# Introduction to Naturally Fractured Reservoirs

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## Talk Outline

- When is it a fractured reservoir vs. a reservoir with fractures?

- Fracture parameters – exactly what is important?

- Characterisation – how do we measure what is important?

- Modelling & Managing – putting it all together, risk mitigation

- Questions & Discussion

Start with what we know – Matrix Reservoirs

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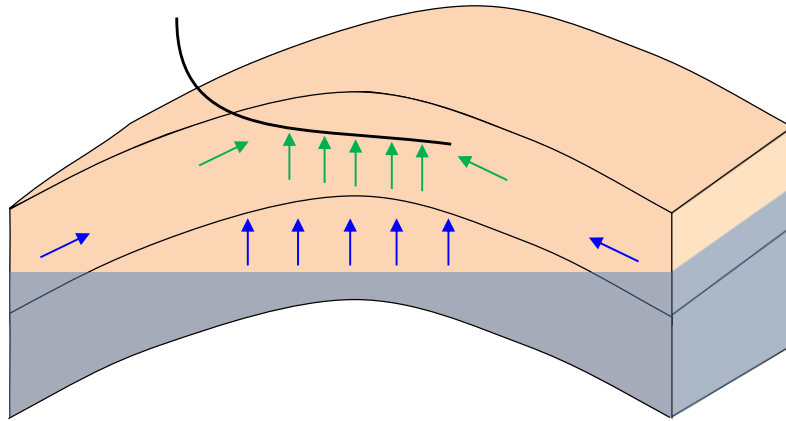
- Anticlinal structure with parallel sandstone bedding. Oil above water with a transition zone of water saturation.

- Matrix only reservoir with a water leg developed by a single horizontal well

- Oil will flow initially into the well. This may be followed either by bottom water if Kv/Kh is high or shale layers are breached

- Alternatively edge drive may occur if Kv/Kh is low or shale layers are intact

- Water cut development controlled dominantly by viscous forces due to pressure sink and rates in the well, matrix permeabilities, gravity and fluid viscosities
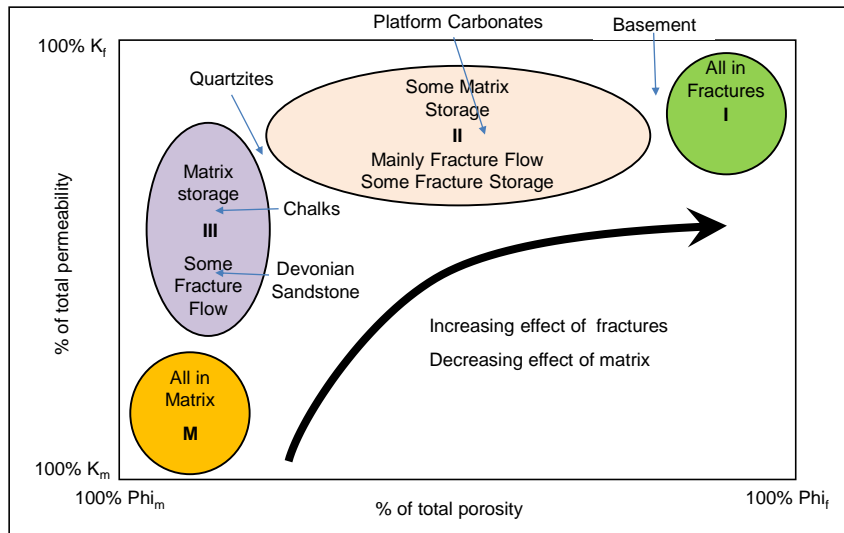
Fractured Reservoir – Matrix & Fractures
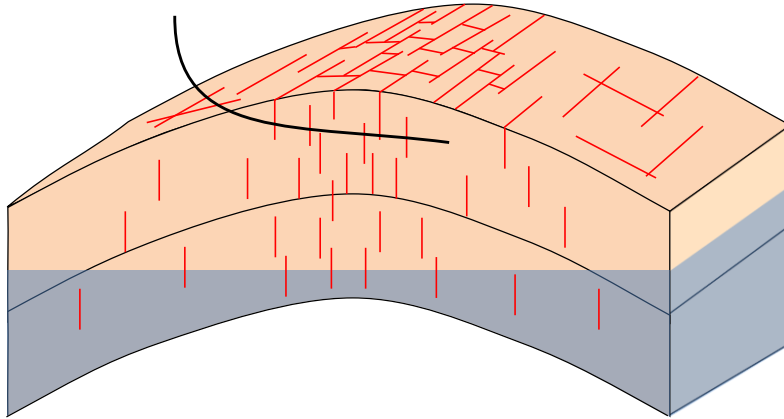
A reservoir with a system of connected natural fractures that have a significant impact on production behaviour

- Same structure, lithologies and fluid distribution as previous slide but with an overlay of sub vertical fractures
- In this case fractures are shown clustered on the fold hinge and parallel to the fold axis.
- Assuming these fractures are considerably more permeable than the matrix, how will they behave?
- How will they control oil flow?
- Will they change how the water cut develops?
- How do they interact with the fluids in the matrix?
- Note in reality these fractures are more likely to be perpendicular to layering than subvertical

*After Nelson 2001*

- Fractured reservoir classification scheme developed by Ron Nelson
- Horizontal axis shows ratio of storage from 100% in matrix at origin to 100% in fractures on bottom right corner
- Vertical axis shows ratio of permeability from 100% in matrix at origin to 100% in fractures in top left corner
- The three types are III (three), II (two) and I (one) that show a progression toward more dominance of fractures
- Some examples of fractured reservoir types are given:
- Chalks (Machar, Banff), Devonian Sandstone (Clair, Buchan), platform carbonates (S Mediterranean, Middle East), Basement (Cairngorm, Lancaster)
- In general, fractures become more dominant as the matrix poroperms reduce

# Fracture Parameters

## Fracture Permeability & Porosity
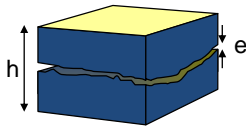
e = fracture aperture    h = interval of interest
typically 0.05 – 1mm    e.g. fracture spacing

$$k_f = \frac{e^3}{12h}$$ Fracture Permeability – 'Cubic' law

Fracture porosity is:    $$\emptyset_f = \frac{e}{h}$$ Typical average 0.05% to 1%
Very hard to measure

Effective Fracture Permeability
Relevant to unit volume of rock    $$k_f = \frac{e^2}{12}\emptyset_f$$ Measured on well tests
Used in most simulators
Typically 10 mD to 5000 mD

Intrinsic Fracture Permeability
Relevant to fracture volume only    $$k_{ff} = \frac{e^2}{12}$$ Required by some software
Values can be huge ~$10^6$ mD+

Theoretical maxima of single fractures
Measurements in metres. Permeability is in $m^2$
(multiply $m^2$ by $10^{15}$ to get mD)

- Description of the key elements in defining fracture permeability and porosity for a single fracture
- The permeability equations are derived from Darcy's flow law and Poisseulles flow Law
- The aperture e is assumed to represent an average aperture of a smoothed walled fracture or parallel plate model. It is termed the hydraulic aperture and is controlled by the minimum apertures found in a rough natural fractures.
- In the simple case shown here, e is also used for porosity. However, the aperture relevant for the porosity is the mechanical aperture E. This is the actual volume within the fracture itself divided by the area over which it is measured
- The permeabilities are relevant for single fractures or sets of parallel fractures with the same orientations and hydraulic aperture
- Complex natural fracture system permeabilities are controlled by variable apertures, fracture lengths, fracture orientations and fracture connectivities – generally need to be modelled and matched to dynamic data

## Fracture Permeability Exercise

| Intrinsic | Effective | Porosity |
|---|---|---|
| 1. $k_{ff} = \dfrac{e^2}{12}$ | 2. $k_f = \dfrac{e^3}{12h}$ | 3. $\emptyset_f = e/h$ |

(multiply m$^2$ by $10^{15}$ to get mD)

- Fracture System A
  - e = 0.0005 m (0.5 mm)
  - h = 1 m

  1. $k_{ff}$ = 20,833,333 mD
  2. $k_f$ = 10,417 mD
  3. $\phi_f$ = 0.05 %

- Fracture System B
  - e = 0.00005 mm (0.05 mm)
  - h = 0.1 m

  1. $k_{ff}$ = 208,333 mD
  2. $k_f$ = 104.17 mD
  3. $\phi_f$ = 0.05 %

Permeability totally dominated by fracture system A
Porosity equal in the two fracture systems
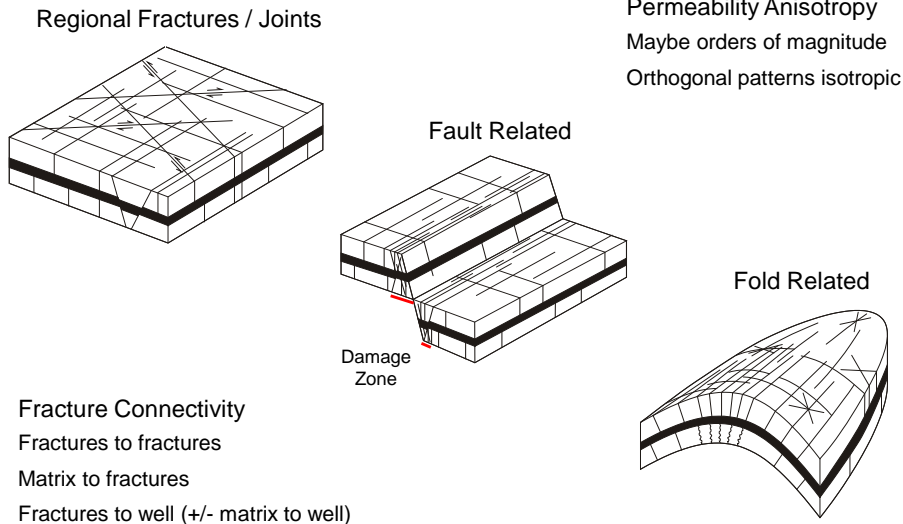This is the simple case for one planar fracture…..

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NOT IN TALK

Exercise demonstrating the non-linear relationship of fracture porosity and fracture permeability even in the simple single planar fracture case.

Classification Scheme – Small Scale
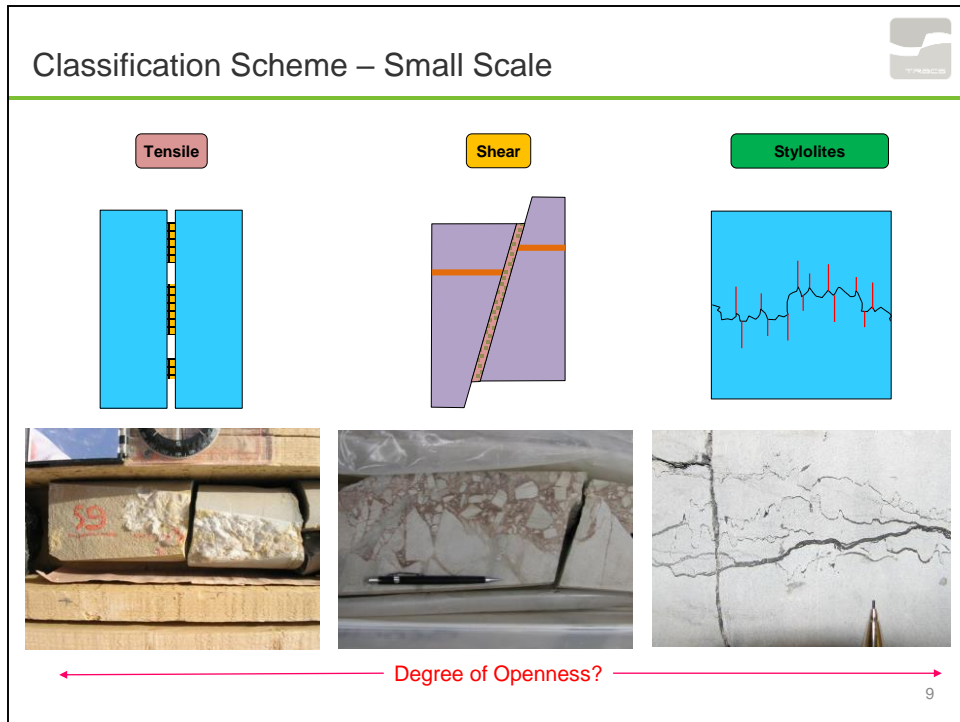
NOT IN TALK

- Examples of different fracture types. Assume one principal stress is vertical and one is horizontal

- Tensile fractures form when rock is 'pulled apart' under tension – usually when fluid pressures are high. Minerals may be deposited and bridge the tensile fractures to form veins

- Shear fractures form when the difference between the two principal stresses is large enough to cause the rock to form a slip plane or fault. This may be filled with breccia, clay gouge and veins

- Stylolites form when the rock is compressed (vertically in this case) and pore fluids preferentially dissolve the rock at stressed grain contacts. The remaining material (clay, quartz, organics etc) forms a stylolite seam.

- The stylolite itself may be permeable or short tensile Stylolite Associated Fractures (STAs) may branch off and also cause local permeability enhancement. Some stylolites can form pressure baffles or seals but others are not.

Fracture Distributions – Larger Scale

Regional Fractures / Joints

Permeability Anisotropy
Maybe orders of magnitude
Orthogonal patterns isotropic

Fault Related

Fold Related

Damage Zone

Fracture Connectivity
Fractures to fractures
Matrix to fractures
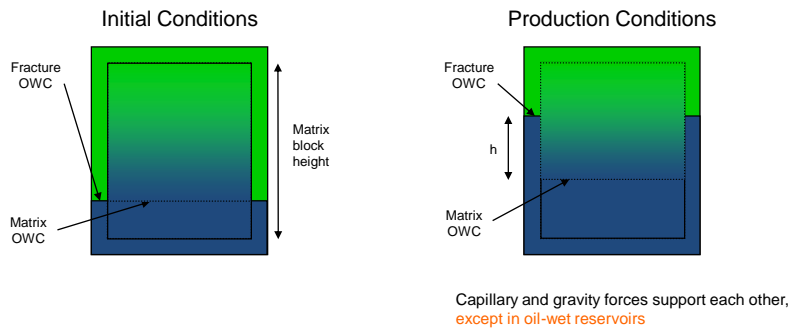Fractures to well (+/- matrix to well)

- Regional fractures joints are typically 1-100m scale. Usually tensile fractures, often in orthogonal sets. Form during stress, fluid pressure and temperature changes during gradual burial and uplift of relatively stiff rocks.

- Faults may be any scale. Fault damage zones comprised of smaller tensile fractures and shear fractures. Usually associated with high permeability anisotropy and significant vertical and lateral connectivity parallel to the fault. May also baffle or seal across the fault.

- Folds (as relevant to hydrocarbon accumulations) usually a few hundred metres to kilometres in scale. Fractures will be associated with the hinge zone if thick stiff beds dominate the sequence. However, strain and fracturing may be more common on the fold limbs if many thin stiff beds are separated by weaker beds such as shales.

- Distributions not mutually exclusive – overprinting possible especially folds amplifying regional joints and faults cutting either of the other two

Depletion - especially in fractured gas reservoirs but also some oil reservoirs

Oil-Water Imbibition (water wet)

| Initial Conditions | Production Conditions |
|---|---|

Fracture OWC

Matrix block height

Matrix OWC

Fracture OWC

h

Matrix OWC

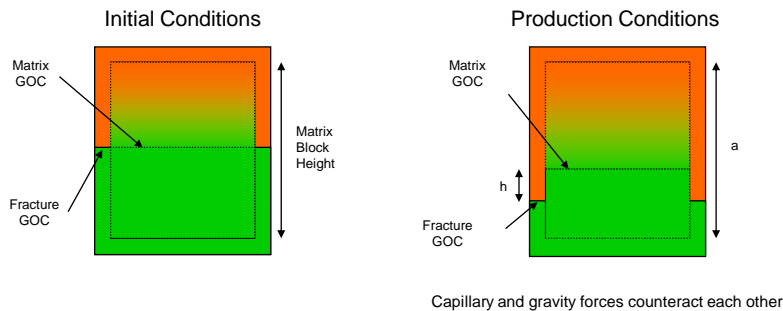Capillary and gravity forces support each other, except in oil-wet reservoirs

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- Depletion is important in the initial stages of many reservoirs production but it is often the prime driving force in fractured reservoirs, especially where there is little or no support from matrix volumes or an aquifer. Compressibility of the fractures may be quite high and this can help contribute energy to the depletion. Depletion will also encourage some hydrocarbons to be produced from the matrix into the fractures – especially in gas reservoirs – but this may take time

- Oil water imbibition occurs where a water wet matrix block is conceptualised as surrounded by open fractures. Under initial conditions, the matrix block has an oil-water transition zone but the fractures are too permeable and do not have one.

- Under producing conditions from a well or perforated interval situated in the top of the matrix and fracture system, the oil gets produced from the fractures (ignore direct contribution from the matrix) and the water level rises from aquifer or injection sources (gravity forces). This water will imbibe into the matrix from spontaneous and forced imbibition (capillary forces) and help sweep the oil out of the matrix and into the fracture system to be produced. Eventually water in the fractures will reach the well but oil can still be produced from the matrix by the imbibition process. The process is less efficient in oil wet systems as the capillary forces work against gravity and forced imbibition plays a greater role.

- Examples include some fractured sandstones like Clair and many chalk reservoirs

Production Mechanisms

Gas-Oil Gravity Drainage

Initial Conditions

Matrix GOC

Matrix Block Height

Fracture GOC

Production Conditions

Matrix GOC

a

h

Fracture GOC

Capillary and gravity forces counteract each other

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- Gas oil gravity drainage occurs with oil as the preferential wetting phase and gas occurring above it as the non-wetting phase. Water will often also be present but is assumed to be residual in this case and is ignored here.

- Under initial conditions, the gas oil contact in the fracture is at the free oil level due to its high permeability and the matrix shows a transition zone of oil to a residual oil saturation in the gas gap.

- Under producing conditions, a well or perforated interval will be in the oil leg and drain the oil in the fractures. The gas will expand and help drive the oil production. Once there is the gas level is deep enough, oil will start to drain out of the matrix from gravity. As the capillary forces are trying to retain oil in the matrix block, this process is helped by tall matrix blocks allowing greater gravity forces to help. The gas will often break through to the wells early but oil will continue to drain. This process is not as efficient as water wet oil water imbibition.

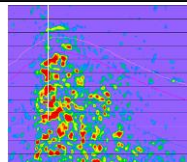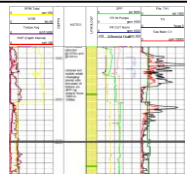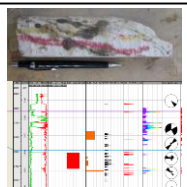- Examples include many of the Middle East fractured carbonates such as Natih

# Fracture Characterisation
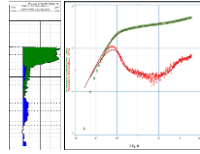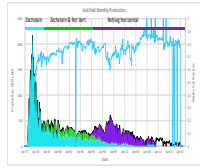
Permeability            If this isn't >matrix – is the reservoir fractured?

Porosity               Hard to measure but the range needs estimating

Distribution           Where are the porous and permeable ones?

Connectivity           Reservoir plumbing. What is connected to what?

Production Mechanism   Depletion? Imbibition? Gravity drainage?

Matrix

Data – Gather as much as possible. Integrate & Iterate

| Type | What can it Measure | Examples |
|------|---------------------|----------|
| Seismic (3D) | 3D distributions, orientations, anisotropy | |
| Drilling Data | 1D distributions, what's open near the well | |
| Core & OH logs (incl. images & adv. sonic) | 1D distributions, types, orientations, apertures, what's open at the well | |

- Seismic data has often been heralded as the data type that can provide the links between wells. P-wave anisotropy and amplitude variations can yield good results but seismic energy is fundamentally responding to anisotropy and heterogeneity, Therefore it can be difficult to derive meaningful fracture set parameters where multiple open fracture sets occur or where the in-situ stress anisotropy has a significant effect

- Fracture properties such as coherency and 3D curvature can indicate the locations and orientations of fracture clusters or small faults but careful calibration is required from well data

- Core and image logs are very good at defining 1D fracture distributions and fracture sets defined by mineral fills, tensile vs shear origins and fracture set orientation. However, in-situ stresses can often enhance the appearance of openness at the wells. Core and logs only sample a small volume and suffer from orientation bias. Because single fractures are often heterogeneous over many metres and fracture networks have complex connectivities, a lot of well data is required to derive a representative sample of reservoir fractures (5-10+ for appraisal).

- Both the e and E average apertures are very hard to measure accurately. They can be estimated from core but core is a small sample and measurements are usually taken under relaxed stresses. Apertures can also be estimated from electrical image logs (Luthi and Souhaite 1990) but image log estimates use empirical factors than need calibrating.

Data – Gather as much as possible. Integrate & Iterate

| Type | What can it Measure | Examples |
|---|---|---|
| Dynamic well data | Open fractures at well, larger scale connectivity to fractures +/- matrix | |
| Field performance (incl. 4D seismic, microseismics) | Open frac distributions, frac system connectivity, production mechanisms | |
| Analogues (offset fields, outcrops) | Connectivity and distribution templates, production mechanism scenarios | |

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The data types are many and varied. The key things to remember are:

- Look at everything that is available

- Get the full team of all disciplines reviewing and interpreting and analysing data at the same time

- Get the team to talk to each other to allow perceptions to be challenged – fractured reservoirs may not look consistent from all datasets. This avoids silo thinking but beware single scenario group think

- Constantly iterate analyses including full loops through modelling, The key is to come up with some plausible scenarios that can be taken through to modelling and history matching (if appropriate)

- Keep the range wide especially on parameters like fracture porosity unless a significant amount of production data is available to constrain it

- Note that the best estimate of fracture system permeability often comes from well tests or production derived PI's. HOWEVER this supposes the wells have sampled the full fracture system which they may not. Even after several years of production, fractured reservoirs can behave in unexpected ways. Keep an open mind.

# Modelling & Managing

Representing Reality

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- This talk hasn't really covered fracture modelling methods which are also many and varied. However, for many people working on fractured reservoirs in many companies, standard finite difference reservoir simulators and cellular geomodelling packages will be key parts of the process.
- This slide illustrates that the complexity of a real fracture system usually has to be collapsed into average properties within a single grid cell (blue shaded boxes). This can be done directly using standard tools in the geocellular modelling packages or via more complex packages like Discrete Fracture Networks that then explicitly model fracture networks and then upscale the parameters. Added complexity can be included from geomechanical effects. The choice of the modelling route will be dependent on model purpose, data availability, team skills, available software, budget and time.

Warren and Root Model for Dual Porosity
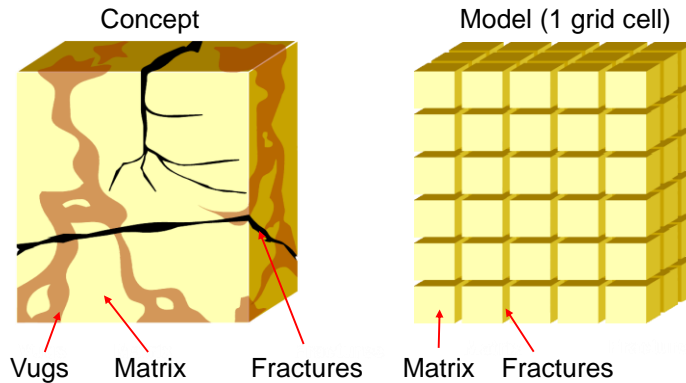
- It is assumed here that the end product of the analysis and modelling effort are well profiles from a finite difference simulator (e.g. Eclipse). These simulators all have something called the dual porosity mode.

- Dual porosity mode allows the simulator to retain separate descriptions of the parameters related to the matrix block and the parameters related to the fractures separating those blocks.

- In the conceptual diagrams above, the left hand one is from the geologist and the right hand one is how the reservoir engineer needs to represent that concept in the model. Note that the right hand diagram represents a single grid cell that contains separate parallel fracture sets that separate individual blocks of matrix.

- These matrix blocks and fractures shown on the right are not represented explicitly in the simulator. the average fracture set properties are captured by the fracture XYZ permeabilities, porosity, rel perms, and saturations. The average properties of all the individual matrix blocks are also captured as average perms, porosity etc for that cell. The effective size of the individual matrix blocks are captured by the sigma factor which is a coefficient used with matrix permeability. The larger the sigma factor, the smaller the matrix blocks within that grid cell

Dual Porosity Parameters for Numerical Modelling

Model
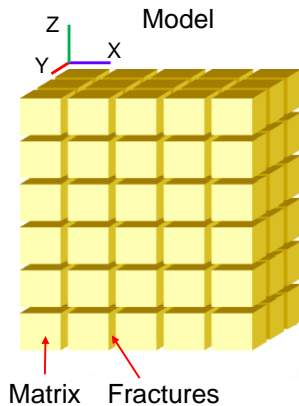
$$\alpha = \frac{4j(j+2)}{L^2}$$

Where:
j = no of fracture sets (3 in this case)
L = matrix block dimension

Sigma factor (Kazemi):

$$\sigma = 4\left[\frac{1}{L_x^2} + \frac{1}{L_y^2} + \frac{1}{L_z^2}\right]$$

Matrix    Fractures

Sigma is the numerical equivalent to $\alpha$

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NOT IN TALK

- This slide highlights the derivation of the sigma factor used in finite difference simulators.

- The alpha factor is also shown which is the equivalent factor used for the dual porosity model in analytical well test packages. The derivations of the two factors are very similar.

- A number of different derivations exist for these factors and they get more difficult to define with irregular block sizes and changing fracture lengths

- As a rule of thumb these sigma values are often only accurate when the matrix block is half depleted
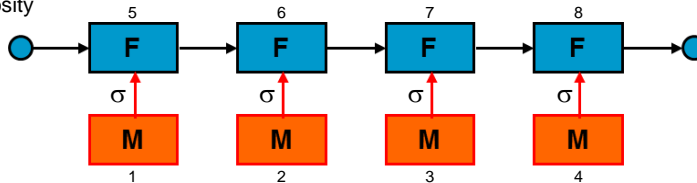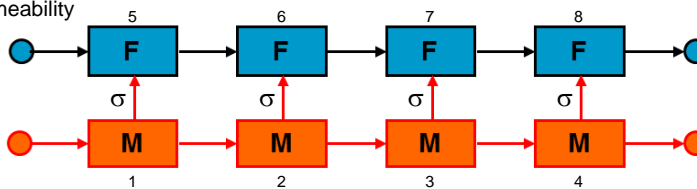
Finite difference simulators can be run in a variety of modes to account for the presence of fractures.

- Single porosity mode – the standard mode and all properties stored in a cell represent matrix properties. Wells can connect to the matrix and adjacent matrix cells connect to each other. In reservoirs where fractures are relatively widespread, well connected and provide a small boost to the matrix permeability (x2-5), the fracture properties can be added to the matrix properties and run in this mode. This is because the time lag for pressure and fluid saturation changes between the fractures and matrix are too small to warrant modelling specifically

- Dual porosity mode – the data is stored in arrays numbered 1 to n for the matrix properties and n+1 to m for the fracture properties. So in a 4 cell array, matrix cell 1 is associated with the fracture cell properties at cell index 5. Cells 1 and 5 occupy the same volume, 2 with 6 and so on. Wells can connect to fractures for flow and pressure changes but wells do not directly connect to matrix cells. Fracture cells connect to each other to allow flow in the reservoir. Pressures and fluid saturations transfer from the matrix cell and its associated fracture cell as controlled by the sigma factor.

- Dual permeability mode – The basic premise is the same as dual porosity but matrix cells can also connect (flow, pressure) directly to the wells and to each other.

- As the modes become more complex, more computing power or time is required to

complete the simulations. This is less of a time problem in absolute terms with modern computers but the relative time differences between the modes still stand.

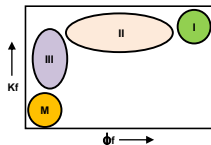| Fluid Type \ Nelson FR Type | M | I | II | III |
|---|---|---|---|---|
| Gas | SP | SP | SP | SP |
| Oil | SP | SP | SP | SP |
| Oil/Gas | SP | SP | DP | DK |
| Oil/Water | SP | SP | DP | DK |

SP      Single Porosity (Conventional)
DP      Dual Porosity
DK      Dual Permeability

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The simulator mode selection is not just a function of the fracture properties vs matrix properties, the reservoir fluid is also relevant.

- Where the fluid is single phase and therefore produced by depletion, single porosity mode is generally suitable in all fracture/matrix property combinations

- Where matrix properties are very dominant (M) or only fracture properties are relevant (Type I), single porosity mode is adequate for all fluid combinations.

- Where there is mainly fracture permeability and some fracture storage (Type II), dual porosity mode is often recommended for two phase situations

- Where there is a mix of matrix and fracture permeability and mainly matrix storage (Type III), dual permeability is required in two phase situations

Issues in simulators:

- High perm anisotropy convergence problems. Permeability anisotropy may need to be reduced to get the simulation to work but this makes the reservoir permeability more isotropic than desired

- High pore volumes flowing through small fracture volumes can cause numerical dispersion – hard to simulate. Minimum Pore Volumes for fractures can be set to avoid this but places fracture properties everywhere – makes model more homogeneous than desired.

- Very high permeabilities may cause convergence issues. Set max perm limit to something reasonable rather than what the permeability equations or upscaled DFNs come up with. Also reduces permeability range from what is desired.

- Can set matrix poroperm as frac poroperm in global DP mode where frac poroperms are zero. Must set matrix poroperm to zero in this situation.

- In general, the above issues and their fixes tend to make the model more isotropic and homogeneous than it should be. To retain the heterogeneity and anisotropy, specialised simulators may be required such as Discrete Fracture Network (DFN) packages – FracMan, FracaFlow, CSP etc. These specialised simulators are often only worth using where a lot of high quality static and dynamic data is available to constrain them. However, they are also useful to test What-if? anisotropy and connectivity scenarios.
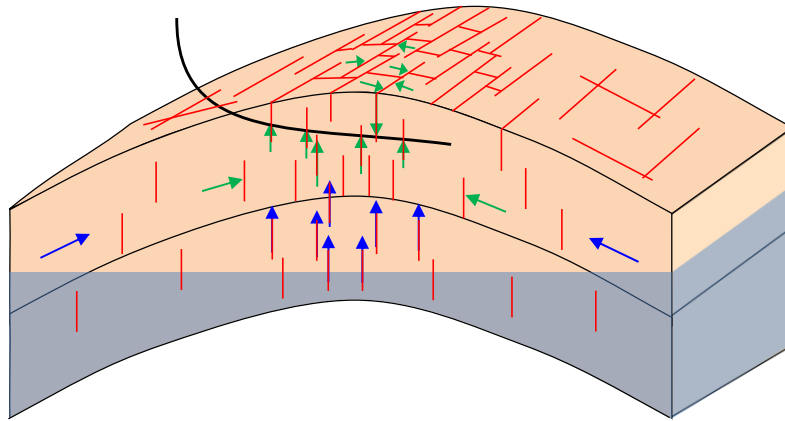
Back to our simple concept of fold related open and connected fractures in a two phase oil-water reservoir (depletion and oil water imbibition processes relevant).

- Initial flow will be via the fractures, probably high oil rates. Fracture system probably rapidly depleted unless connected to water (aquifer or injectors). With some fracture depletion, the matrix blocks will also yield oil into the fractures which will take longer to come out. Water may start entering the fracture system and then the well. The water may also start imbibing (spontaneous or forced) into the matrix which will also help push out dome oil. This process is helped by long hydrocarbon columns and relatively low offtake rates.

- Once the water has largely flooded the fracture system, from vertical or lateral connectivity to the aquifer / injectors, some oil may still be produced from imbibition processes. However, a lot of oil may be bypassed and left in the matrix so more wells may be needed (e.g. flanks in this example).
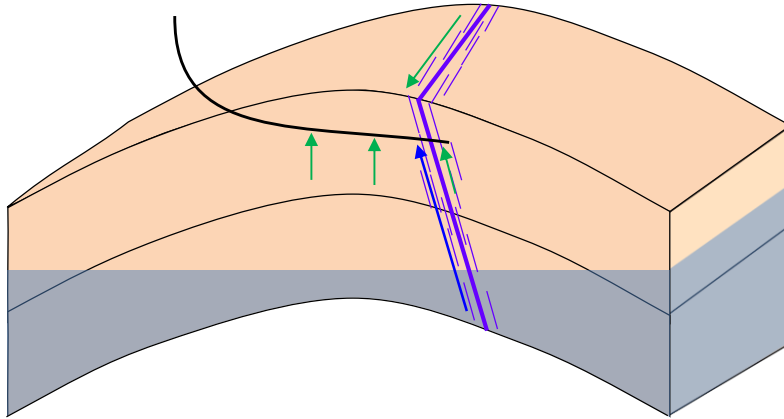
## Fractured Reservoir – Heterogeneity Focus

A reservoir with a system of connected natural fractures that have a significant impact on production behaviour

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In this scenario, the matrix is largely unfractured but a laterally extensive, high permeability, anisotropic fault related fracture system cuts the well.

- Initial oil rates may be very good but water may start being produced within days or weeks, especially if the fault is connected to a strong aquifer or injector system

- Management strategies:

- Avoid drilling large faults, don't perforate large faults, plug or blank off large faults if they start producing water

- Reduce offtake rate if water is coning up the fault

- Drill wells and injectors parallel to the fault system and treat as a matrix only reservoir

## Summary - Managing the Risks

- Identifying the poroperm system elements. Integrate data
  - Non-intuitive open fracture directions – stress & mineralisation
  - Connectivity of matrix to fractures
  - Multiple concepts and iterate models

- Fluid system & permeability architecture
  - Think about fluid saturations and mobilities – matrix & fractures
  - Well tests / EPS don't always see everything
  - Phased development often optimal but increased cost and time

- Connectivity of wells & injectors to fracture system
  - Skin and drainage. Stimulations required to access natural fractures?
  - Injector placement WRT wells and fracture system – avoid shortcuts
  - Patchy fractures > more wells or longer wells

- Well performance – manage offtake & injection
  - High rates > More oil up front but possible early high water or gas cut
  - Low rates > Less water, better imbibition & recovery but longer to get oil

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Please contact me at tim.wynn@tracs.com with any queries, comments or corrections