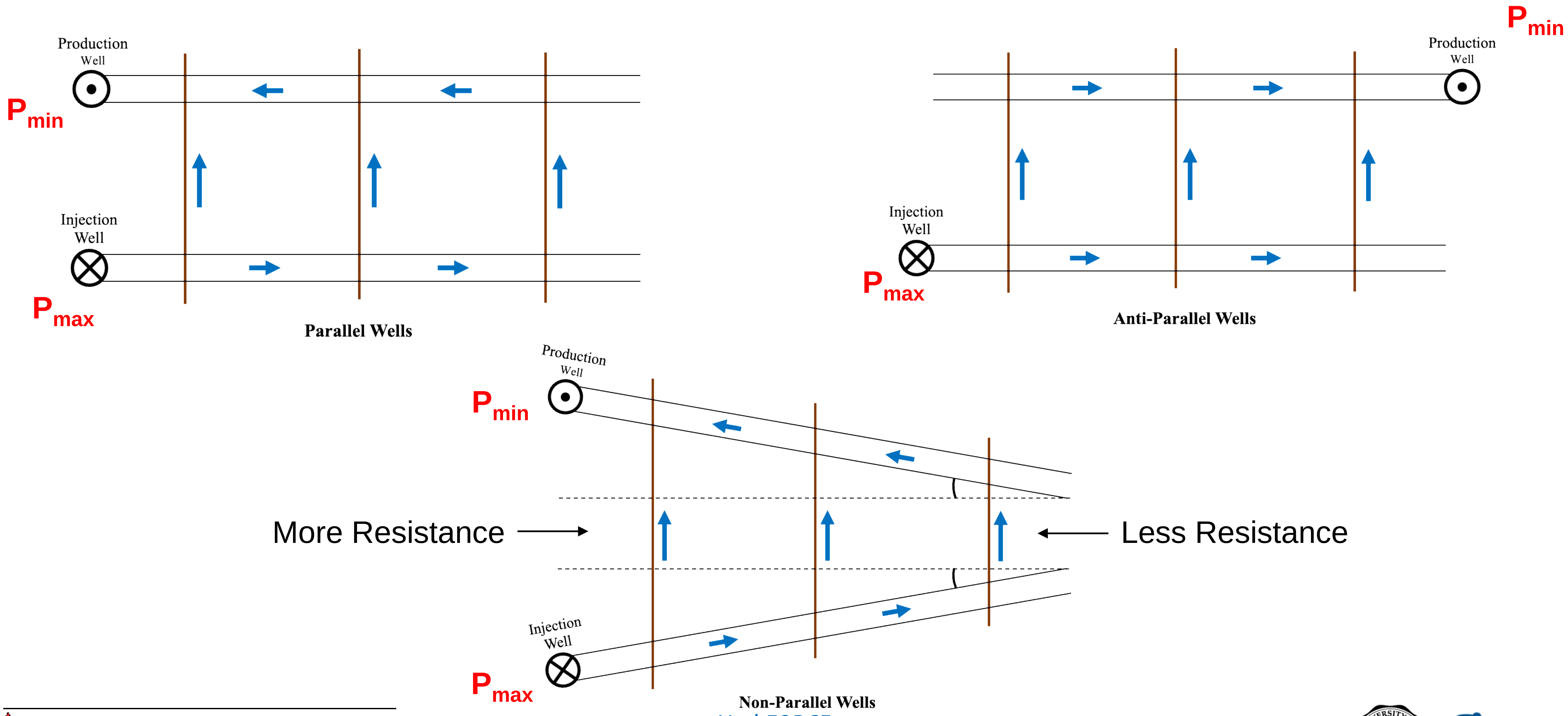
Analytical Fluid distribution Model



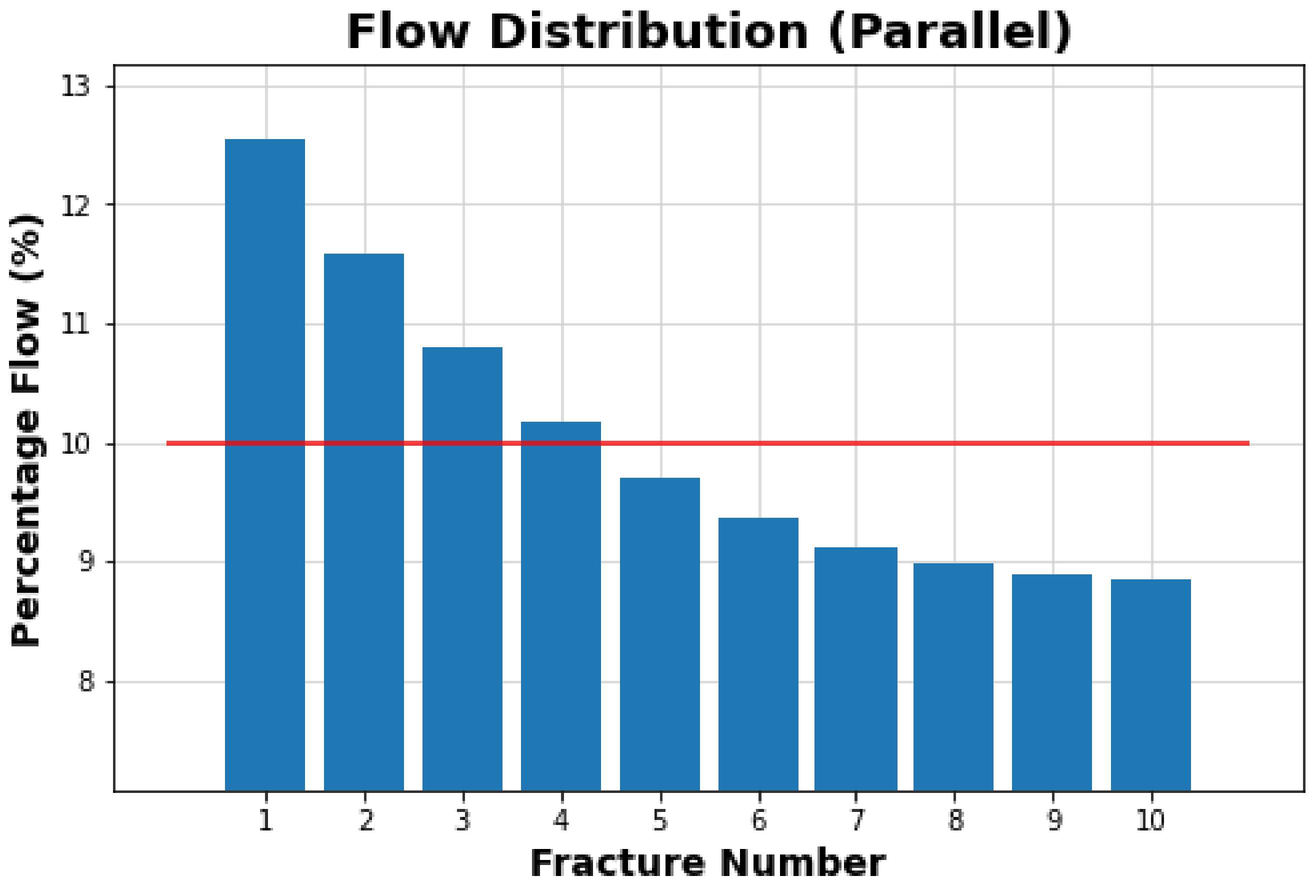
Parameters Used for the Model

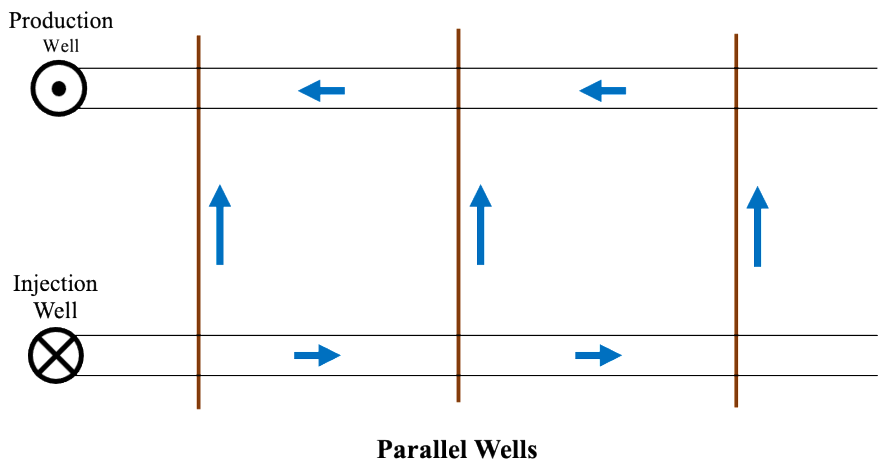
- Fracture Permeability : $1e^{-12}\ m^2\ or\ 1\ Darcy$
- Well Length: $1000m$
- Well spacing: $100m$
- Well Diameter: $0.1778m\ or\ 7in$
- Number of Fractures: $10\ zones$
- Pipe Roughness: $0.015mm$
- Number of Perforations: 6
- Diameter of Perforation: $0.0095m\ or\ 3/8in$
- Discharge coefficient: 0.75
- Flow rate: $50kg/s\ or\ 792gal/\min$

Different Well Configurations



Flow Distribution in Parallel Doublet System



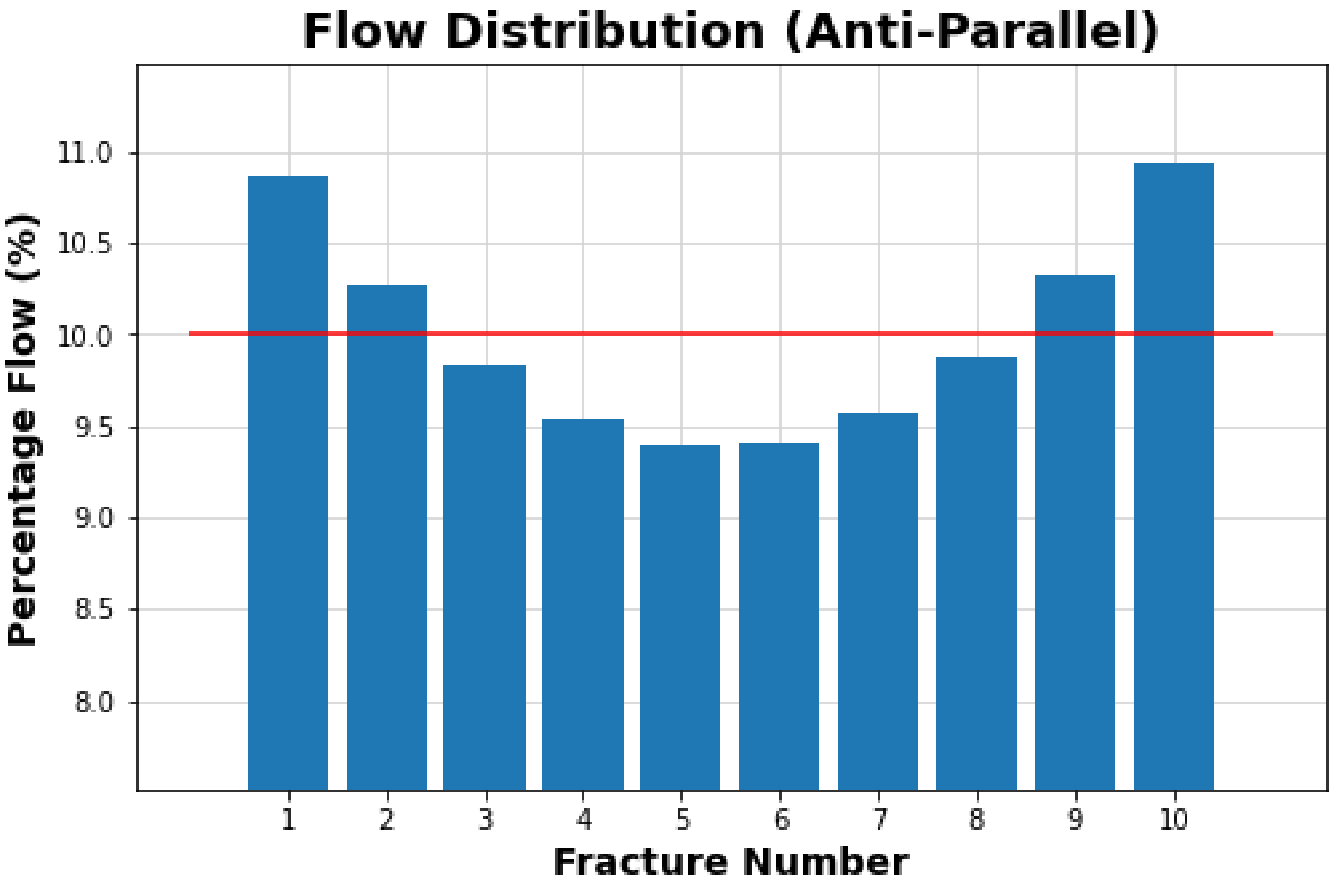


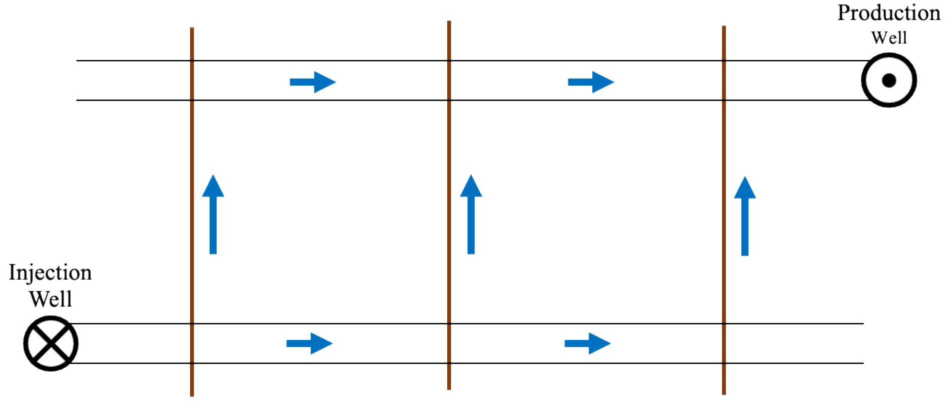
Frictional Head Loss = 136.35m **(7.89%**)**

- The fluid distribution is skewed towards the heel of the well
- Uneven extraction of heat from the reservoir

**Represents the portion of energy spent into pumping from the total energy extracted

Flow Distribution in Anti-Parallel Doublet System



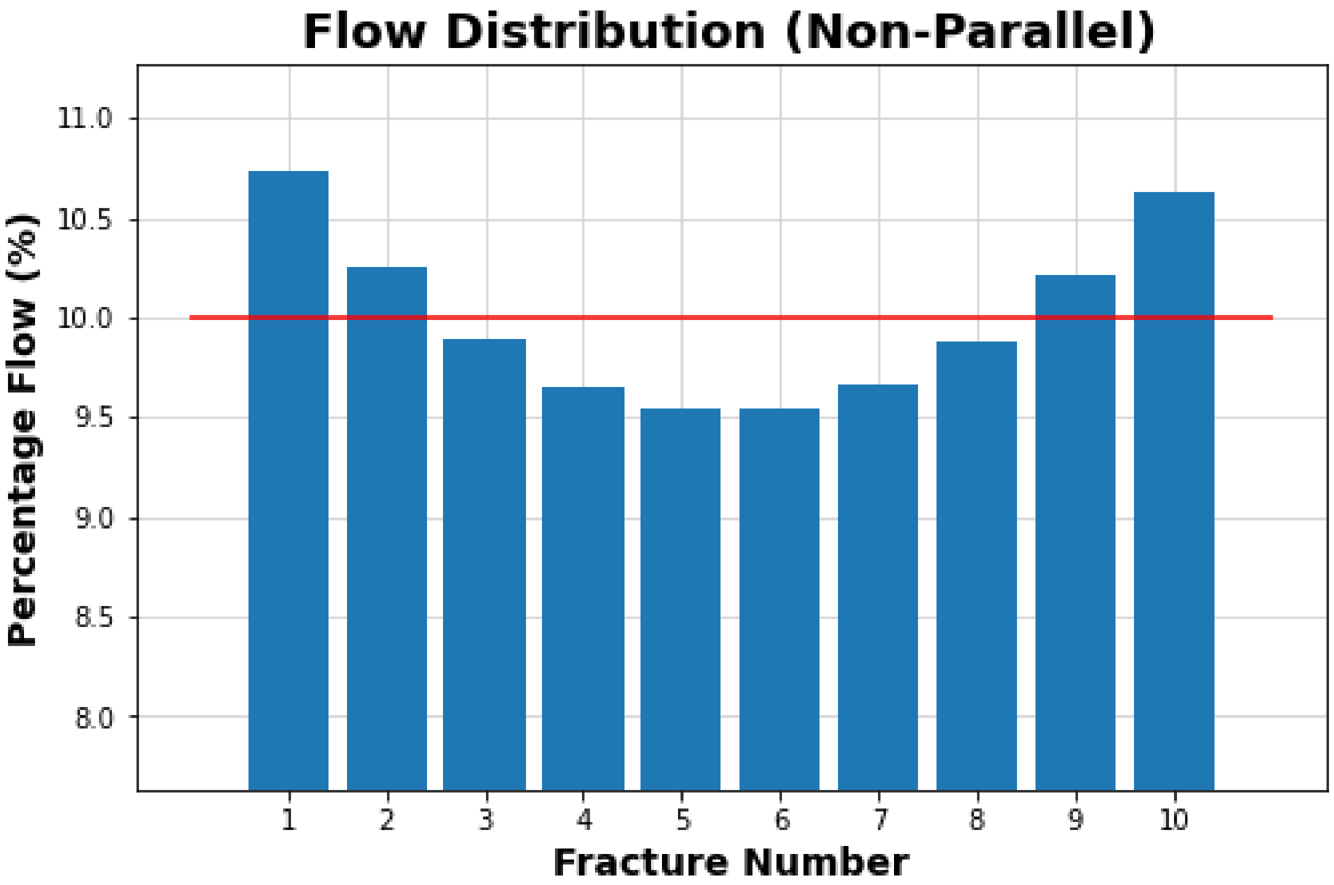


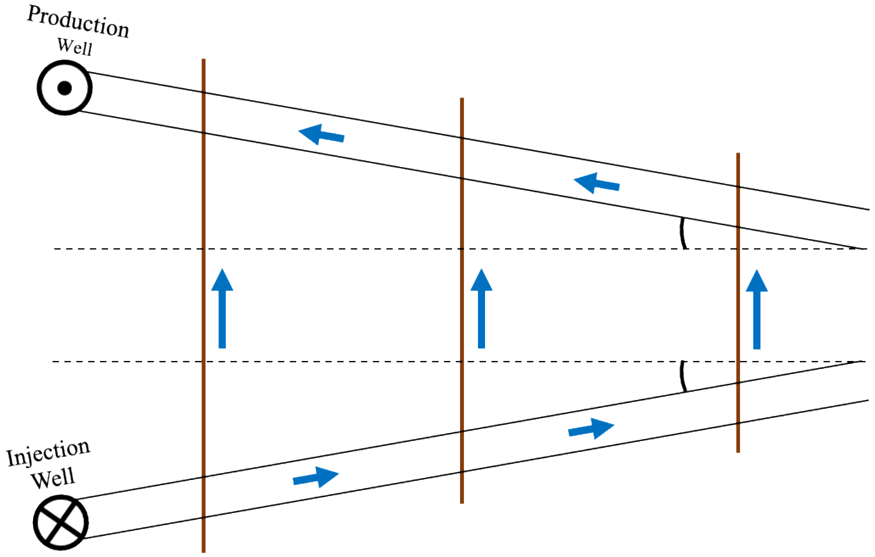
Anti-Parallel Wells

Frictional Head Loss = 135.81 m **(7.86%)**

- The fluid distribution much better than parallel
- The wells need to be drilled from two different locations

Flow Distribution in Non-Parallel Doublet System





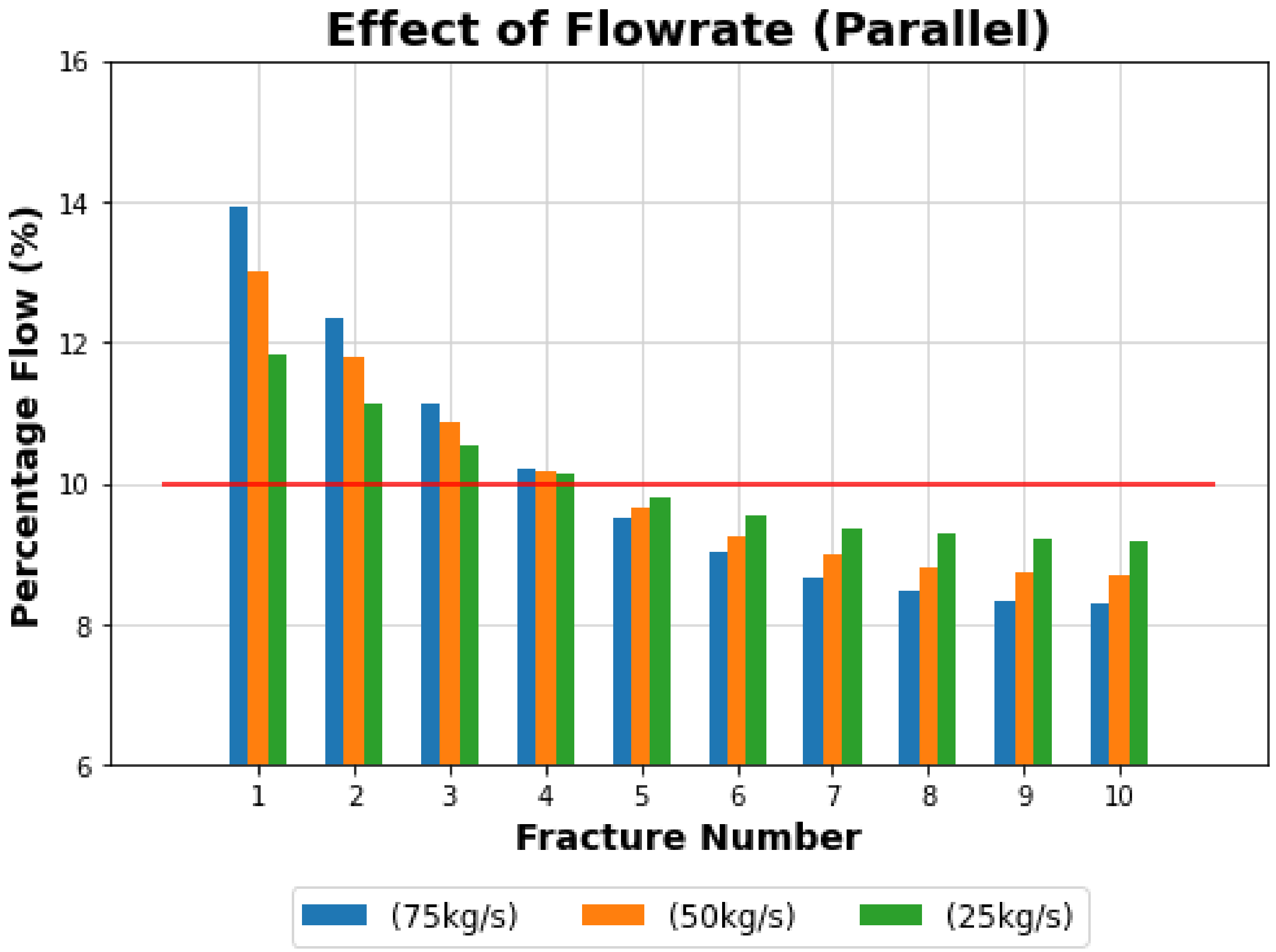
Non-Parallel Wells

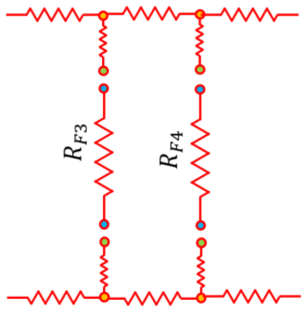
Frictional Head Loss= 160.26 m **(9.27%)**

Angle: 3.82 degrees

- Similar fluid distribution and can be drilled from the same location
- Would require additional energy for pumping

Effect of Flowrate on Parallel Well System





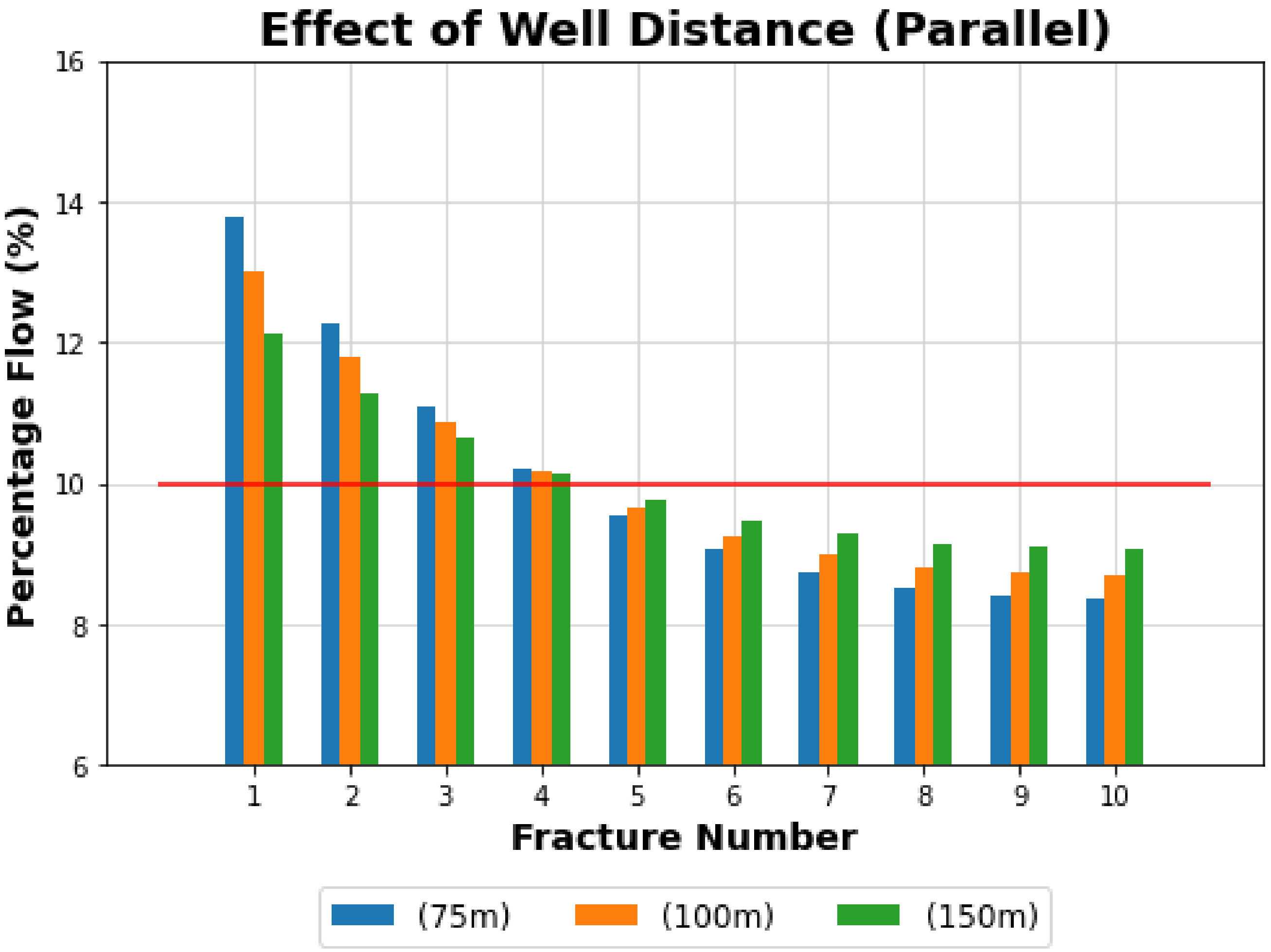
Frictional Head Loss= 224.65m (13.00%)

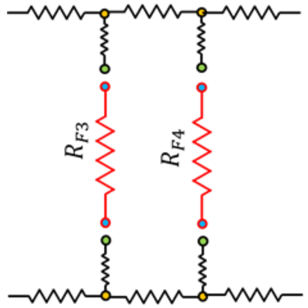
Frictional Head Loss= 133.82m (7.74%)

Frictional Head Loss= 57.95m (3.35%)

- Higher flowrates would skew the distribution even more
- This happens due to increased resistance in the wellbore

Effect of Well Spacing on Parallel Well System





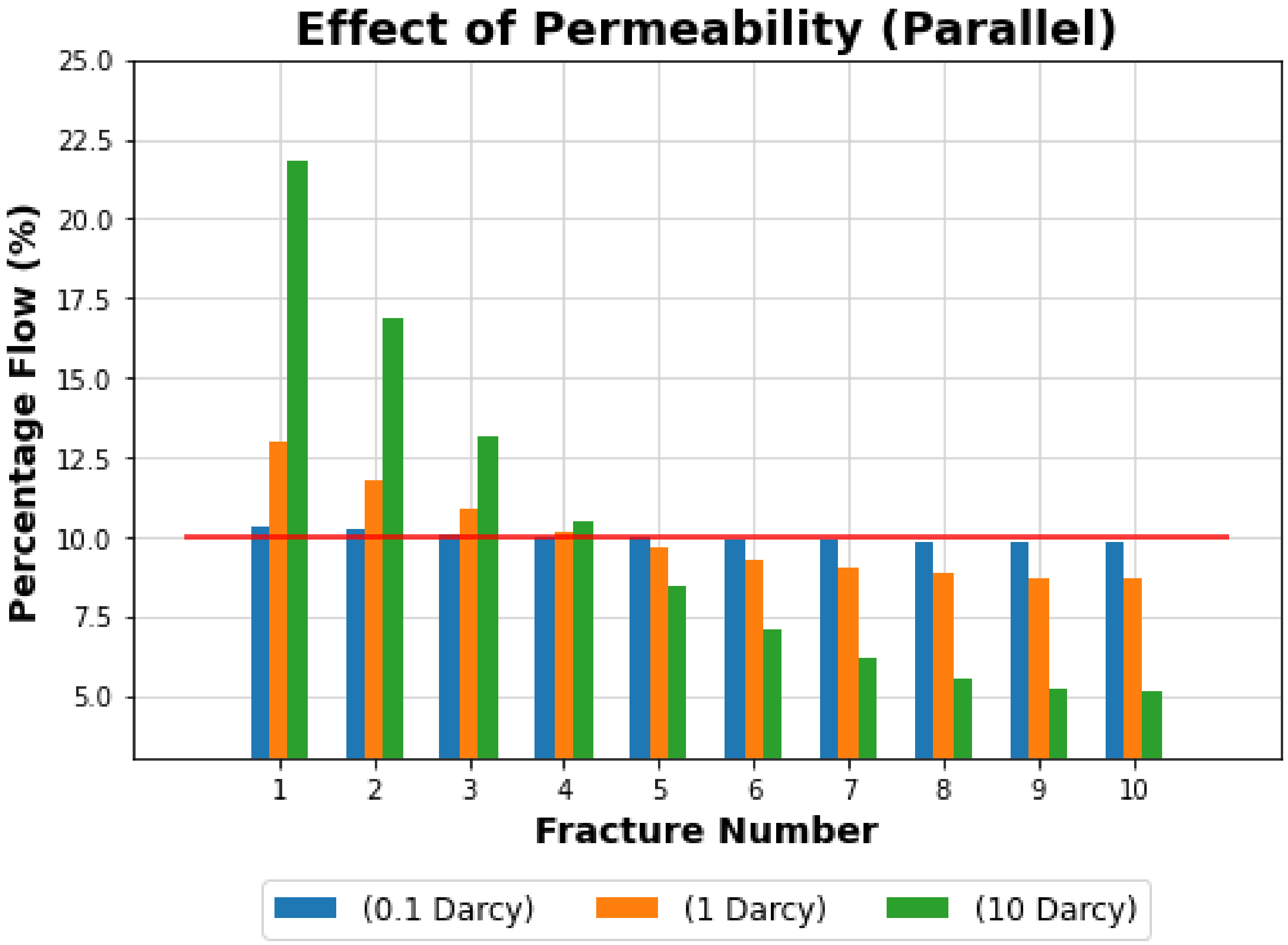
Frictional Head Loss = 109.87m (6.36%)

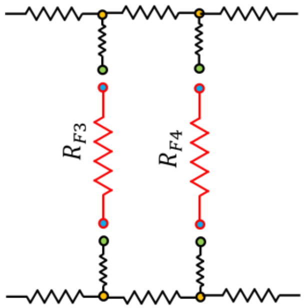
Frictional Head Loss = 133.82m (7.74%)

Frictional Head Loss = 180.70m (10.46%)

- Increasing well spacing improves fluid distribution
- But it would also increase the pumping cost

Effect of Permeability on Parallel Well System





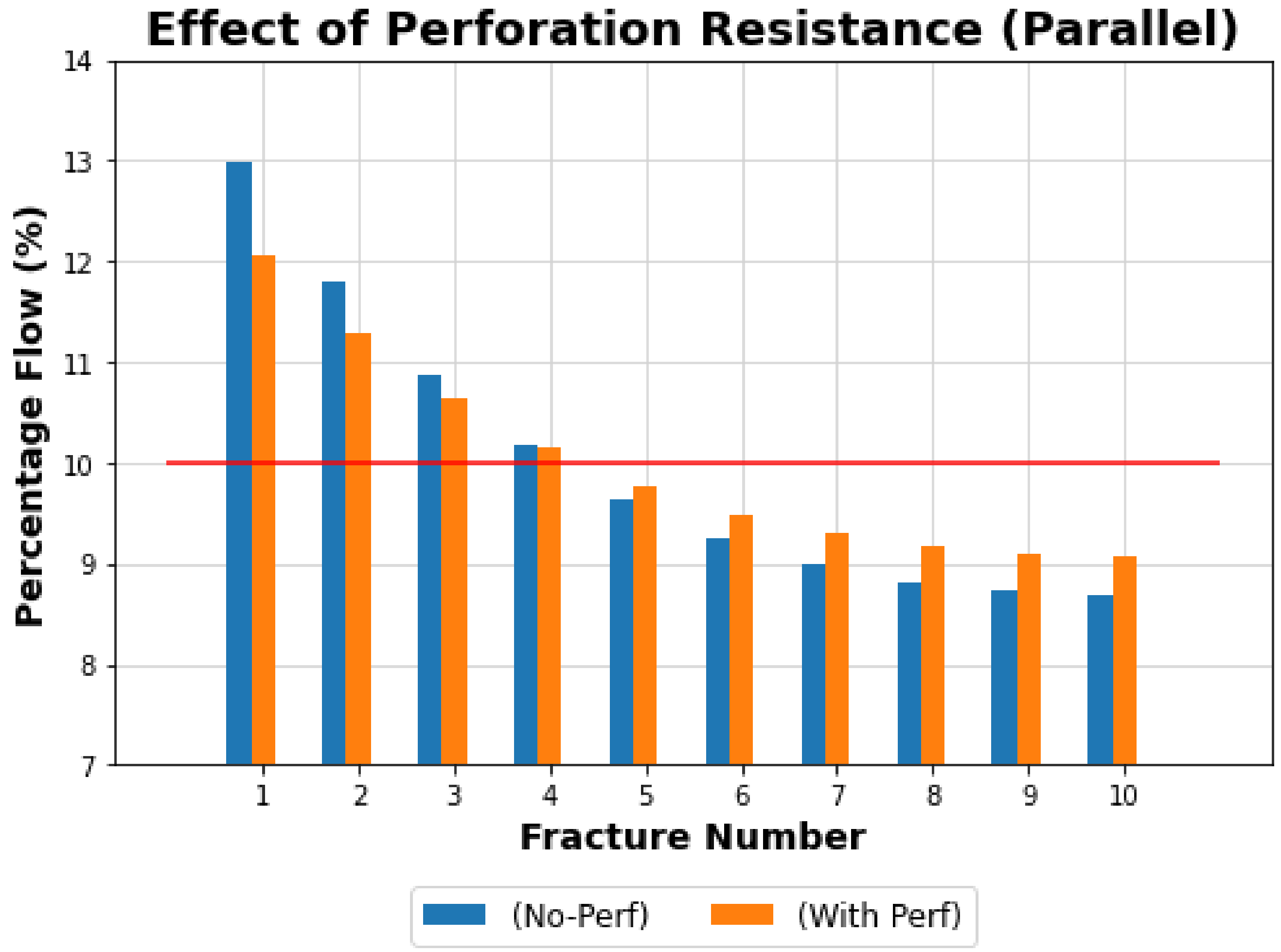
Frictional Head Loss = 956.54m (55.35%)

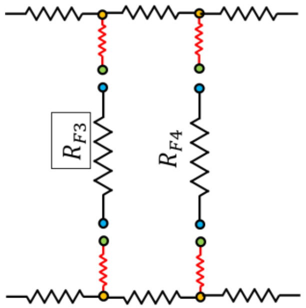
Frictional Head Loss = 133.82m (7.74%)

Frictional Head Loss = 39.97m (2.3%)

- Low permeability fracture would allow better fluid distribution
- But pumping cost increases significantly

Effect of Perforation Resistance



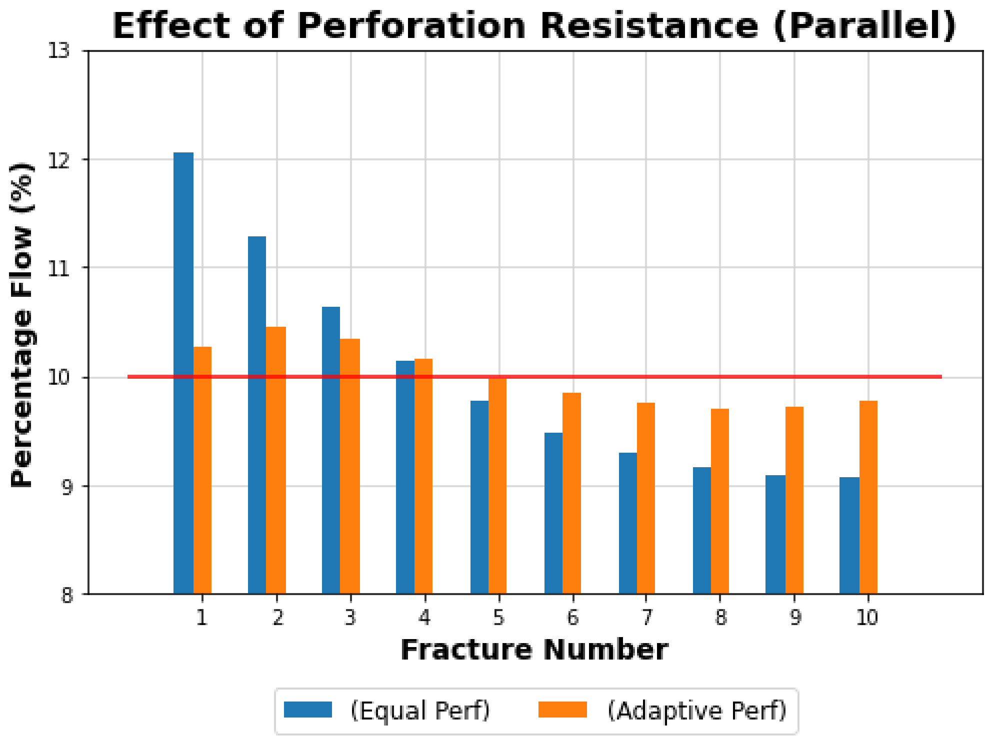


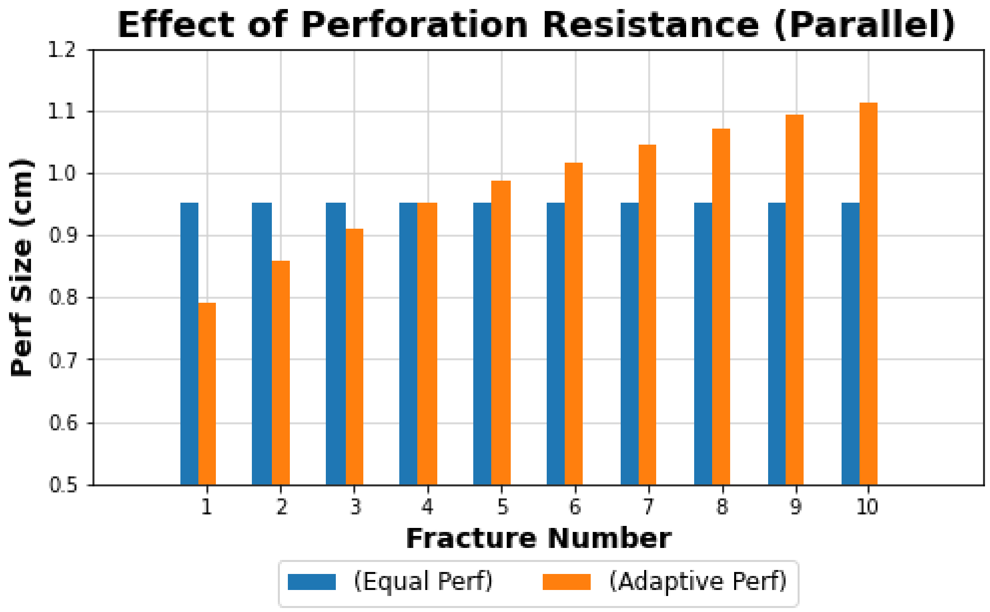
Frictional Head Loss = 136.35m (7.89%)

Frictional Head Loss = 160 m (9.26%)

- Another way to improve the flow distribution is by perforation size/numbers
- The increase in pumping cost is negligible as compared to other methods

Effect of Adaptive Perforation Diameter

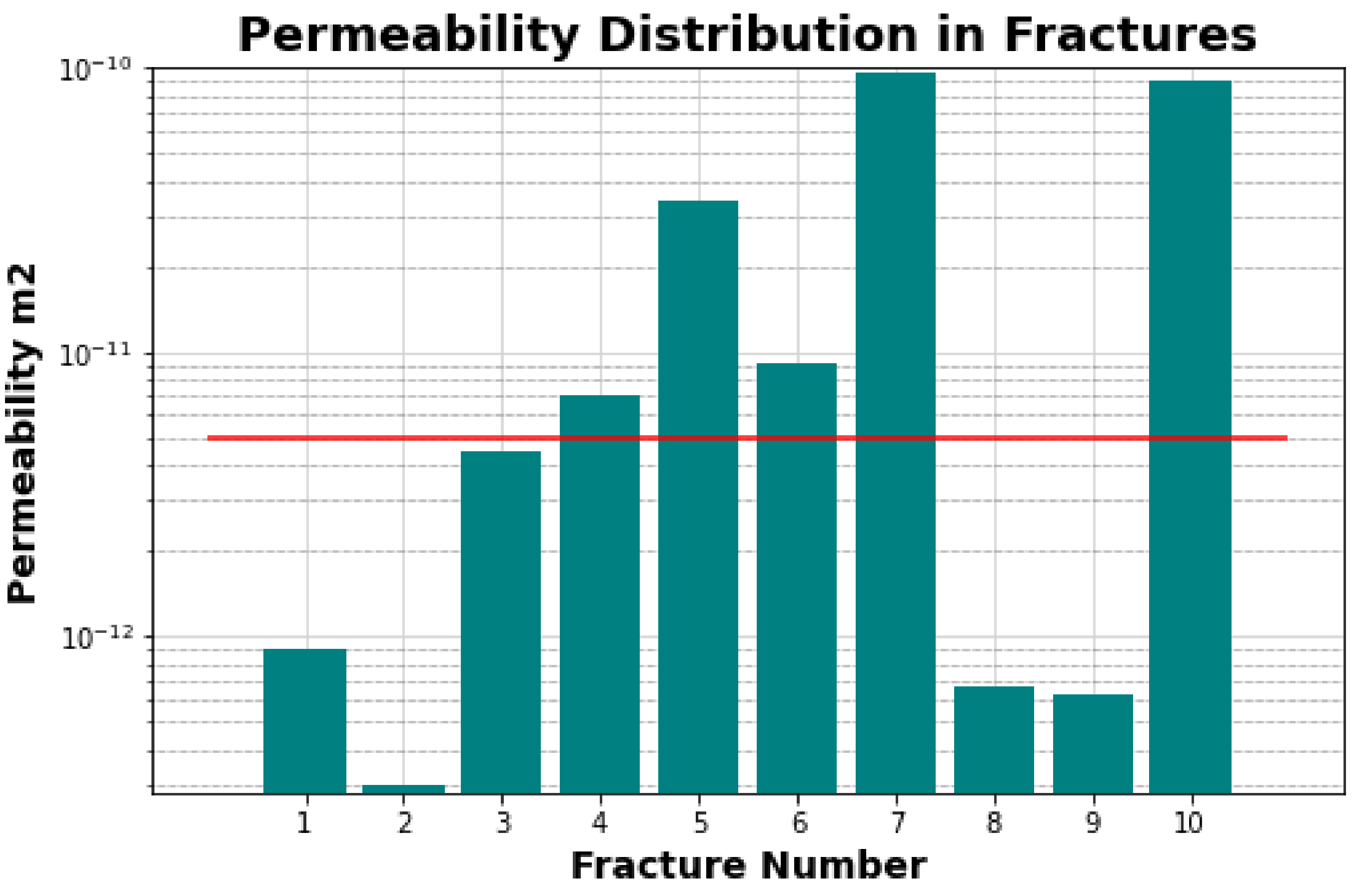




Frictional Head Loss = 160 m (9.26%)

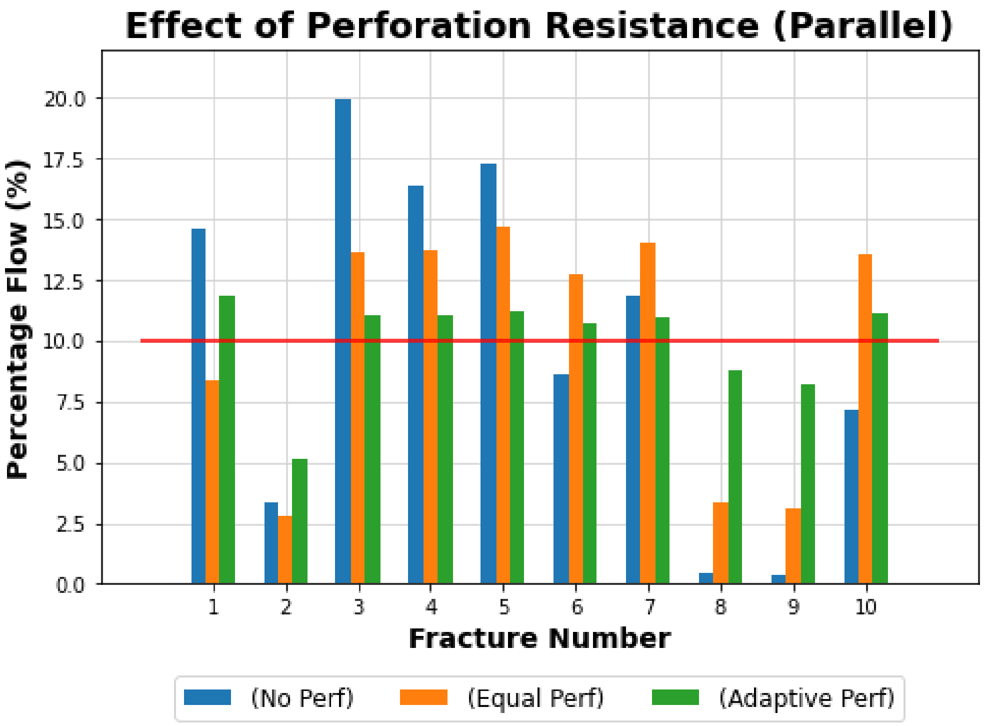
Frictional Head Loss = 162.82m (9.42%)

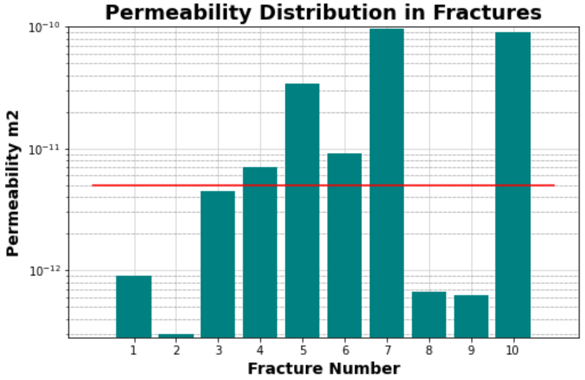
Heterogeneous Fracture System

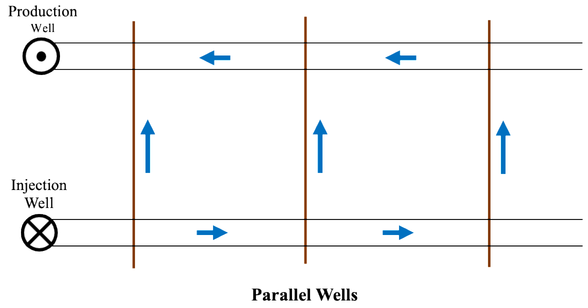


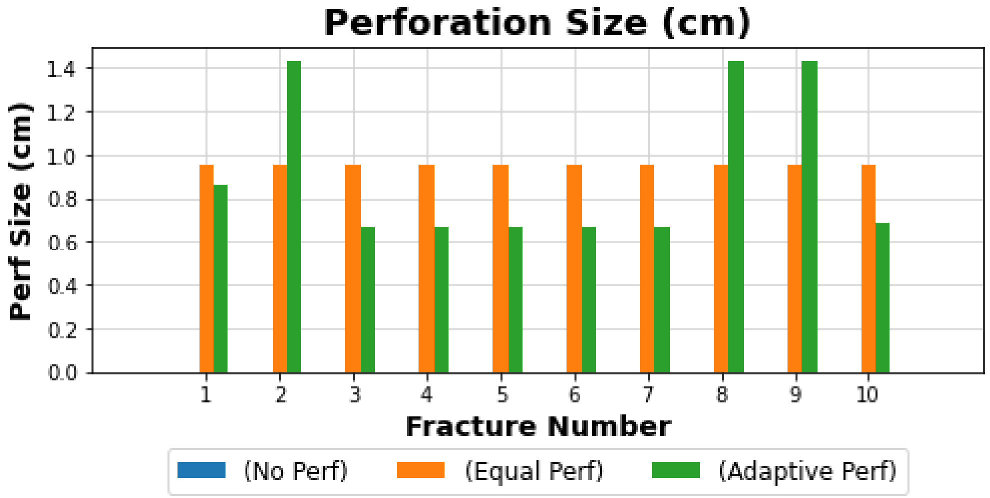
- It is almost impossible to create an EGS with identical fractures
- This is a random distribution of fracture permeability to evaluate how it affects the fluid distribution
- The permeabilities are varied at three order of magnitudes

Heterogeneous Fracture System









Frictional Head Loss = 47m (2.72%)

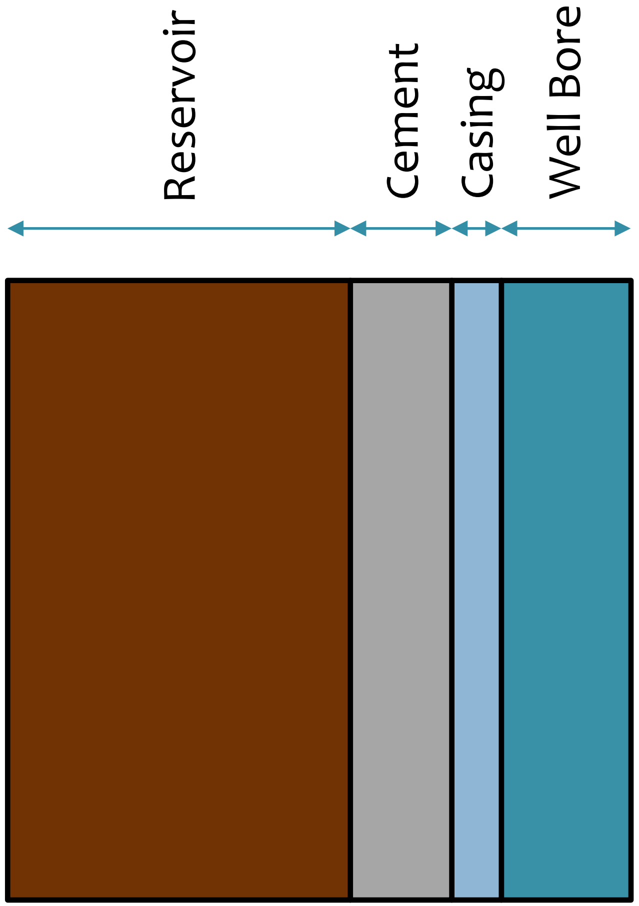
Frictional Head Loss = 116.95 m (6.77%)

Frictional Head Loss = 186.56 m (10.79%)

Wellbore Dynamics coupled with Falcon

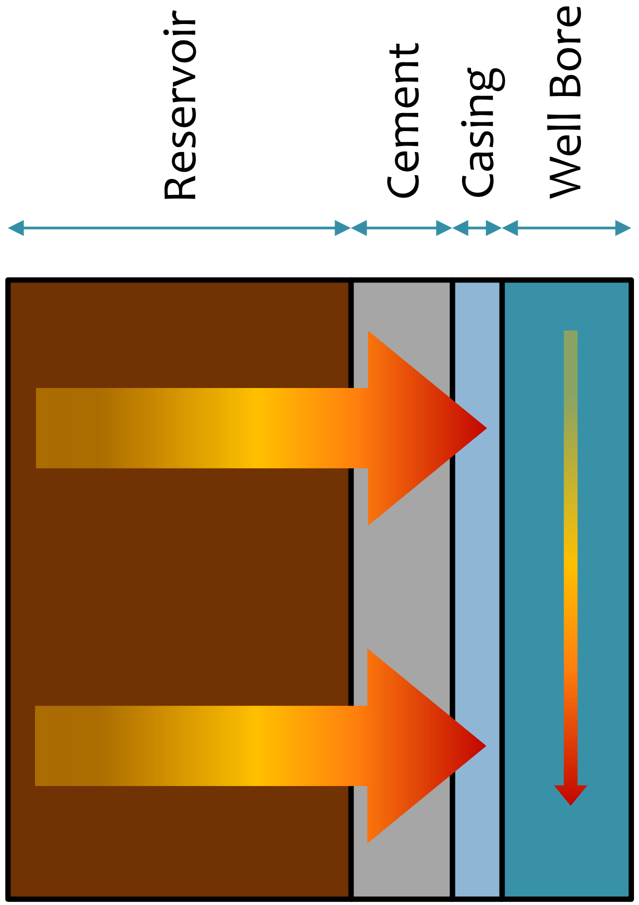
Features of Multi-app THM Coupling

- Well bore is simulated and coupled with Falcon
  - Heat structure capabilities
  - Added perforations zones (size and count)



Features of Multi-app THM Coupling

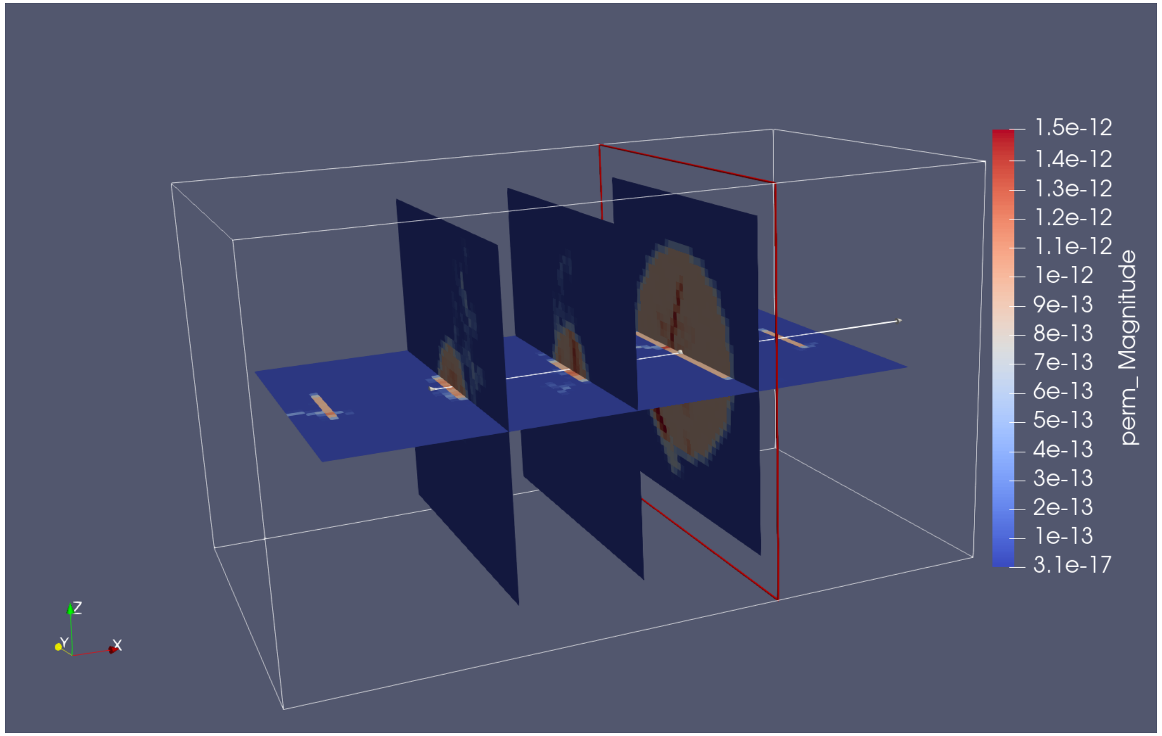
- Well bore is simulated and coupled with Falcon
- Enabled pipe flow dynamics along with heat flow
  - Heat transfer inside and outside the wellbore
- Provides accurate fluid distribution
  - It takes the pressure values from the reservoir to calculate the flowrate.
- Capabilities to be run with THMC coupled models



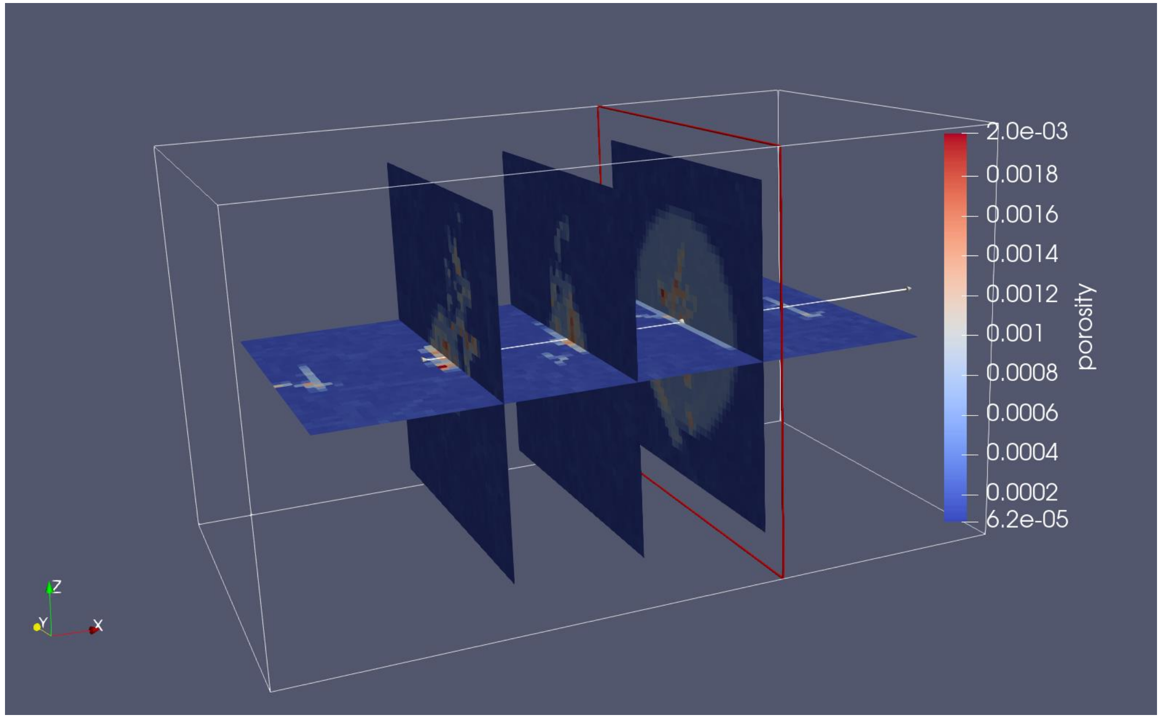
Test Run with Heterogeneous Reservoir Model

- **Simulation Details**
  - Fracture Permeability : $Variable\ Permeability$
  - Well Length: $500m$
  - Well spacing: $150m$
  - Well Diameter: $0.1778m\ or\ 7in$
  - Number of Fractures: 3 fracture zones
  - Pipe Roughness: $0.015mm$
  - Number of Perforations: 6
  - Diameter of Perforation: $0.0095m\ or\ 3/8in$
  - Discharge coefficient: 0.75
  - Flow rate: $15kg/s\ or\ 238gal/min$

Test Run with Heterogeneous Reservoir Model



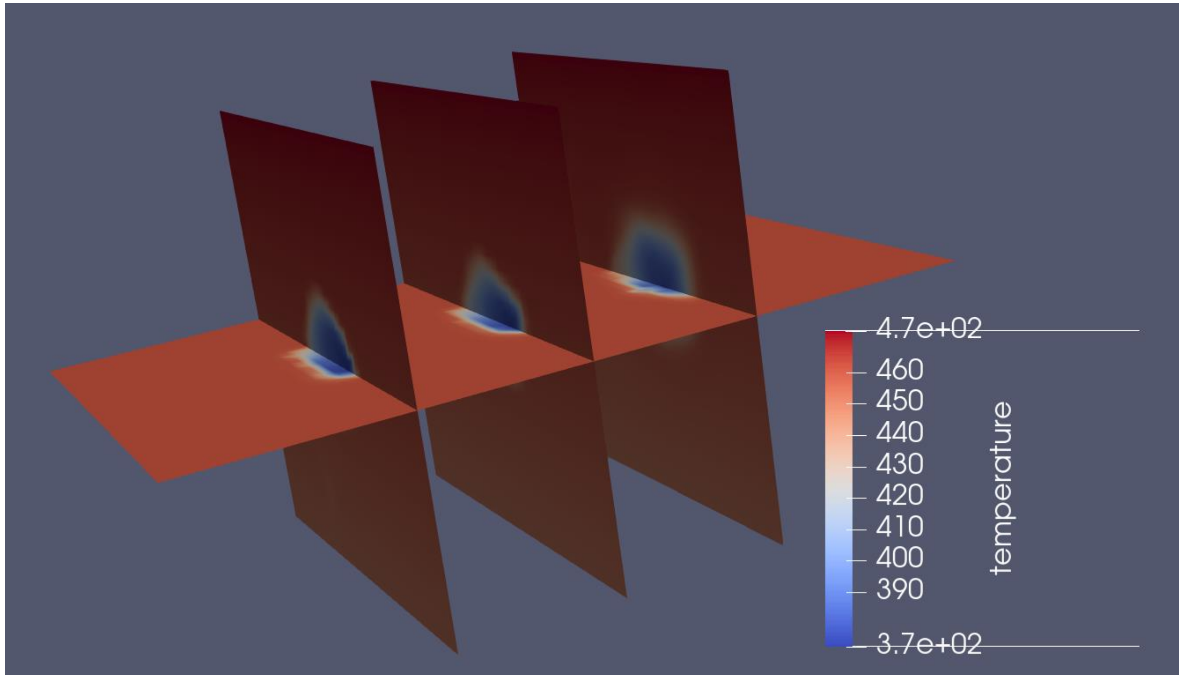
Heterogeneous Permeability



Heterogeneous Porosity

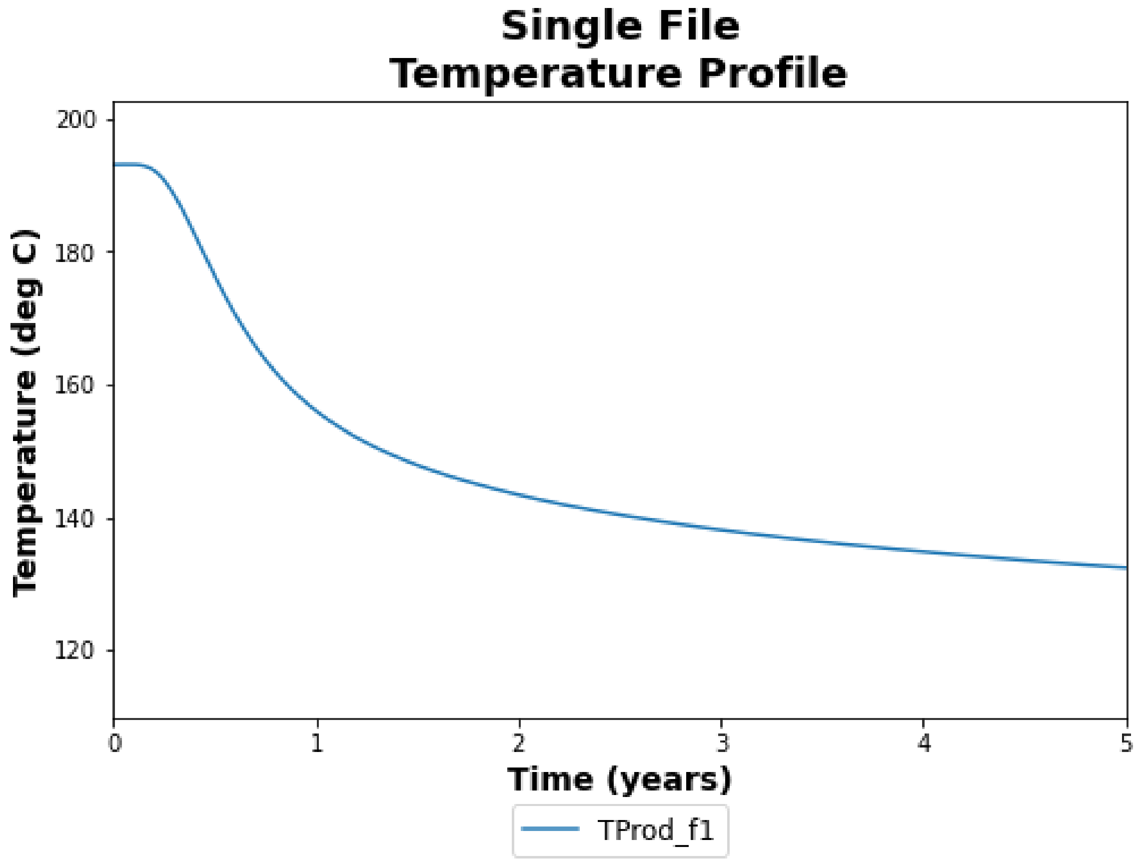
Models provided by: Aleta Finnila (@Golder)

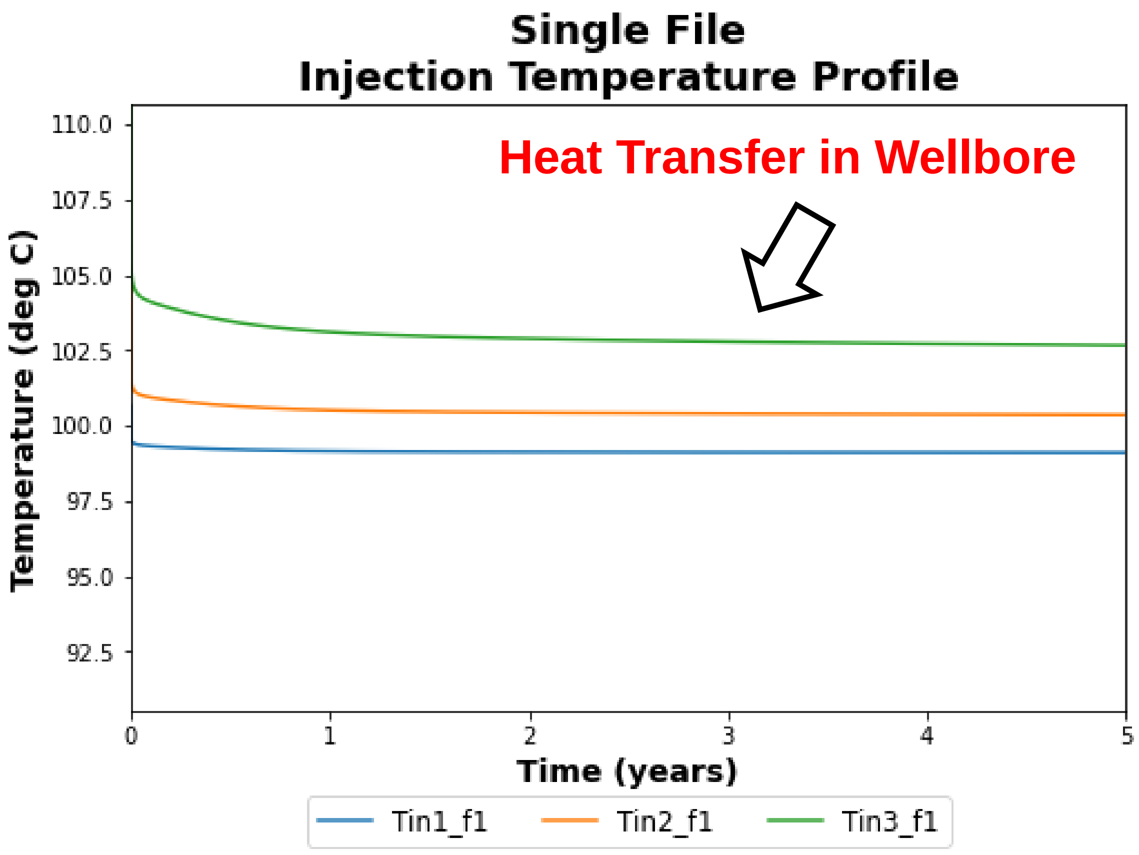
Heat Extraction in the Heterogeneous Model



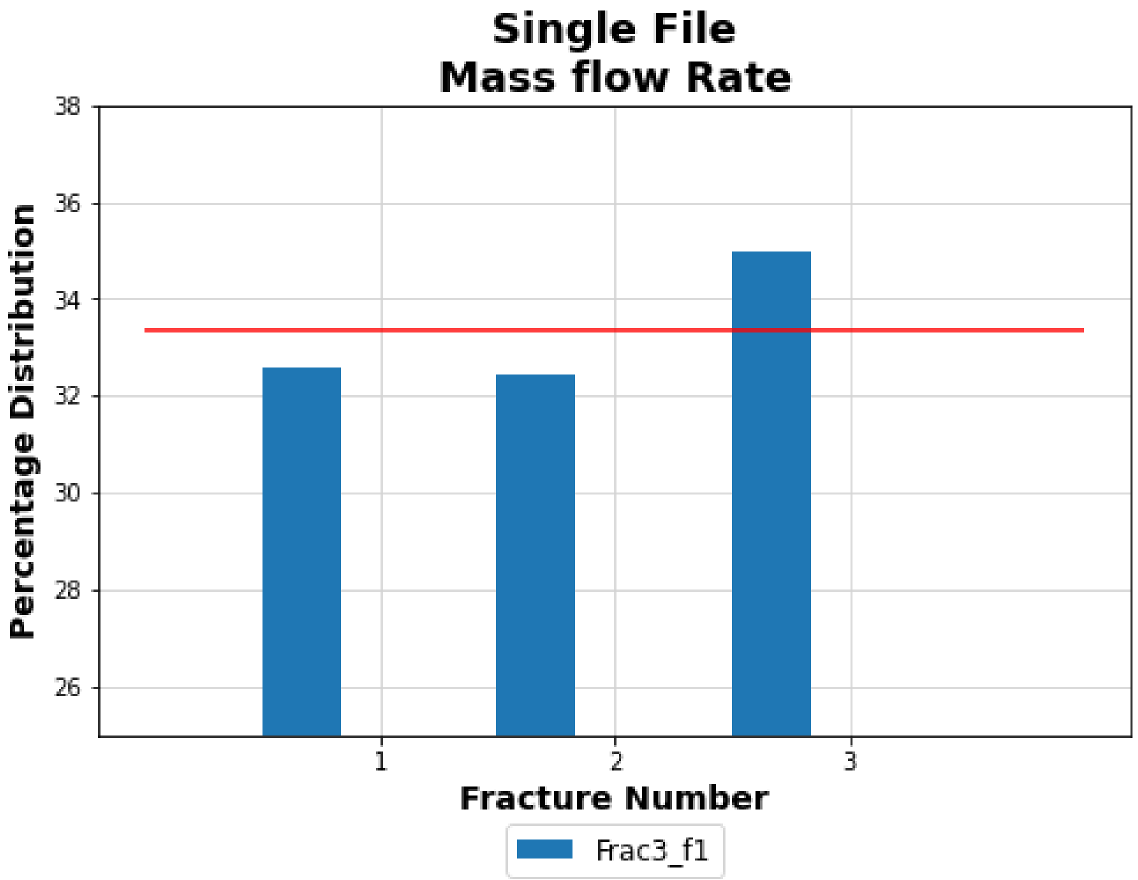
- Injection well simulated with the multi-app
- Production well simulated using Peaceman Borehole model

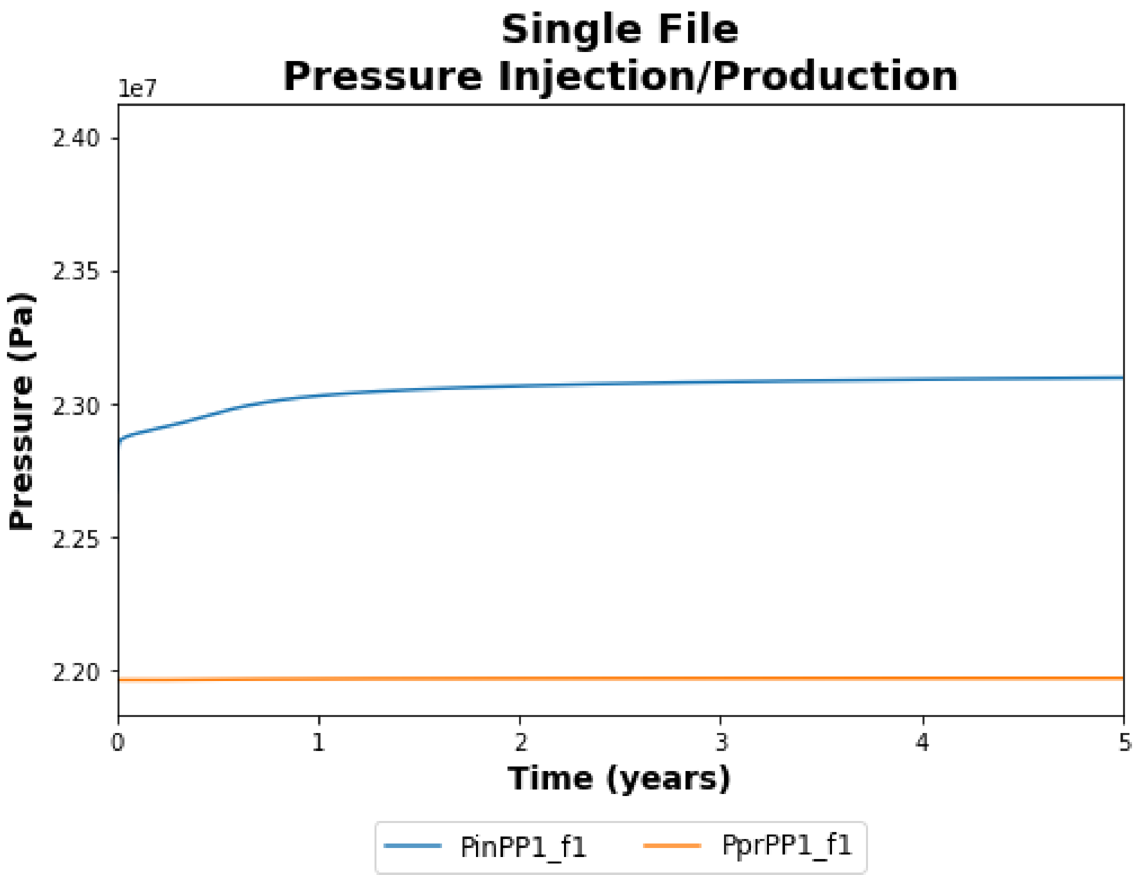
Test Run with Heterogeneous Reservoir Model





Test Run with Heterogeneous Reservoir Model

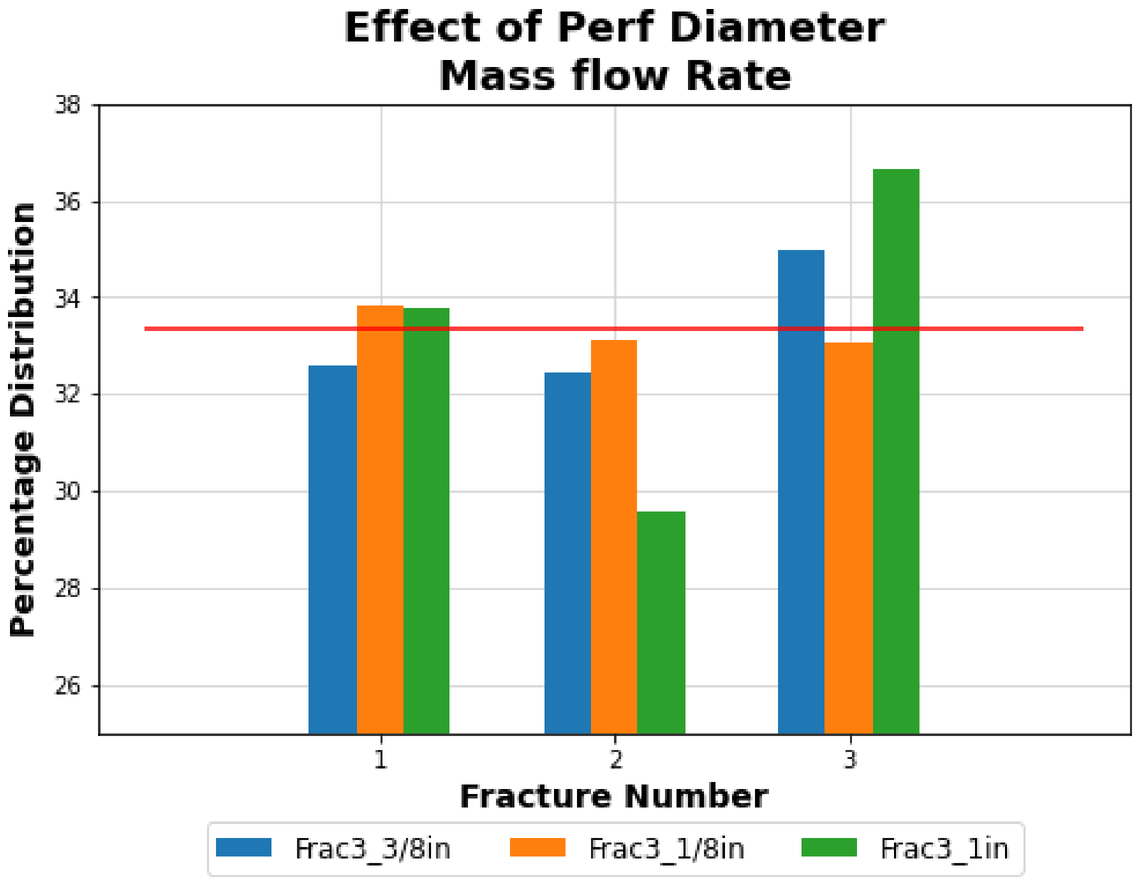


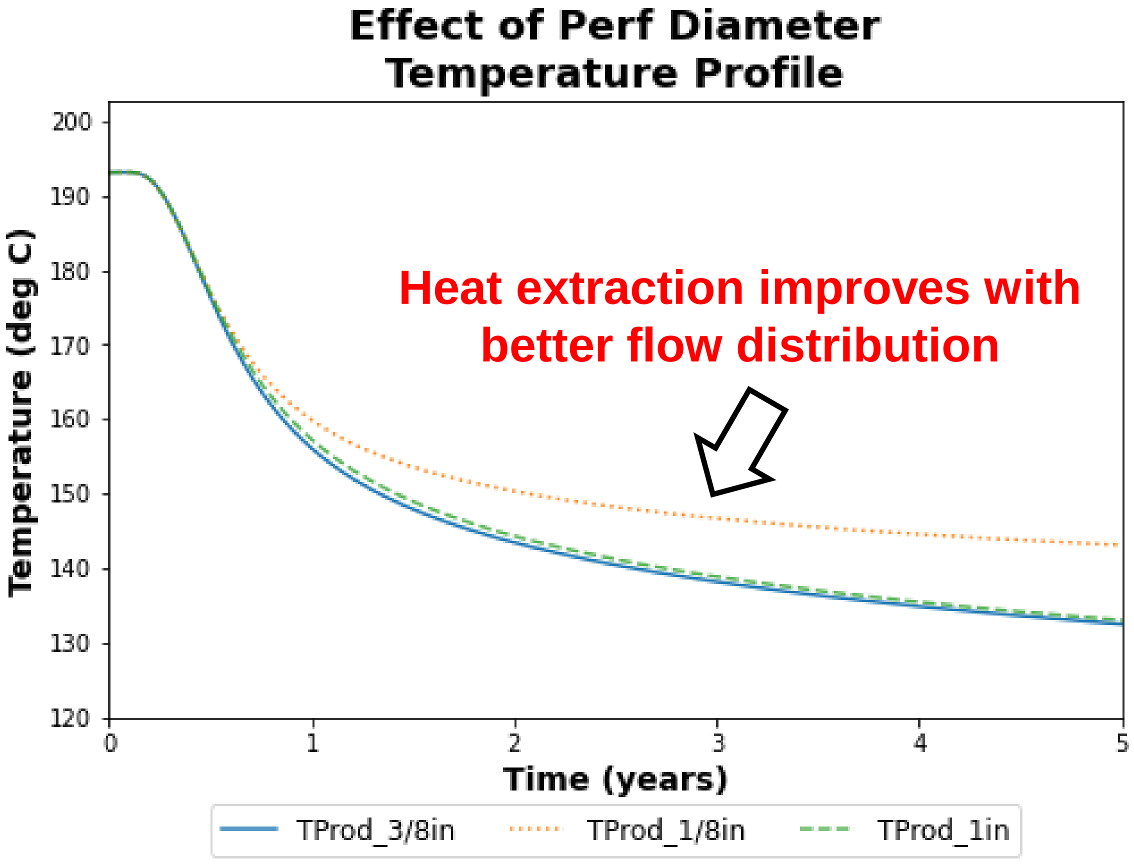


THM gives accurate fluid distribution

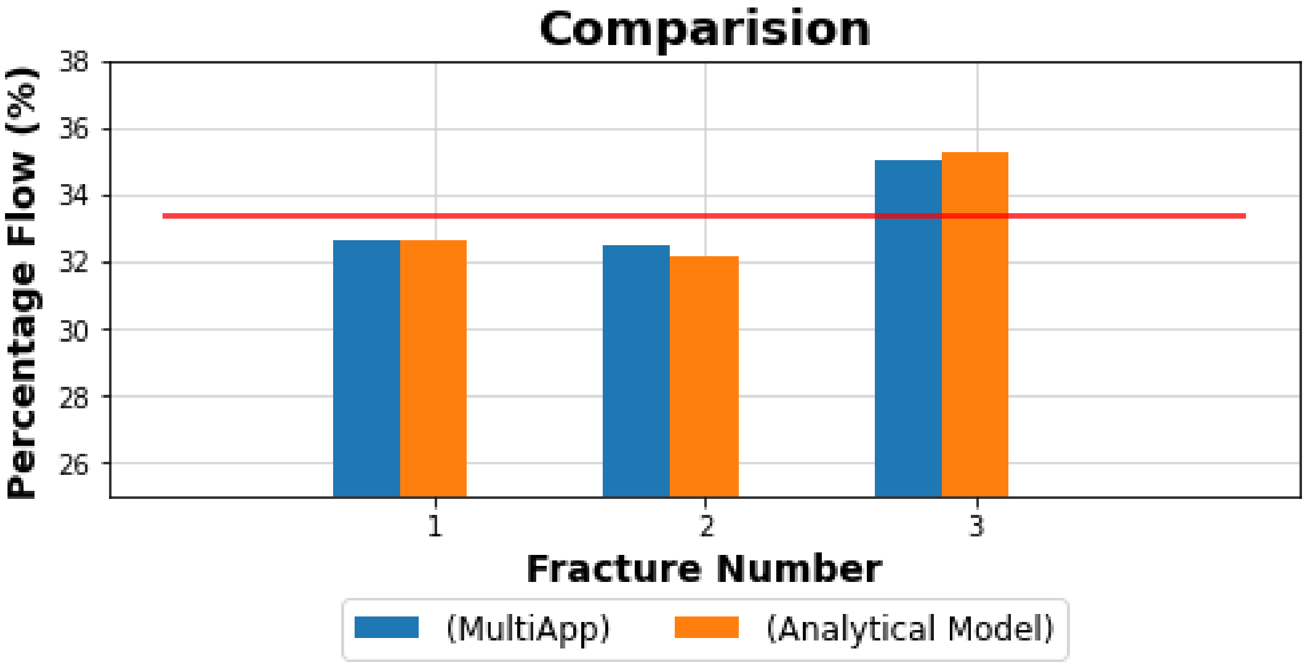
Frictional Head Loss = 89.08m (7.06%)

Effect of perforation using Multi-App





Comparison Between Multi-App and Analytical Model



Frictional Head Loss = 89.08m (5.15%)

Frictional Head Loss = 95.28m (5.51%)

Summary

Summary

- The EGS can be optimized individually at different stages (based on Natural/Completion/Operating parameters)

- The analytical model provides a quick result (under 5 seconds) to evaluate the performance of any well design.

- We need to find innovative ways to address the flow distribution challenge

- The wellbore coupling allows accurate representation of an EGS system and would allow to maximize the heat extraction potential at the FORGE site.

- Future Work:
  - Incorporating gravity in the analytical model
  - Publishing the model to be used by anyone
  - Run full scale reservoir model with FORGE well trajectories

THANK YOU

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Comparative Analysis

- Assumption:
  - Production temperature : $150°C$
  - Injection temperature: $100°C$
  - Efficiency of ORC: 10%
  - Pump efficiency: 90%
  - Motor efficiency: 90%

$$Total\ Energy\ Recovered = \dot{m} C_p \Delta T \eta_{ORC}$$

$$Total\ Energy\ for\ Pumping = \frac{\dot{m} g H_{fric}}{\eta_{pump}\eta_{motor}}$$

$$Percentage\ Pumping\ Energy = 100 \times \frac{g H_{fric}}{C_p \Delta T \eta_{ORC}\eta_{pump}\eta_{motor}}$$

$$Percentage\ Pumping\ Energy = 100 \times \frac{g H_{fric}}{C_p \Delta T \eta_{eff}}$$