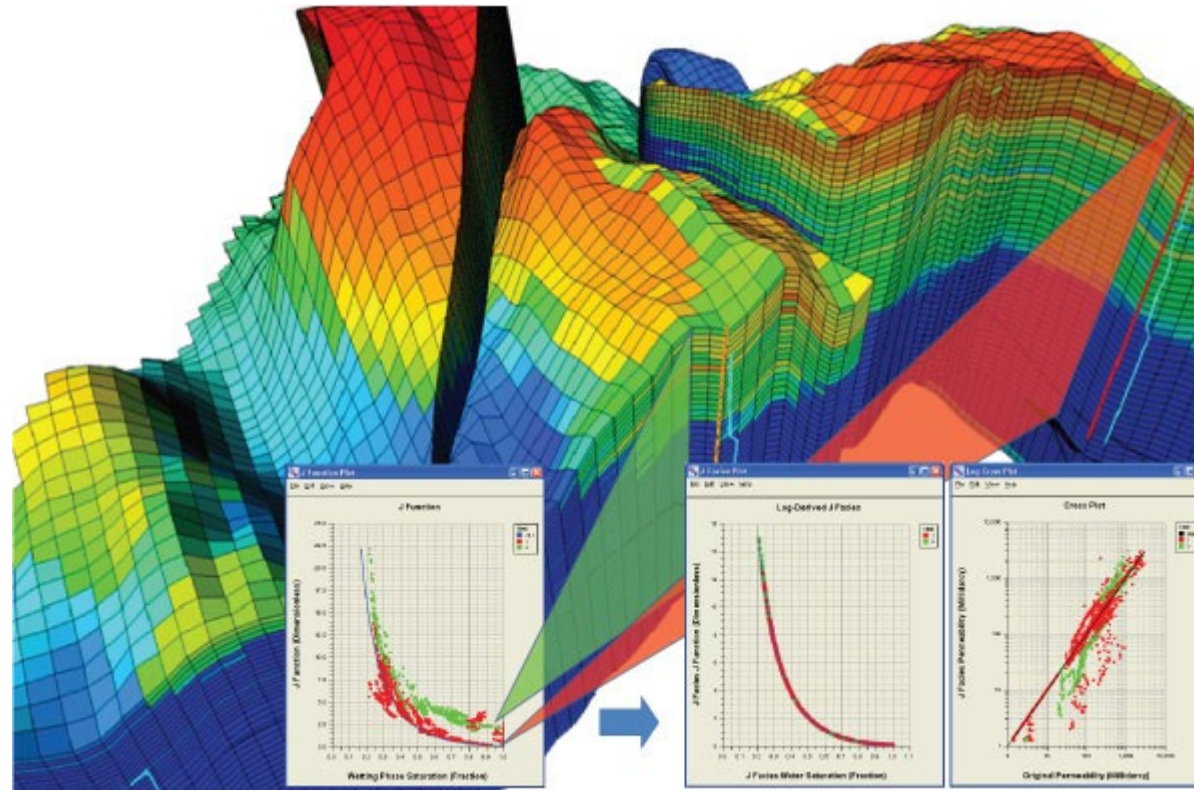


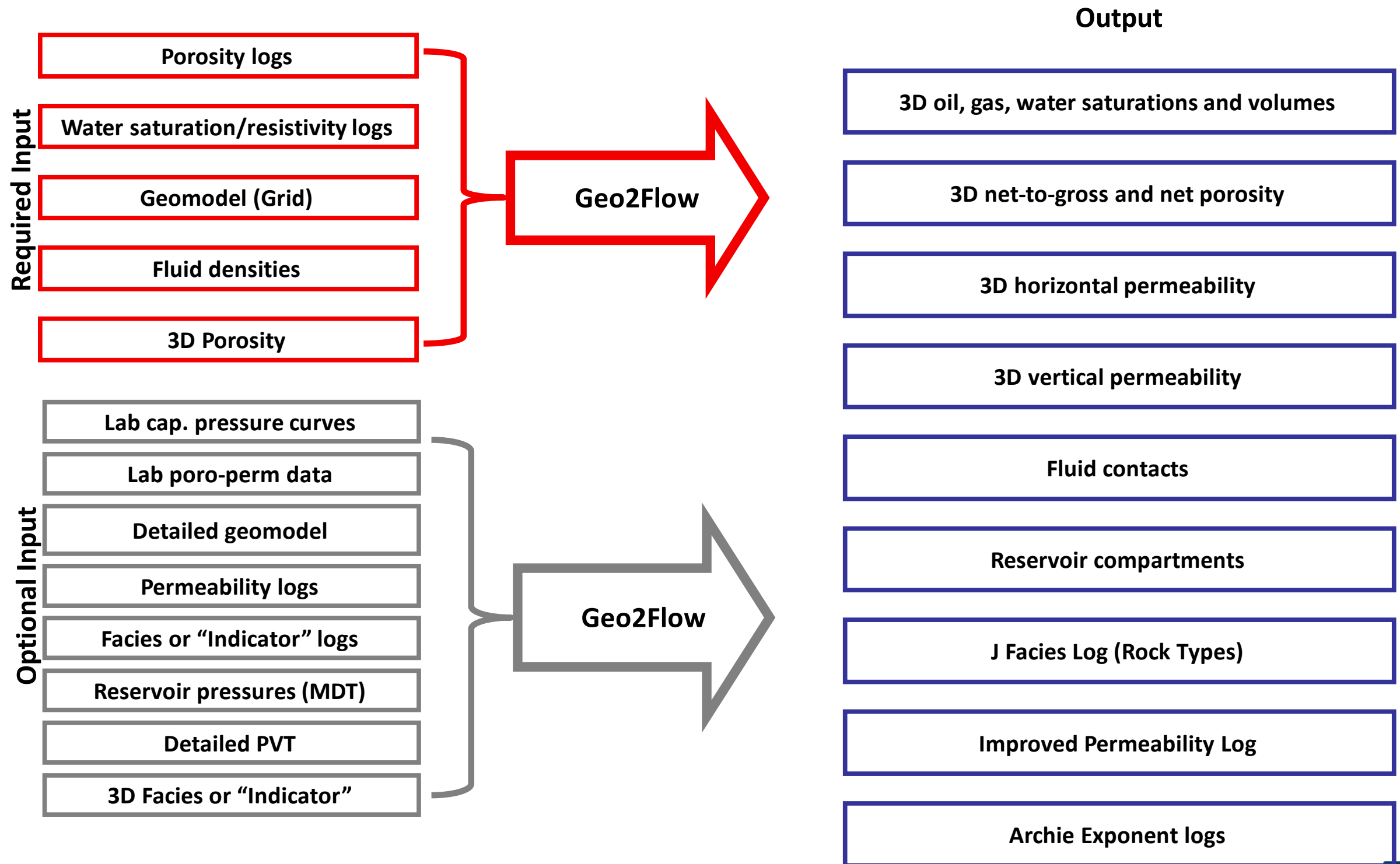
Geo2Flow: Compartments, Saturations, and Permeabilities



1. *Identifying flow compartments.*
2. *Calculating 3D saturations that honor logs.*
3. *Estimating permeabilities constrained by saturations.*

Dr. Daniel J. O'Meara

Look How Little You Need To Get Started...



Main Reasons For Using Geo2Flow

Compartments

- How connected?
- Identify free water levels.
- Multiple data sources.
 - Core data.
 - Logs.
 - Pressures.
- Closely linked to Petrel:
 - Fault segments.
 - Zones.

3D Saturations

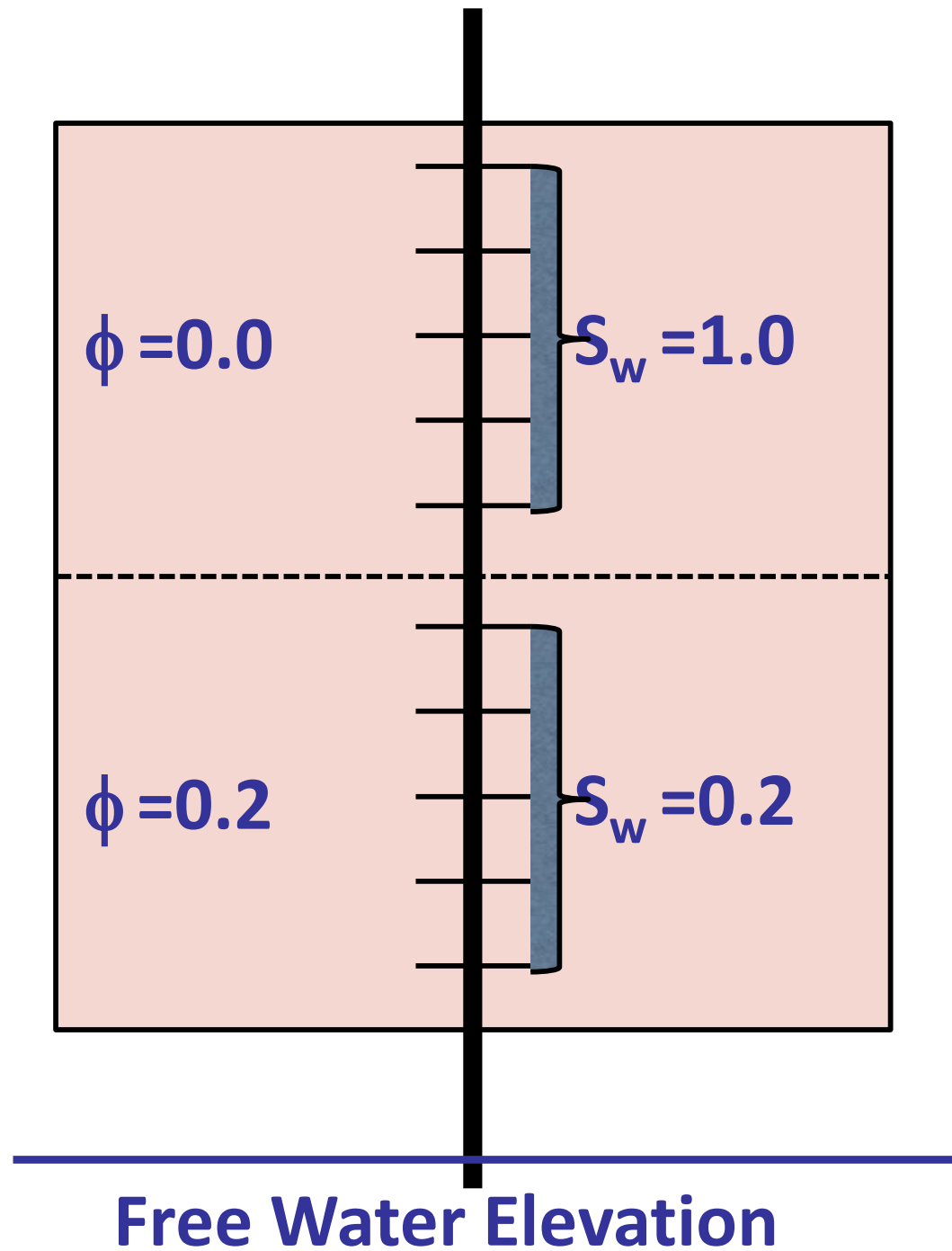
- How much?
- Honors physics of capillarity.
- Honors saturation logs, within known errors.
- Flexible reinterpreting of resistivity logs.
- Estimates relative permeability curves.

3D Permeabilities

- How fast?
- Constrained by saturations.
- Takes advantage of well-behaved J Functions rather than noisy poro-perm.
- Calculates horizontal and vertical.
- Upscales: core, log, geocell, gridblock.

- *All three must be modeled together because they are coupled.*
- *Typical modeling is “silo-ized”.*
 - *Reservoir engineers interpreting MDT to determine free water levels.*
 - *Petrophysicists using saturation-height functions.*
 - *Geologists using geostatistics with noisy poro-perm correlations.*
- *Workflows encourage “what if” scenarios to explore uncertainties.*
- *Brings together geologists, petrophysicists, and reservoir engineers, naturally.*

10 Log Measurements



What is average saturation?

1. 0.4
2. 0.6 **Volumetric**
3. 0.2 **Correct**
4. Haven't a clue.

$$\bar{S} = \frac{\sum_{i=0}^n S_i \phi_i V_i}{\sum_{i=0}^n \phi_i V_i}$$

Pore Volume

A Little History...

→ At Shell, beginning in 1986.

- First geomodeling: PROFAM -> Monarch -> GeoCap.
- GeoSim: 4 million cell unit mobility flow simulation: sweep

→ With Stratamodel, 1992-2002.

- StrataSim: 36 million cell model of Ekofisk (1996).

→ Worked with Gocad, RMS, and Petrel.

→ Expect models to honor observations and physics.

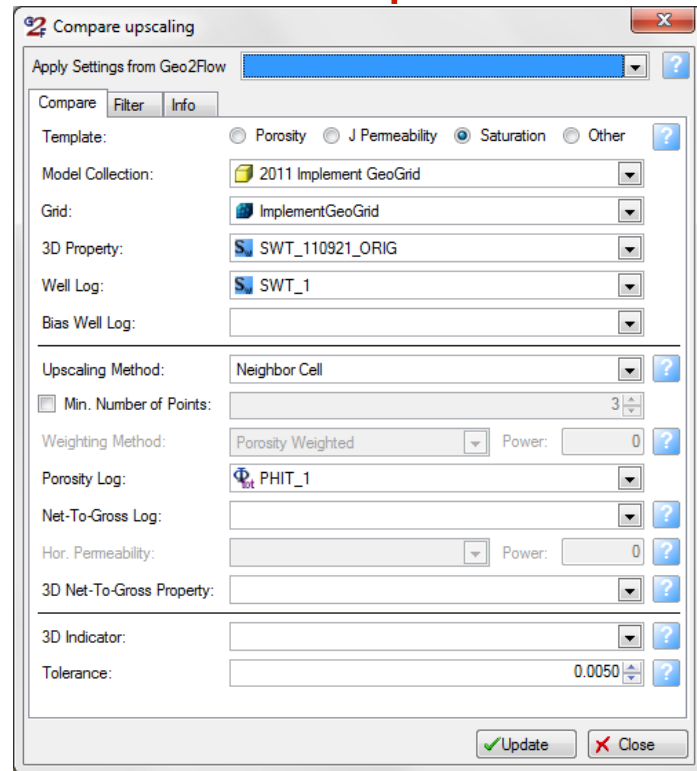
→ “How do we check that 3D saturations honor Sw logs?”

- “We don’t”.
- Devised the following plot to check.

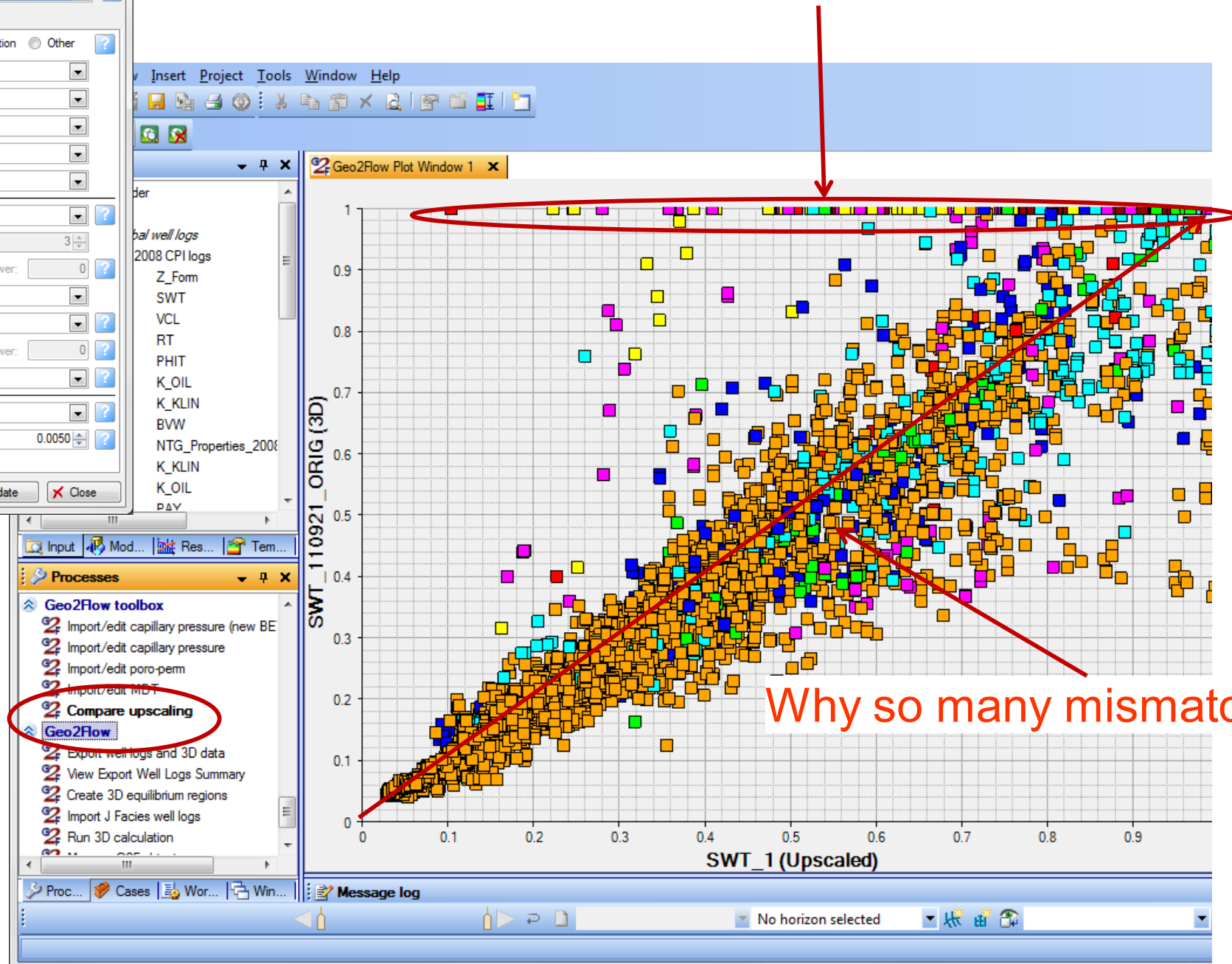


Peer Review: Does 3D Saturation Match Upscaled Sw Log?

- Use Geo2Flow's "Compare Upscaling" plug-in to check whether your 3D saturation matches the pore volume weighted Sw log.



Indication of oil below the free water level.



$$\bar{S} = \frac{\sum_{i=0}^n S_i \phi_i V_i}{\sum_{i=0}^n \phi_i V_i}$$

- Most models without Geo2Flow show a poor match.

Saturation Comparison: Why Not Match Every Time?

→ *Imagine history-matching with a noisy match.*

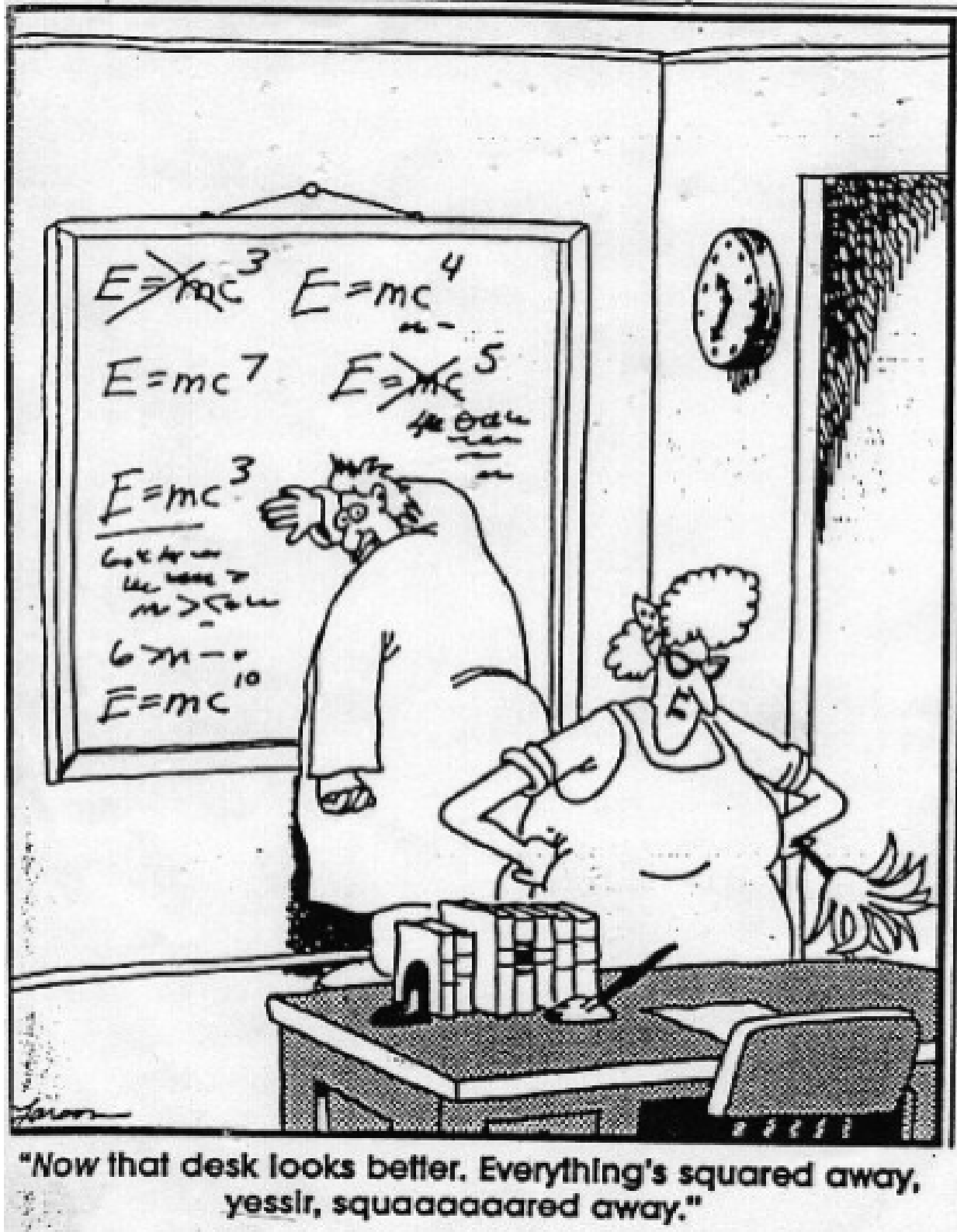
→ *Cheating: a perfect match can be obtained by treating saturation like porosity ...purely geostatistically.*

- *Non-physical saturations: not matching J Functions.*
- *Good match is a necessary but not sufficient sign of a good model*

→ *A poor match can be caused by:*

- *Incorrect free water levels (compartmentalization).*
- *Saturation-height functions that do not depend on permeability*
- *Assumption that lab functions apply to upscaled geomodel.*
- *Failure to use a pore volume weighted saturation log.*

Einstein's Maid – The Far Side by Gary Larson



→ Dimensional Consistency

$$E = mc^3 \quad \frac{ML^2}{T^2} [=] M \left(\frac{L}{T} \right)^3$$

$$E = mc^4 \quad \frac{ML^2}{T^2} [=] M \left(\frac{L}{T} \right)^4$$

$$E = mc^2 \quad \frac{ML^2}{T^2} [=] M \left(\frac{L}{T} \right)^2$$

→ If Einstein were a petroleum engineer...

$$E = 5.4 \times 10^{-15} mc^2$$

m [=] pound-mass

c [=] feet/day

E [=] British Thermal Units

→ The sound barrier. Supersonic flight.

$$\text{Mach Number} = \frac{V_{\text{object}}}{V_{\text{sound}}} = \frac{\text{Speed of object}}{\text{Speed of sound}}$$

→ Turbulent flow; swirling eddies.

$$\text{Reynold's Number} = \frac{\rho V L}{\mu} = \frac{\text{Inertial}}{\text{Viscous}}$$

→ Chemical flooding: decreasing residual oil saturation.

$$\text{Capillary Number} = \frac{\mu V}{\sigma} = \frac{\text{Viscous Forces}}{\text{Surface Forces}}$$

J Functions Are Dimensionless

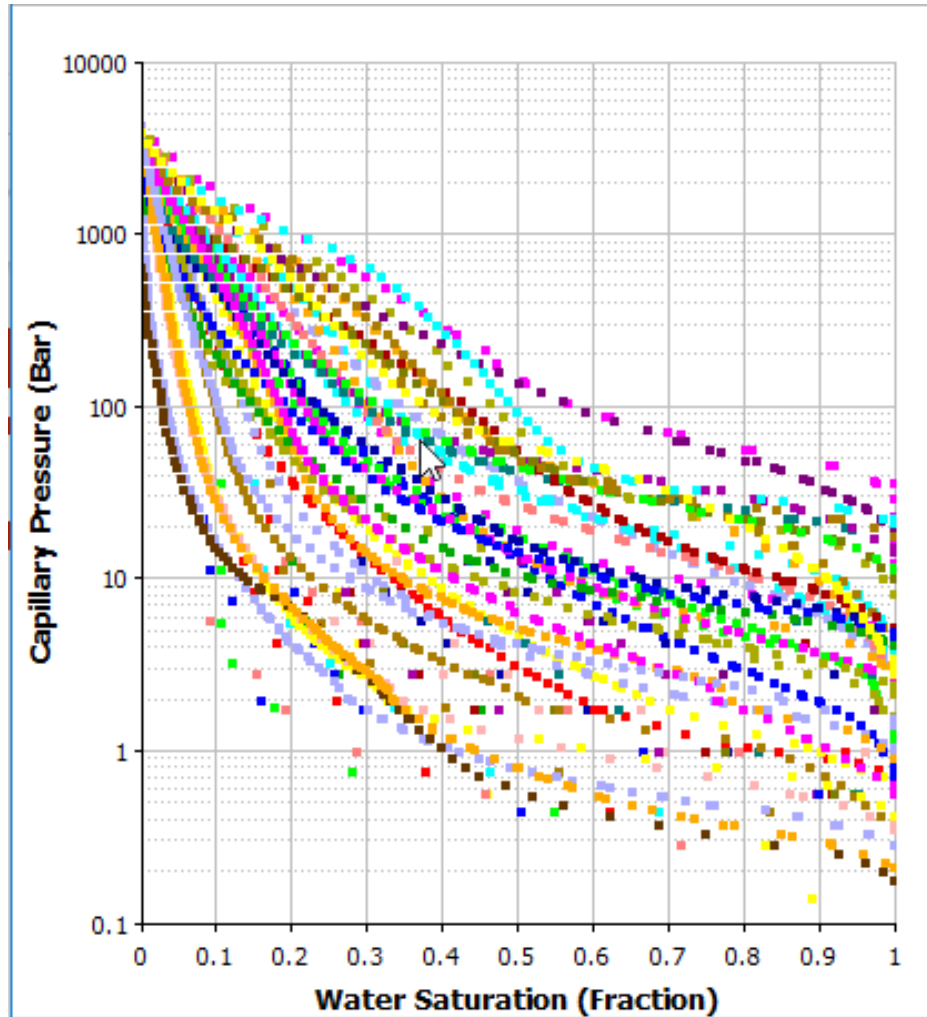
$$J(S_w) = \frac{\frac{F/L^2}{P_c}}{\frac{F/L}{\sigma \cos \theta}} \sqrt{\frac{\frac{L}{k}}{\phi}} \quad [=] \text{ Dimensionless}$$

→ Seem obvious? What's wrong with the following?

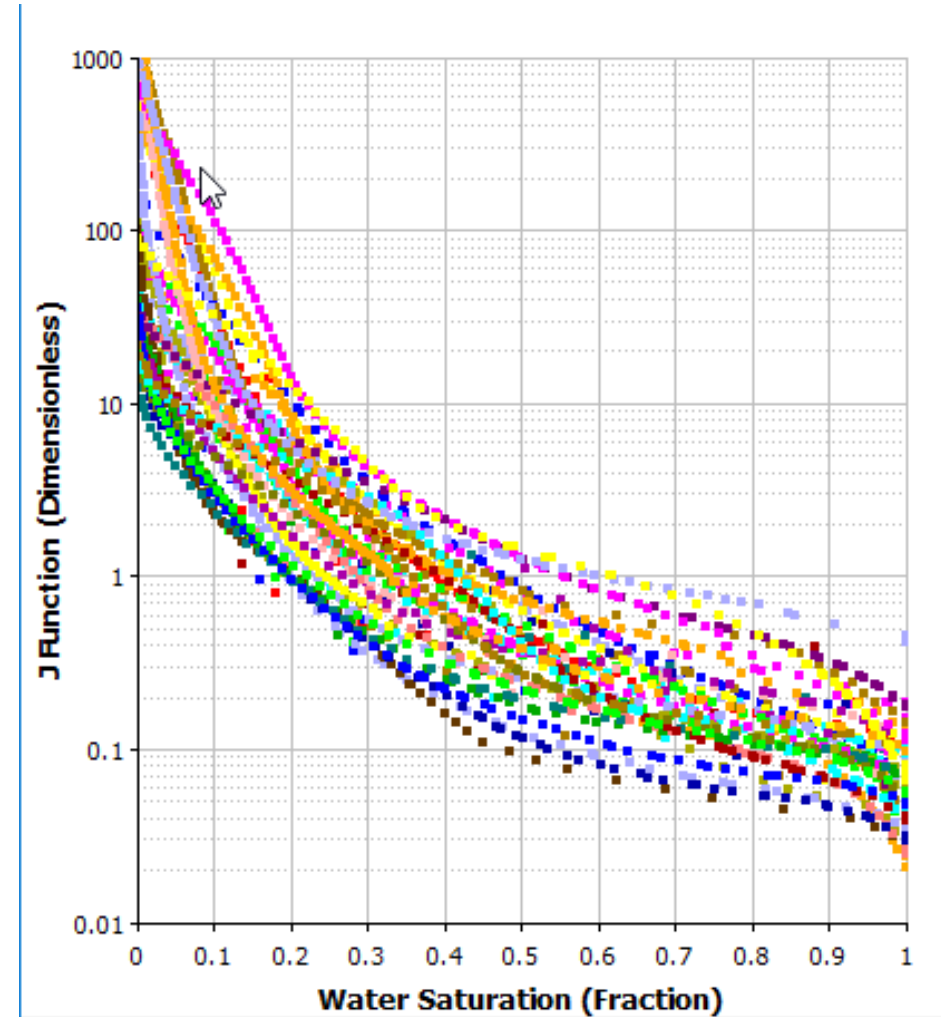
$$J(S_w) = \frac{\frac{F/L^2}{P_c}}{\frac{F/L}{\sigma \cos \theta}} \left[\frac{k}{\phi} \right]^n \quad [=] L^{2n-1}$$

Quick J Function Review – Why Use Them?

Capillary Pressure (0.02-400 md.)



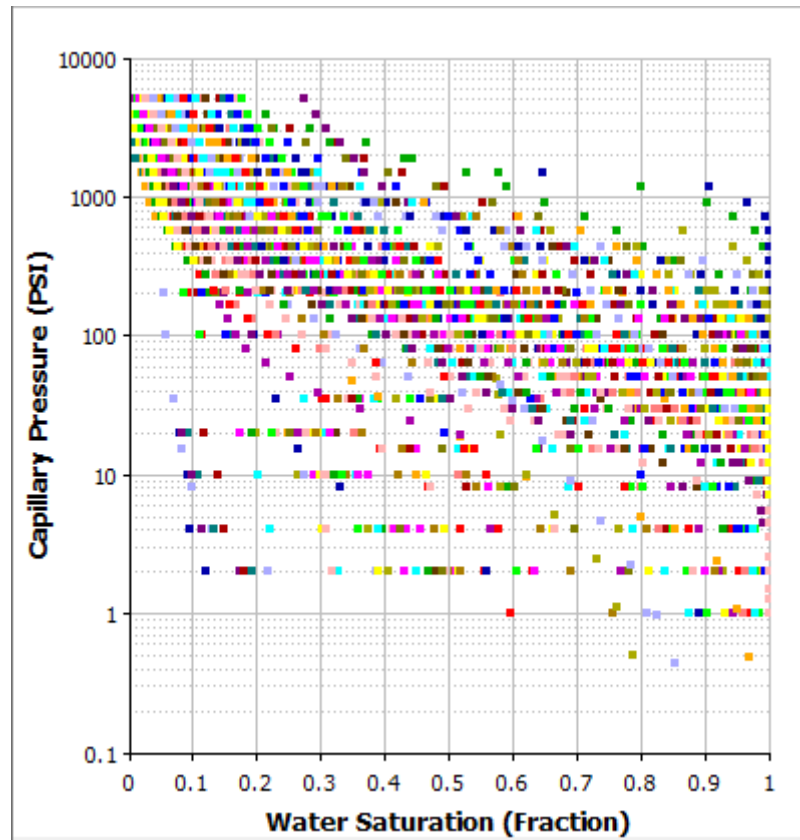
J Function (per rock type)



➔ Dimensionless J Function collapses many capillary pressure curves.

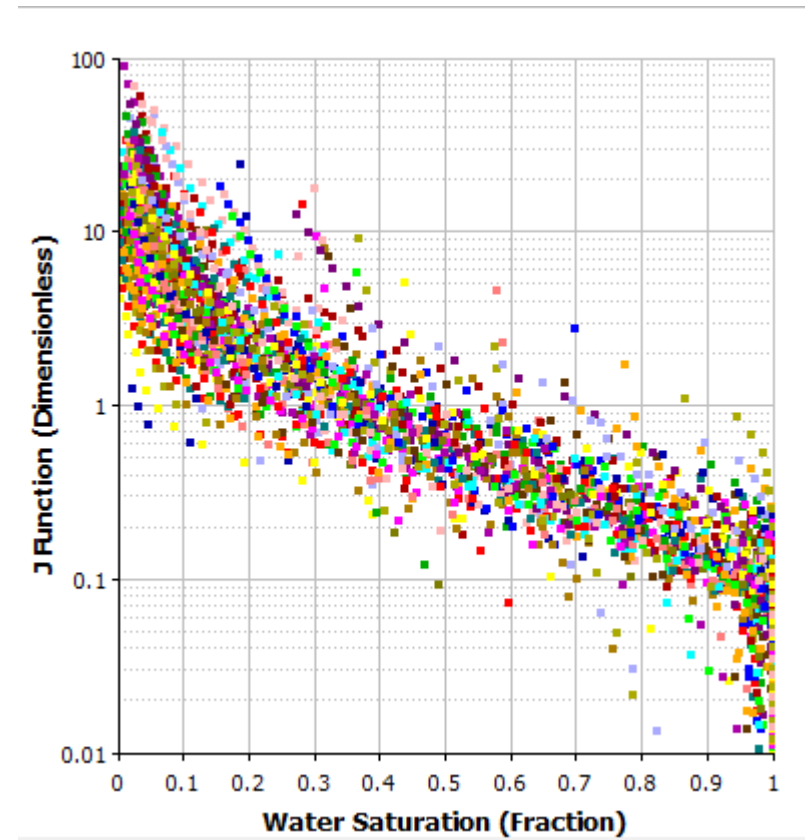
But Do They Work for Carbonates?

**Capillary Pressure
(0.01-3400 md.)**



**Entry Pressures
(0.5-1000 psi)**

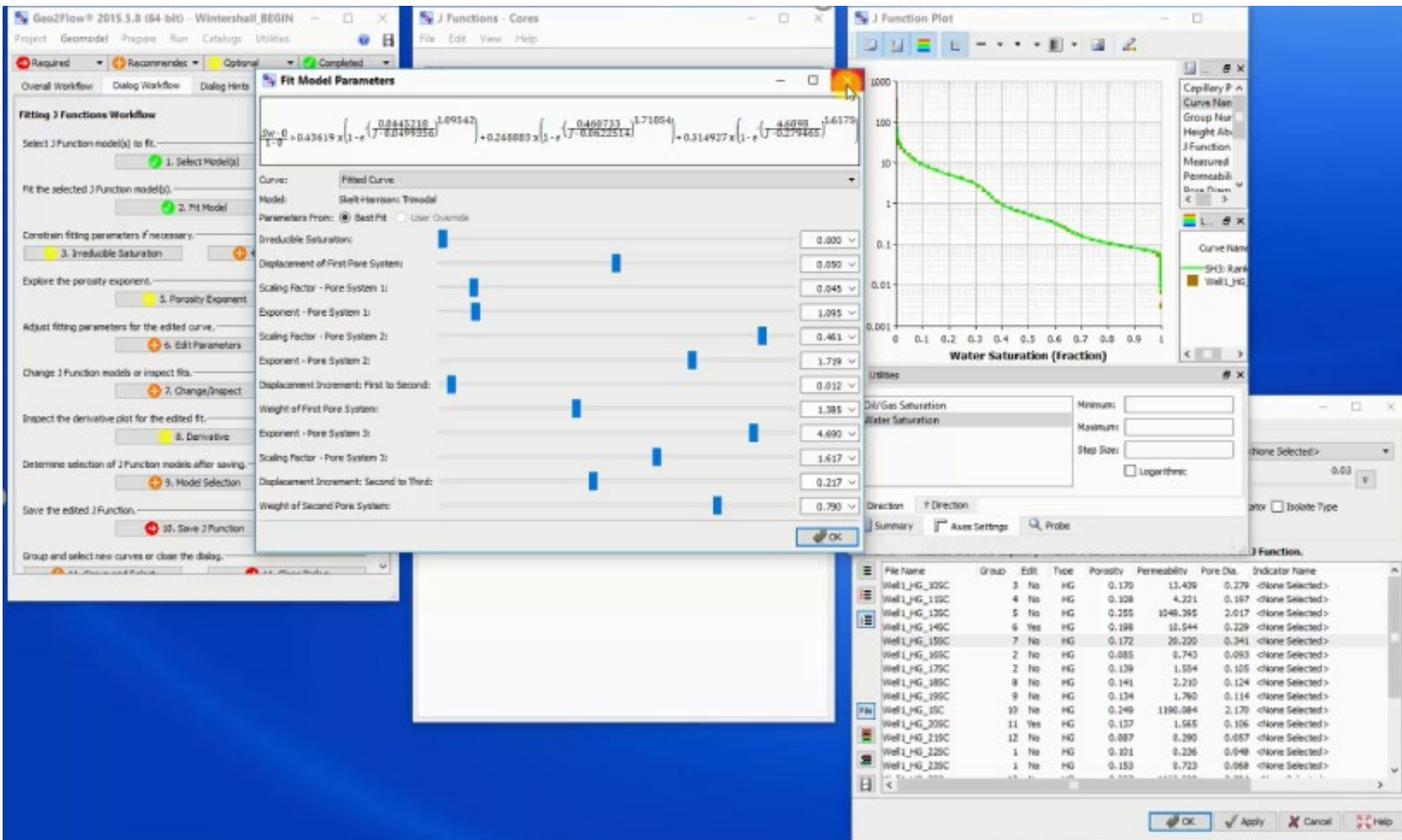
**J Function
(per rock type)**



**Entry Values
(0.05-0.20)**

➔ Dimensionless J Function collapses many capillary pressure curves.

Geo2Flow: Fitting Capillary Pressure Data



Geo2Flow: Grouping by Indicator

File Edit View Help

Fit	Model Name	Legend	Modes	Rank of Fit	Error in Fit	Edit Plot
☐	O'Meara	OM1	Unimodal	---	---	☐
☐	Skelt-Harrison	SH1	Unimodal	---	---	☐
☐	Thomeer	TH1	Unimodal	---	---	☐
☐	Brooks-Corey	BC1	Unimodal	---	---	☐
☐	Bensten-Anli	BA1	Unimodal	---	---	☐
☐	O'Meara	OM2	Bimodal	---	---	☐
☐	Skelt-Harrison	SH2	Bimodal	---	---	☐
☐	Thomeer	TH2	Bimodal	---	---	☐
☐	Brooks-Corey	BC2	Bimodal	---	---	☐
☐	Bensten-Anli	BA2	Bimodal	---	---	☐
☐	O'Meara	OM3	Trimodal	---	---	☐

Selection of J Function Models After Saving A Fit

Clear Selection of J Function Models

Constrain J Function Fitting Parameters

Irreducible: From Best Fit 0.1 (Fraction)

Displacement: From Best Fit 0.1 (Dimensionless)

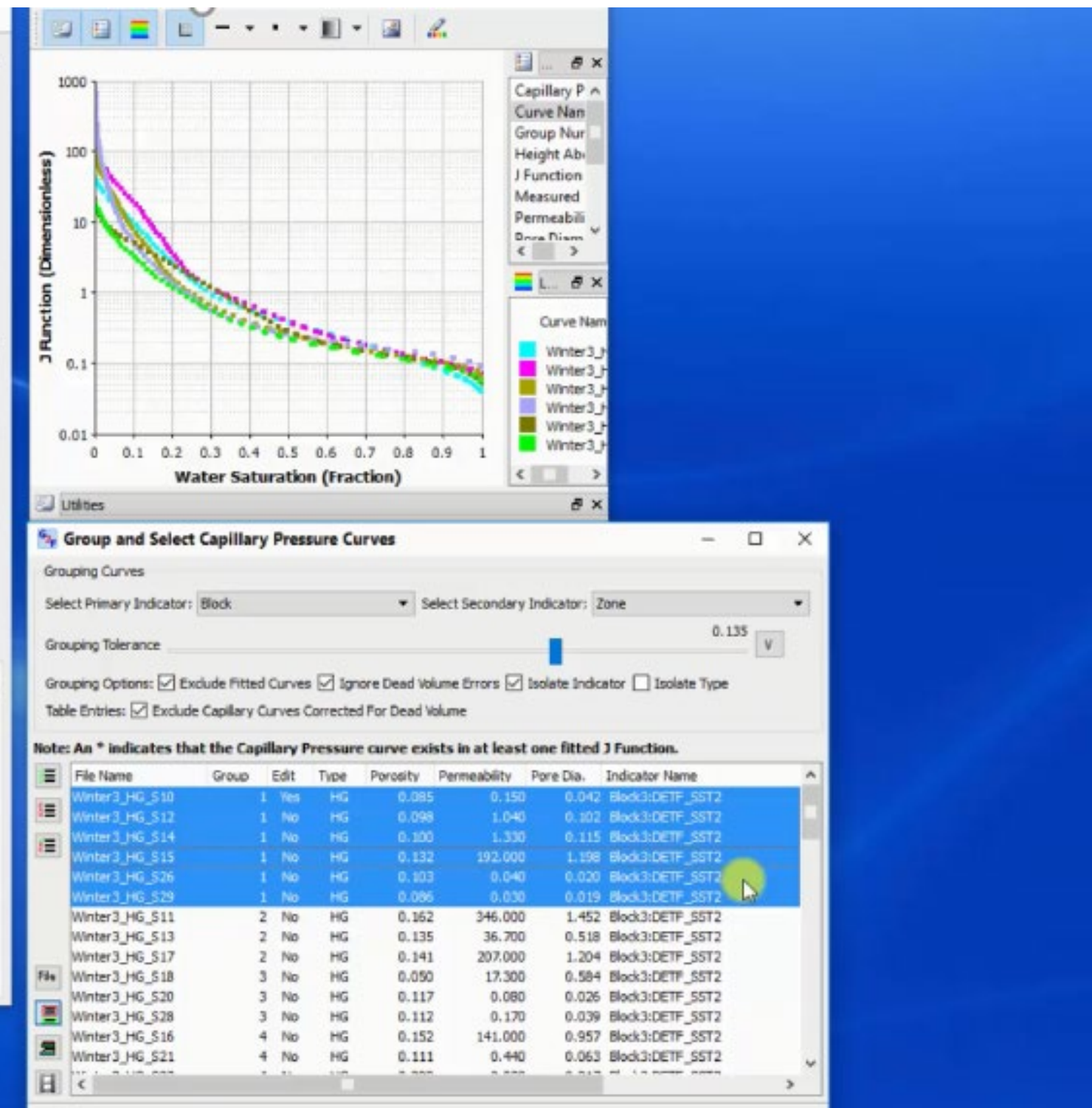
Calculate Best Fit of J Function Model

☐ Use Bracketing of Models

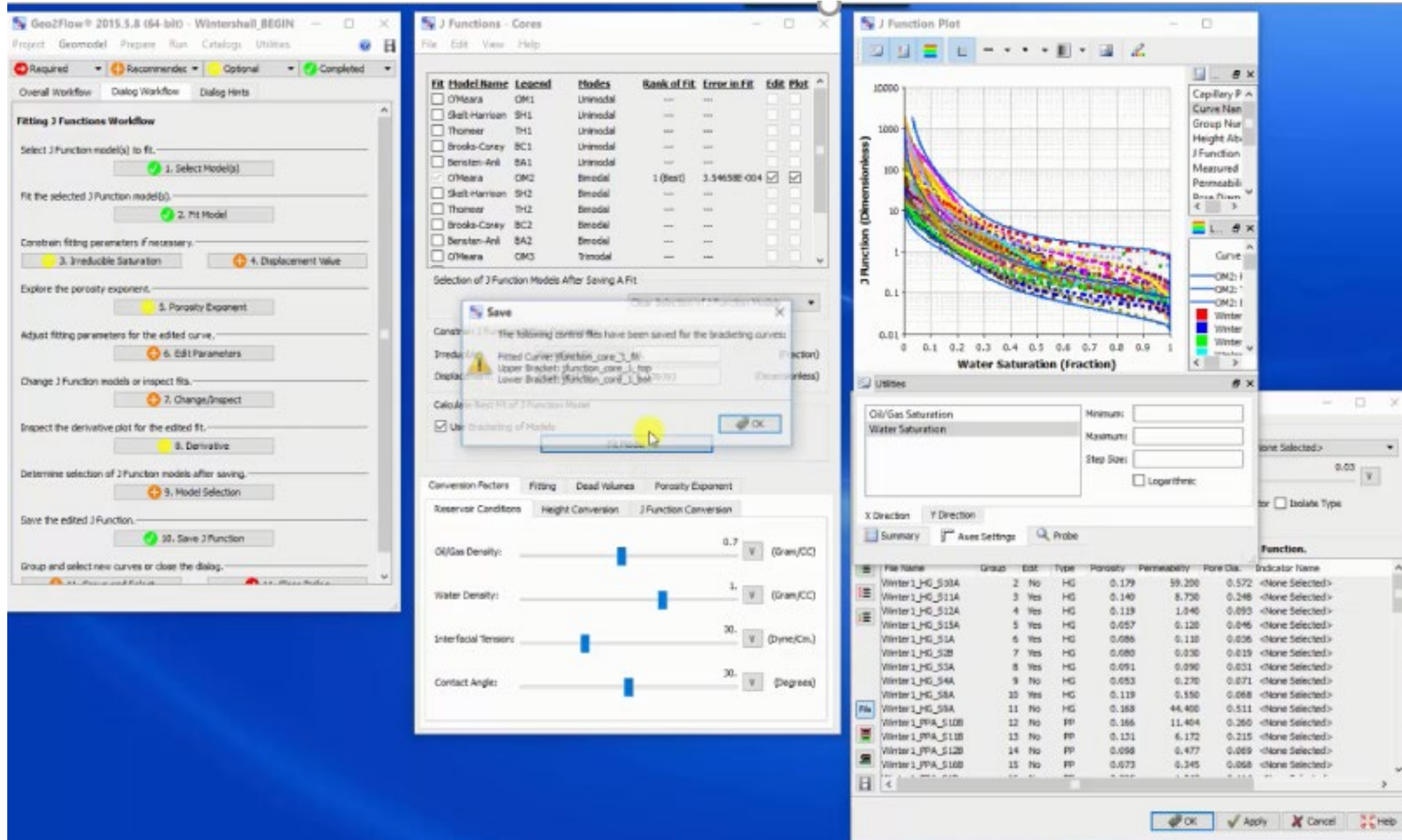
Fit Model

Conversion Factors Fitting Dead Volumes Porosity Exponent

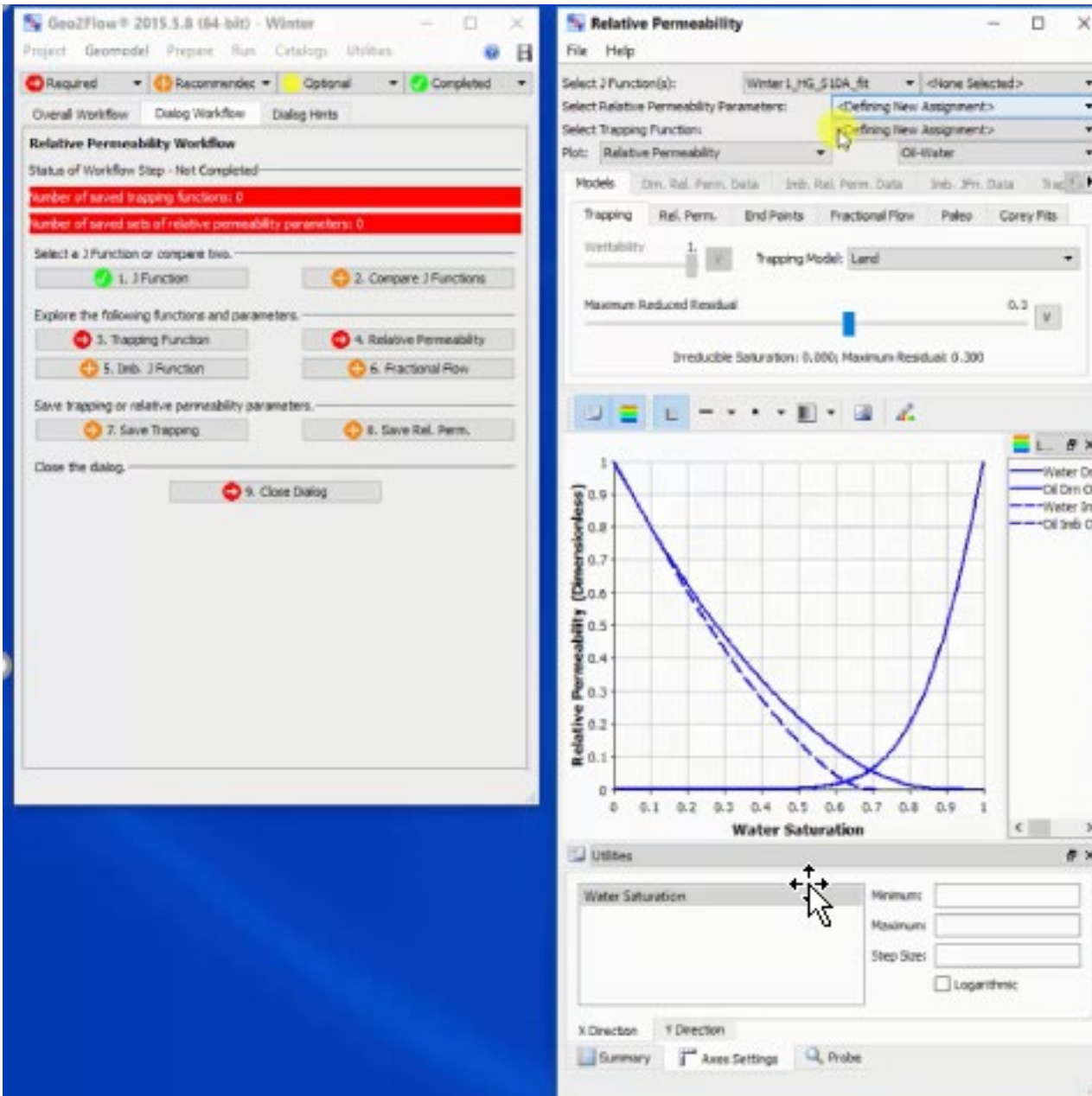
Identify Dead Volume Error Error Range (Fraction) 0.1



Geo2Flow: Bracketing Capillary Pressure Data



Geo2Flow: Relative Permeability



$$P_c = \Delta \rho g (z - z_0)$$

Correlation or Log

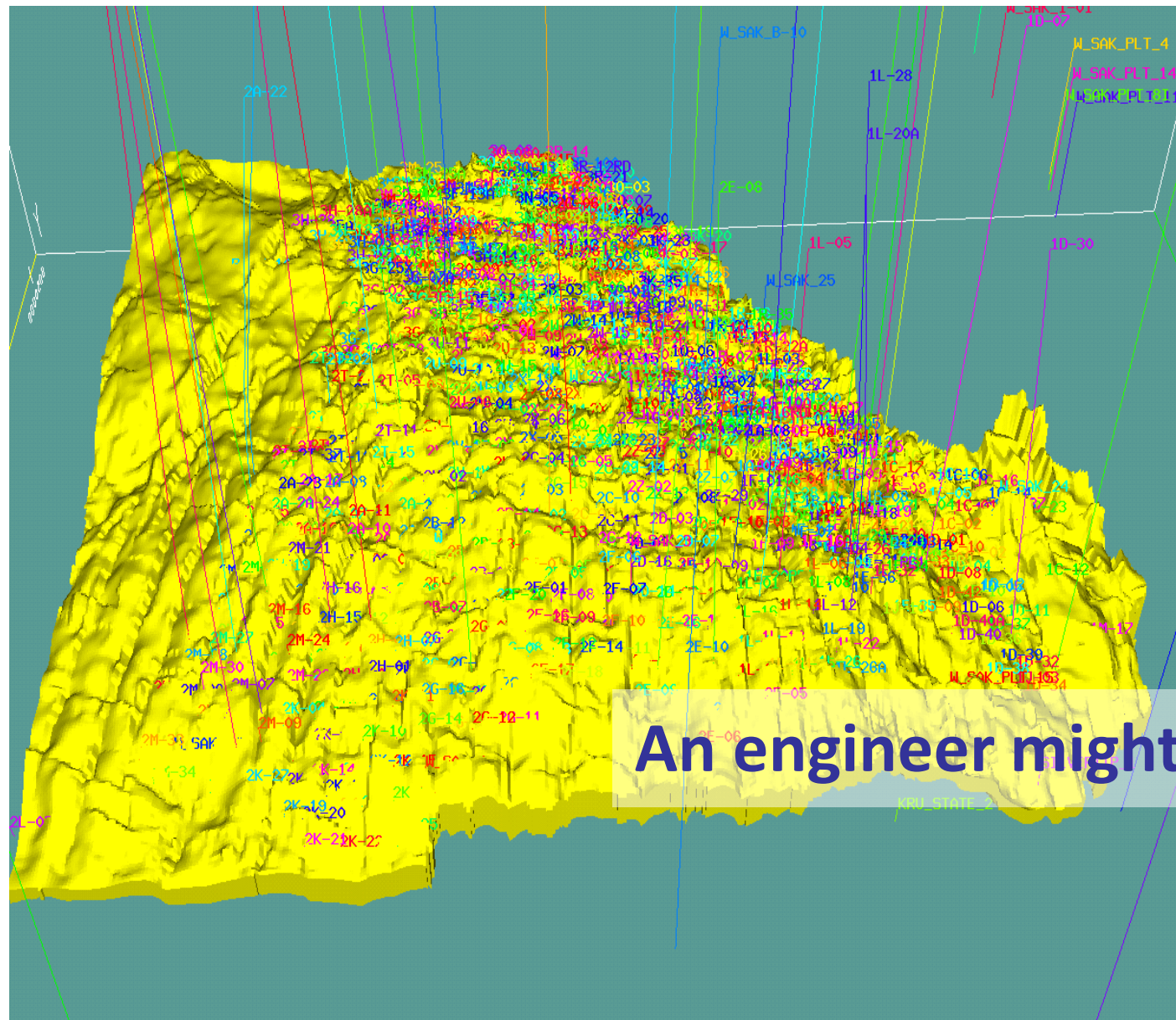
$$J(S_w) = \frac{P_c}{\sigma \cos \theta} \sqrt{\frac{k}{\phi}}$$

From Log

- $\sigma \cos \theta$: not necessary with log-derived J Functions.

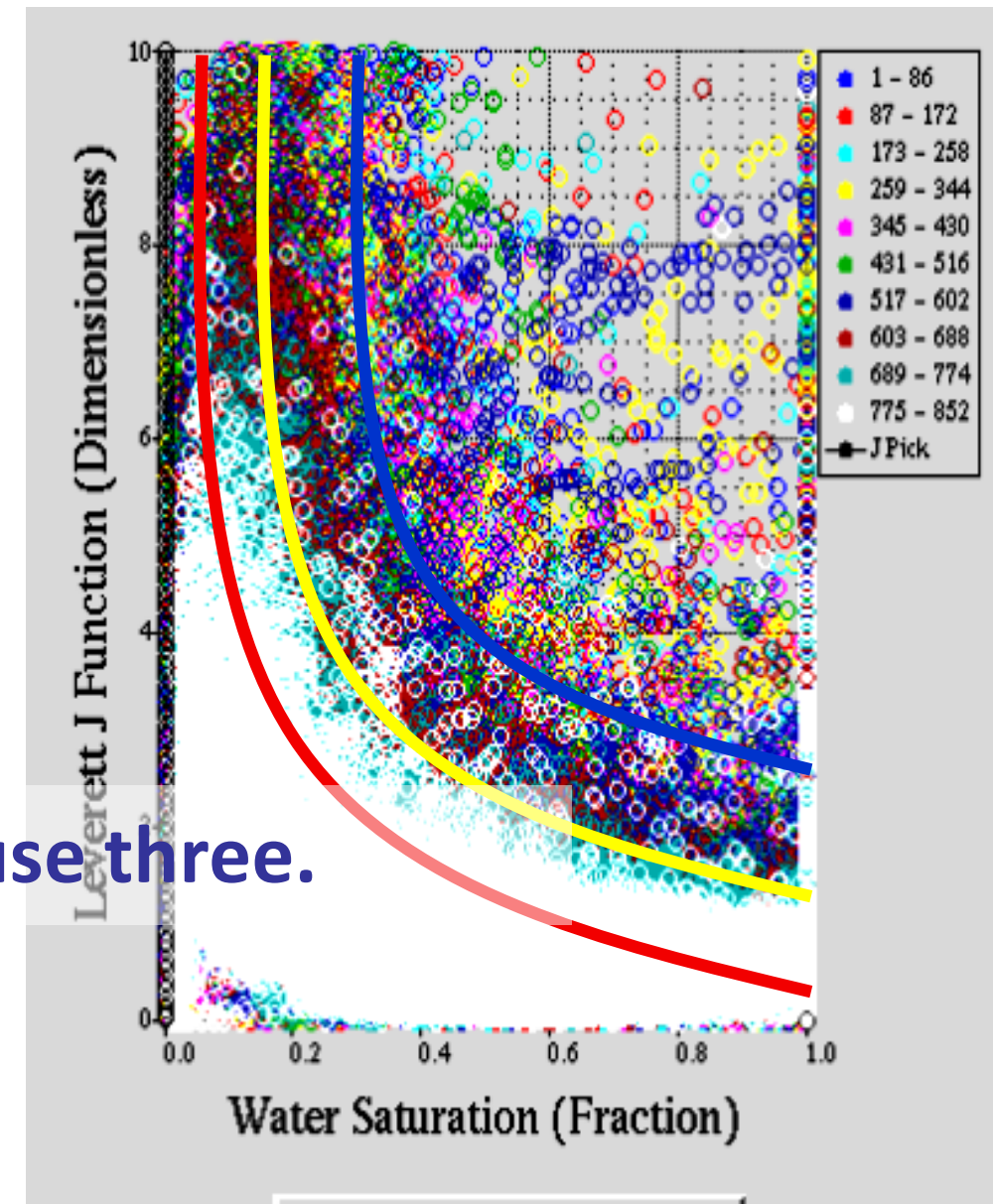
Can You See J Function Patterns in This Field?

Highly faulted model



An engineer might use three.

How many J Functions?



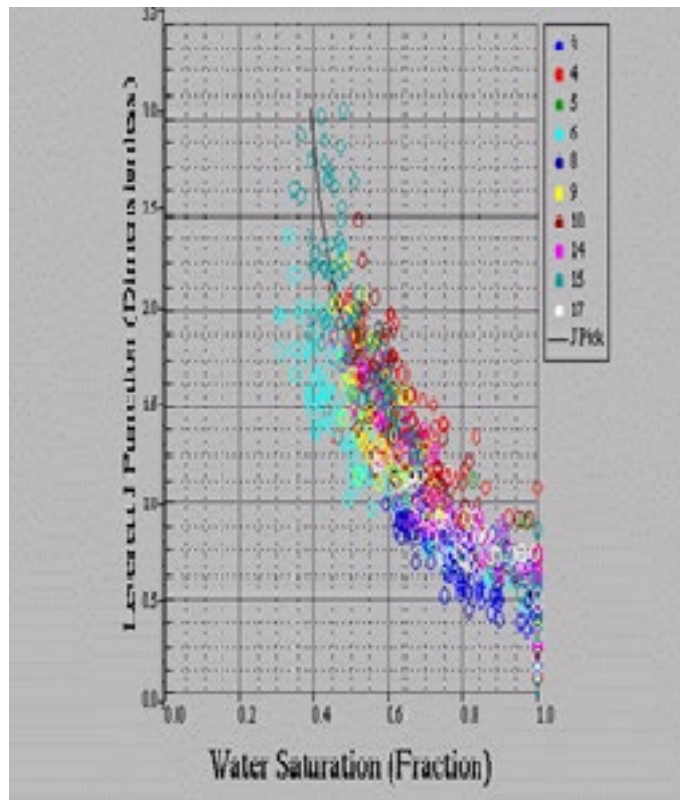
→ All of the scatter leads translates directly to errors in reserves.

Scatter caused by compartments

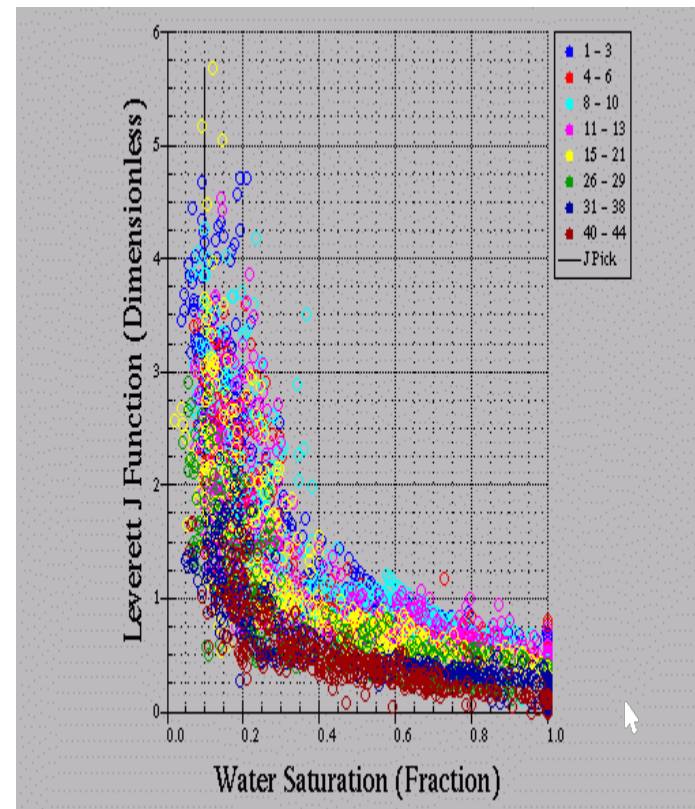
Geo2Flow Reveals Compartments

➔ Three compartmentalizing fault blocks in one zone.

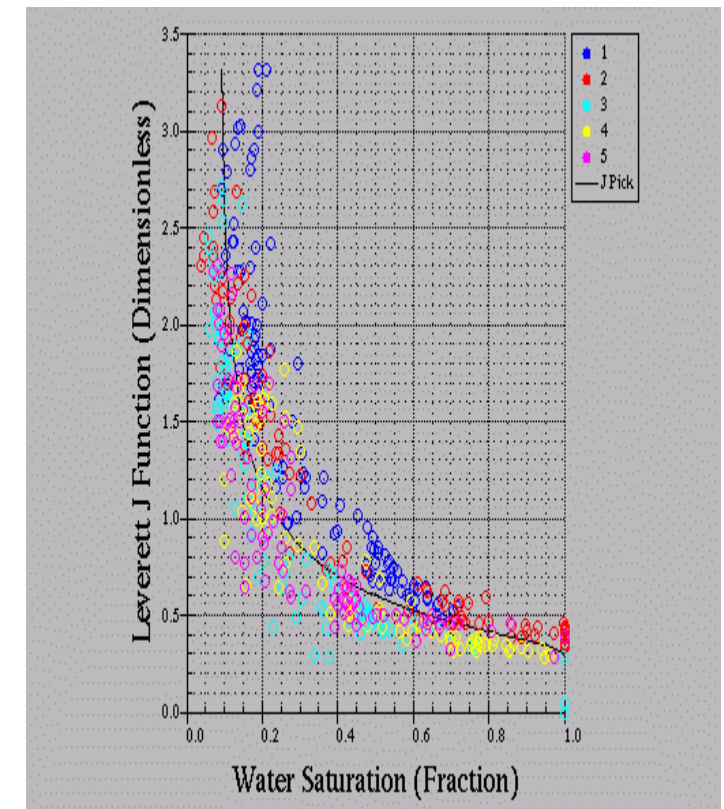
10 Wells, Zone 1



26 Wells, Zone 1



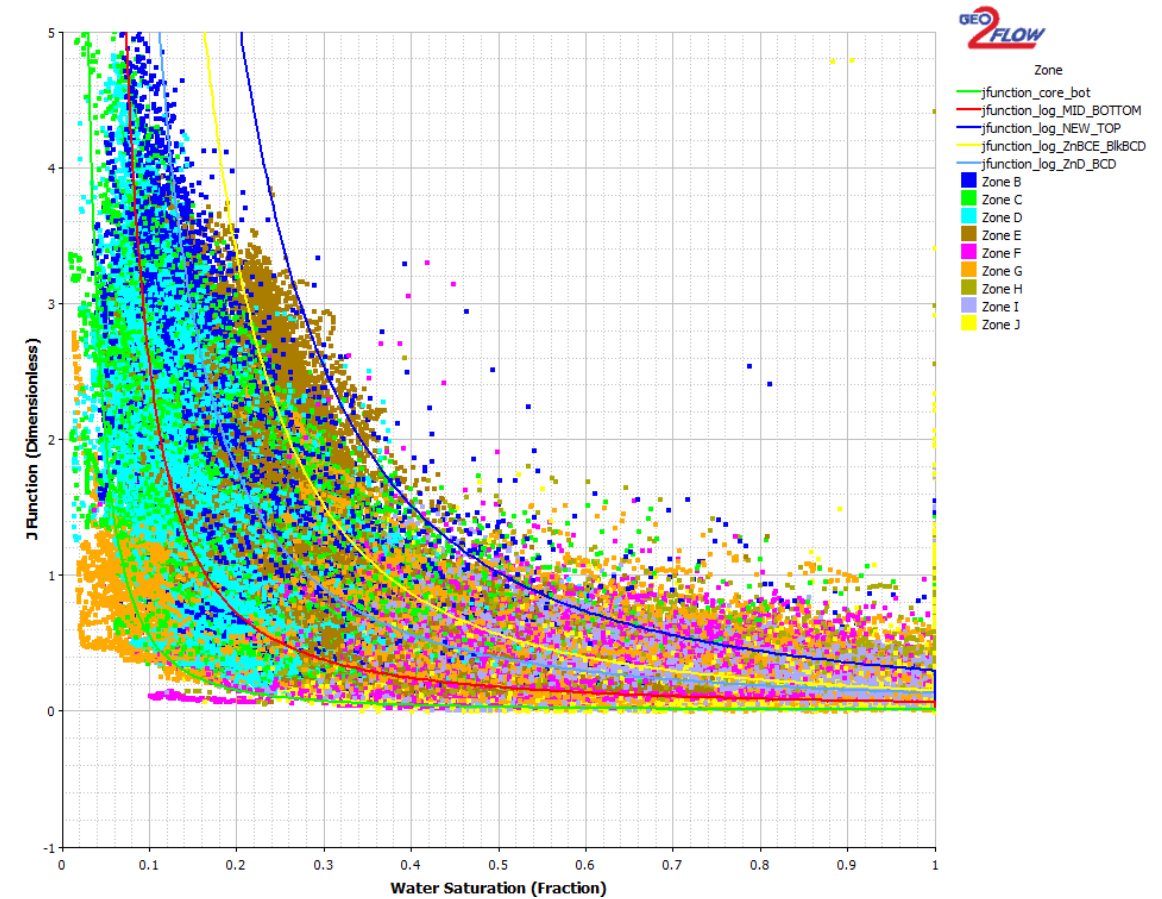
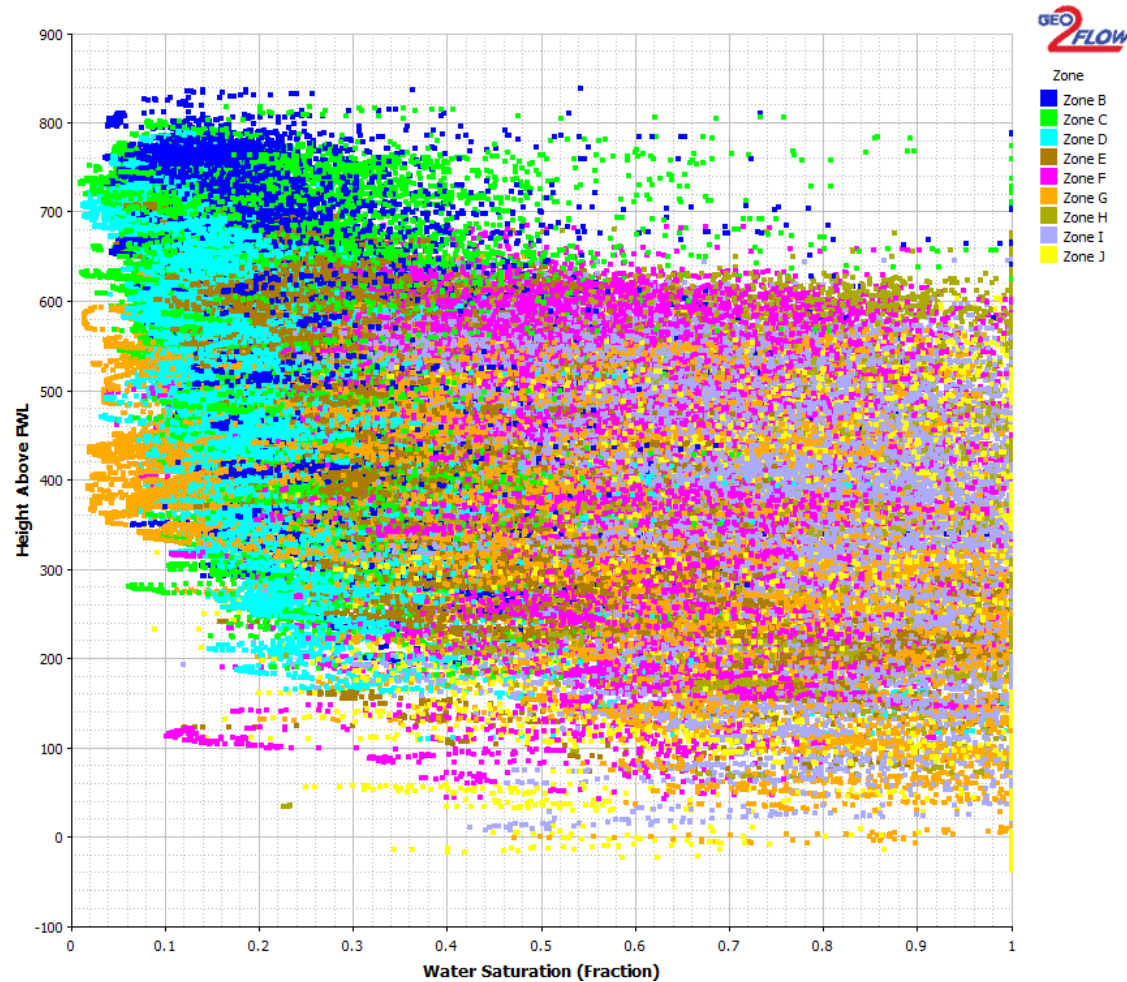
5 Wells, Zone 1



➔ Worst of the scatter removed because compartmentalizing faults have been identified.

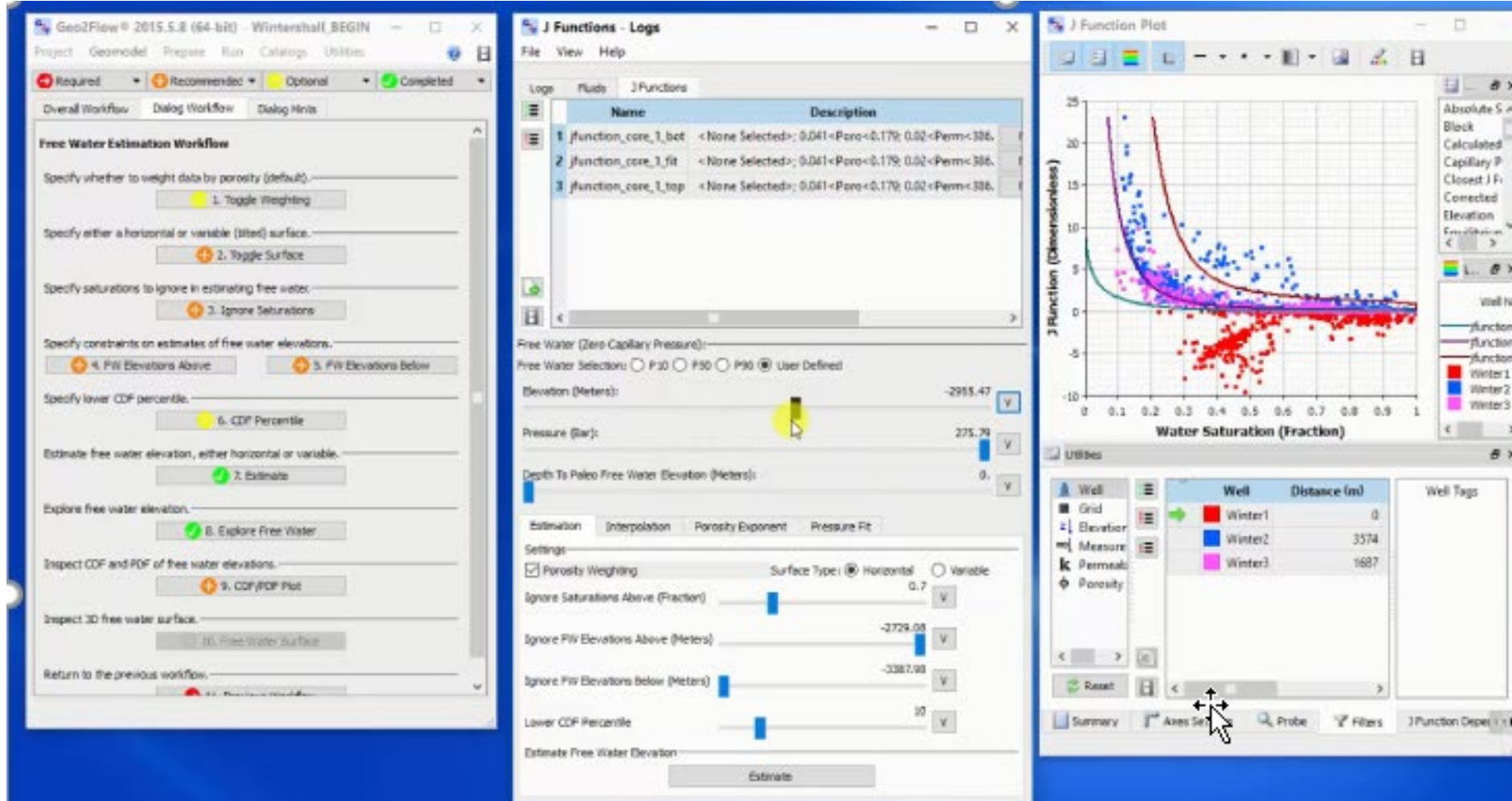
➔ Remaining scatter due to differing rock types.

J Functions versus Saturation-Height (Carbonate)



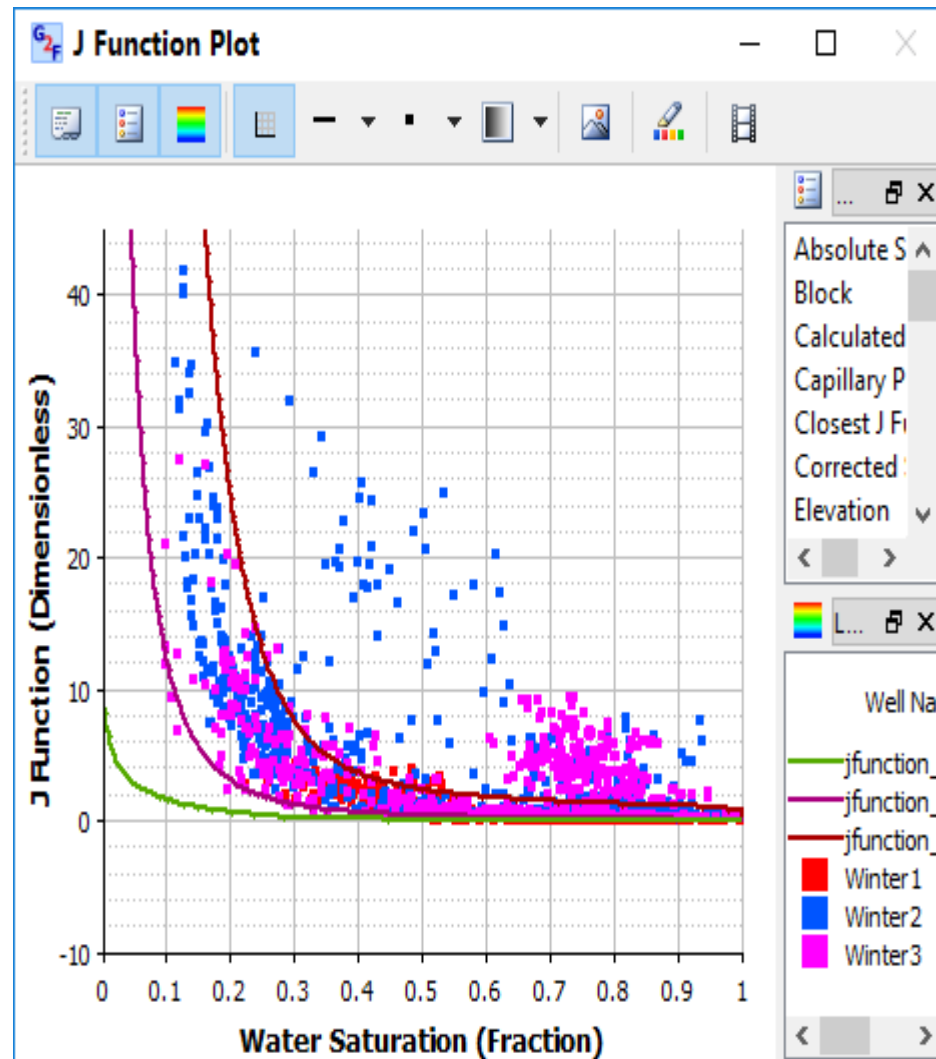
- ➔ Remarkably well-behaved J Functions (right).
- ➔ Log-derived J Function data (points) fit within core-derived J Functions (curves).
- ➔ Ill-behaved height vs. saturation (left).

Exploring the Data: Equilibrium Regions and Dependencies

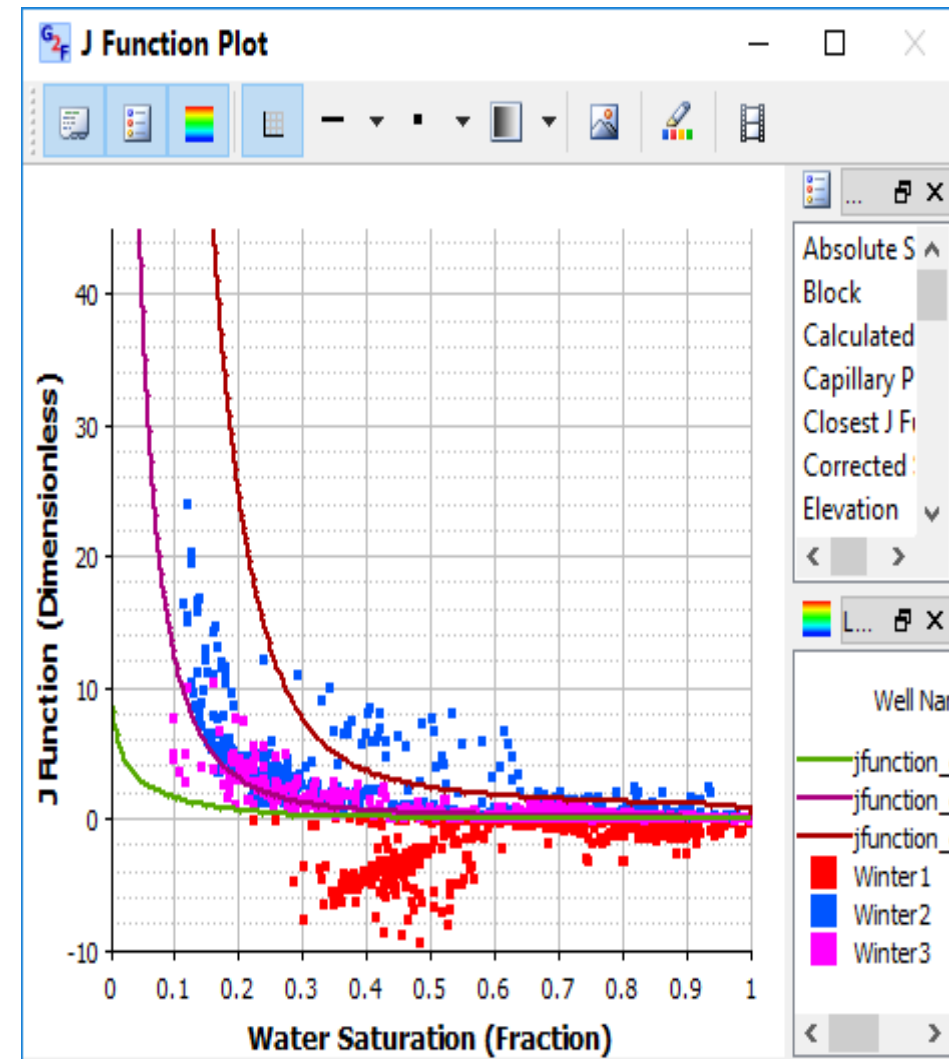


One Free Water Elevation or Two?

Free Water: -3117 m.



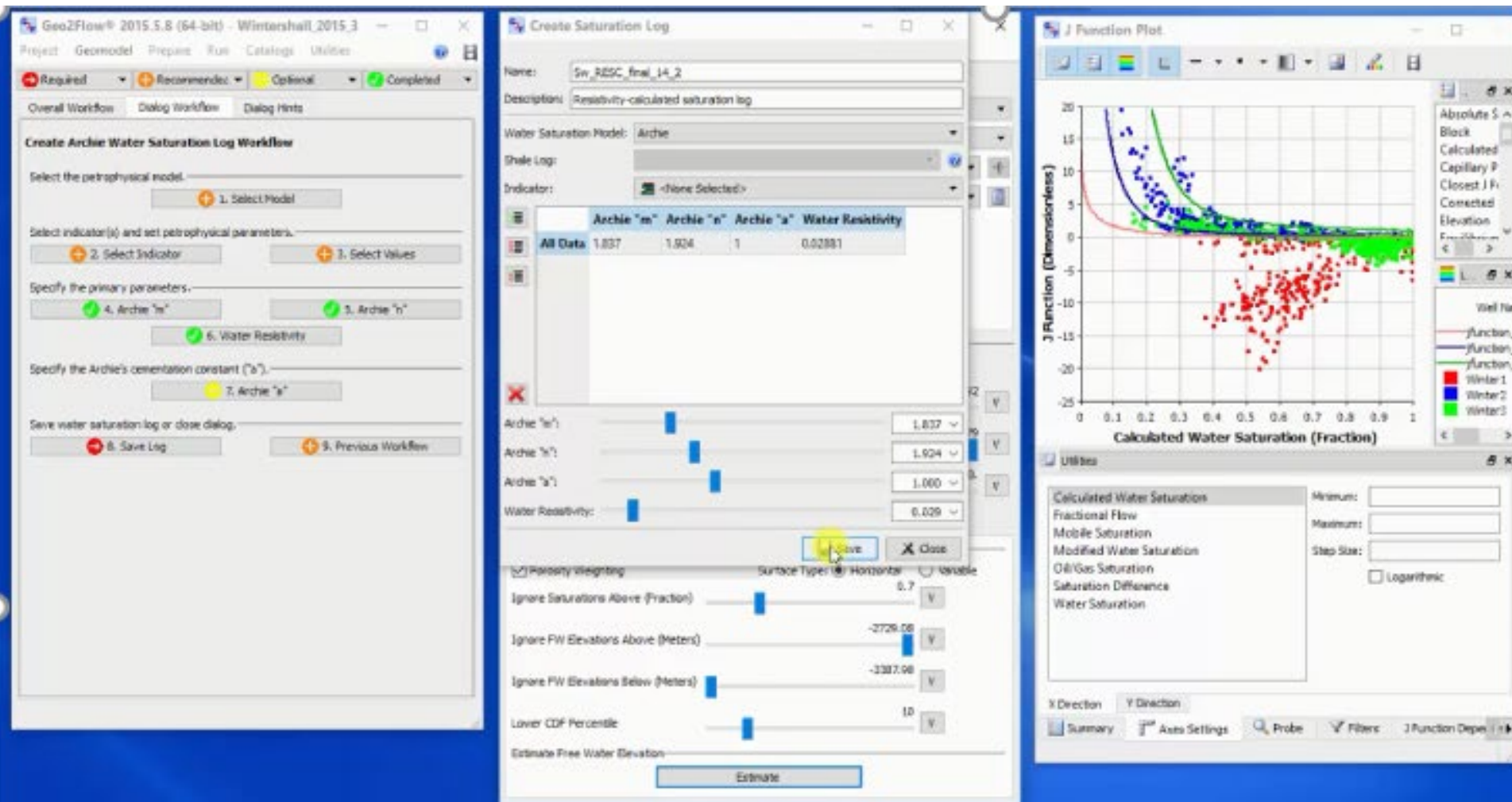
Free Water: -2973 m.



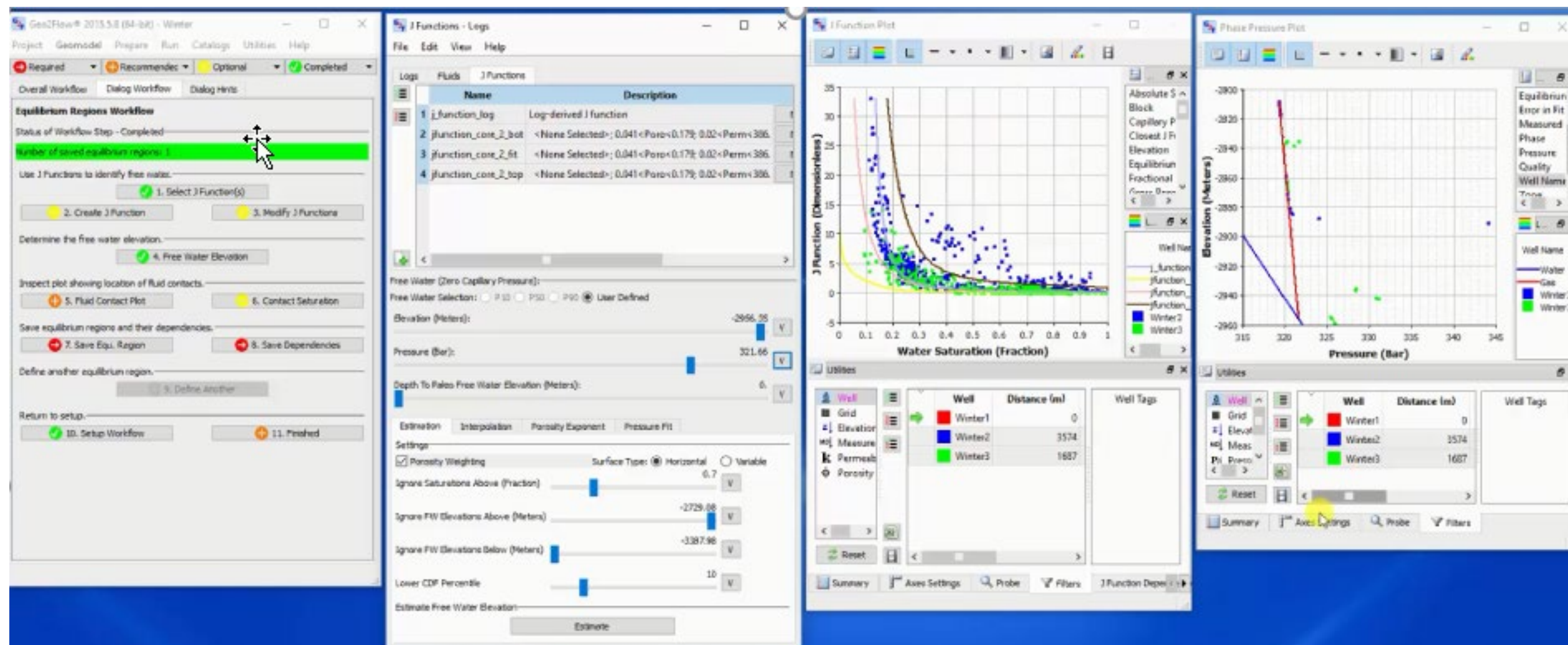
→ Color-coding by well.

→ Note: Better match of core-derived J Functions on right.

Water Saturation From Resistivity Compared With J Functions



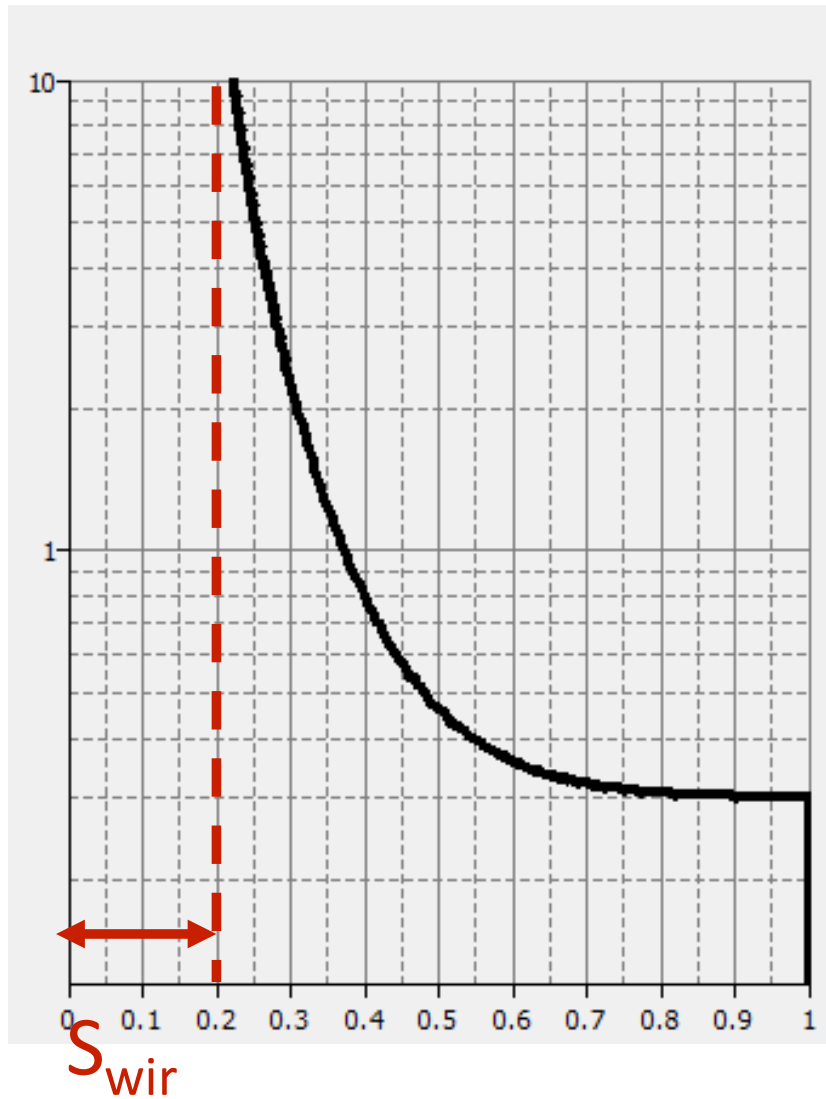
Using MDT and J Functions simultaneously



Why is the Contact Not Flat?

→ Assume a single J Function.

J Function



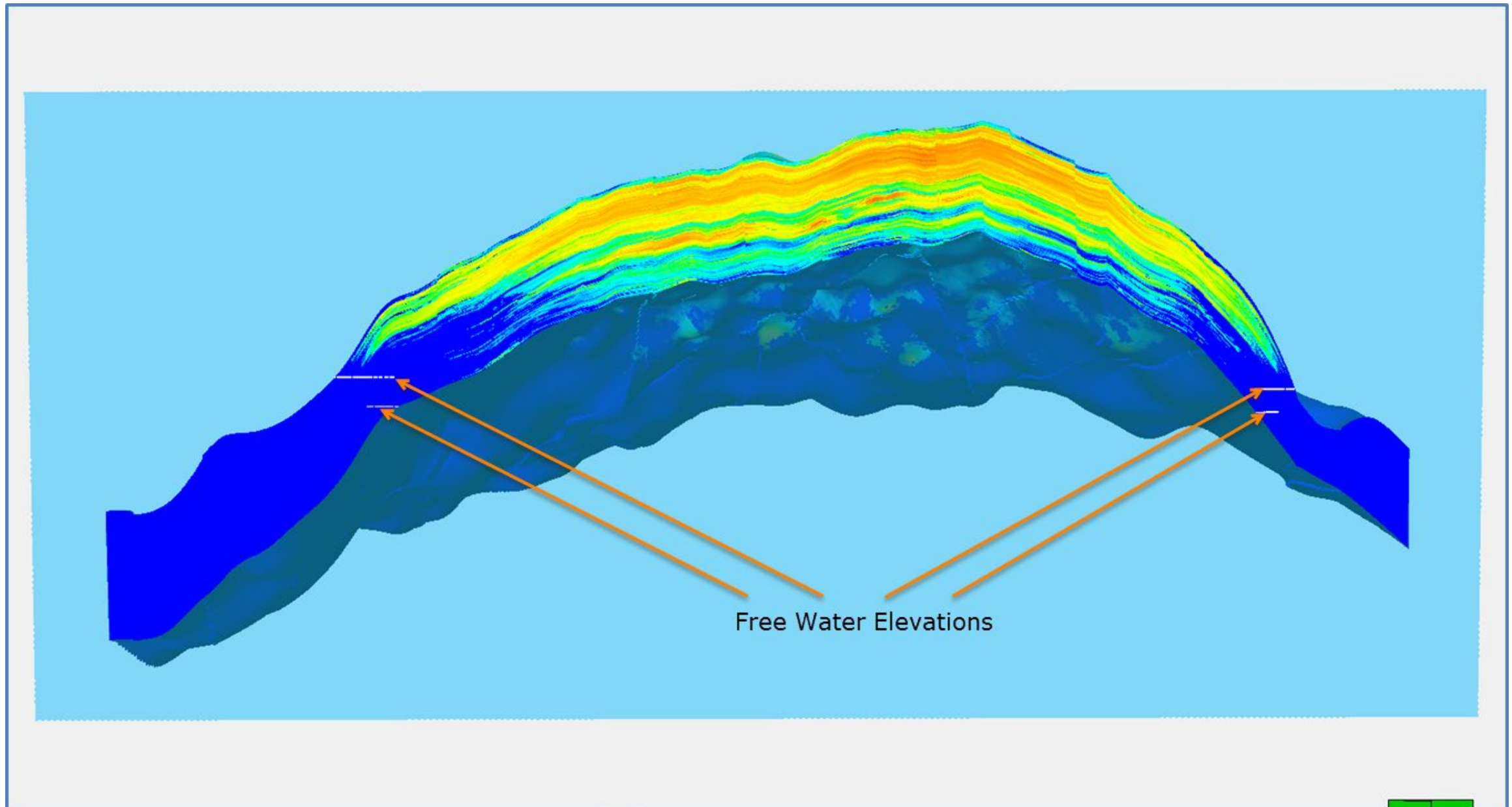
Water Saturation

- Equation for contact (z) above free water:

$$J_d = \frac{\Delta \rho g (z - z_0)}{\sigma \cos \theta} \sqrt{\frac{k}{\phi}}$$

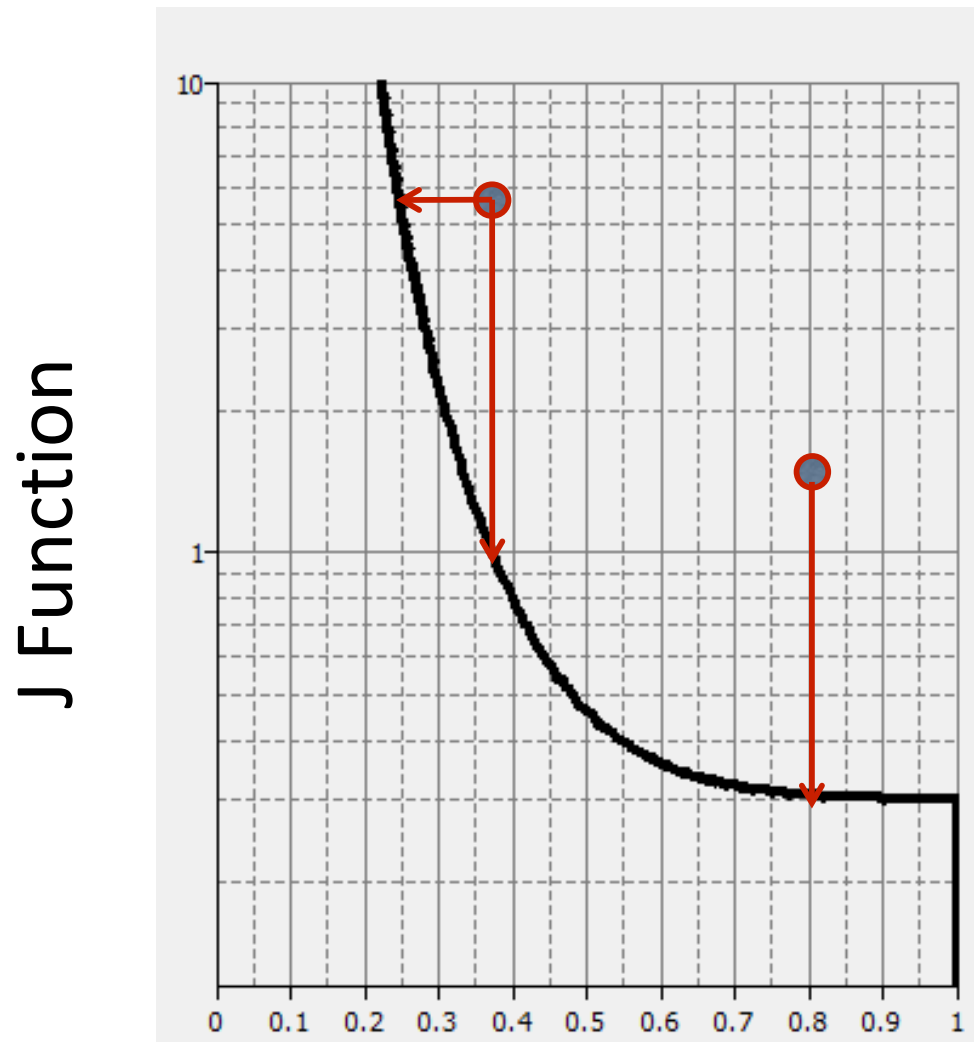
- **Key Point:** If permeability and porosity vary in 3D, then so does height of the contact above the free water elevation.

Identification of Free Water Levels for Compartments



➔ Note: oil-water contacts are significantly shallower than free water levels.

Use Log-Derived J Point To Estimate Free Water Elevation



Water Saturation

→ Estimate z_0 that puts point on curve.

$$z_0 = z - \frac{J \sigma \cos \theta}{\Delta \rho g} \sqrt{\frac{\varphi}{k}}$$

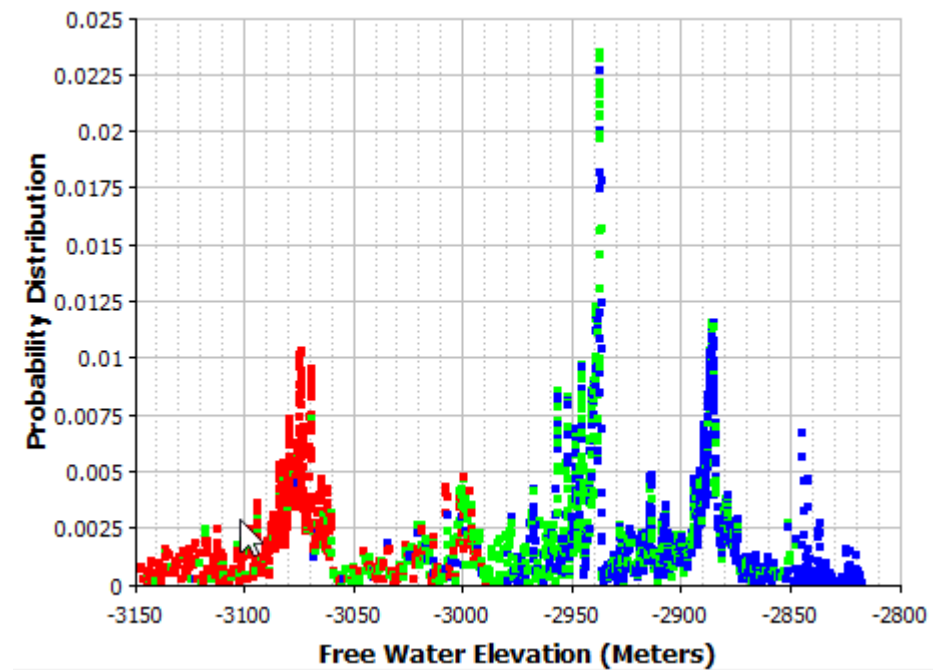
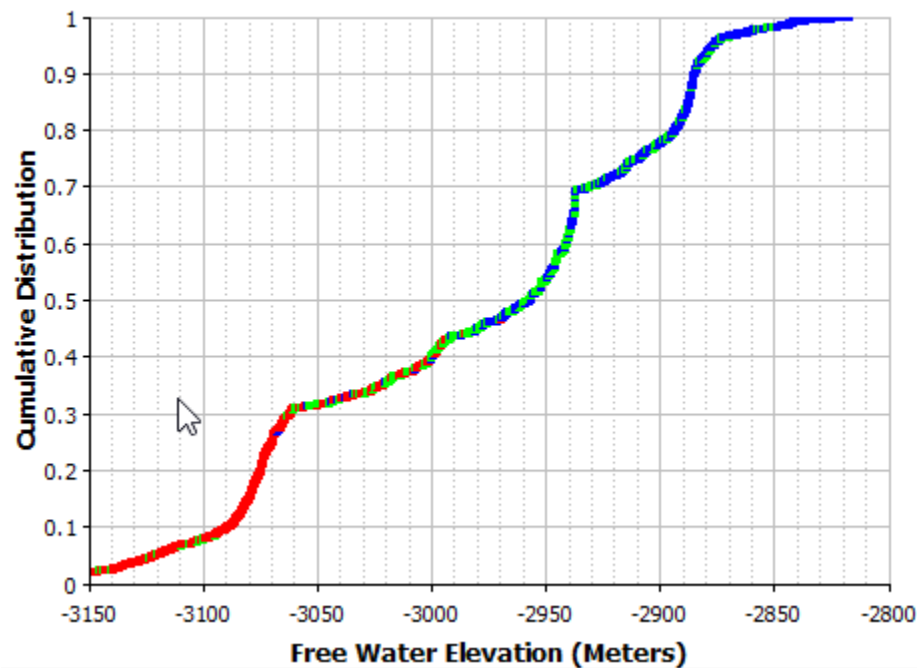
→ Points near steep portion of curve introduce more error.

→ Weight points according to inverse slope.

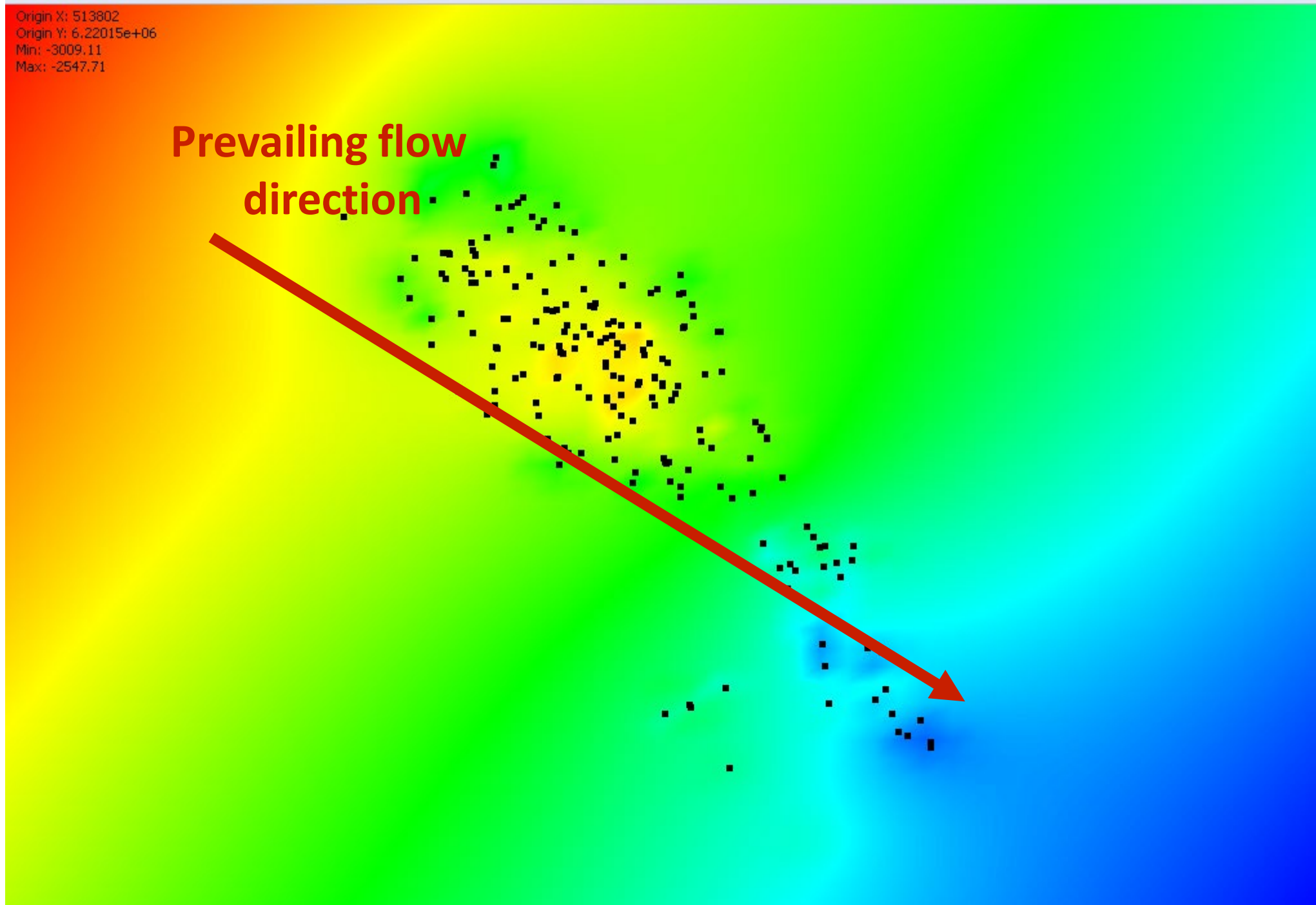
CDF and PDF for Multiple Free Water Elevations

→ Multiple free water elevations.

- Constrain be shallowest oil down to.
- Constrain be shallowest free water up to.

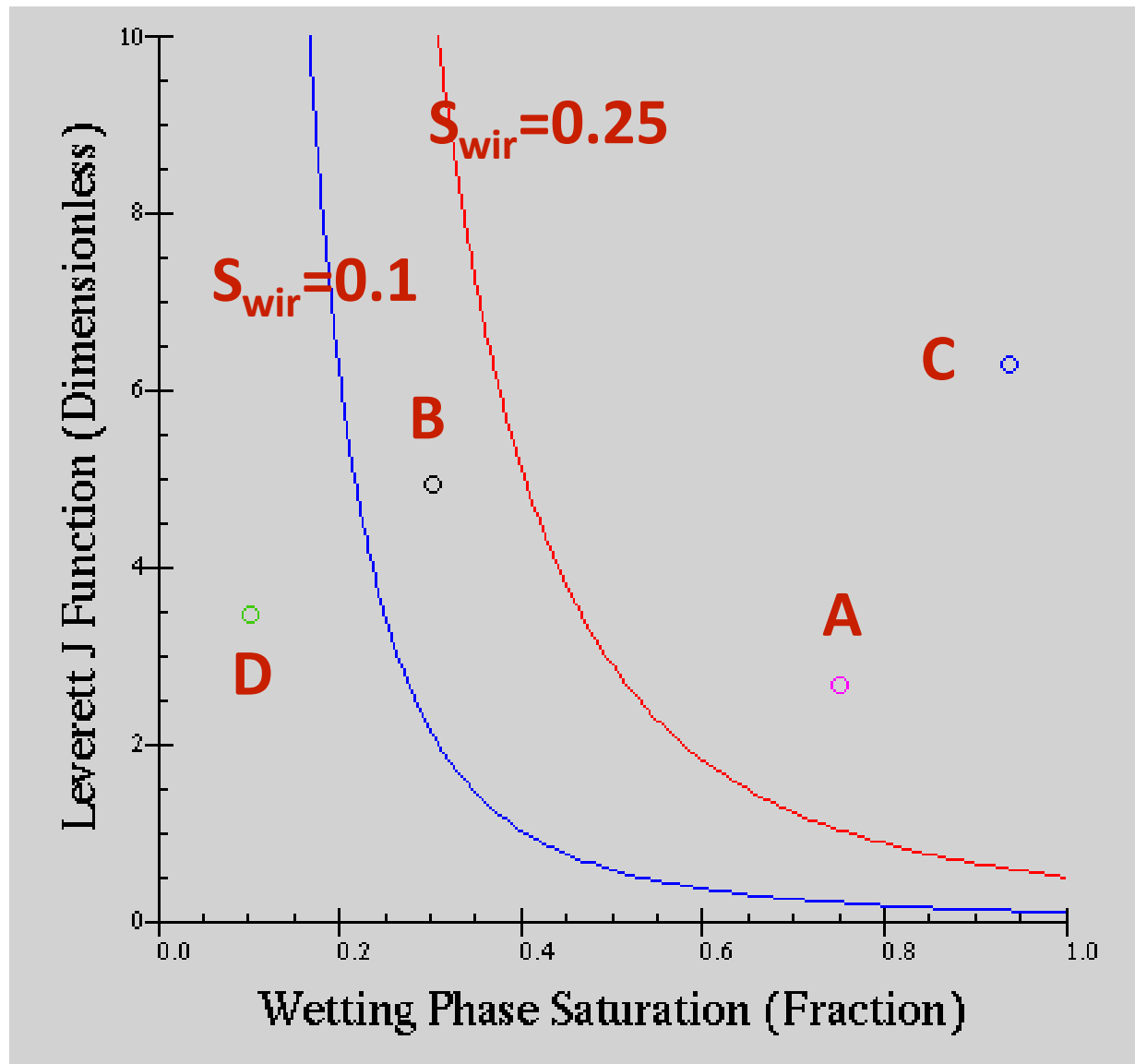


Tilted Free Water Surfaces in Geo2Flow



→ Geo2Flow estimates surfaces in equilibrium regions, defined by zones and blocks.

Two Log-Derived J Functions Have Been Identified



Consider four data points pictured here.

→ How do you explain mismatches?

→ Consider errors in S_w and J.

- What reinterpretations would you make?

→ Modify the Permeability

- Poro-perm plots are notoriously noisy.
- Vertically moves points to J Functions.

→ Modify the Irreducible Saturation.

- NMR logs claim to measure variable S_{wir}
- Horizontally moves J Functions to points.

→ Modify Archie's exponents of S_w logs.

- Horizontally moves points to J Functions.

Move Points With New Free Water Elevation

→ Modify the Free Water Elevation.

- Free Water Elevations are partition-dependent, not well-dependent.
- Infer new compartment from fault blocks or zones.

FWE=-1687 m.

FWE=-1659 m.

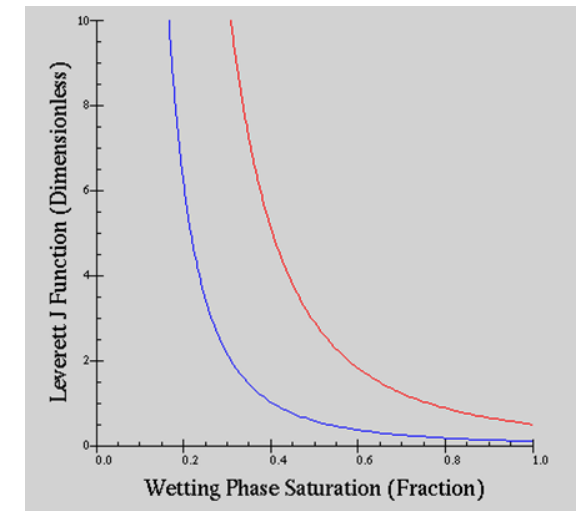
Alternatives to Moving Points

→ Identify a new J Function.

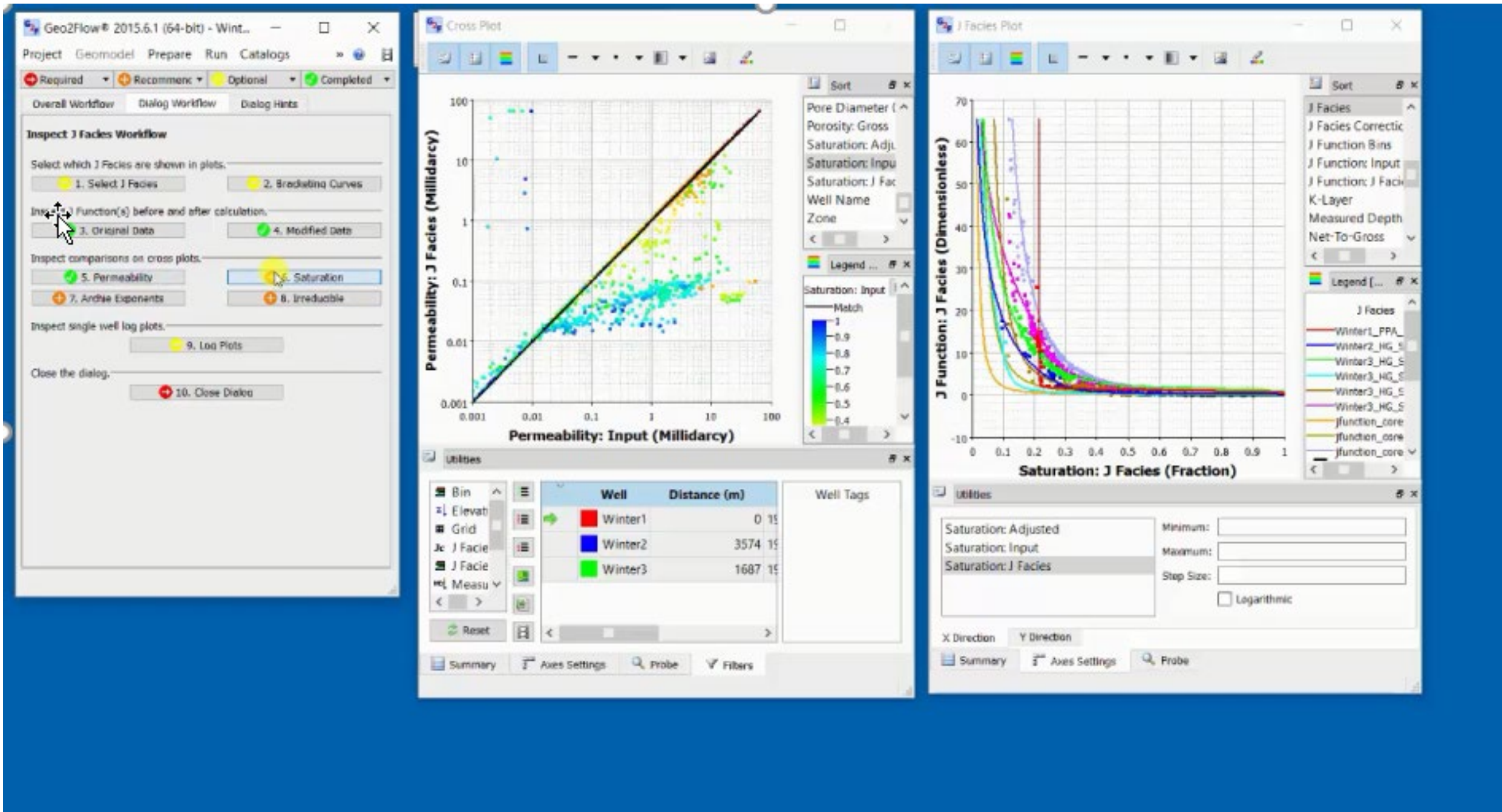
- Correlate with lithologies, if they are described in geological model.
- Laboratory capillary pressures?
- Likelihood of not encountering new rock type in coring program.

→ Discard data point.

- Last resort: outside error bounds.

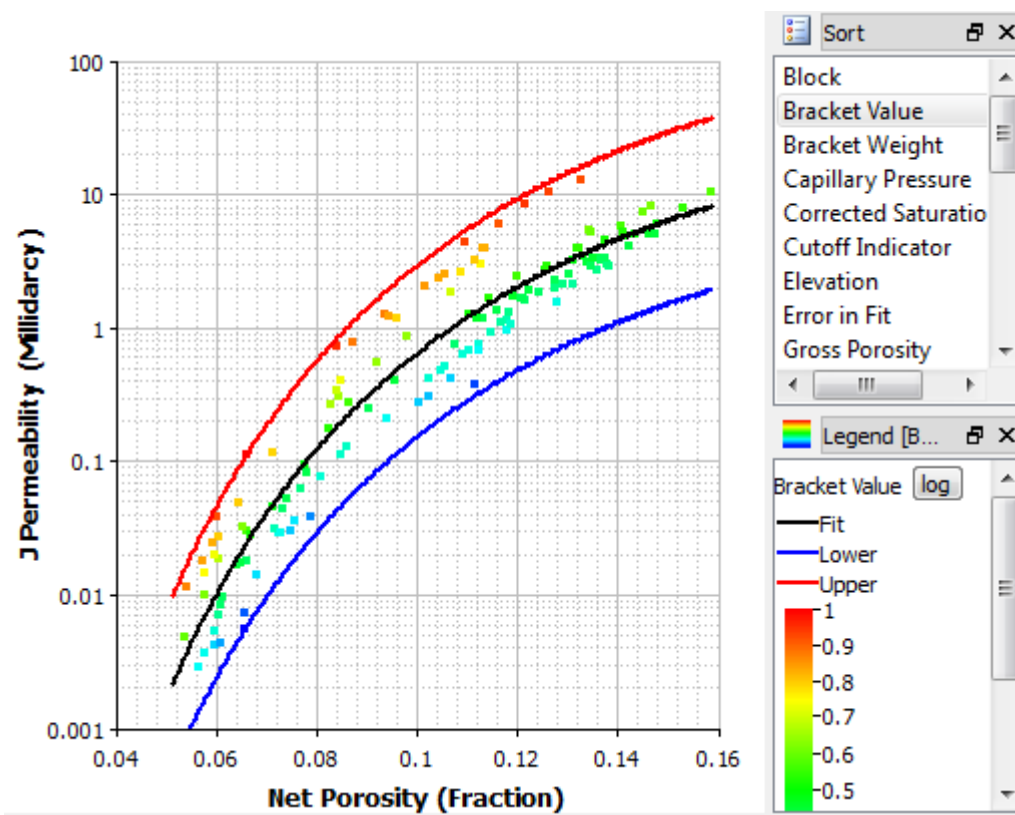


Resolving Permeability, Archie Exponents, And Irreducible

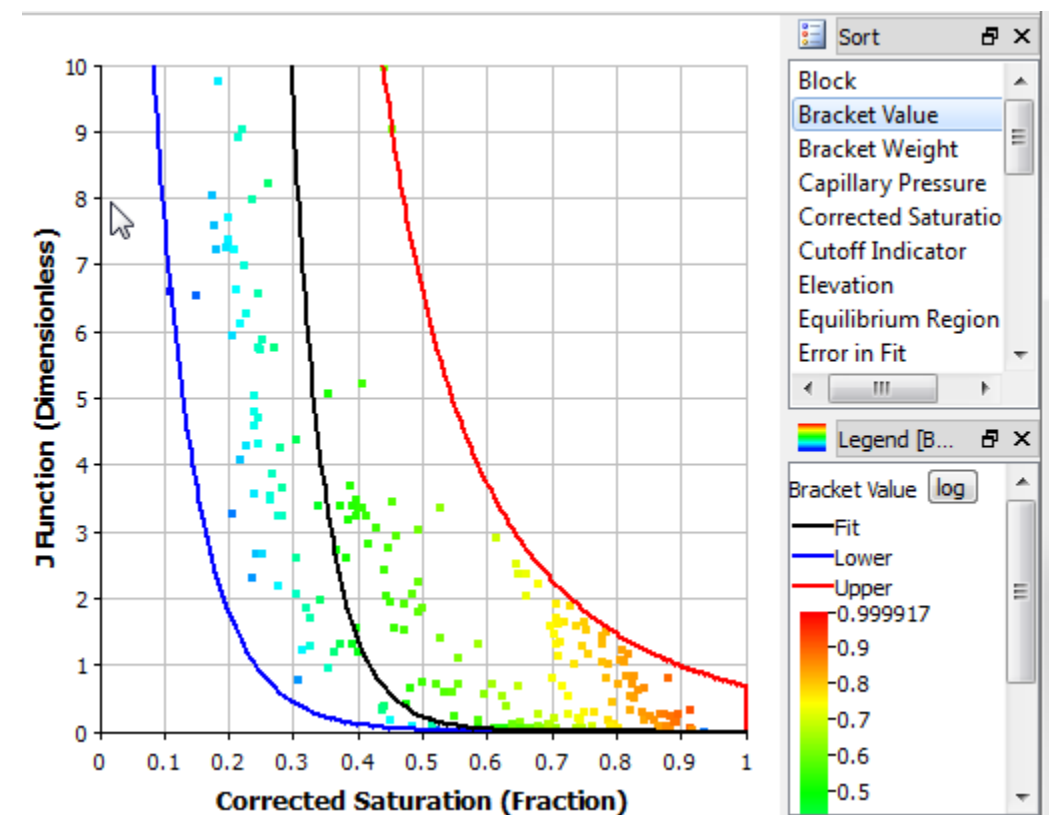


➔ Emphasizes governing equations.

- Geostatistics is assigned to handling variability around equations.
- “Bracketing” captures variability around equations.



Upscaled Poro-Perm



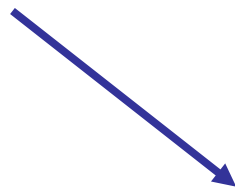
Upscaled J Function

➔ Upscaled into Petrel cells.

From Core $\log k = a + b \phi$

$$\frac{\sum_{i=0}^n V_i \log k_i}{\sum_{i=0}^n V_i} = \frac{\sum_{i=0}^n V_i (a + b \phi_i)}{\sum_{i=0}^n V_i}$$

Geometric Average
Permeability



Upscaled

$$\log \bar{k}$$

$$=$$

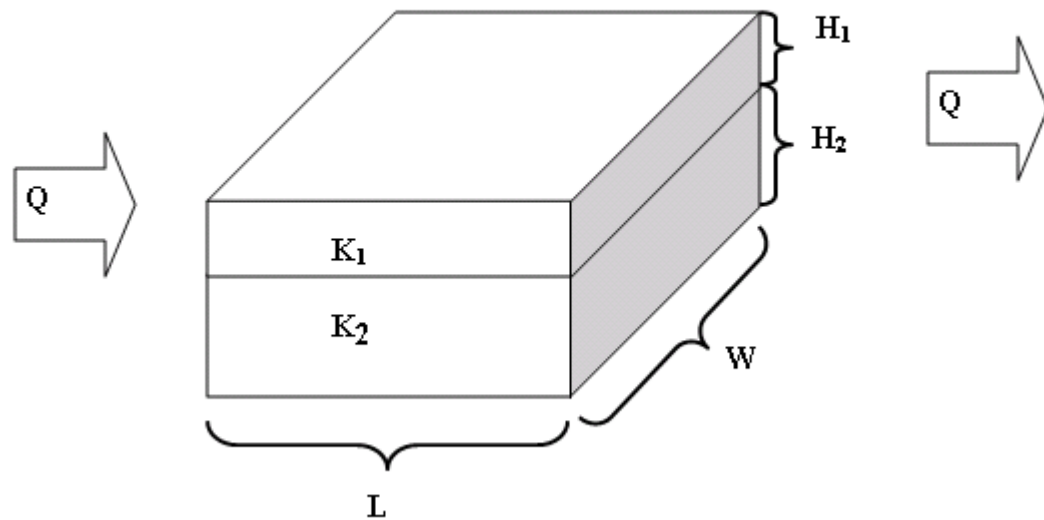
$$a + b \bar{\phi}$$

Volumetric Average
Porosity



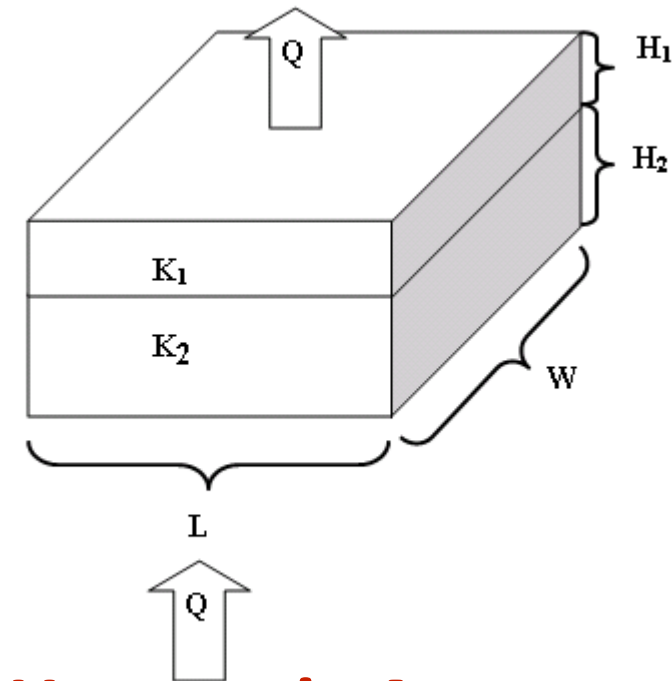
Upscaling Permeability: A Simplified View

Horizontal Flow



Arithmetic Average

Vertical Flow



Harmonic Average

$$\bar{K}^n = \frac{H_1 K_1^n + H_2 K_2^n}{H_1 + H_2}$$

→ Harmonic ($n=-1$) < Geometric ($n=0$) < Arithmetic ($n=1$).

- Horizontal (well test) permeability - Arithmetic.
- Vertical permeability – Harmonic.

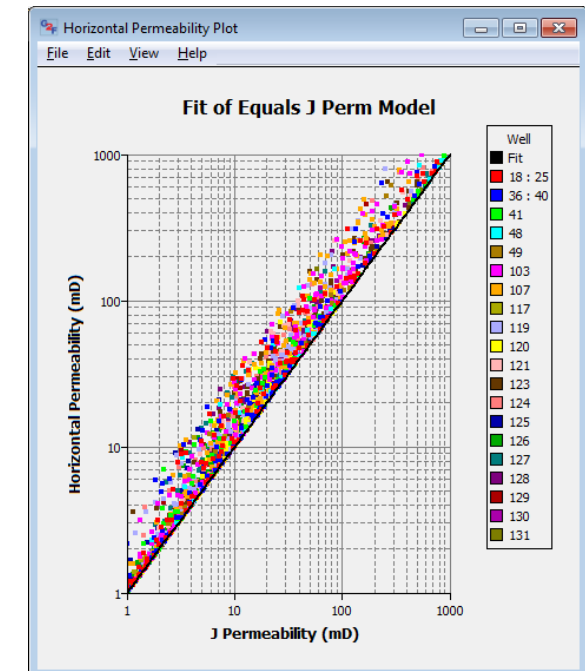
3D Permeability in Geo2Flow

→ Geometric Average: called J Facies Permeability.

- Best for upscaling J Functions (most scale invariant).

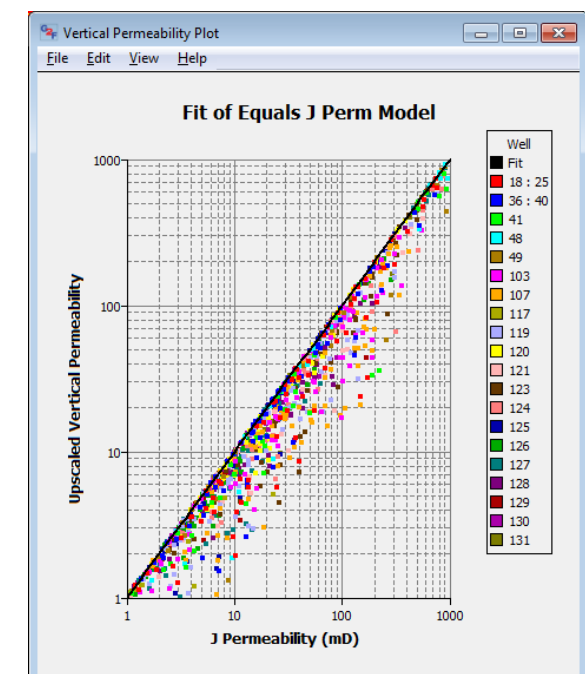
→ Horizontal permeability.

- Linear correlation with J Permeability at wells.
- Always greater than J Permeability

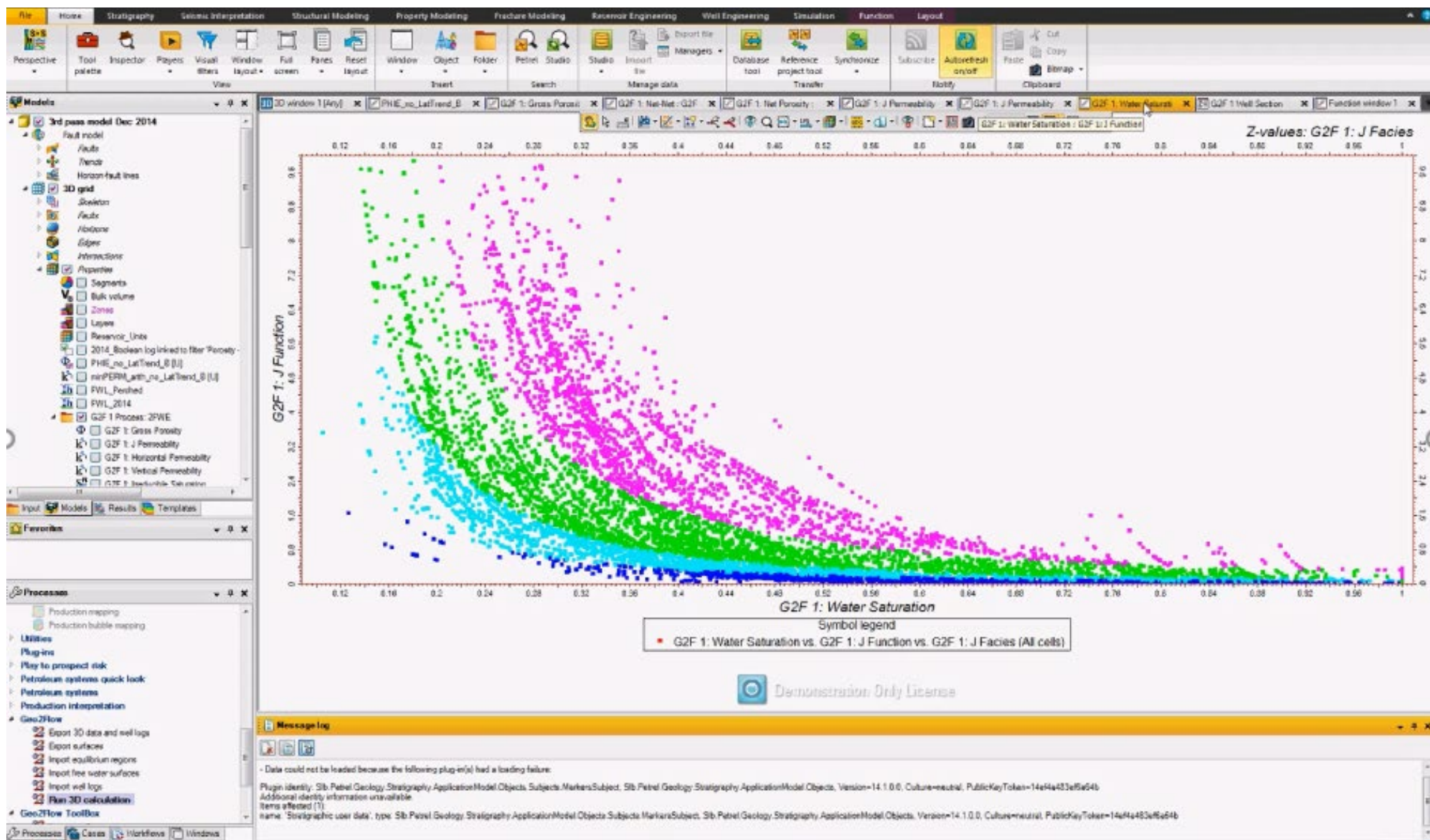


→ Vertical permeability.

- Linear correlation with J Permeability at wells.
- Always less than J Permeability



3D Calculation and Outputs



Define Simulation Case

The screenshot displays the GEO2FLOW software interface. The 'Define simulation case' dialog box is open, showing the 'Grid' tab. The 'Simulator' is set to 'G2F ECLIPSE 100' and the 'Type' is 'Single porosity'. The 'Grid' is set to '3D grid'. The 'Description' tab is active, showing a table of input parameters.

Input	Keyword	Fracture
1 ☒ G2F 1: Horizontal Permeability	Permeability I (PERMX)	☐
2 ☒ G2F 1: Horizontal Permeability	Permeability J (PERMY)	☐
3 ☒ G2F 1: Vertical Permeability	Permeability K (PERMZ)	☐
4 ☒ G2F 1: Net Porosity	Porosity (PORO)	☐
5 ☒ G2F 1: Net-To-Gross	Net to gross ratio (NTG)	☐
6 ☒ G2F 1: Local grid set		☐
7 ☒ G2F 1: Water Saturation	Initial water saturation (Pc scaling) (SWATNIT)	☐
8 ☒ G2F 1: Irreducible Saturation	Swc (Connate water saturation) (SWC)	☐
9 ☒ G2F 1: Irreducible Saturation	Swcr (Critical water saturation) (SWCR)	☐
10 ☒ G2F 1: Equilibrium Region	Multiplier region (MULTNUM)	☐

The background shows a 3D geological model with a wellbore. The 'Processes' panel on the left lists various simulation steps, with 'Define simulation case' highlighted. The 'Message log' at the bottom shows an error message: 'Error reading plug-in data. The exception log file contains more information. Hint(s): Unable to find assembly 'Schlumberger\WellPatternModule, Version=1.3.0.4, Culture=neutral, PublicKeyToken=7456e7d8625d2d'...'.

What Do You See In Geo2Flow?

“Your aim determines what you see.” – Jordan Peterson

- Scientifically strong: patented.
- Identifies reservoir compartments.
- Matches simulation models to saturations logs.
- Constrains permeability with saturations.
- Stronger history-matching from physically consistent inputs.
- Helps assess true uncertainties, not just easy ones to study.
- Stimulates interdisciplinary cooperation through workflows.
- Voluminous documentation and videos for training.



➔ *Science plus technology.*

➔ *Detailed Glossary (over 200 entries).*

➔ *Frequently Asked Questions.*

➔ *Whitepapers.*

➔ *Instructional videos.*

Help

File Go

Home | Glossary | Acronyms | FAQs - Key Words

Frequently Asked Questions for "J Function"

The following Frequently Asked Questions (FAQs) contain the above key words:

1. How do I ensure that there is no fluid movement just after the initialization step in the flow simulator merely because of inconsistencies between the input capillary pressure curves or J Functions and the initial saturations that are required to match the volumetrics of the geological model?
2. Why should I refit J Functions in the Initial Saturation 3D dialog, using the "Fitting Blocked Data" option? Doesn't this seem to wipe out all the meticulous work I did identifying J Functions earlier in the J Functions - Logs dialog and using them in the J Facies - Calculate dialog?
3. Why is it that the blocked J Function data that I see in the Initial Saturation 3D dialog, using the "Existing J Facies" option, do not match the J Functions that I defined in the J Facies - Calculate dialog?
4. I use the Catalog J Functions dialog to plot cataloged J Functions on a log-derived J Function Plot in the J Functions - Logs dialog. When I sort the plot by porosity, is there any correspondence between the colors of the catalogued J Functions and the log-derived J Function data?
5. Why isn't there a more automated way of fitting of J Functions in the J Functions - Cores dialog? If I have 20 capillary pressure curves, why can't I fit them all at once?
6. What is the significance of negative values of the J Function? Is the water saturation always equal to 100%?
7. Why would irreducible saturations of log-derived J Functions be less than any of the irreducible saturations we see in capillary pressure curves run with either air-mercury, oil-water (centrifuge), or air-water (centrifuge)?
8. Do I use one core-derived J Function for each zone in my geological model?
9. If I fit a J Function from core data in the J Functions - Cores dialog at a specific depth in a specific well, then should I use it at other depths and at other well locations when I select J Functions from the catalog in the Catalog J Functions dialog?
10. Why can't I sort by X and Y coordinates when I am inspecting log-derived J Function data in the J Functions - Logs dialog?
11. Within the Geo2Flow workflow, is each J Function defining a J Facies in the J Facies - Calculate dialog limited to one irreducible saturation or does the option exist to assign (maybe denormalize is a better word) the J Function with some other irreducible saturation tied to a rock property such as porosity or Leverett pore diameter?
12. As any functional curve fit of J Function data will typically have dependence on the irreducible saturation, does Geo2Flow provide the fitted equation coefficient parameters in the event that the user wants to vary the irreducible saturation outside of Geo2Flow?

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J Function Models

We use several **J Function models** (or fitting functions) in order to parameterize **J Functions**. You might imagine that J Function models would describe J as a function of **saturation**, which is the natural thing to do. However, it turns out that two of the best fitting models, the **O'Meara Unimodal** and bimodal, can be analytically expressed only when saturation depends on J . Consequently, all of our J Function models describe the dependence of saturation on J . Specifically, they describe the dependence on J of the **reduced saturation**, which is defined as follows:

$$S_r = \left(\frac{S_w - S_{ir}}{S_{end} - S_{ir}} \right)$$

Here S_w denotes the water saturation, S_{ir} denotes the **irreducible saturation**, and S_{end} denotes the end-point saturation, which for fractional **units** is 1.0 and for percent is 100%. This saturation is scaled so that it equals 1 when the **wetting phase** is at its end-point value and 0 when it is equal to the irreducible saturation. This scaling of saturation makes it easy to ensure that all of the **J Function** models conform to the following conditions:

- S_r is equal to 1 when J is less than or equal to the **J Function Displacement value**.
- J approaches infinity as S_r approaches zero.

Solving the above equation for the water saturation obtains the following:

$$S_w = S_r(1 - S_{ir}) + S_{ir}$$

So, to calculate the water saturation for a value of J begin by using one of the following models to calculate the reduced saturation and then use the above equation to translate from the reduced saturation to the actual water saturation.

We recommend using the following J Function models:

1. **O'Meara Unimodal Model**
2. **O'Meara Bimodal Model**
3. **Thomas Model**
4. **Brooks-Cores Model**
5. **Bentzen-Ard Model**
6. **Skell-Harrison Model**

Rarely have we found experimental data that cannot be fit with the functions presented here. In fact, if you have trouble fitting your data with these functions, it may be an indication of experimental errors in the measurement of the underlying **capillary pressure curves**.

Generally, for **primary drainage mode** J Functions (the ones needed for initial saturation and **reserves** calculations), the **displacement value** is greater than zero. Whenever, we see zero **displacement values**, they are usually connected to rapidly rising curves in the neighborhood of high wetting phase **saturations**. Such

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above the **displacement pressure** oil begins to enter smaller and smaller pore throats.

Capillary Pressure Curves

When such experiments are done in the laboratory using core samples of reservoir rock, we obtain so-called capillary pressure curves relating the capillary pressure to the water (or oil) saturation, the fraction of the pore space that is filled with water (or oil). More generally, capillary pressure curves relate capillary pressure to the **wetting phase** or **non-wetting phase** saturations. In a water-oil experiment, the water is (usually) the **wetting phase**. In a mercury-air experiment, the air is the **wetting phase**.

Figure 1 below shows two such curves, depicting different shapes and **displacement pressures**. Curve A has the lower **displacement pressure** and the sharpest curvature. Going back to the coffee straw analogy, this sample has effectively a single pore size: once the **displacement pressure** is exceeded, the rock is filled with oil down to what is called the irreducible water saturation (which in this case is 0.1). Curve B has a higher **displacement pressure** and a wider distribution of pore sizes. One of the challenges of reservoir characterization is to relate these kinds of curves to the more qualitative descriptions of the geologist. For example, curve A might be described by a geologist as a **facies** of well-sorted, ripple-laminated sand; whereas, curve B might be called a poorly-sorted mudclast. Geo2Flow helps you to make these connections between quantitative and qualitative descriptions.

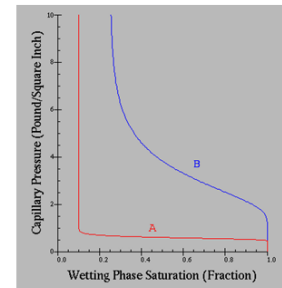


Figure 1. Two capillary pressure curves. Curve A depicts a rock with a lower displacement pressure.

As you can see, capillary pressure curves offer a way to "fingerprint" reservoir rocks by quantitatively describing their pore size distributions. That is both the good news as well as bad news: good because it uniquely characterizes a rock; bad because characterizing a reservoir requires a multiplicity of capillary pressure curves. For a reservoir model containing millions of combinations of porosities and permeabilities, we would need (in principle) millions of capillary pressure curves.

Calculating Capillary Pressure in the Reservoir

Now, let's return to the coffee cup example. Here we see that coffee, in spite of its being heavier than air, works its way up the straw. Thus, capillary forces compete with gravity; the latter pulls the coffee downwards and the former pulls it up through the straw. This sort of thing happens in reservoirs. Generally, oil is lighter than water (although we have used Geo2Flow to analyze a Canadian reservoir in which oil is heavier). So, you might expect that rock that is 100% filled with oil might be superposed on top of rock that is 100% filled with water. However, this does not happen. Above the 100% water-filled zone, you will find increasingly greater saturations of oil, but the change will be gradual rather than dramatic. In fact, the change in saturation is just like what is shown in the capillary pressure curves in the Figure. Such a relationship can be understood from a straightforward application of **Darcy's Law** for no-flow conditions, and is

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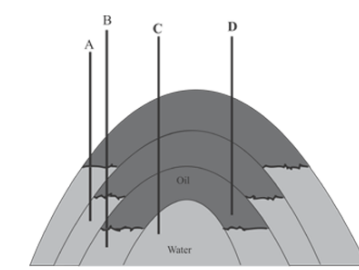
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If we relax our assumption of a single J Function, there is even more reason for the elevation of the contact to vary because we now couple heterogeneities in porosity and permeability to heterogeneities in **J Function displacement values**. Thus, if you think of reservoirs that are described by multiple **J Functions**, heterogeneous pore-perm distributions, and complex fluid properties, the likelihood of encountering a flat contact is practically nil. The more rare situation of flow in the aquifer adds an additional reason for variability in the contact surface. Indeed, flow in the aquifer is the only reason for variability in **free water surface**, which is translated directly to the fluid contacts.

Multiple Contacts

The following figure shows multiple contacts within the same field due to three **reservoir compartments**. This example underscores the need to confine the definition of a contact to a single **equilibrium region**.



Three oil-water contacts in three superposed reservoirs.

Now, let's go back to taking imaginary tips up wellbores from the bottom up. In the above figure, well D has not encountered a contact because it has only seen oil. The lowest elevation or depth at which the oil is seen would be referred to as an "oil-down-to" (ODT) level. Wells A and C have both encountered single **oil-water contacts**, albeit at different levels. In and of itself, this information would not conclusively indicate the presence of multiple **compartments**. There could be **flow in the aquifer** from the direction of well A to well C, consequently elevating the free water surface and, thereby, the **oil-water contact**, in the neighborhood of well A. Or, there could be variabilities in rock quality whereby poorer quality rock, having higher **J Function displacement values**, are in the neighborhood of well A and better quality rock is in the neighborhood of well B, thus causing variable elevations of a single contact, as we discussed above. Well B begins with water at its bottom, then upwards to oil, then water, and consecutively oil, water, and oil. Yet, even with this well, we need to restrain ourselves (especially with the figure in hand) from jumping to the conclusion of multiple compartments. Well B could be interpreted as having a single contact above which there are alternating good and bad intervals of rock, where water **saturations** are high in the bad rock.

The above discussion demonstrates some of the pitfalls of interpreting **saturation** data in a disintegrated way, in isolation from other sources of information. The explanations put forth above for explaining variability in contacts due to differences in rock types could be buttressed or deflated with additional data such as **porosity logs**, fluid pressures, visual inspection of cores, drill cuttings, or laboratory **capillary pressure** measurements. If, for example, wells A and C were shown to have similar **core-derived J Functions** and dissimilar **log-derived J Functions** when referenced to a common **free water elevation**, the case for compartmentalization would be buttressed, even in the absence of pressure data. Beware though, when putting together an integrated interpretation, of the illusions of data that add or detract from your case. For example, the author attended a conference where a technical presenter proudly pointed out that one could see a pronounced J shape on one of his well logs, thus supporting his claim that **J Functions** worked in his field. One has to wonder whether his faith in J Functions would have been shaken if such a shape had not appeared in a single log. Oftentimes, **log-derived J Function** patterns do not appear on isolated logs but reveal themselves when considering cluster of wells within close proximity.