ResFrac Calibration Cheat Sheet

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This cheat sheet lists field observations that you typically use for model calibration, and lists the parameters that we recommend that you vary to achieve a match to these parameters. The list is not exhaustive. However, if you find yourself varying parameters that are *not* on this cheat sheet, you may consider checking with us for advice, and to confirm that you are on the right track.

The order in which you perform the calibration is important. For parameters that affect the model's ability to match a variety of observations, you want to calibrate them *earlier* in the process. That way, you don't find that later changes mess up your matches from earlier stages in the calibration.

The parameters are listed in the rough order in which they should be calibrated.

Fracture length

Relative fracture toughness – larger values make the fractures shorter. In formations with larger fractures, we use values between 0-0.2 ft^(-1/2). In formations with shorter fractures, we use values as high as 0.8-1.0 ft^(-1/2).

Effective fracture aperture conductivity factor – smaller values make the fractures shorter and, especially, more symmetrical. The default value is 1.0. Values may be reduced to be as low as 0.2.

(Optional alternative) Fracture strands per swarm – larger values make the fractures shorter and they tend to remain mostly symmetrical. The default value is 1.0. Field data suggests that realistic values may be closer to 5.

To keep an eye on: If the value of permeability time 'pressure dependent permeability' is greater than 0.1 md, it can start to significantly limit fracture size.

Fracture height

Stress layering – fracture height growth is inhibited by high stress layers. To reduce height growth, you can increase stress in zones above and below.

Toughness anisotropy – if stress logs do not give any indication of stress laying, but you need to reduce height growth, increase the vertical fracture toughness to be higher than the horizontal fracture toughness. The default is for vertical fracture toughness to be approximately equal to horizontal fracture toughness. To limit height growth, we often increase vertical toughness by 20-30%. In a handful of cases, we have made vertical toughness 2-3x higher than horizontal toughness.

Perforation erosion

Perforation erosion alpha – higher values result in more perforation erosion.

Perforation efficiency

Perforation efficiency is strongly affected by fracture net pressure/toughness. Therefore, it should be calibrated *after* calibrating fracture length.

Perforation efficiency is strongly affected by cluster spacing and perforation design, but those are usually taken as 'given,' and cannot change them during calibration.

NW complexity coefficient (in well vertices table) – higher values tend to increase perforation efficiency (as well as increasing injection pressure overall).

Tensile strength (in the geologic units table), in conjunction with setting 'Randomized tensile strength' to true – higher values tend to decrease perforation efficiency. This setting is used to account for the nonuniform breakdown pressure in each cluster along a well. There is empirical evidence to support this approach. Figure 2 from SPE-204185-MS suggests that breakdown pressure can vary from 300 psi to 2300 psi within the same stage.

ISIP

Shmin or fracture gradient (in the geological units table) – higher values tend to increase ISIP. However, these values should typically be constrained by DFITs, and should not be set to values significantly different from the DFIT results.

NW complexity coefficient (in well vertices table) – higher values tend to increase ISIP and WHP during fracturing.

Pressure dependent NW dP – these four parameters, at the bottom of the advanced section in well vertices, can be used as an *alternative* to the NW complexity coefficient. The NW complexity coefficient technique tends to dissipate NW tortuosity too quickly after shut-in. The pressure dependent NW dP parameters give more flexibility to extend the duration of NW pressure drop after shut-in. However, they are more complicated to use. Refer to the built-in help content for more information.

Relative fracture toughness affects ISIP, but should be used to calibrate fracture length, not for the ISIP calibration.

Generally, we recommend not being overly concerned with matching the details of ISIP and the pressure behavior in the few minutes after shut-in. They are affected by complex (and relatively unimportant) near-wellbore effects that are difficult to characterize. Therefore, you may not gain a significant better model by working hard to improve the match on ISIP.

Treating pressure

Treating pressure should be calibrated after you are satisfied with the ISIP.

Wellbore friction adjustment factor – lower values reduce wellbore friction and decrease WHP. Friction adjustments are necessary because friction reducer chemicals in the wellbore cause wellbore friction to be much lower (ballpark 85%) than would be predicted from standard pipeline friction correlations for Newtonian fluids.

Friction adjustment factor (in the water solutes table) – has the same effect as ‘wellbore friction adjustment factor,’ but can be specified separately for each type of water solute.

Viscosity multiplier per 0.001 mass fraction (in the well) (in the water solutes table) – specifies an effective viscosity parameter for water solutes specifically for when they are in the wellbore. Useful for modeling cross-linked fluids that do not crosslink and increase viscosity until they are exited the wellbore.

Wellbore proppant friction adjustment factor – lower values reduce wellbore friction and decrease WHP, specifically related to when you increase proppant concentration. For example, if you increase proppant concentration, hydrostatic changes tend to make WHP go down, but friction changes may tend to make WHP go up. This parameter allows you to tune the degree to which proppant affects wellbore friction.

Generally, we recommend achieving only a general match to WHP during injection. WHP can show a variety of upward or downward trends during injection, and they can have so many different causes, that it is risky to overinterpret them. Trying to match them can lead to a model overfit.

Propped height

Vertical proppant flow holdup factor – Increasing this value reduces propped height. The default is zero. To significantly decrease propped height, you may find it necessary to increase this parameter to 0.9 or even higher.

Propped length

Maximum immobilized proppant mass per area – larger values result in a smaller propped fracture surface area. A reasonable default value is 0.3 lbs/ft^2. To match field data, we have gone as low as 0.05 lbs/ft^2, and as high as 0.75 lbs/ft^2.

Production volumes, RTA trends, and GOR

First, construct an RTA plot of reciprocal productivity index versus sqrt material balance time. You can use ResFrac's built-in specialized plot tool for assistance. The slope of the line is inversely proportional to propped area times the square root of permeability. If the fracture is significantly finite conductivity, then the plot will have a y-intercept.

Global permeability multiplier – higher values increase production and reduce the slope of the RTA plot. Your initial guess value for permeability can be taken from DFIT analysis.

Larger propped area increases production and reduces the slope of the RTA plot (see section above on propped area). It is best if you have independent constraint on propped length from interference tests. If you do not, you may consider modifying propped area as part of a match.

k0 (in the proppants table) – Higher values of k0 increase production by increasing the conductivity of the proppant pack. But only up to a limit – once the proppant pack is effectively infinite conductivity, further increases in conductivity have minimal effect. Lower k0 creates a y-intercept on the RTA plot. Increasing k0 removes a y-intercept on the RTA plot.

At some point, the RTA curve will begin to bend upwards. For single phase flow and constant permeability, this occurs because of interference between adjacent fractures. Their radius of investigation begins to overlap and so they produce less than they would if they were not in proximity. However, this is not the only cause of an upward bending RTA curve.

Very often, we observe that RTA curves begin to bend upwards when fluid pressure goes below the saturation pressure. The upward bend seems to coincide with an increase in GOR. This suggests that it is a multiphase flow effect.

To match this effect, we set up the oil (and possibly also the gas) rel perm curves so that they drop off relatively quickly as saturation drops, and use aggressive gas rel perm curves. As the fluid in the formation goes below the saturation pressure, gas forms. That gas can flow more easily than the oil, and so is preferentially produced, causing an increase in GOR.

Typically, we use gas rel perm curves with residual saturation around 0.01, and Brooks-Corey exponent around 1.0. For more information on setting up the oil rel perms, check out the worked example in Section 8.4 of the A to Z Guide.

Finally, in overpressured formations, we find evidence that the RTA curve bends upward due to pressure dependent permeability loss as pressure is drawn down. This strategy can be used, even if the formation is a gas reservoir without a dew point. In this case, go to the Curve Sets panel, and go to the pressure dependent permeability table. Set up a curve so that the permeability goes below 1.0 for values of dP less than 0. It is best to make the curve continuous and avoid abrupt changes. For example, you could use:

dP (psi)	Multiplier
0	1
-1000	0.562341
-2000	0.316228
-3000	0.177828
-4000	0.1
-5000	0.056234
-6000	0.031623
-7000	0.017783
-8000	0.01
-9000	0.005623

What should you do if you see BHP go below saturation pressure, but GOR does not increase? In order for GOR to increase, fluid pressure needs to go below the saturation pressure *in the formation*. So first, open the 3D image and confirm whether the fluid pressure in the fracture is below saturation pressure. If the proppant pack conductivity is not high enough, then the fluid pressure in the fracture may not be as low as the pressure in the well.

It is useful to understand how ResFrac calculates rel perm for production. For each fracture-matrix element connection, the code performs a special flash calculation using the composition of the matrix element and the pressure of the fracture element. Or more precisely, the code does not actually use the pressure of the fracture element, but uses a pressure from the 1D submesh method that is close to the fracture element. The code defaults to using the pressure 0.5 m away from the fracture element, out in the matrix. However, recently, we've realized that sometimes this can cause an excessively delayed increase in GOR. So, we've modified the validator in the UI and changed the recommended settings wizard to suggest defaulting the value of 'adjust submesh for multiphase flow distance' to 0.1 ft.

Water flowback

Water flowback at the start of production comes from two places – the fractures themselves, and the formation surrounding the fractures.

If the fractures have not yet mechanically closed at the start of flowback, then they will have very high conductivity and you will see a brief period of extremely high flowback rate at high water cut. To avoid this happening, make sure that you set up the 'pressure dependent permeability' table to accelerate leakoff during fracturing. This mimics the effect of unpropped fracture strands on water leakoff (but not on production). Use the pressure dependent permeability wizard to easily set this up. Use the 3D image to confirm that the fractures are mechanically closed when fluid production starts. Open cracks have Eopen value greater than zero.

Second, water may flow back after leaking off into the formation. ResFrac uses a special ‘water bank’ treatment to keep track of how much water has leaked off and accumulated in the near-fracture region. The water bank grows as water leaks off, and depletes as water is produced back. Water flowback is accelerated as long as the water bank region thickness is not zero.

Water bank 'rel perm increase' scaling thickness – lower values cause water to flow back faster, and so cause a higher water cut early on, but cause a more steeply decreasing water cut over time. Higher values cause lower water cut early on, but more slowly decreasing water cut over time.

Water bank 'rel perm decrease' scaling thickness – this parameter defaults to be unspecified so that it has no effect. If specified, it causes early-time water cut to be even higher by reducing the rate that oil/gas can be produced, based on the thickness of the water bank. Smaller values cause higher water cut early on, with oil/gas production increasing over time. Larger values may cause less water cut increase at early time, but it will take longer for oil/gas production to recover. Overall, we typically recommend that you leave this parameter blanks.

Long term water cut

Once the water bank thickness has reduced back to near zero, the water cut is affected by the mobility ratio of the oil/gas and water phases.

Lower value of Swr (curve sets panel) – Lower values cause more water production and higher water cut.

We primarily recommend modifying Swr. As a supporting option, you may choose to modify ‘water phase exponent’ (curve sets panel). Lower values cause more water production and higher water cut.

When modeling water production, it is useful to assess – in the first year of production, do you produce more or less water than was injected? If less, then Swr may be higher than initial Sw, suggesting that some of the injected water is lost to the formation indefinitely. If greater, then Swr may be less than initial Sw. This suggests that you will eventually flow back the injection water, and that you will continue to produce water from the formation indefinitely.