

Reservoir Characterization Of Fractured Reservoirs In Western Canada

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Abstract

The author has worked on a number of fractured reservoirs in Western Canada, which show common characteristics. Production performance, pressure transient responses and stimulation results are discussed.

A reservoir characterization is presented which is consistent with observed production performance, pressure transient responses, production logging results, core analysis and well stimulation. A key component is structural geological style.

This description has been applied to a number of different reservoir situations. It has application to stimulation design, predicting reservoir performance, numerical simulation and pressure transient analysis. An example is also highlighted from a gas condensate reservoir.

Introduction

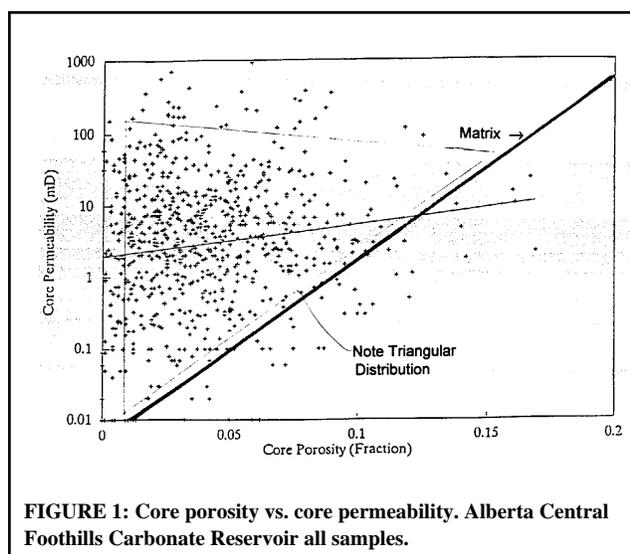
The material in this paper was derived from a number of large detailed reports (for example see reference 1). Such detail and volume of material cannot be covered in a single technical paper. The paper therefore only presents a summary of a number of key concepts derived based on the author's experience. Evaluating a fractured reservoir [after Nelson⁽²⁾] involves four main steps:

1. Interpreting the origin of the fracture system. This information allows one to predict geometry and the extent of communication.
2. Determining petrophysical properties of the fractures and matrix. This allows for prediction of the variation in reservoir response. The relative storage (ie porosity) must be determined as well as effective permeabilities. Another important property is compressibility.
3. The flow interaction between the matrix and fracture system is evaluated to determine ultimate reserves from the reservoir.
4. Classification of the reservoir. Depending on the type of flow interaction the reservoir will fit one of several depletion strategies. Note that most of the variations in strategy apply to waterflooding oil reservoirs.

A large proportion of the above data is obtained from core. The following conventional core analysis data and plots can be used:

1. Core permeability vs. core porosity—all data.
2. Core permeability vs. core porosity—sorted by lithology.
3. Vertical permeability vs. horizontal permeability.
4. K90 plotted vs. Kmax.

Fractured reservoirs do not show the typical straight line relation on core permeability vs. core porosity (semilog) plots.



Typically lower porosity rock is more prone to fracturing. Fractured reservoirs also tend to have higher anisotropy, which is seen as large variation in K90 vs. Kmax.

Core Description

In the author's experience, based on a number of studies in Western Canada, there is a typical core permeability vs. core porosity relationship. The following diagrams and points are based on an example from the central Foothills:

1. Core permeability vs. core porosity is shown in Figure 1. The data show tremendous scatter, which is typical of a fractured reservoir. There are a total of 762 data points, which have an average air permeability of 23.392 mD and an average core porosity of 4.11%. At first glance the data looks almost completely random. However, more careful examination shows there is a triangular distribution. As outlined earlier, lower porosity core is more prone to fracturing. The lower bound of the triangle approximates matrix properties.
2. Fractured samples were then isolated, as shown in Figure 2. These 564 points comprise about two thirds of the total sample set. Note that the average porosity drops from 4.11% for all samples to 3.65%. At the same time, the permeability increases from 22.39 mD for all samples to 29.15 mD for fractured samples only.

Further examples are shown later.

It is interesting to compare the above results with a non-

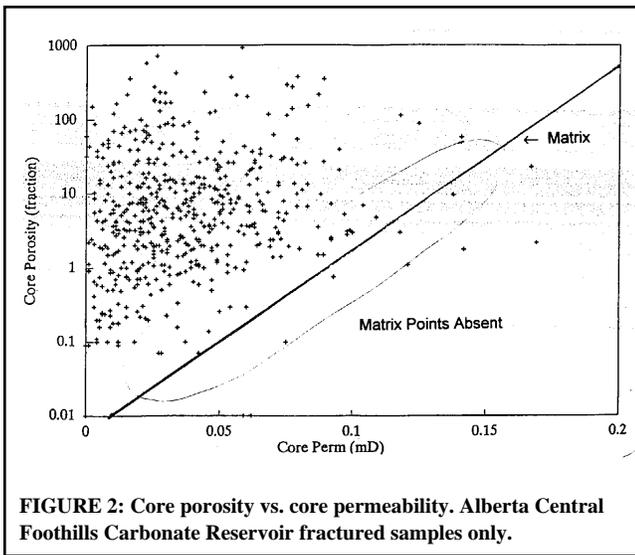


FIGURE 2: Core porosity vs. core permeability. Alberta Central Foothills Carbonate Reservoir fractured samples only.

Foothills reservoir. The Brazeau River Elkton/Shunda is located about 50 km to the east of the preceding example. The pool is located on a subcrop edge and is also a type of fractured reservoir. However the fracturing is derived from a different source—Kars development. Core permeability vs. core porosity from this field is shown in Figure 3. It is immediately obvious that the data does not resemble the “shotgun blast” or “triangular” appearance of the foothills reservoir.

The average permeability and porosity are 56.54 mD and 9.25% (574 points). The Foothills reservoir core averaged 22.392 mD with a porosity of 4.11%. It is interesting to note that at an average porosity of 4.11%, the non foothills core has an average permeability of 0.3 mD to air (at surface conditions).

Another reservoir that shows the Foothills type of core permeability vs. core porosity was plotted for a Wabamun D-1 reservoir, as shown in Figure 4. The core data shows a classic triangular distribution of core permeability vs. core porosity. In the author’s opinion this is diagnostic of fracturing derived from structural (Foothills type) deformation.

Structural Style Effect

Figure 5 shows a cross-section through a Western Canadian sandstone reservoir. As part of an economic evaluation the author plotted well AOF and type curve reservoir interpretation.

This diagram shows the basic building block of structural style in Western Canada, which is a thrust fault. Well performance is

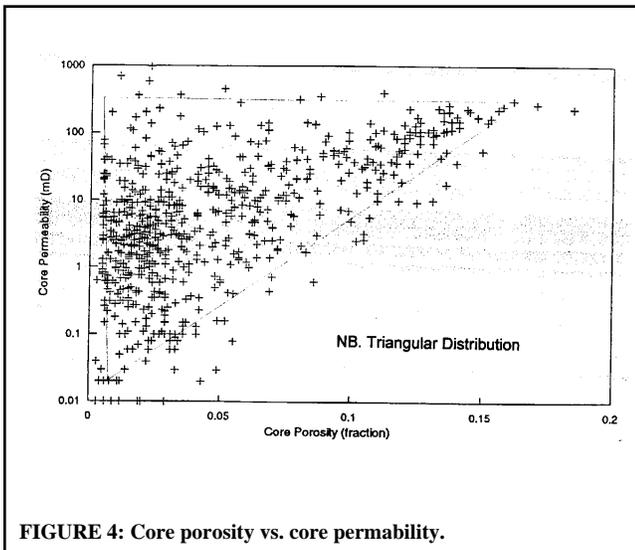


FIGURE 4: Core porosity vs. core permeability.

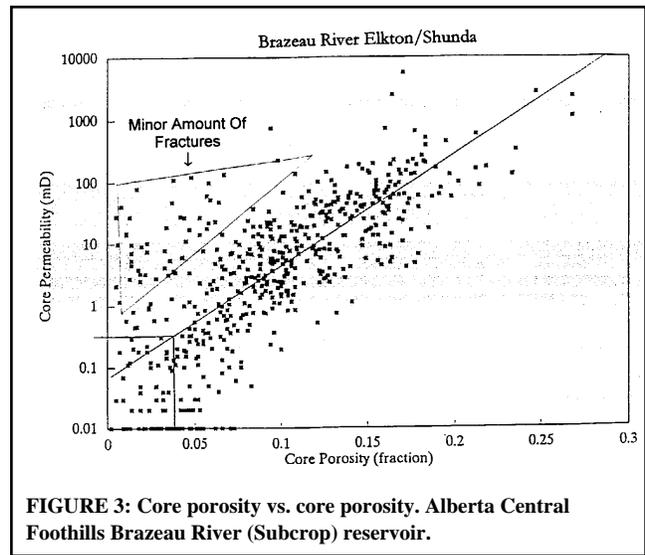


FIGURE 3: Core porosity vs. core permeability. Alberta Central Foothills Brazeau River (Subcrop) reservoir.

strongly affected, depending on where in the structure wells are completed:

1. Along the top of the overthrust sheet leading edge, well deliverabilities are very high. Type curves, for this reservoir were typically single porosity radial responses.
2. Underneath the thrust sheet, and adjacent to the shear zone, long slivers of reservoir rock are dragged up or broken off. In this area a number of bi-linear test results were obtained.
3. Further ahead, there are a series of faults, that are of a much smaller scale than the thrust sheet. In this area, type curves indicate systems with concentric permeabilities.
4. Behind the thrust sheet on the “back limb,” well tests indicated hydraulic fractures and mixed medium deliverabilities.

One thing that was immediately obvious was that there was good permeability across the front of thrust sheet.

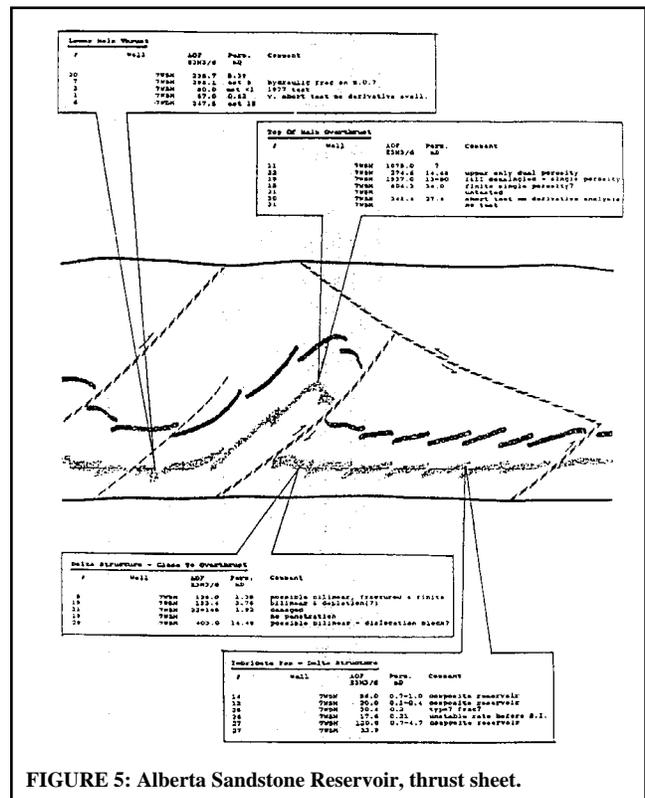


FIGURE 5: Alberta Sandstone Reservoir, thrust sheet.

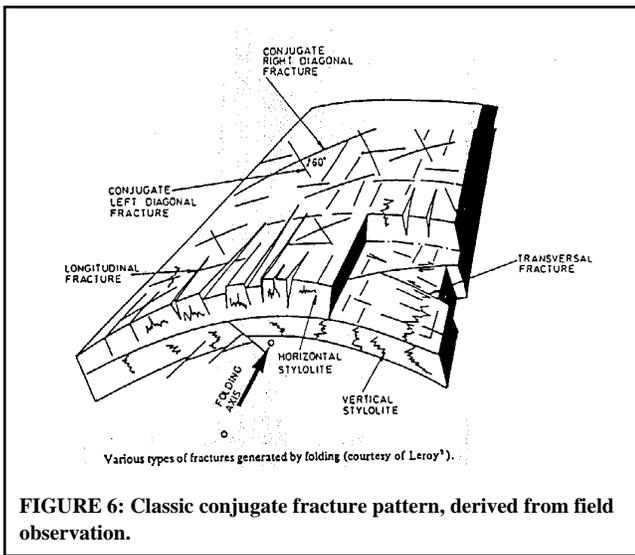


FIGURE 6: Classic conjugate fracture pattern, derived from field observation.

Fracture Patterns

Classical work on anticlines indicates that dominant fractures normally occur in a conjugate pattern⁽³⁾. This is shown in Figure 6. Although there are longitudinal fractures shown, most petroleum reservoirs are located well below surface, which is a compressive environment. The longitudinal fractures are unlikely to be open. The large number of conjugate fracture and their orientation would seem to suggest that communication should be best down dip.

Permeability is, however, controlled by fracture connectivity⁽⁴⁾ as shown in Figure 7. At first glance it is tempting to think that permeability would be highest along the trend of the fractures. This work, which uses stochastically generated fracture widths, orientations and lengths clearly indicates that connections govern permeability. Hence the dominant conjugate fractures would actually result in good communication along the leading edges of thrust sheets. This is consistent with the production data the author has evaluated.

Stress Sensitivity

Fracture permeability is strongly affected by the amount of nor-

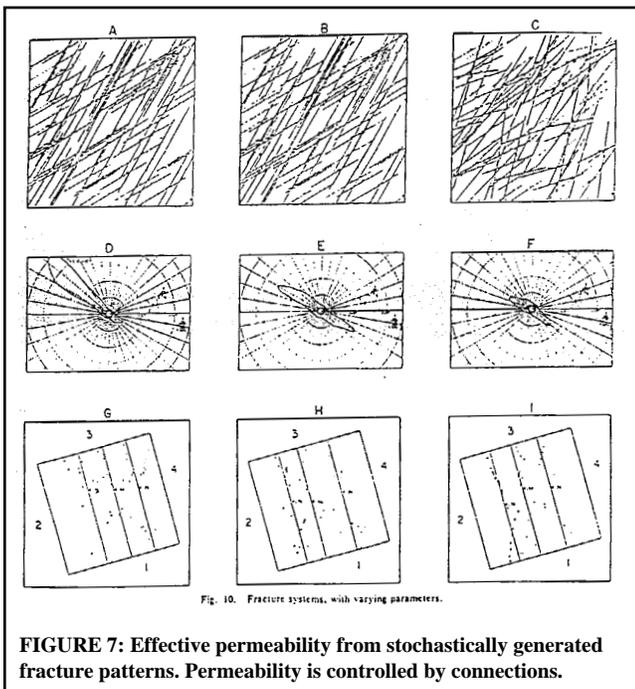


FIGURE 7: Effective permeability from stochastically generated fracture patterns. Permeability is controlled by connections.

mal stress across a joint or faults. Permeability reductions as high as 60% are common. This is a result of closing of microfractures and changes to the pore fabric. This was identified in Muskat's classic⁽⁵⁾. Further work was done by Fatt and Davis⁽⁶⁾ and Willhelmi and Somerton⁽⁷⁾. This work pertains mostly to rocks which are relatively competent ie. non fractured reservoirs.

The conductivity of joints is greatly affected by the state of stress in the reservoir. To date relatively little work appears to have been done in Canada and the United States on this subject. The best examples that the author is aware of come from the North Sea.

One of the most pronounced effects of stress in on well completions. Figure 8 shows the cross-section through a reservoir(s) that consisted of up to three different thrust sheet. Two attempts were made to complete the bottom most zone (C sheet) by perforating and acidizing.

In two separate completions, it was not possible to get a breakdown in the lower zone, adjacent to the upward ramp of the thrust sheet. This area will have very high compressive stresses. So high, that a conventional frac breakdown cannot be achieved, without bursting the tubulars (tried).

Discrete Blocks

This leads to some very interesting work regarding completion treatments by Harper and Last⁽⁸⁾. Their work describes a new type (to the petroleum industry) of mechanical model—Discrete Element analysis. This type of analysis was developed by geotechnical engineers to account for discontinuities. The design of tunnels, mines, and other excavations is frequently governed by rock joints (discontinuities).

This type of model has been coupled with a fluid flow model. There are a number of key points. First, it is not possible to hydraulically fracture a jointed rock mass. The fracture will follow the existing discontinuities.

Figures 9 and 10 show a number of different situations with different joint patterns, principal stresses and fluid injection. Quite bizarre results are obtained. High rate injection gives a very high breakdown pressure (Figure 9) and low injection pressure. A different orientation of principal stresses does not require a significant breakdown pressure, but requires higher pressures on a long-term basis.

Pressure Transient Analysis

One of the areas where dual porosity reservoirs have become most fashionable is well test analysis. This is particularly true since the development of Gringarten et al. type curves and the use of derivatives. One would naturally expect this type of behaviour

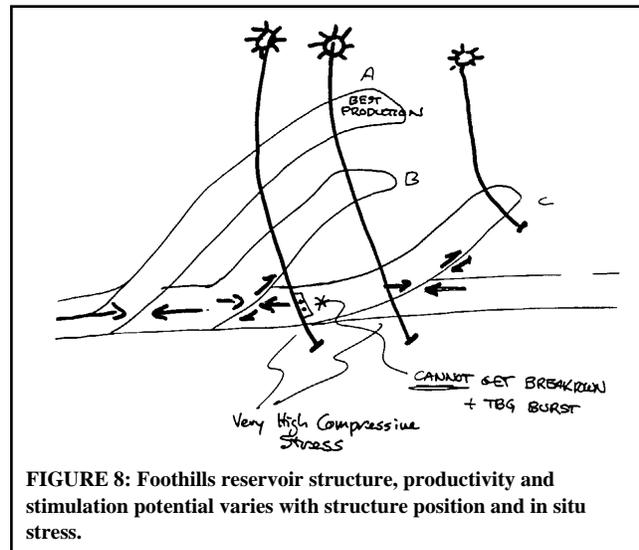


FIGURE 8: Foothills reservoir structure, productivity and stimulation potential varies with structure position and in situ stress.

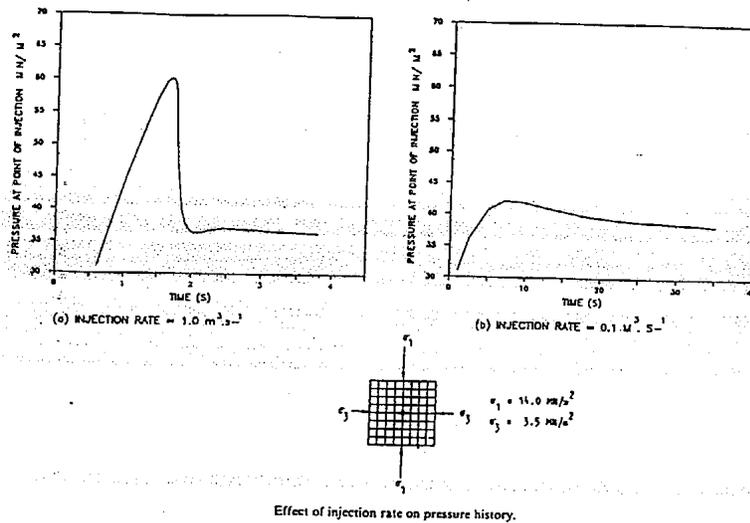


FIGURE 9A: Injection pressure profiles, various rates, discrete element analysis (Harper & Last).

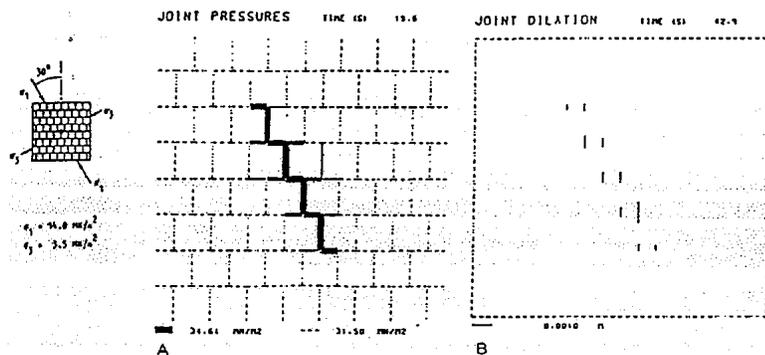


FIGURE 9B: Development of discontinuous fracture conductivity. A. During injection. B. Dilated joints remaining after injection.

from a reservoir that is known to be fractured.

The basic model was developed by Warren and Root⁽⁹⁾. The reservoir is basically conceptualized as a series of sugar cubes. This model has a number of severe limitations. It is assumed that the fractures extend infinitely. The fractures are also assumed to be evenly spaced. All flow to the well takes place in the fractures.

The fractures are, in turn, supported by a matrix of lower permeability.

The original work concentrated on Horner analysis and has been extended in a number of stages by various authors (such as Gringarten). Despite all of these advancements, the technique has very limited application in practice. Part of this problem is that a

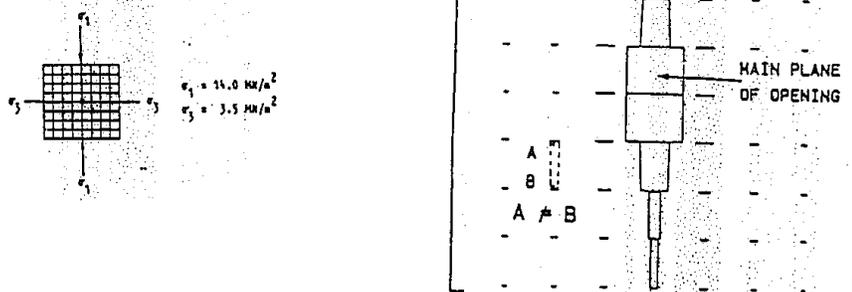
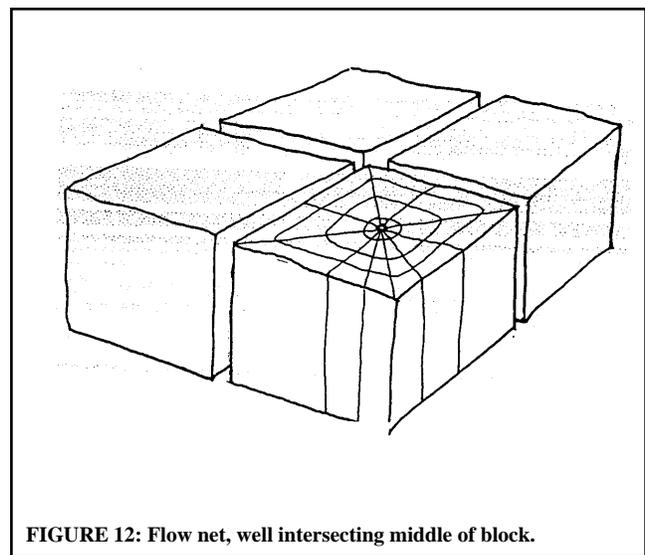
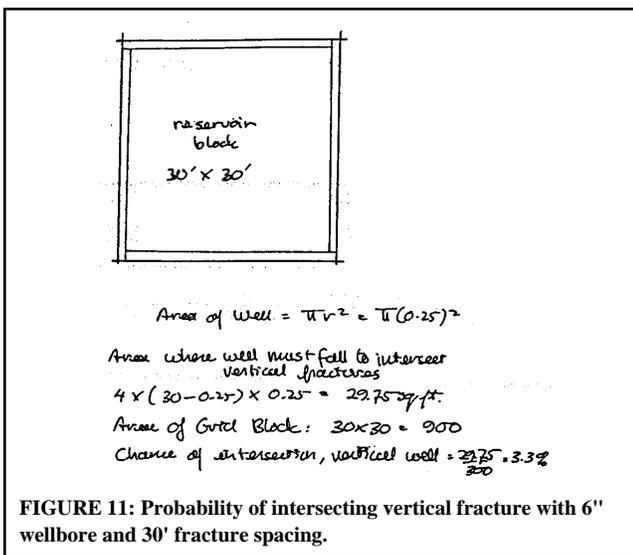


Fig. 3. Illustration of relative fracture aperture values during injection. Note that selected aperture plots have been joined to illustrate spatial changes.

FIGURE 10: Effect of injection on fracture apertures. Note permanent changes after injection. (Harper & Last).



multi-layered system produces the same mathematical solution as the dual porosity system.

There are very few examples of dual porosity interpretations published. This lack of practical application has not been widely discussed, partly because the mathematics has been very popular. Two authors have braved this issue. The first is Sabet⁽¹⁰⁾ and the other is Streltsova⁽¹¹⁾. Sabet's comments are as follows:

"Based on the author's experience, it is highly unlikely that the semi-log plot of the test data obtained from wells producing from naturally fractured reservoirs would exhibit the characteristic curve predicted by Warren and Root, de Swaan, Najurieta, or Streltsova. The same conclusion was reached earlier by Odeh (1965) who studied several fractured reservoirs. Rather, the given examples were all related to layered reservoirs, and Streltsova's examples were drill stem tests in which the flow rates cannot be stabilized.

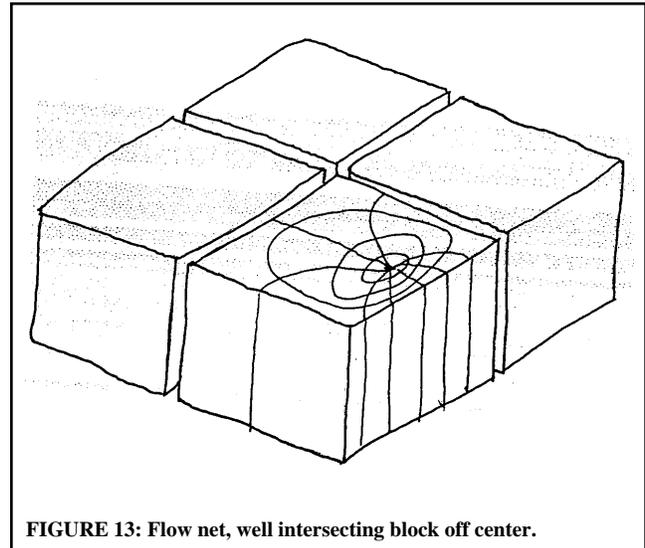
The pressure derivative method is theoretically very powerful, but in reality it cannot be applied in the case of field data except in ideal situations where the semi-log analysis would be more than adequate. Furthermore, if there is a linear boundary in a homogeneous reservoir, the derivative method will give the impression of a naturally fractured reservoir."

Streltsova, in her book *Well Test Interpretation in Heterogeneous Formations* basically concurs with Sabet's observations.

Implicit in these developments is the assumption that the fracture network is continuous and of uniform permeability throughout a well's drainage radius.

Present day exploitation of hydrocarbon deposits has shown that fractures within a reservoir are not necessarily interconnected over a well's drainage area. Reservoirs with fractures of limited lateral connectivity are, in fact, not uncommon.

The behaviour of a formation with a discontinuous network of fractures is entirely different from that of a formation with uniform fracture permeability. If a producing well intersects a localized fracture system, the initial well behaviour is indicative of the fractures system response. Generally, a fracture network imparts an anisotropy to the formation's permeability: Parallel to fractures the permeability is at its lowest value. If the fracture network is continuous, a single-well test yields an effective transmissibility equal to the square root of the product of the transmissibility values along the major and minor axes of the anisotropy. (Streltsova references the solution of anisotropic reservoirs). If, however, the fracture network intersecting a well is disjointed, then the preferentially oriented high permeability extends only a short distance away from the wellbore. Beyond this distance, flow takes place through the lower permeability matrix that connects the fracture network to its neighbouring networks. Given sufficient flow time, the pressure response of a formation with disjointed fracture networks assumes the character associated with radial flow.



Consequently the pressure curve has a shape similar to that of either a fractured well or a well in a layered system with laterally terminating layers. The former type of behaviour occurs when only a single fractured zone is open to the well; the latter is usually observed whenever multiple zones are open to the well."

Sabet discusses two circular concentric regions in his chapter on Testing of Naturally Fractured Reservoirs. The basis of Adam's paper⁽¹²⁾ was well test results, for which he developed an analytical model to match observed performance. Warren and Root's paper was developed strictly theoretically and did not include practical examples.

As pointed out by DaPrat⁽¹³⁾, the dual porosity model has a number of restrictions. There must be approximately two orders of magnitude difference in permeability for the phenomena to develop.

Reservoir Modelling

The author has modelled a reservoir using a reservoir simulator that is based on the Warren and Root type model. It was found that no significant difference in pressure existed between the matrix and the fracture system unless large spacings of 10 m (30 ft.) were used. This is similar to results derived by others such as Bennion et al.

At this point it is necessary to go back and re-examine the use of a dual continuum. We assume that the fractures can be modelled as a "field" property. In some massive Iranian reservoirs, there maybe 600 ft. of pay where there will be at least 20 fracture

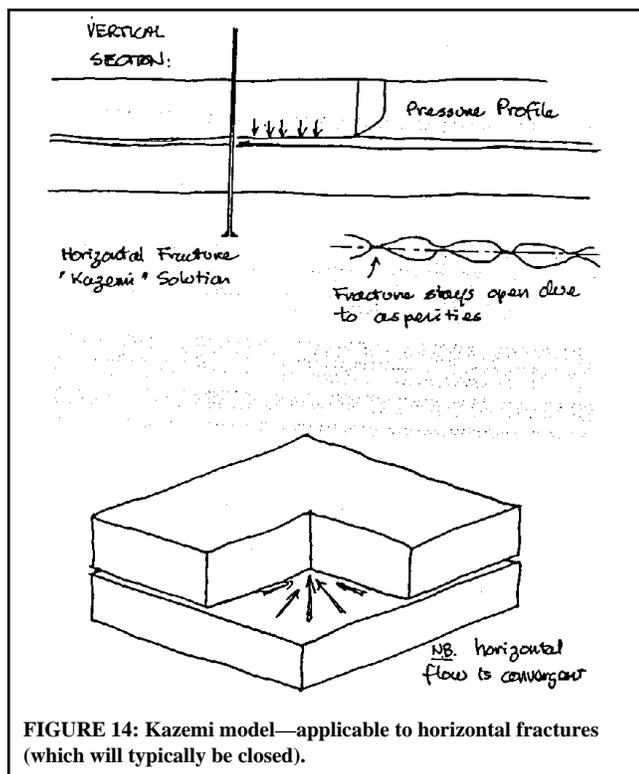


FIGURE 14: Kazemi model—applicable to horizontal fractures (which will typically be closed).

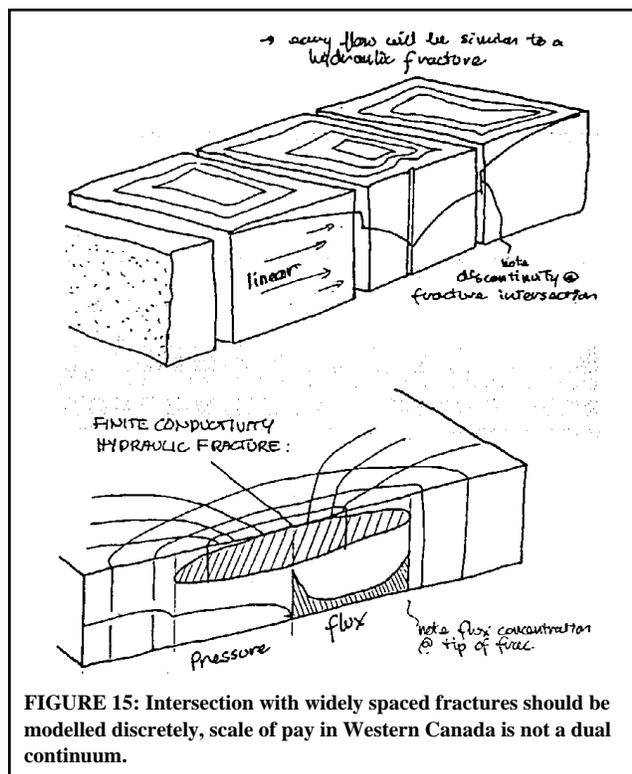


FIGURE 15: Intersection with widely spaced fractures should be modelled discretely, scale of pay in Western Canada is not a dual continuum.

intersections vertically. Most Western Canadian reservoirs have net pays of 30 m or less. Intersections with fractures then become of the same scale as the wellbore and a continuum cannot be assumed.

Figure 11 shows that the chance of hitting a vertical fracture pattern at large spacing is very low. Figures 12 through 15 show what type of local wellbore effects should really occur around wells intersecting large spaced fracture systems.

The dual continuum model (Warren and Root) is not an internally consistent model. The question then remains, how do these reservoirs really behave?

Core Pictures

The best way to get an immediate understanding of the character of a reservoir is to look at the core. Normally it is not possible to take management to view core, so the author has made it a practice to take core pictures. Pictures allow consensus to be quickly reached on the nature of the fracture system.

Most of the fractures observed are on a relatively small scale, approximately hairline in width and appear to have a fairly extensive network. There are normally no signs of large displacements.

Typically, it was found that the fractures were found only in limited vertical sections of the core. Core is rarely uniformly fractured. Based on these observations, a new model was put forth for fractured foothills reservoirs.

Production Logging

On one central Alberta foothills reservoir, a production spinner survey was run. The interpretation of the log coincided with a presentation to working interest partners of the pressure transient analysis. Two models were presented; a composite reservoir and a poddy (reservoir simulated) model.

Based on limited entry from three thin zones identified on the spinner survey, the poddy interpretation was chosen over a concentric permeability model.

Poddy Model

The general idea of this model is shown with a geostatistical realization in Figure 16.

Rocks do not have uniform mechanical properties. In fact they are strongly influenced by original bedding. It is logical that the rock would not crack uniformly, but rather in beds of stiffer rocks (often low porosity). This is of course reminiscent of a geostatistical representation for porosity.

One clarification needs to be made. This is not a purely random process. Therefore it is not possible to use a Monte Carlo technique to generate this type of characterization. It involves a constant standard deviation (either a sill or nugget effect). This approach totally ignores the spatial information. An example of entirely random results are shown in Figure 17.

Reservoir Simulation Of Poddy Model

The Poddy reservoir model is introduced using a dry gas. Output from the simulation was entered into a well test package. The type curve from this simulation is shown in Figure 18. The overall shapes obtained are similar to that expected from a hydraulically fractured well, and are very similar to the expected models described earlier. A number of more detailed examples are outlined in the companion paper.

An example is also shown for a gas condensate system. This reservoir has a very high CVD dropout, on the order of 40%. Figure 19 shows that the condensate drops out at the interface between the high permeability pod and the surrounding lower permeability matrix at 30 days and 730 days.

Note that there is an element of feathering in permeability and porosity at the edges of the pods. A gradual change has been approximated in the model by a ring of intermediate permeability at 1.0 mD at the outer edge of the pod.

In all of the cases examined, the gas properties within the well test package were calculated based on molar average Pcs and Tcs to derive pseudo critical temperatures and pressures. The fluid in this reservoir is near critical and estimates of properties calculated based on standard correlations will have larger than normal errors. Finally, pressure transient solutions are based on single phase assumptions, which are obviously not applicable. The interpretations from the well test package will therefore only be approximate.

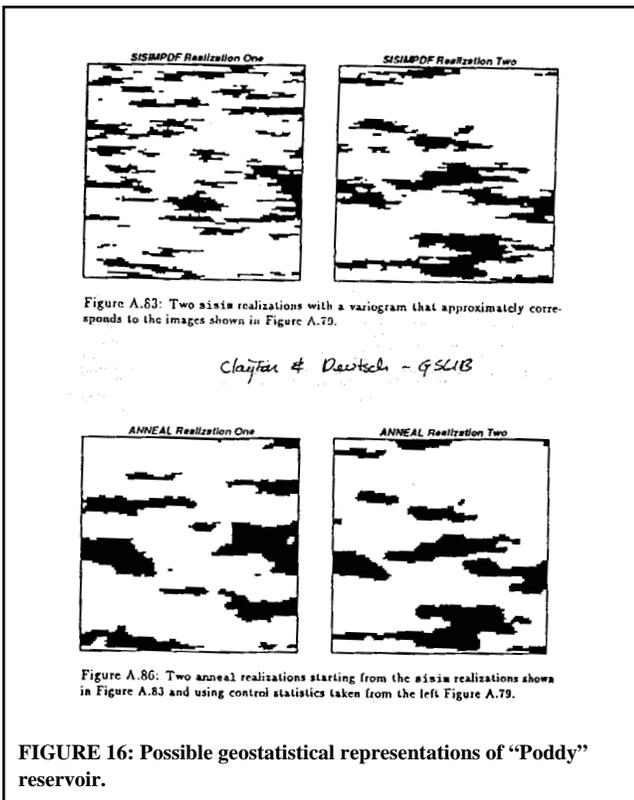


Figure A.83: Two SISIMPDF realizations with a variogram that approximately corresponds to the images shown in Figure A.79.

Figure A.86: Two anneal realizations starting from the SISIM realizations shown in Figure A.83 and using control statistics taken from the left Figure A.79.

FIGURE 16: Possible geostatistical representations of "Poddy" reservoir.

Examining the production profile of these pod representations shows a decline behaviour consistent with that displayed as shown in Figure 20. There is initially a rapid drop off in well productivity as the pod is initially depleted. The rate then declines moderately steeply for about nine to 18 months. Following this there is a long term exponential decline at slow rates of decline.

The GOR on this type of system shows an unexpected behaviour. The outline has a "hump." The GOR increases after the flowing bottom hole pressure drops below the dew point. Eventually it drops to levels slightly above the initial levels.

The condensate is forced out of the gas at the interface of the pod, and deposits mostly in the low permeability surrounding matrix. With less liquid produced, the GOR increases. Over time,

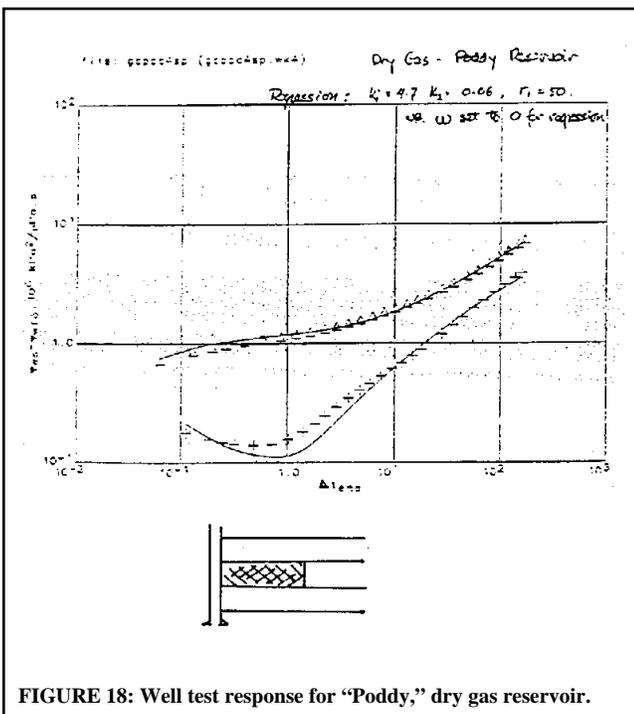


FIGURE 18: Well test response for "Poddy," dry gas reservoir.

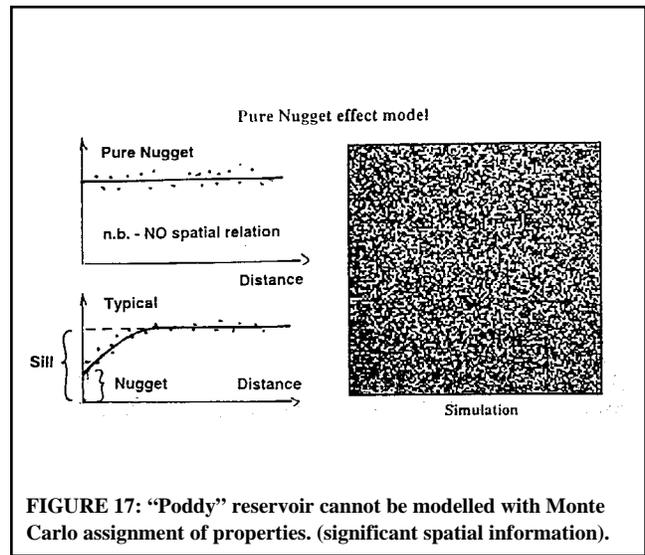


FIGURE 17: "Poddy" reservoir cannot be modelled with Monte Carlo assignment of properties. (significant spatial information).

the liquid saturation in the high permeability pod increases. When the pod fills up to S_{or} , the GOR drops back to near initial levels.

This can be quite misleading and could be interpreted as a bubble point system, if a homogeneous reservoir is (incorrectly) assumed.

Sensitivities were run using gas-oil relative permeability curves and stick curves (gravity segregation or miscible gas-oil relative permeability curves). The results of these runs did not change the trends described above.

Figure 21 shows the pressure transient response with condensate. This curve is virtually indistinguishable from the earlier curves derived for dry gas. Note that homogeneous radial systems do have a notable character on the derivative curve. The pod masks this effect.

The pod moves the relative permeability impairment away from the well. It therefore has less effect on productivity. Most of the condensate drops out is at the interface between the low permeability and the high permeability. The condensate also drops

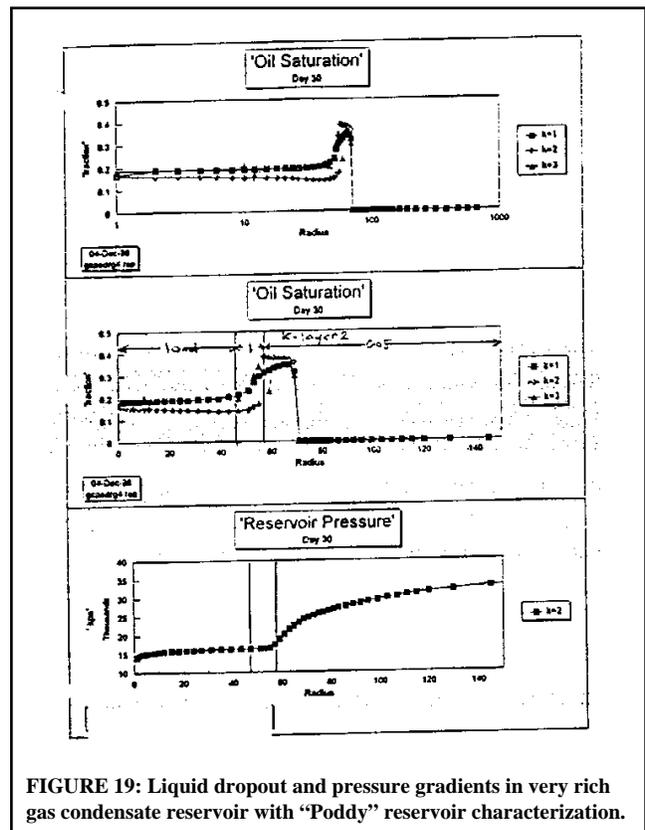


FIGURE 19: Liquid dropout and pressure gradients in very rich gas condensate reservoir with "Poddy" reservoir characterization.

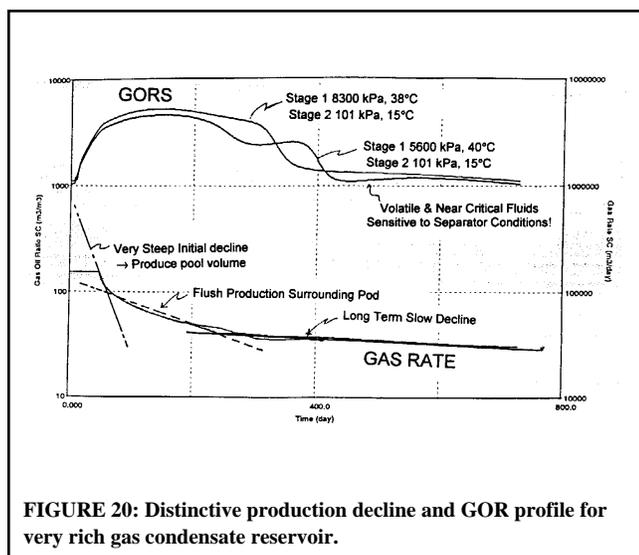


FIGURE 20: Distinctive production decline and GOR profile for very rich gas condensate reservoir.

out inside a much larger rock volume than for a homogeneous radial system. Since the condensate is held up within the tight matrix, condensate gas ratios are reduced. Less condensate will be recovered from the well.

This is an apparent paradox, if one assumes a radial homogeneous system. The condensate is stripped (must be dropping out) yet the productivity is not impaired (by K_{rg} reduction from dropout) to the degree expected.

Note that with lower CVD dropout levels, it is unlikely that the GOR would ever drop. See Carlson and Myer⁽¹⁴⁾ and Yadavelli and Jones⁽¹⁵⁾ regarding hydraulically fractured wells.

Conclusions

1. A systematic approach is important in fractured reservoirs, which are more complex than single porosity reservoirs.
2. Fractured reservoirs in Western Canada show a number of distinctive characteristics, such as core permeability vs. core porosity and pressure transient response.
3. To date, the author has not found reservoirs in Western Canada that behave anything like Warren and Root "sugar cube" models. (There have been some fault boundaries).
4. Reservoir conditions required to get Warren and Root type behaviour are extremely restrictive, to the point where such behaviour should be extremely rare.
5. The use of a dual continuum approach causes serious inconsistencies for scales typical of Western Canadian reservoirs.
6. A "poddy" type reservoir model is put forth. Such a model could also be described geostatistically.
7. This model is consistent with pressure tests analysed and empirical observations.
8. The poddy model has interesting implications for gas condensate systems. Condensate is trapped in the formation where formation permeability changes. The author believes that this reservoir characterization will help explain the behaviour of some foothills reservoirs, such as Waterton.
9. This type of reservoir description should be expanded to a 3D geostatistical representation.

Acknowledgements

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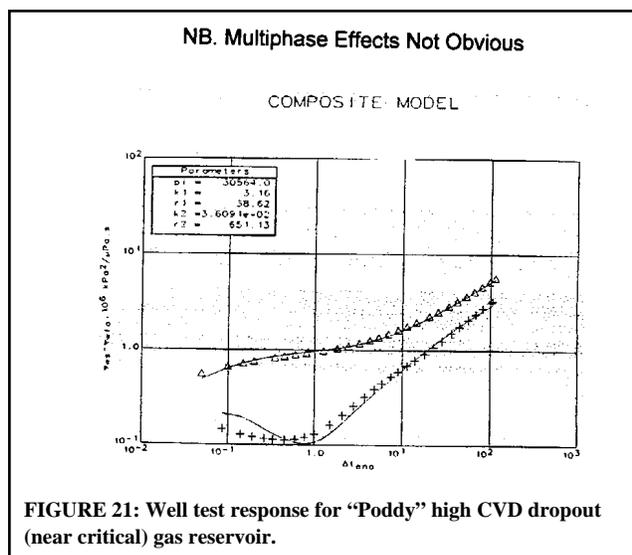


FIGURE 21: Well test response for "Poddy" high CVD dropout (near critical) gas reservoir.

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Author's Biography



Mike Carlson is president of Applied Reservoir Engineering Ltd. which provides independent engineering services in training, economic evaluations, reservoir engineering and numerical simulation. Prior to this, he worked for Gulf Canada Resources Ltd. as team leader-reserves management, and was vice president-technical services for McDaniel & Associates Consultants Ltd. Mr. Carlson founded Applied Reservoir Engineering & Evaluation Ltd in

1990. He held various technical and supervisory positions for Scientific Software-Intercomp, Home Oil Company Limited and Amoco Canada Petroleum Ltd. His experience covers operations, new well completions, drilling, exploitation, reservoir engineering, corporate evaluation, securities reporting, property evaluation, log analysis, reservoir simulation and instruction of industry courses; both internationally and domestically. Mike graduated from the University of Toronto with a degree in geological engineering in 1979. He is currently serving his second term on the National Board of the Petroleum Society and is co-chairman for the 1999 Annual Technical Conference. He is a past technical program chairman for the Petroleum Society 45th Annual Technical Meeting and also served on a publicity committee (newsletter advertising) for two years. He has written ten technical papers and has been invited to make many industry presentations. Mike was recently a *Journal of Canadian Petroleum Technology* distinguished author. He has appeared as an expert witness in Alberta Court of Queen's Bench. He is a member of the Petroleum Society, CWLS, CSPG, SPE, and APEGGA.