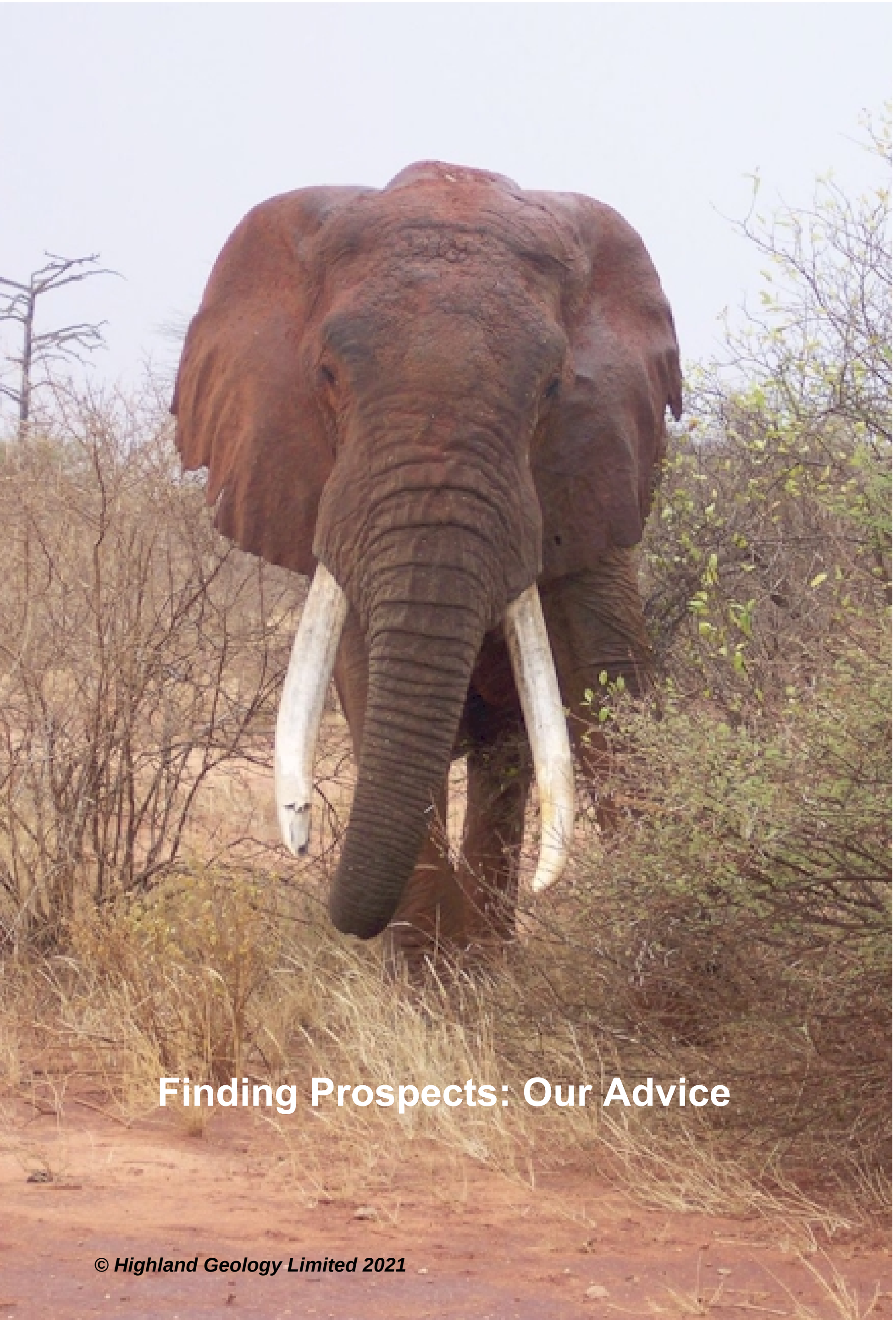


Size and risk in prospect evaluation

Here we look at volumetrics issues and assessment of technical risk in prospect evaluation. The aim of this summary is to provide a useful quicklook basis for fast-track play assessment.

As an opening comment, we've met numerous people in exploration who seem more comfortable with smaller prospects than larger ones. This note tries to encourage the mindset that we can find big fields. Take each opportunity on its merits, look for the upside.

There are elephants out there, they do turn up!

Large discoveries tend to be made early in a particular play's history: and that means explorers who win are those who react quickly and positively to opportunity in areas with limited data. Yes, discovery sizes do tend to be lognormally distributed, when a play has been tested by many wells. This led Quirk and Ruthrauff (2006) in J. Pet. Geol. 29(2) to suggest that P50 reserves are likely to lie within the range 7-35 MMbbl, or 15–150 bcf, and that explorers have only a 20-25 percent chance of finding reserves larger than the average.

Well.....be one of the more successful players, buck the trend!

Prospect Description and Risking: Finding the Winners.

Here, we offer some advice on assessment of exploration play upside potential.

- •How do you make realistic oil and gas expectation curves for prospects?
- •How do you assess prospect risk in a meaningful way?
- •How do you know whether what you do in these calculations and assessments, actually is realistic?

Obviously, its very helpful if volumetrics and risk factors (chance factors) proposed for exploration plays are consistently calculated, and that oil and gas in-place volumetric estimates are sensible and realistic. These are judgements which form the basis of informed exploration policy. Systematically describing prospects helps you, the play originator, to fully understand prospectivity and to present your proposals to other people as complete and attractive concepts.

Valuations for share issues, development projects, etc require probabilistic estimation for key assets. These tend to be done by independant specialist teams in consulting companies, using in-house software. They will be conservative.

For decision making purposes all of the large and medium-sized operators run software to regulate and standardise prospect evaluation procedures, and to compute expected monetary valuation, rate of return etc calculations. These tend to be formulaic. When you look at these calculations and reports you will commonly see opportunity which is poorly recognised.

Many small companies don't try to rank plays in this way. They may not have enough plays to pick and choose from; they may be obligated to drill their top plays; they may take the view that farminees will do their own figuring. This makes them prone to poor analytical evaluation of their own best assets.

Content:

1. We are going to start with a look at risking method, how to calculate a realistic chance factor for prospects.
2. Then we will review method in the calculation of oil and gas in-place expectation curves, and introduce a quicklook technique and spreadsheet.
3. We'll discuss how the input parameters can be estimated.
4. Some generalisations about exploration prospect presentation conclude the review.

What should prospect evaluation deliver?

When you ask the right questions the method used has to flag the best opportunities clearly.

What we are after, is identification of the one-in-twenty really prospective plays with large potential reserves which will come past you as acquisition candidates; and to highgrade promising new plays which you map in your present acreage.

- and, an optimum approach to presenting and promoting your exploration prospect portfolio.

If the in-house system is only good for describing prospects of the type you know about, its just a catalogue and you will end up drilling smaller and smaller targets of the same kind, and reduce your options to grow the company organically.

Even with companies which go to great lengths to run economics on prospects and field assets, the basic input for risking and volumetrics of particular prospects can often be shown by a few minutes' inspection to be unreasonable or incomplete. One reason for this may be that bought-in software is "black box" and gives inconsistent input more legitimacy than it deserves.

If you feel insecure about how to establish sensible parameters for in-place oil and gas calculations, you are not alone! In the literature there aren't firm rules or standard methods clearly proposed, and basic work flows and clear advice on prospect evaluation input are few and far between.

"Software should be used with extreme caution"

This is a comment by Demirmen, F., 2007, in "Reserves estimation: the challenge for the Industry". J Pet Technology, 80-89. We bet the splash screen of your prospect evaluation package doesn't say this, when you load it!

Subjective thinking (intuition) plays a large part in recognising new traps. There's a lot of scope for disagreement in evaluating plays. Its critically important that the person who maps the prospect is the person who calculates the hydrocarbons-in-place, and the risk. Third parties involved in documentation will make unwarranted assumptions which downgrade plays. The greatly over-rated "peer review" process makes this clear, when highly experienced explorationists get together to exercise their prejudices over the same prospect.

Our observations of the past years:

- **The best prospects stand out, irrespective of statistical methods.**

- **Prospect evaluation sessions high-grade similar plays to the ones the company knows best, whilst unfamiliar new-play concepts are downgraded. Chance factors computed for unfamiliar plays are typically too low.**

- **It is very common that companies under-estimate the potential volumes of oil and gas in undrilled targets.**

Invalid risking of frontier plays commonly leads to insecure acquisition and farm-out policy, and of course to the discarding of valid prospects.

Chance Factor

CF, also called Pg meaning probability of geological success, is the chance that some movable oil or gas is present in the target closure.

The following four charts suggest a reasonable method for estimating the probability of a trapping closure, a caprock, viable reservoir, and the chance of migration of oil and/or gas into the target structure. The product of the four probabilities is the chance factor.

The question is, will there be a cup full of oil in the closure: not whether its commercial or not. This is not the chance of commercial success. For that, you need to know the minimum size of reserves needed for a development plan which meets corporate objectives, and find the probability of exceeding at least that amount of oil (what percentage of the distribution is bigger than that critical value?), then multiply by CF to risk the outcome.

CF does directly give the cost of failure: 1 minus the CF, multiplied by the dry hole cost of the well, is the probability-weighted amount of cash being risked on the well. You could add other special costs which aren't bookable assets if the well fails.

There is no reference to volumes of oil and gas which might exist, in the four charts. Other schemes (for example Rose in AAPG's 2001 Methods in Exploration Series 12 volume, which is widely used), do incorporate volume concepts in CF. We think that raises the likelihood of a misleading assessment.

Its clear from looking at the charts that opinion plays a major part in how the definitions are framed, and that there is significant dependence between some of the components. What's important, is whether you know what the definitions mean: have they been calibrated against a sizable database. If the answer is yes, you can forgive some illogicality in what is a very subjective exercise. If no, then you really don't have the basis of a reliable expected-value calculation.

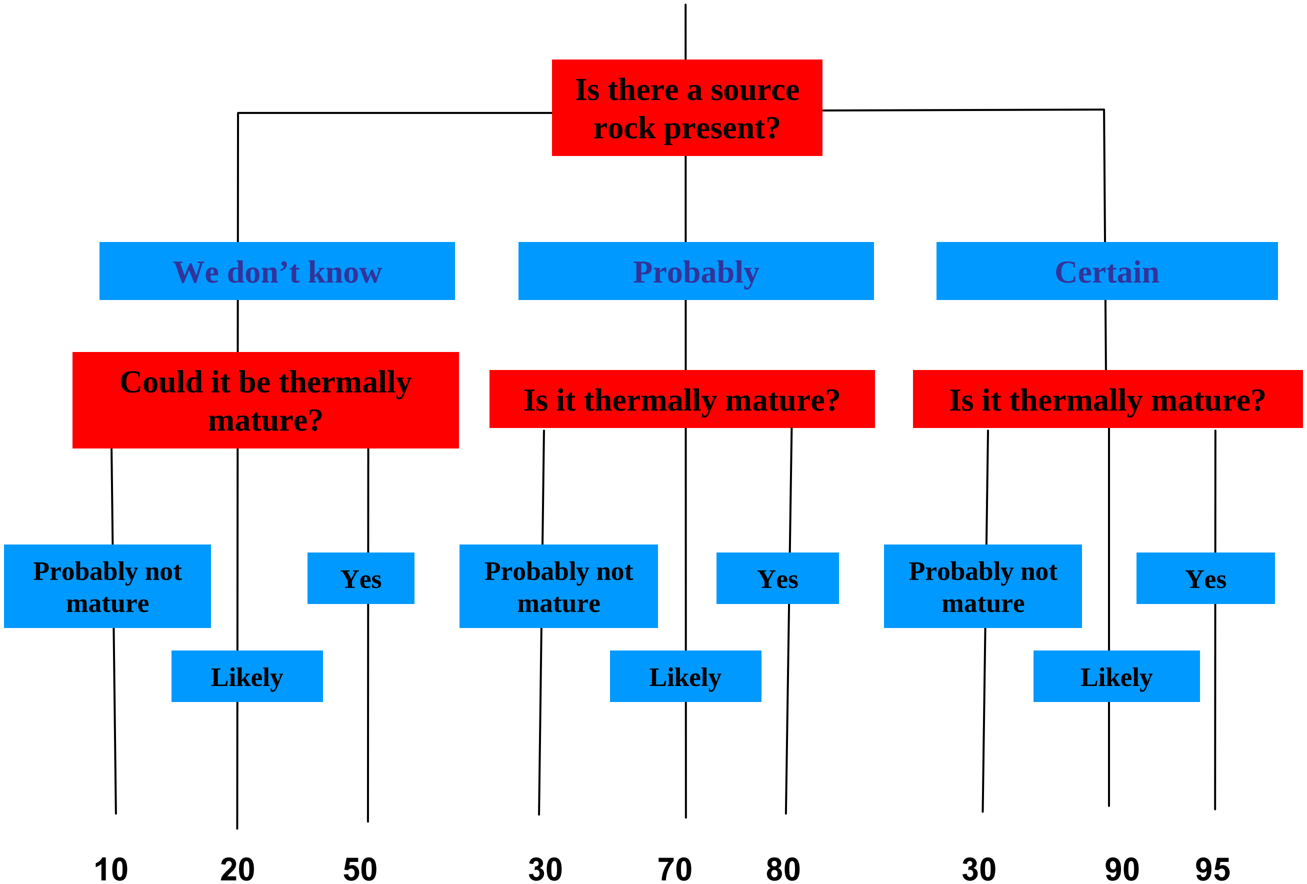
What does CF tell us?

The following four slides show a simple scheme for assessing probability of viable source, reservoir, caprock and trap. Multiply these four values, that's the Chance Factor.

We recommend the 4-estimator method, we think its a powerful estimator of risk in wildcats, it really works.

This weighting scheme is based on the old Britoil method which was developed in the mid 1980s. Britoil at that time had a first-class data set for North Sea exploration, and was an early user of rigorous prospect evaluation method. We ran a group which was tasked with applying the post-drilling knowledge of some 100 wells, to calibrate the initial chance factor evaluation system, and we made a credible statistical study to do this and retrospectively find out how good the method was. It turned out that CF has a very convincing predictor capability, nearly always recognising which wells would be successful and which would be rank failures, and the study resulted in revised weightings. The figures suggested in the charts are a bit different from the originals, they are based on further perspective and experience with the system.

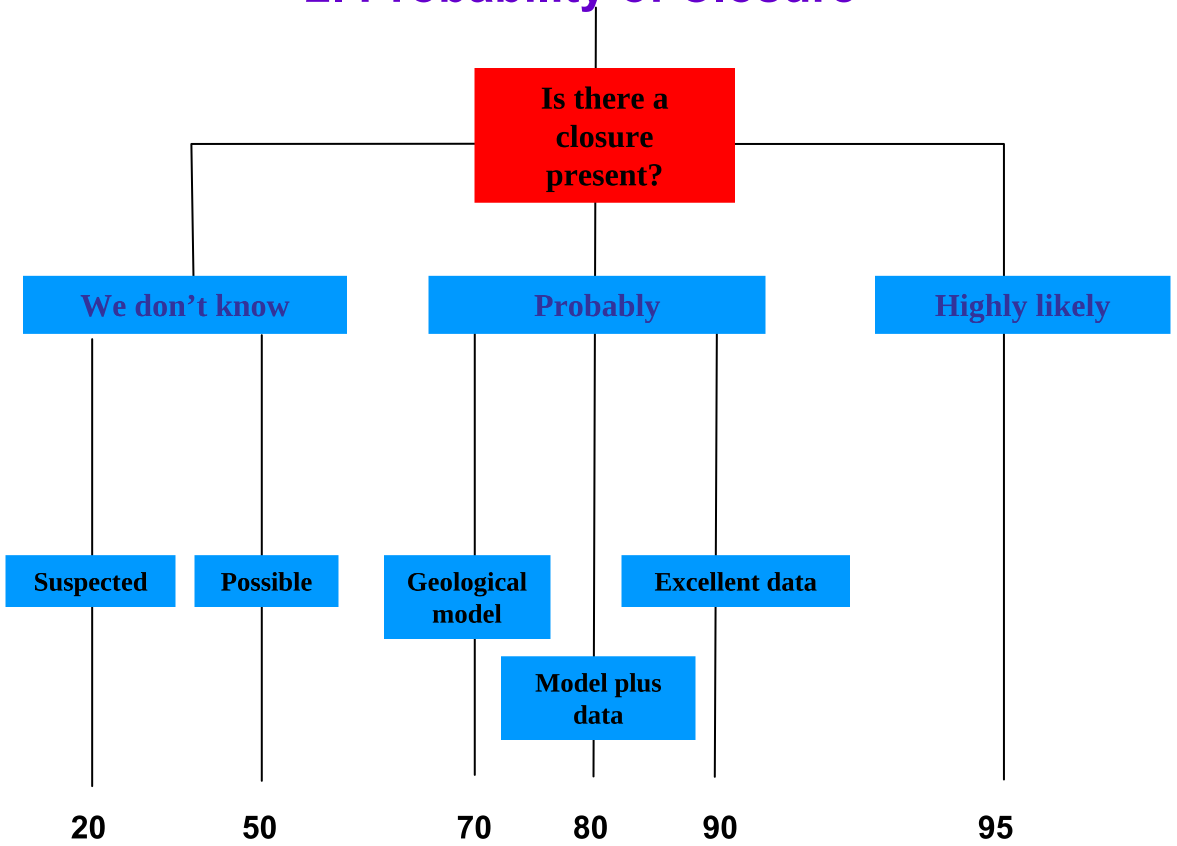
1. Mature Source Probability



Probability of mature source rocks generating oil and/or gas in adjoining areas, having significant volume and organic richness, and expelling some quantity of hydrocarbons which can access the target trap.

We think that a separate decision tree for assessing migration probability, is double-risking. If we assign a probability to whether a trap leaks (exists), we shouldn't separately risk whether oil and gas can get into it! Likewise, asking questions about the timing of migration with respect to trap development, is a matter tested in assessing the trap probability.

2. Probability of Closure

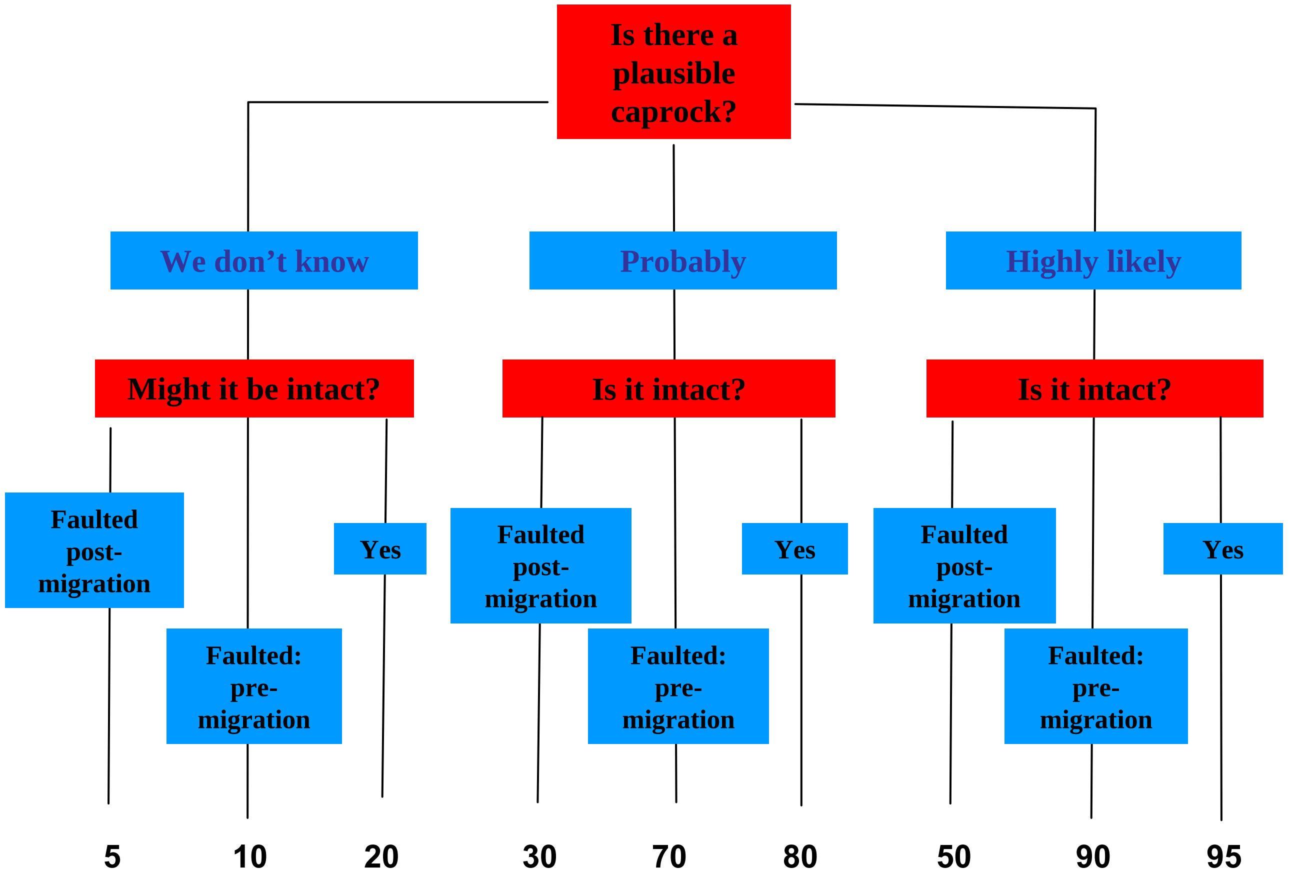


Probability of target closure. There is no judgement being made about the potential size of the trap. Because this question tests stratigraphic traps as well as structural closures, its a very general tree. You might decide to score an amplitude anomaly as highly as a 3D-defined structure.

Sidewall-sealing by faults if required, is included in the trap question. Arguably a caprock is part of the trap too, but we risk that separately. We're not sure how logical that is! Other schemes do the same, if that's a justification.

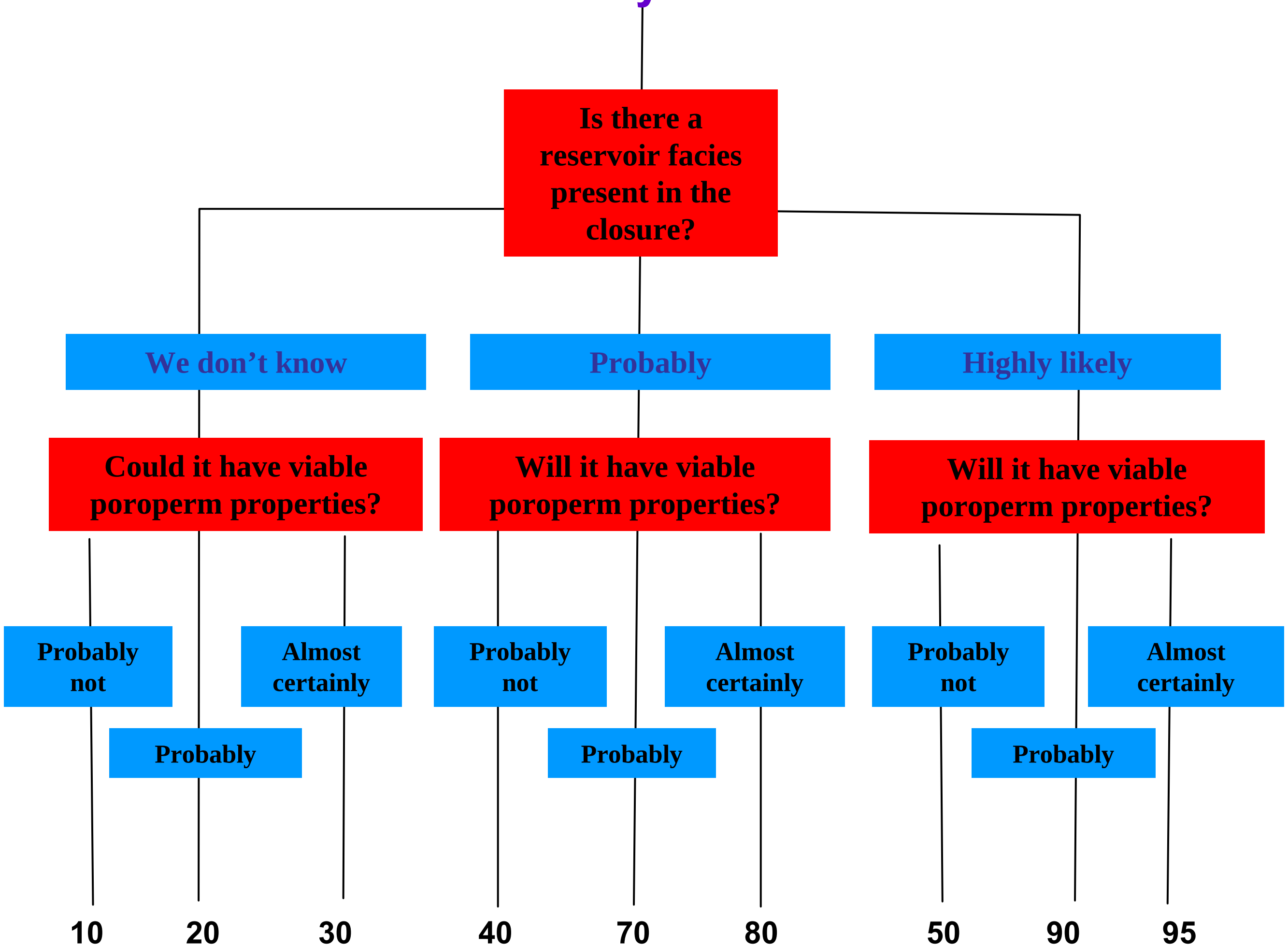
Timing issues, was the trap in place before migration, are implicit in this decision tree. If migration is judged to have ceased before the trap formed, give a poor rating under source rock assessment.

3. Probability of Caprock



Probability of valid cap rock for structure. Sometimes the cap rock is actually the side seal too, if its downfaulted, but that case is arbitrarily treated under Trap potential. Subseismic fracturing is of course hard to assess.

4. Probability of Reservoir



Probability of reservoir at target level, of unspecified extent, capable of flowing oil or gas. It doesn't need to be a commercial flow rate, if its a tight rock unit it can be fracced.

Do we believe the Chance Factor?

We should do, because it encapsulates a great deal of information about the play. It should be more reliable as a statement about the prospect, than the volumetrics we derive. There are lots of ways in which the volumetrics calculation can go wrong, but the CF has key factors built into the number. <u>If there is a fundamental weakness in the prospect, CF will show it.</u>

Probabilities for some movable hydrocarbon should be around 0.7- 0.8 if we are exploring a familiar play type in a mature province.

CF of 0.4- 0.6 is a statement that appreciable uncertainty exists, bearing in mind that we are only asking for a cup full of oil or gas in the target closure.

If a prospect doesn't score better than 0.4, its a high-risk play. Odds are you are going to get a dry hole.

Anything less than 0.2 CF with the 4- factor assessment can be regarded as a very long shot, you'd need a very large potential EMV, to invest. If you like the prospect, get some more data.

Commonly companies use 5-factor methods, which with the extra multiplier may produce Pg around 0.2- 0.3 If a calibration has been done so that you know what the 5-factor risking actually means (in the same way as we did for the 4-factor method, i.e. there are say 50-100 wells drilled which were risked by your team prior to spudding and the results have been used to demonstrate what the weightings in the risk system really indicate), then we suppose there's no harm in using low chance factors in-house to rank plays. But they don't help, psychologically, when you go into a technical committee meeting with third parties and explain that the prospect has only a 20 percent chance of some movable oil. Would you put your own cash into a prospect where the proposer states the chance of movable oil is only 10-15 percent? Us, no.

Sensible Volumetrics

Different teams look at exploration opportunity in very different ways, as you'll know if you have presented your hot prospects to people from other organisations. This is good: its one of the key reasons why large finds are still being made in mature basins. You will see things that other people don't.

What follows is one person's subjective approach to prospect description issues. It isn't a course in statistics and doesn't go into a lot of the areas which decision analysis courses dwell on.

Different types of prospects present different challenges in estimating potential reservoir volumes. In multiplying together the gross rock volume, the net/gross factor, the porosity, etc, to get a range for oil and gas potentially in-place, its vitally important to estimate ranges for each parameter which really do capture the uncertainty in each parameter. And its important to record how you did it, in a systematic way, so that subsequent review by you and other people will maximise the value of new information. Perception of the "rules" for oil trapping in a basin changes with time, and a database of prospect evaluations is really valuable when new insight for explorationists appears, as periodically it does.

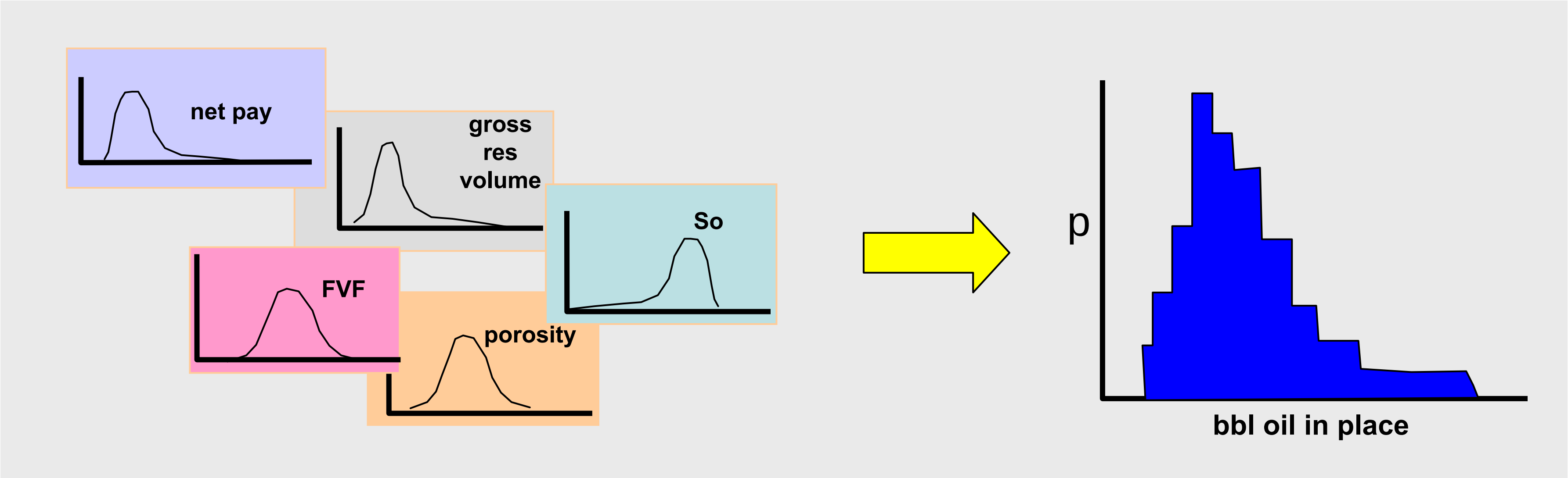
Experts are not good at estimating ranges. Gross cost over-runs in engineering projects of all kinds, attest to this.

For us, the best reference to read on this topic is still Paul Newendorp's "Decision Analysis for Petroleum Exploration" book, which dates back to 1975. The author didn't dress up opinions as fact. Since Newendorp the approach has proliferated and become more complicated, whilst some of the basic "how-to" issues remain poorly defined. In re-visiting this topic in 2021 we found that the decisions we feel are most insecure in the exercise, are the same ones which were challenging 40-odd years ago.

Building sensible Expectation curves

The Industry-general way to develop expectation curves for hydrocarbons in oil and gas prospects is based on the Monte Carlo simulation approach, to randomly sample each of the input parameters and calculate the product of the values, store that number, do this a few thousand times and the result will be a stable probability distribution. The p50 value is commonly taken to express the average answer, assuming that all the input values were indeed possible ones. The 10 percent chance of having equal to or more than that value is p10. P10 and p90 show the spread of uncertainty, p50 is a favourite key value used for economics.

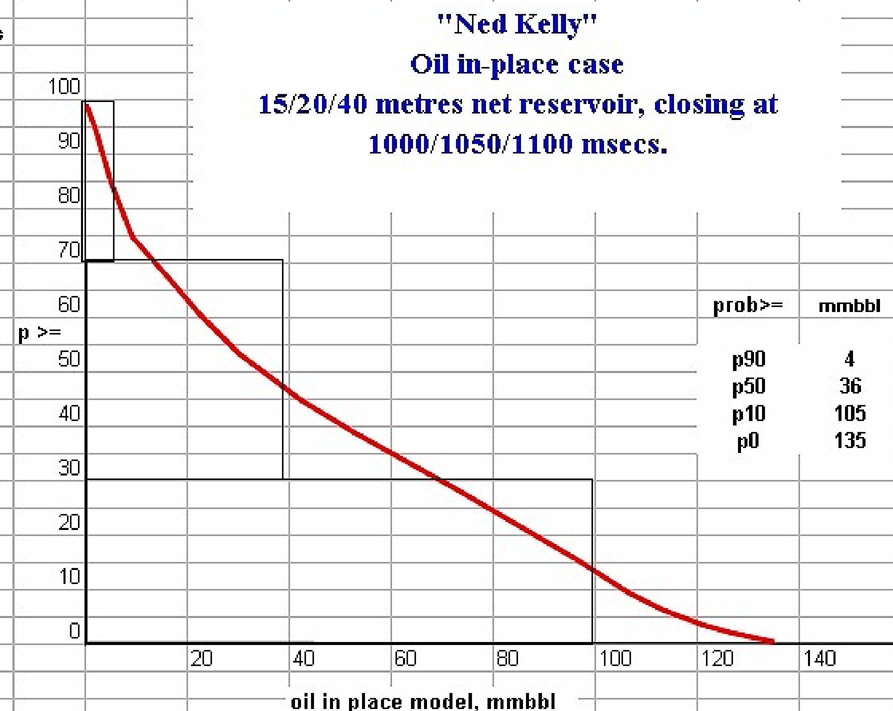
There is partial dependence between the input variables, and more sophisticated methods invite you to specify what form that dependence takes.



If you want to determine reserves and bid criteria you can input as many variables as you like, including recovery factor ranges, tax, operating costs, price of oil, etc. These programs are available off the shelf and your Company very probably has one. Its still useful to run a quicklook spreadsheet.

Alternative to Simulation: a quicklook spreadsheet

Gross reservoir volume (million cubic metres) and probabilities		
GRV low-case	8	0.30
GRV mid-case	50	0.40
GRV high-case	129	0.30
Porosity data (range zero to unity) and probabilities		
Phi low-case	0.13	0.33
Phi mid-case	0.15	0.34
Phi high-case	0.17	0.33
Net/gross ratio (range zero to unity) and probabilities		
Net low-case	1.00	0.30
Net mid-case	1.00	0.40
Net high-case	1.00	0.30
Hydrocarbon saturation (range zero to unity) and probabilities		
Shr low-case	0.60	0.30
Shr mid-case	0.70	0.40
Shr high-case	0.75	0.30
FVF, and probabilities		
FVF low-case	1.10	0.33
FVF mid-case	1.20	0.34
FVF high-case	1.30	0.33



prob>=	mmbbl
p90	4
p50	36
p10	105
p0	135

Chance factor is 0.55, components being: trap, 0.8; reservoir, 0.9; caprock, 0.8 and generation/migration, 0.95

Monte Carlo is the heavyweight method. Here's an Excel expectation curve calculator we wrote as a Visual Basic program, all it does is cross-multiply the input parameters for oil or gas in-place, carrying forward and re-setting the output by size for each stage.

The code is not offered by us as a download, because systems admin people don't like executables from unknown sources, and which are not secure against hacks. Its straightforward to create a macro for this: it gets its data from the green cell locations and it outputs estimates and associated probabilities for user to sketch the expectation curve, using Excel's draw tools.

We'll now discuss the mechanics and data generation for this technique, and much of the commentary is general to more sophisticated methods.

Spreadsheet method

For this quick approximation the arithmetic is easy, its a successive sampling and multiplication of the variables and their corresponding probabilities. It allows rapid and intuitive analysis of input, so you can see the sensitivity to altering key variables. Its coded in Visual Basic.

Basic method: take any pair of parameters, for example porosity and net/gross, represent each by three samples and cross-multiply them to give a matrix of nine results. Write down the corresponding probabilities (greater-than-or-equal) and cross-multiply those as well. Then find the averages of the smallest-three, mid-value three, largest-three product numbers, and normalise them using their probabilities.

Porosity

n/g	0.10	0.15	0.20
0.5	0.05	0.075	0.10
0.7	0.07	0.105	0.14
0.9	0.09	0.135	0.18

Pporosity

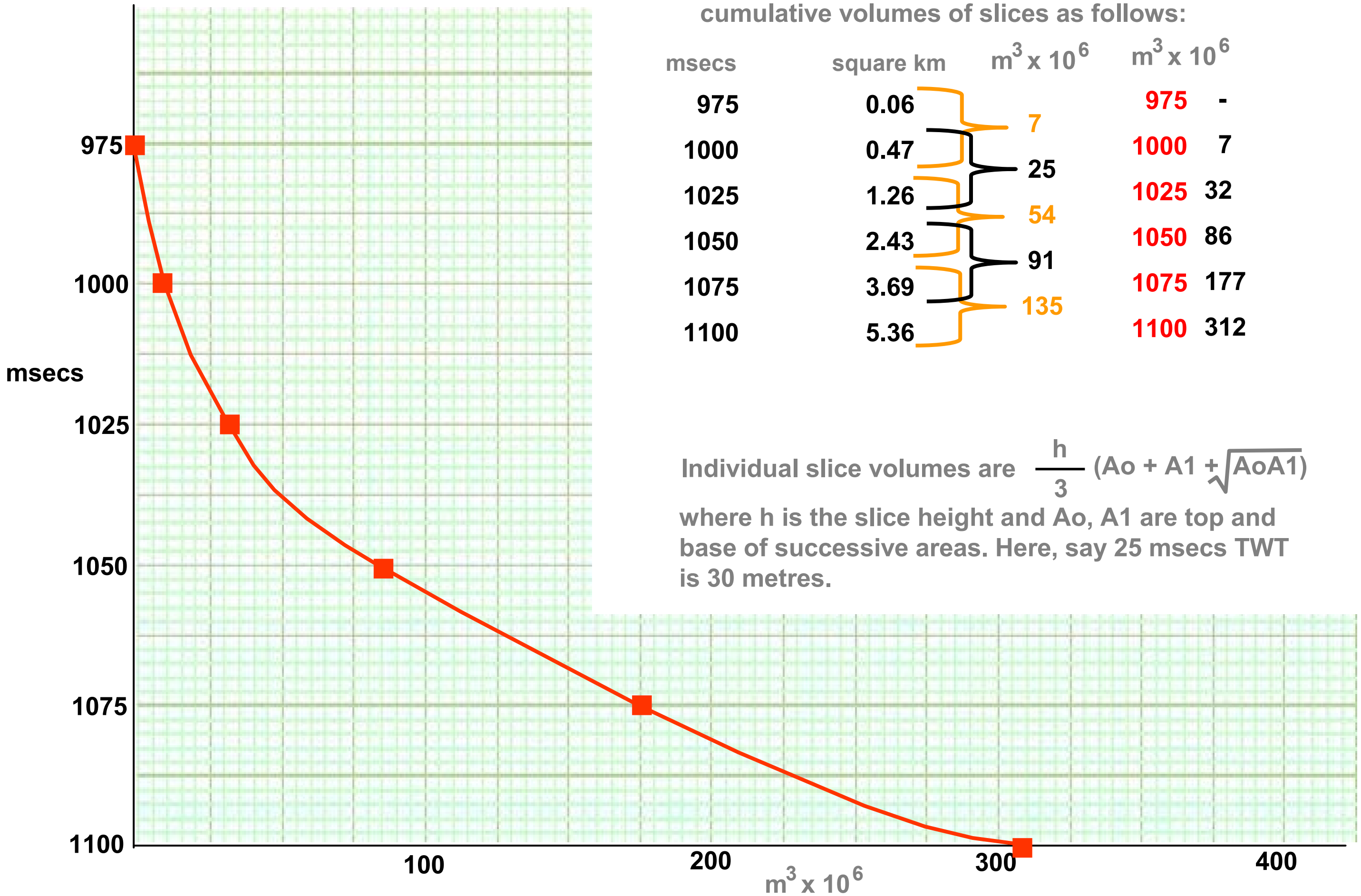
Pn/g	0.3	0.3	0.4
0.2	0.06	0.06	0.08
0.6	0.18	0.18	0.24
0.2	0.06	0.06	0.08

Do the same gathering exercise for mid-three and max-three descriptors.

For the minimum 3 products (red gather) the weighted average is

$$\frac{(0.05)(0.06)+(0.07)(0.18)+(0.075)(0.06)}{(0.06+0.18+0.06)} = 0.067, \text{ with probability } 0.3$$

Getting input data: (1) Gross rock volumes in closure



Suppose we measure successive closure areas and cumulative volumes of slices as follows:

msecs	square km	$m^3 \times 10^6$
975	0.06	
		7
1000	0.47	
		25
1025	1.26	
		54
1050	2.43	
		91
1075	3.69	
		135
1100	5.36	

	$m^3 \times 10^6$
975	-
1000	7
1025	32
1050	86
1075	177
1100	312

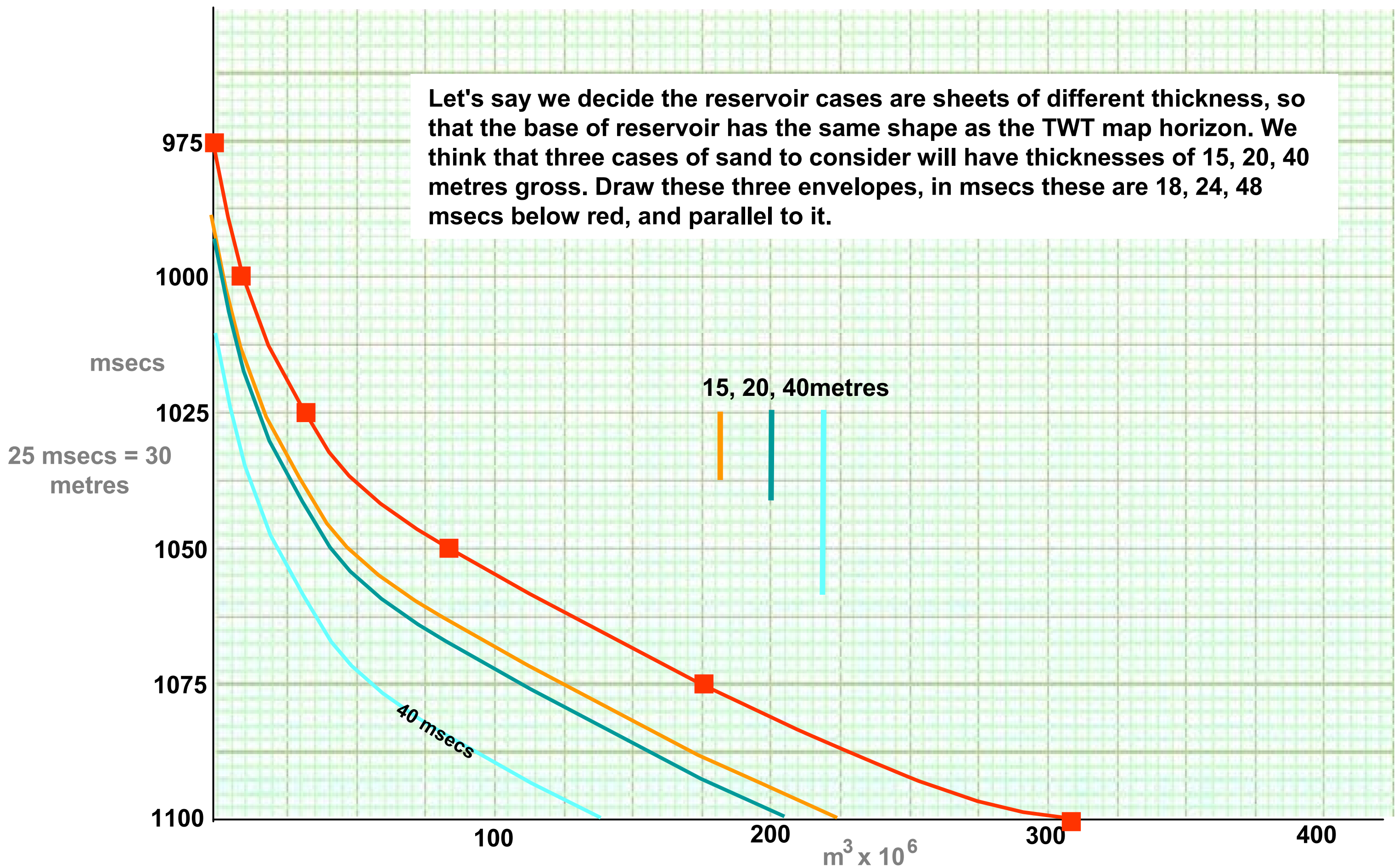
Individual slice volumes are $\frac{h}{3}(Ao + A1 + \sqrt{AoA1})$

where h is the slice height and Ao, A1 are top and base of successive areas. Here, say 25 msecs TWT is 30 metres.

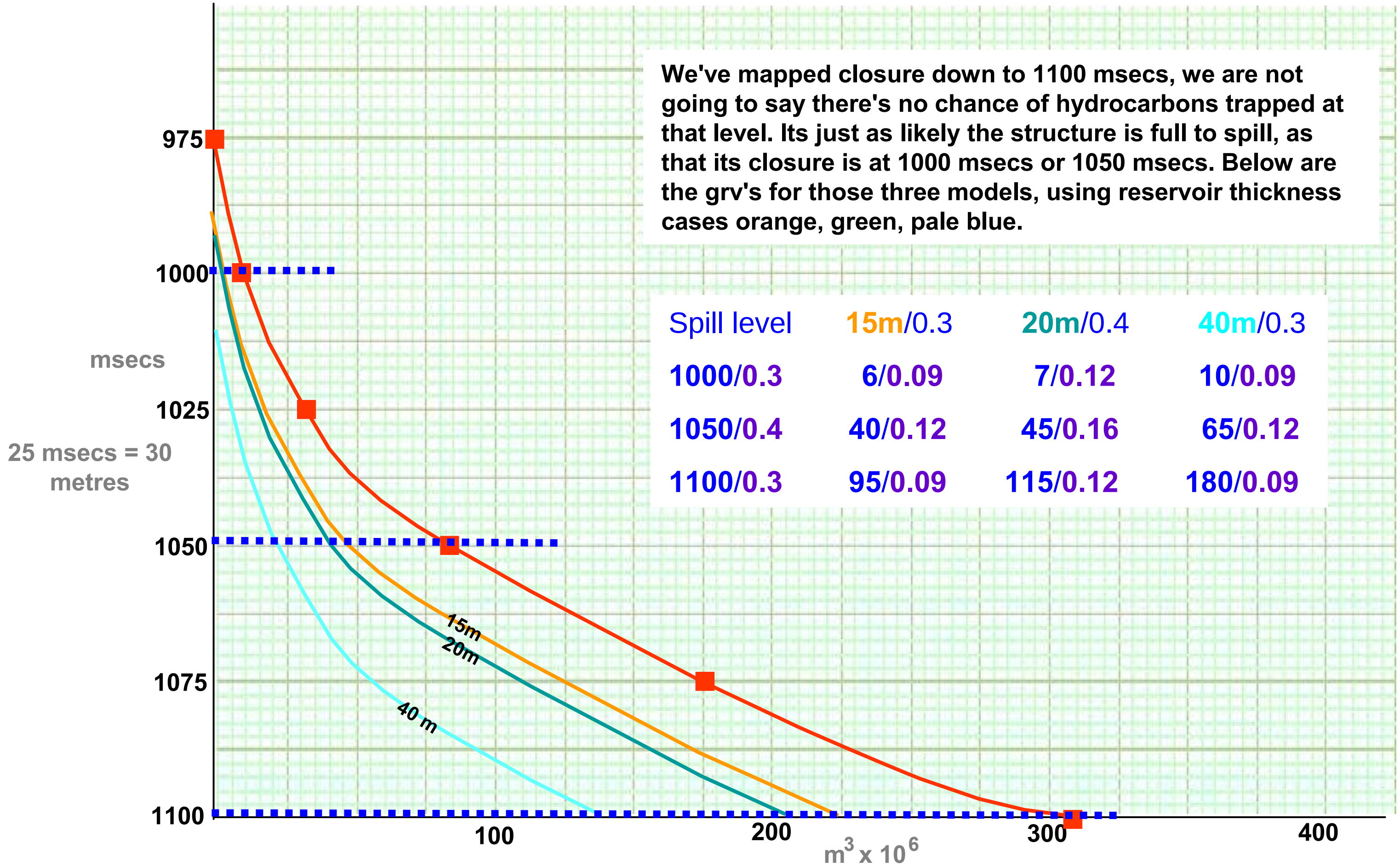
For a prospect this is a plot of its cumulative rock volume curve with increasing depth (actually, based on two-way time where we know 25 msecs is equivalent to 30 metres), the slice volumes between consecutive closing contour areas are calculated down to maximum potential spill.

You might of course have a depth map to work with. If somebody else has done the depth conversion, as its controlling the biggest number in your calculation its a good idea to check it out!

Gross rock volumes in closure, and getting from this to gross reservoir volumes in closure ...2



Gross reservoir volumes in closure



We've mapped closure down to 1100 msecs, we are not going to say there's no chance of hydrocarbons trapped at that level. Its just as likely the structure is full to spill, as that its closure is at 1000 msecs or 1050 msecs. Below are the grv's for those three models, using reservoir thickness cases orange, green, pale blue.

Spill level	15m/0.3	20m/0.4	40m/0.3
1000/0.3	**6/0.09**	**7/0.12**	**10/0.09**
1050/0.4	**40/0.12**	**45/0.16**	**65/0.12**
1100/0.3	**95/0.09**	**115/0.12**	**180/0.09**

We could regard these figures as gross reservoir cases and treat net pay separately as another distribution. Or, we could say the 15/20/40 metres are my net cases. And that's what we did here, what we've calculated is a model for net reservoir variation directly off the grv curve. That's why the three n/g cell values in the spreadsheet shown earlier, are 1.

Next step is to decide what the probabilities for the closure cases are. GRV is the biggest number in the calculation, and the probability weighting we give to the models which are chosen will in effect control the outcome of the in-place distribution. Its the most difficult question in the exercise, how good our answers are depends on what we know about trap types and how they really work, in the basin.

Degree of Fill

Modelling partial fill is one of the ways in which pessimistic volumetrics arise.

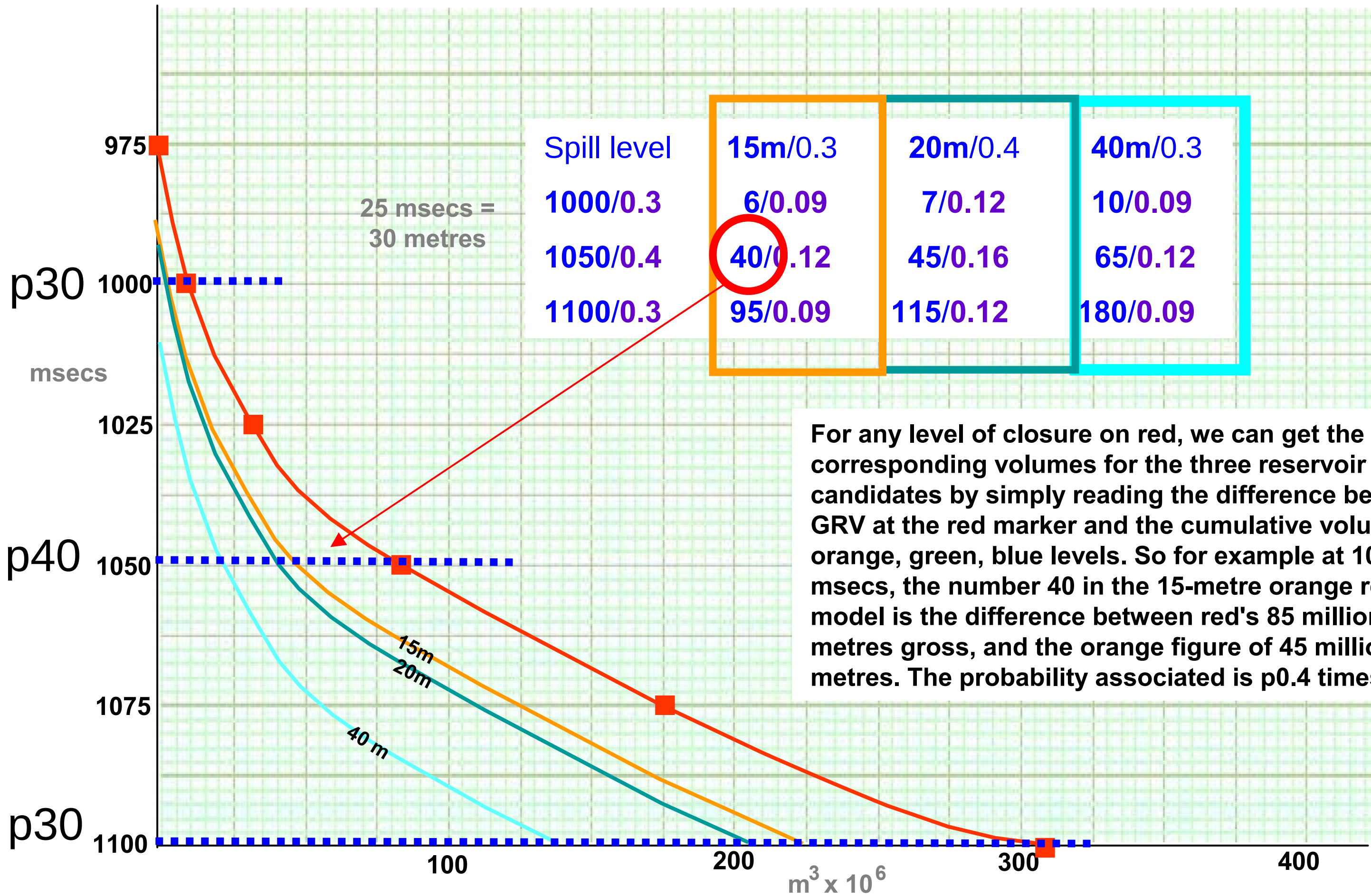
If you have a structure mapped down to some closure level, and a mature effective source rock, why assume it may not be full to spill? Overall, structures do tend to fill to spill point. In the North Sea Southern Gas Basin for example, valid traps are expected to be filled with gas. Local experience is a key factor: look at structures which do trap oil and gas, try to understand how they work. If they are full to spill, assume prospects are too.

Bear in mind that the uncertainty in mapping makes the fill question quite a difficult one to address. And in tight reservoirs there won't be a hydrocarbon-water contact, instead there will be a long transition zone, so its an arbitrary assessment.

Its been suggested by a number of authors that where we see gas caps on an oil leg, the gas-oil contact may mark a gas leakage point, the trap can't sustain a higher gas column and so the process of gas filling does not expel all the earlier oil.

Thick caprocks above a reservoir are a plus factor for assuming trap fill is complete. Recent studies on fraccing and frac persistence suggest that fractures don't propagate upwards in shales by more than a hundred or so metres.

Gross reservoir volumes in closure ...2

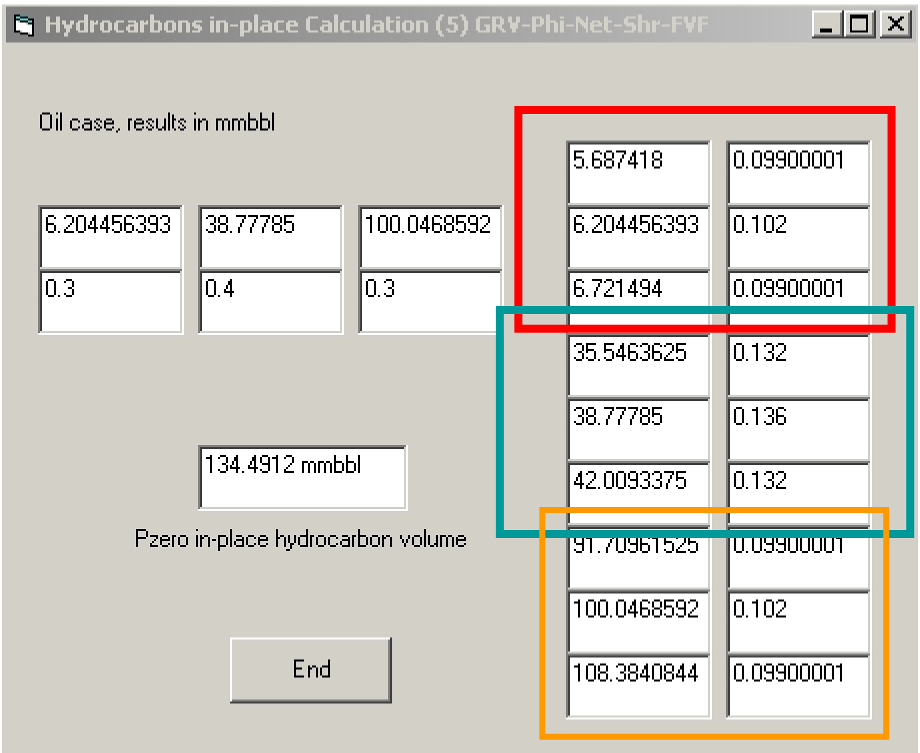


Spill level	15m/0.3	20m/0.4	40m/0.3
1000/0.3	6/0.09	7/0.12	10/0.09
1050/0.4	40/0.12	45/0.16	65/0.12
1100/0.3	95/0.09	115/0.12	180/0.09

For any level of closure on red, we can get the corresponding volumes for the three reservoir candidates by simply reading the difference between GRV at the red marker and the cumulative volumes at orange, green, blue levels. So for example at 1050 msecs, the number 40 in the 15-metre orange reservoir model is the difference between red's 85 million cubic metres gross, and the orange figure of 45 million cubic metres. The probability associated is p0.4 times p0.3.

This condenses to a sample set with GRV = 8 million cubic metres with p0.30; 50 million cubic metres with p0.4; and 129 million cubic metres with p0.3. This is the input for the spreadsheet shown above, for "Ned Kelly", a big range reflecting big uncertainty. Seems reasonable: but what is really happening if we do this? We'll see, in the next slide.

Revisiting reservoir volume probabilities



The spreadsheet results are listed here, for drawing the curve.

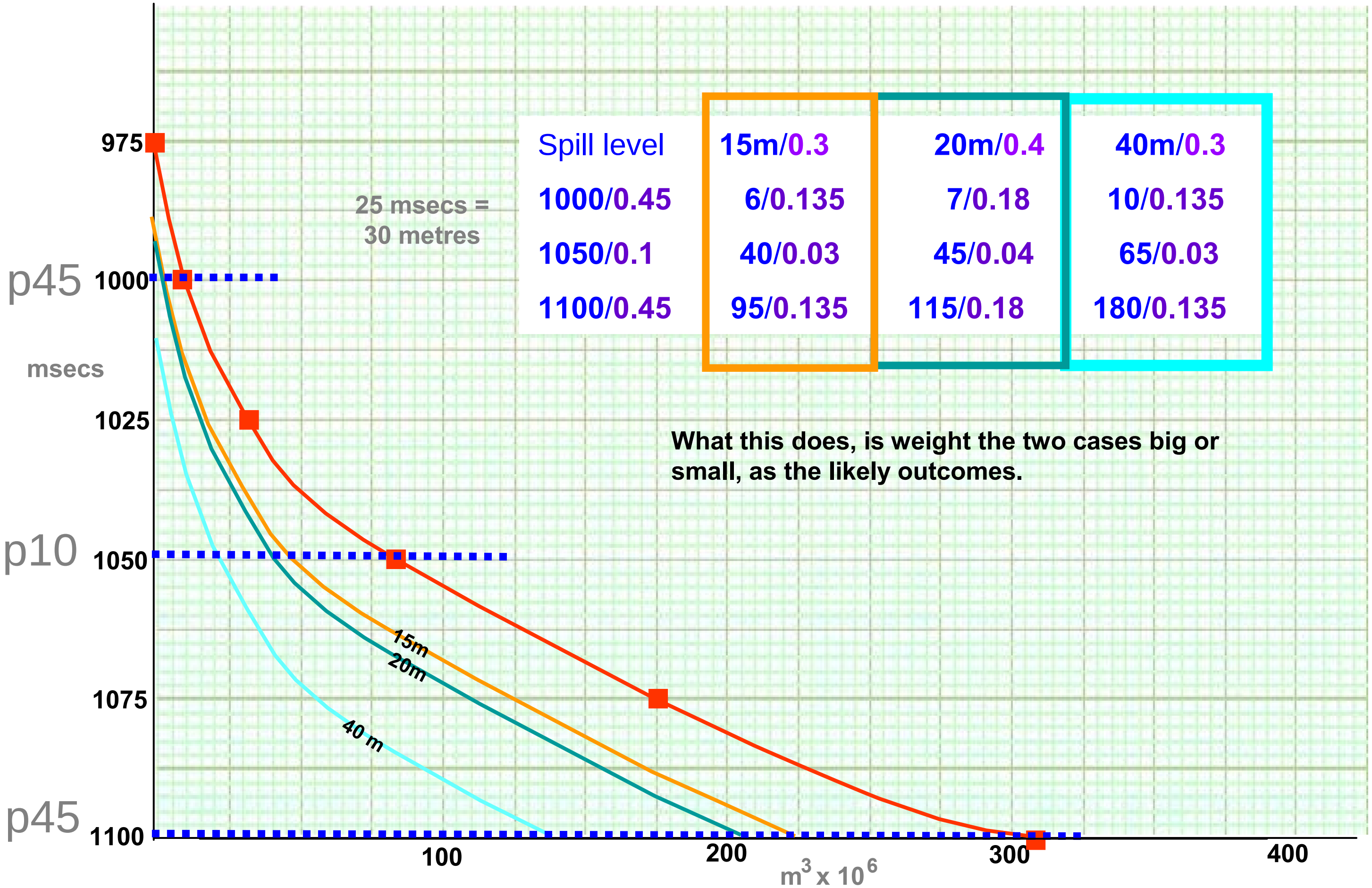
The proposal was that three closure levels had equal likelihood of being the spill level for trapped oil. One was the maximum, on the grounds that if we knew that fields exist in the basin which are full to mapped closure limit, it would be reasonable to expect the prospect may be another such instance. One was a very small case, being a leaky lateral fault seal. The third was an arbitrary mid case, with no particular geological rationale but carrying 40 percent of the probability.

What we've actually created by doing this is shown in the 9-factor listing output by the software, its a stepped distribution and combining these numbers certainly won't give a single, lognormal distribution for reservoir expected volume.

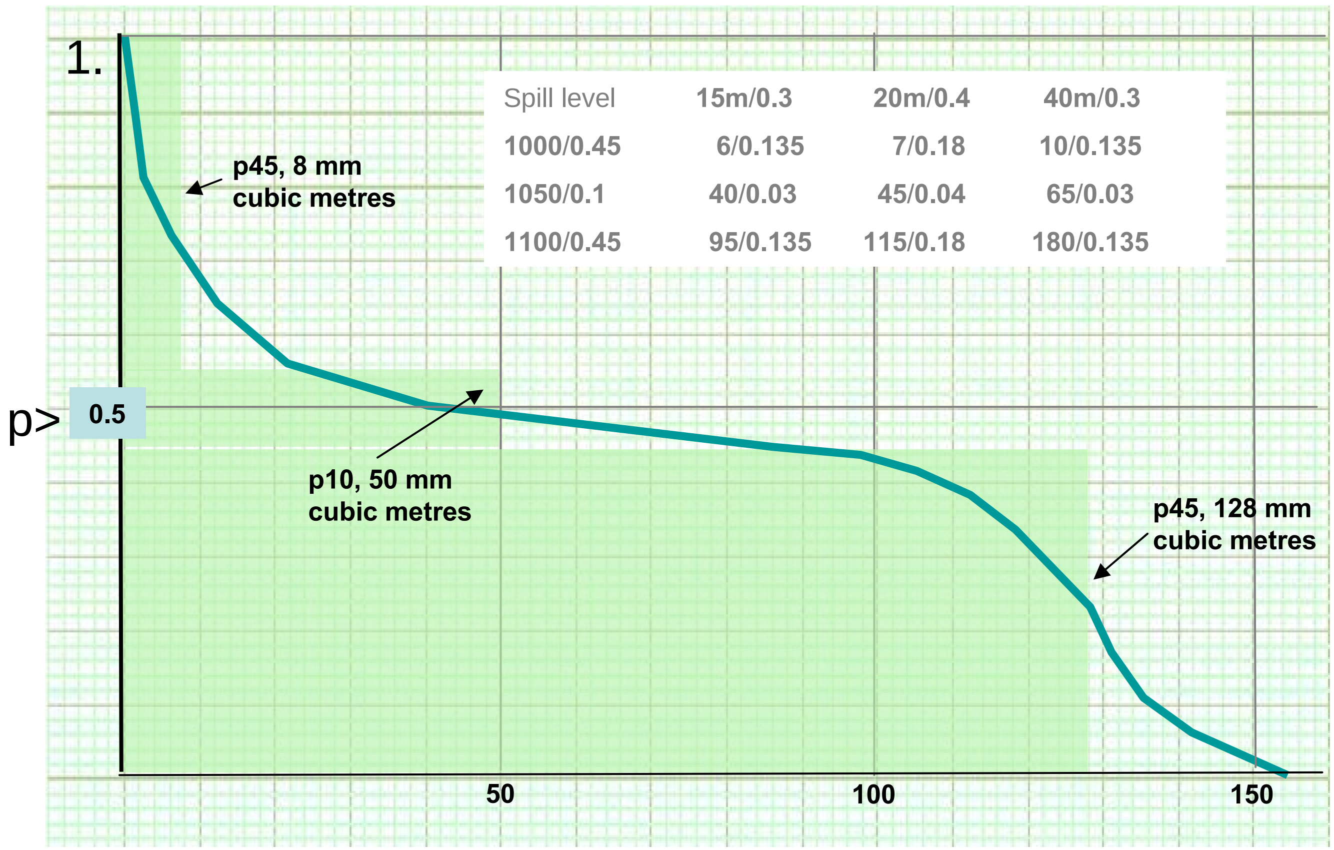
Arguably we should make three separate expectation curves. If we wanted to have gross rock volume in closure plotting as a lognormal distribution, we have to design models accordingly.

If the reservoir model expectation is required to be lognormal, one suggestion that appears in the literature (Rose) is that we can simply draw a straight-line on lognormal probability paper, from p> 1 percent to p> 99 percent, and scale off the p50. One snag with this is that its extremely sensitive to the maximum and minimum likely values. The difference between saying minimum is 1 million cubic metres and 2 million cubic metres, doubles the p50. Its also a completely statistical solution which leaves us with no contribution from geological concepts, and why would we do that?

Gross reservoir volumes in closure

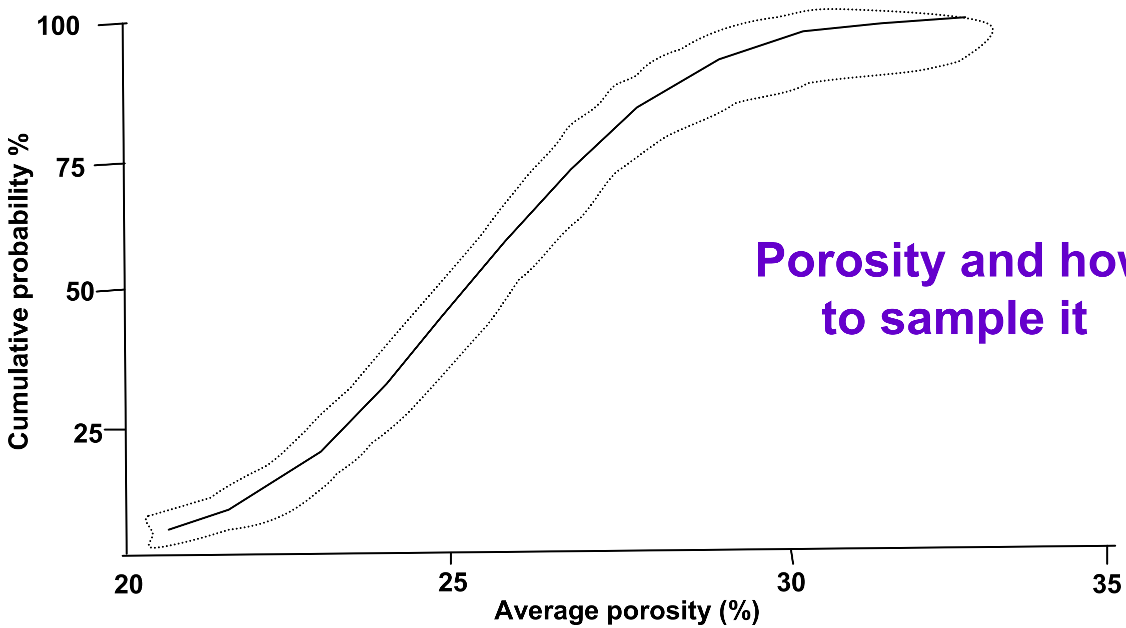


This is a variation on the Ned Kelly closure probability model, where we say let's assign high chance to it being full to spill, also high chance its hardly got any oil at all. The mid case, that there is 10 percent chance of the spill level at 1050 msecs, is just to put a pin point in place, mid range, for drawing the expectation of reservoir volume. Otherwise it'll be a shape like letter "L". Let's see what this looks like.



Quite reasonable, actually. Using the revised min, mid and high cases, here is the smoothed expectation curve for the "large or small" reservoir volume model, predicting the end-member values for us and suggesting that p50 might be around 40 million cubic metres.

If p90 is greater or equal to 2 million cubic metres, and p10 is greater-equal than 136 million cubic metres, we might ask what would p50 be if the distribution is taken to be lognormal? Its the root of p10 x p90, or only 17 million cubic metres. <u>It seems that forcing a reservoir volume model to be lognormal might produce an estimate well below viable alternatives</u>.



Porosity and how to sample it

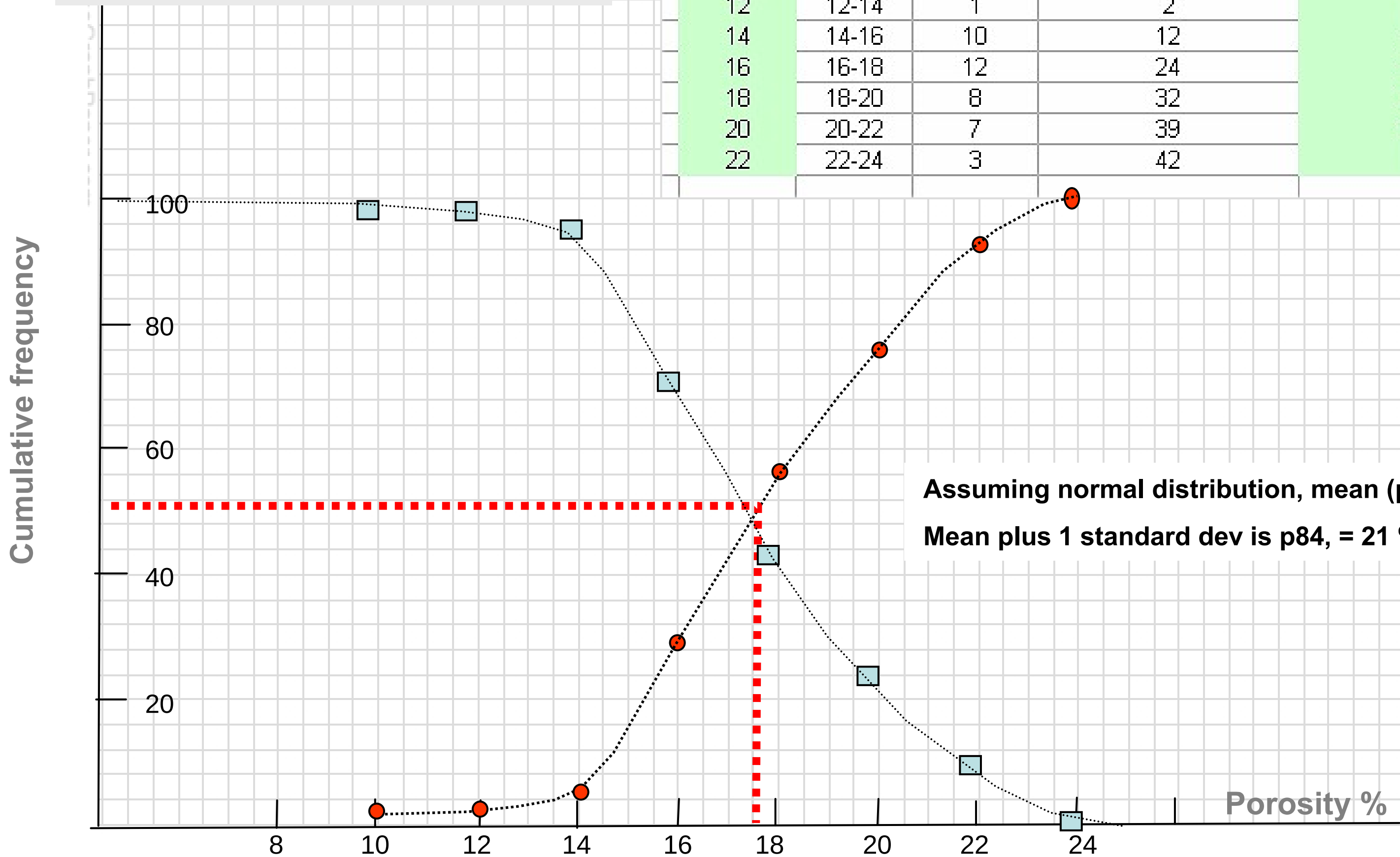
Next question, what porosities will we use?

Its reasonable to assume porosity distribution will be "normal" (Gaussian) and that for a younger simple reservoir the data envelope and cumulative expectation curve will look more or less like this one. (This is a less-than-or-equals cumulative probability). In a distribution which is normal the frequency of observations plots as a symmetrical, bell-shaped curve and the most commonly-seen value (mode) is the same as the mean (which is the sum of all the sample values divided by the number of samples), and the same as the median (which is the value at the middle of the range of samples). About 68 percent of a Gaussian distribution lies within one standard deviation of the mean, 95 percent lies inside two standard deviations, and less than 1 percent is found outside three standard deviations.

Because the average and end-values in a bell curve are easy to conceptualise we generally feel comfortable in choosing descriptive values for these two parameters, towards our evaluation of oil or gas in-place. You don't get extreme variation in the end-values.

Deriving Porosity Estimates

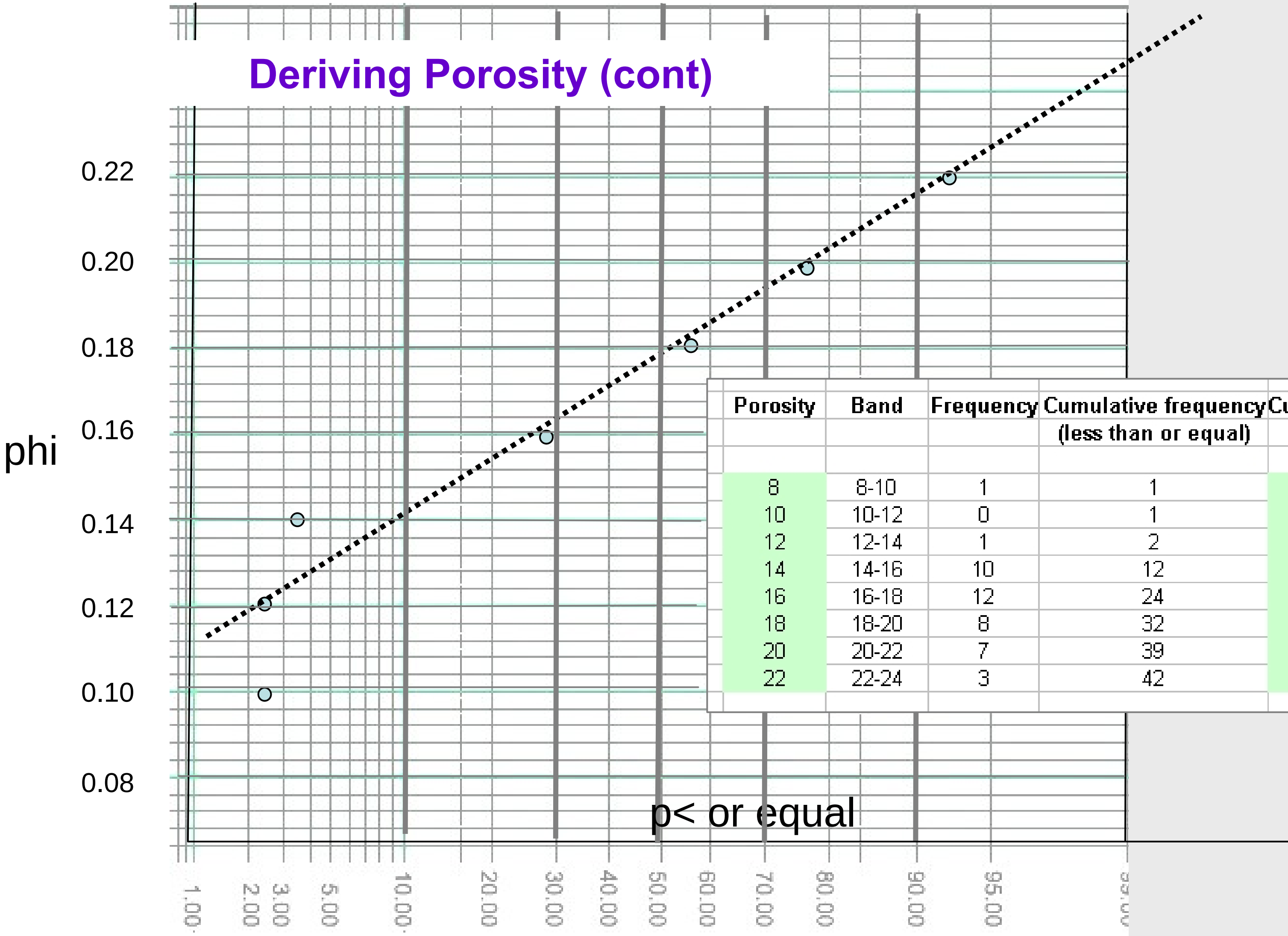
Porosity	Band	Frequency	Cumulative frequency (less than or equal)	Cumulative frequency as a %
8	8-10	1	1	2.4
10	10-12	0	1	2.4
12	12-14	1	2	4.8
14	14-16	10	12	28.6
16	16-18	12	24	57.1
18	18-20	8	32	76.2
20	20-22	7	39	92.9
22	22-24	3	42	100



Given some porosity data, it can be listed and plotted as a cumulative frequency on Cartesian paper. This example shows a probability less-than-or-equal plot as red points, using the upper limits of the classes in column 4. The tail at the left-hand side shows that in this case we are not seeing a classic normal distribution, but its reasonably close.

It also shows the probability greater-than curve, the corresponding cumulative frequencies are subtracted from 1.0 and the points for this curve are plotted as small squares. This is the form we prefer.

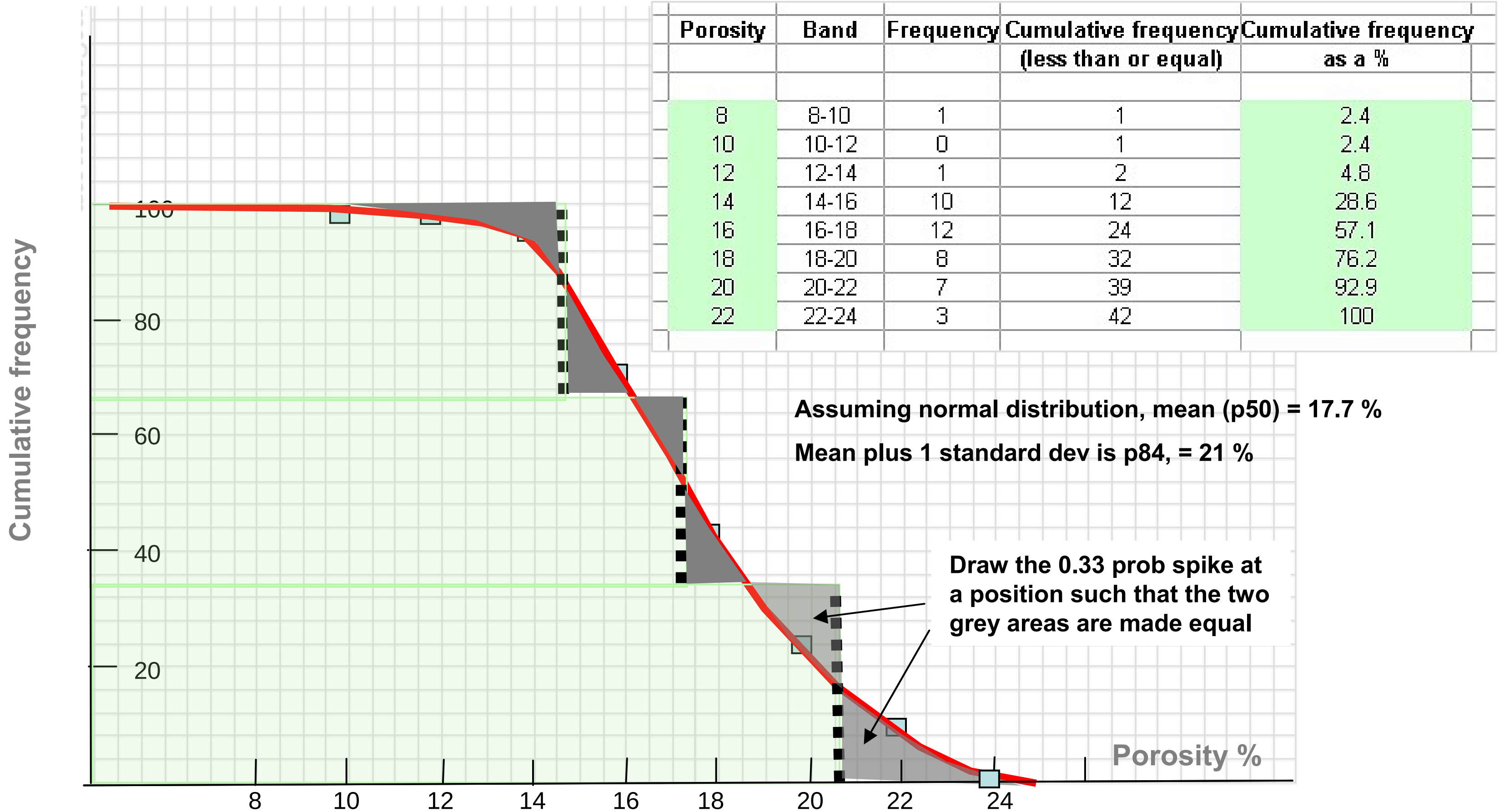
Deriving Porosity (cont)



Porosity	Band	Frequency	Cumulative frequency (less than or equal)	Cumulative frequency as a %
8	8-10	1	1	2.4
10	10-12	0	1	2.4
12	12-14	1	2	4.8
14	14-16	10	12	28.6
16	16-18	12	24	57.1
18	18-20	8	32	76.2
20	20-22	7	39	92.9
22	22-24	3	42	100

Cumulative frequency for the porosity data set, plotted this time on normal probability paper. A more or less straight line is the test for a normal distribution, these data are pretty close to linear, with some departure at the lower-porosity end. The mean is p50, its 18 percent.

Deriving Porosity Estimates (cont)



Porosity	Band	Frequency	Cumulative frequency (less than or equal)	Cumulative frequency as a %
8	8-10	1	1	2.4
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16	16-18	12	24	57.1
18	18-20	8	32	76.2
20	20-22	7	39	92.9
22	22-24	3	42	100

Using the p> curve to get three estimates and corresponding probabilities for the spreadsheet, let's say we'll take equally-probable values: draw three spikes of .33/.34/.33 probability like this, in such a way that the above/below-curve areas balance for each rectangle. Scale-off the corresponding porosity values, which are 14.5/17/21 percent. This will approximate the porosity distribution. We could redraw the curve quite accurately if we had just those three figures, and knowing that the distribution is normal tells me the tails are constrained. (We could of course use any three values of P > or equal, provided they add up to 1.0).

Porosity might not be normally distributed

Yes, porosity of fine to coarse sandstones at shallow-moderate burial depths in relatively undeformed basins can reasonably be supposed to be normally distributed.

If your reservoirs have been diagenetically altered, picking porosity ranges is more complicated. The literature on this topic is huge, see a review by Taylor et al (2010) in AAPG 94(8).

Compaction is the process which mainly reduces porosity. Porosity versus depth plots may look simple down to say 3 km, but quartz cementation starts at around 100 degrees C, and affects different grainsizes differently, so deeper-reservoir plots will rapidly start to show lots of scatter. It gets a lot harder to predict porosity.

People look for reasons to be optimistic about how much porosity is retained at depth. Some favourite ideas are these:

(i) <u>Overpressure helps to support grains and therefore inhibits cementation?</u> It might, but much depends on when the OP arises. Likewise much depends on the history of the basin, has it undergone several phases of subsidence with partial inversion. The more complex is the burial pattern, the less likely it is that OP has had a clear role in preserving primary pore space.

(ii) <u>Grain coatings can have a big effect on primary pore space filling?</u> Yes, if grains have a rim of chlorite for example, this can be a significant inhibiting factor on quartz cementation. Example: North Perth Basin Permian sandstones. Micro crystals of quartz on grain surfaces also stop pore space occlusion by quartz.

(iii) <u>Secondary (dissolution) porosity by removal of feldspar grains or earlier carbonate cement, is important?</u> No, usually it isn't. To get rid of a lot of carbonate there has to be flow of pore fluid and influx of unsaturated water to continue the process, as might happen at a weathering (unconformity) surface.

(iv) <u>Does oil and gas presence at an early stage in traps inhibit quartz cementation?</u> Lots of authors have claimed it does, others don't agree and argue that case histories in the literature are generally inconclusive. Taylor et al say the supposed effect "does not represent a viable model for predicting porosity preservation in sandstone reservoirs"

Overall, with deeper reservoirs we seem to be looking at complex processes running concurrently.

Oil Formation Volume Factor is also normally distributed

Next question: FVF. This parameter is normally distributed, more or less.

People might think at length about porosity and oil saturation, pay etc, and then for FVF they'll just say, what is a reasonable mid-range number for formation volume factor ? Then let's vary it either side by 10 percent, call the three values equi-probable. That's not too bad a way to proceed if you don't know anything else. This is the Standing's Correlation for gas-saturated oil. Its worth experimenting to see what really might happen to Bo as the parameters vary. There are nomograms published in the reservoir engineering books, for doing this easily. As the equation shows, there will be some correlation between Bo and oil gravity.

Solution gas specific gravity

$$B_o = 0.972 + 1.47 \cdot 10^{-4} \left(R_s \left(\frac{\gamma_g}{\gamma_o} \right)^{0.5} + 1.25\, T \right)^{1.175}$$

Rs is the solution gas/oil ratio in standard cubic ft per barrel

Oil gravity, that's 141.5/(131.5 + the API value)

T is the reservoir temperature in degrees F

Gas Expansion Factor

Gas Expansion Factor is the volume at surface in standard cubic feet, which 1 cubic foot of gas in the reservoir has. (Standard conditions are 14.65 psia and 60 degrees Fahrenheit, which is 520 degrees Rankine).

GEF is especially interesting if a prospect reservoir is liable to kick, and particularly if the rig has only marginally adequate mud pump capacity to control the well. Its often better to spud down-flank on a big gas target, because the bigger casing is set deeper and you've got less hole open, when you get to the reservoir.

If you don't know what the GEF value is, and the prospect is a deep structure where there are grounds for suspecting overpressuring may exist, then estimate a wide range of reservoir pressure and temperature conditions.

GEF = (Reservoir pressure/14.7) x ((60+460)/(Fmn temp degrees F + 460) x 1/Z)

where Z is the gas compressibility factor.

GEF data come from drill stem testing. GEF might be around 100-150 scf/reservoircf for a shallow target, perhaps 200-250 scf/rcf if deeper. In an overpressured basin recently we've seen a reservoir with GEF around 320 scf/rcf, scary to drill, giving a huge kick if the structure has a major hydrocarbon column and the reservoir is penetrated crestally. Some of the North Sea HP-HT Triassic fields have GEFs as high as 330 scf/rcf.

Z factor of a gas is its departure from ideal gas behaviour, being the ratio of its actual volume to the volume it would have if it behaved as an ideal gas. Z varies according to pressure, temperature and the gas composition, so you need to know the gas chemistry to be sure what the value of Z is. Otherwise, get it by estimating pseudo-reduced pressure and temperature and using the Standing and Katz chart (next slides). Z can lie between 0.3-1.0 and so again where the data are sparse it needs some thought to estimate a plausible range.

Getting pseudo-critical temperature and pressure estimates, and finding Z.

To get the Z value for a gas, we need to normalise the reservoir pressure and temperature, dividing the data by their critical point values.

Reduced pressure Pr of a gas is its actual pressure P divided by its critical pressure Pc. (The critical pressure is the pressure needed to liquify the gas when its at its critical temperature, above which it isn't possible to liquify it. The phase boundary between liquid and gas ceases to exist, at the critical point). Likewise the reduced temperature is its actual temperature T (in degrees Rankine) in the reservoir divided by its critical temperature Tc.

Then we enter the Standing-Katz chart (next slide) and read-off Z.

For example, if we think we have a natural gas system, mainly methane gas with sg of 0.63, its pseudocritical temperature Tc is given by

$$T_{pc} = 168 + 325\gamma - 12.5\,\gamma 2$$

So that is 378 degrees Rankine.

If we estimate the reservoir temperature is for example 190 degrees Fahrenheit, that's (190 + 460) = 650 degrees Rankine. The reduced T/Tc value to use for this density and temperature is therefore 650/378 = 1.72

Its pseudocritical pressure is given by:

$$P_{pc} = 677 + 15\gamma - 37.5\,\gamma 2$$

which is 672 psia.

Suppose we decide our reservoir is normally pressured, lets say its some number like 4085 psia, the term P/Pc is therefore 4085/672 = 6.1

If we think we have a gas-condensate system the terms are a little different:

$$T_{pc} = 187 + 330\gamma - 71.5\,\gamma 2$$

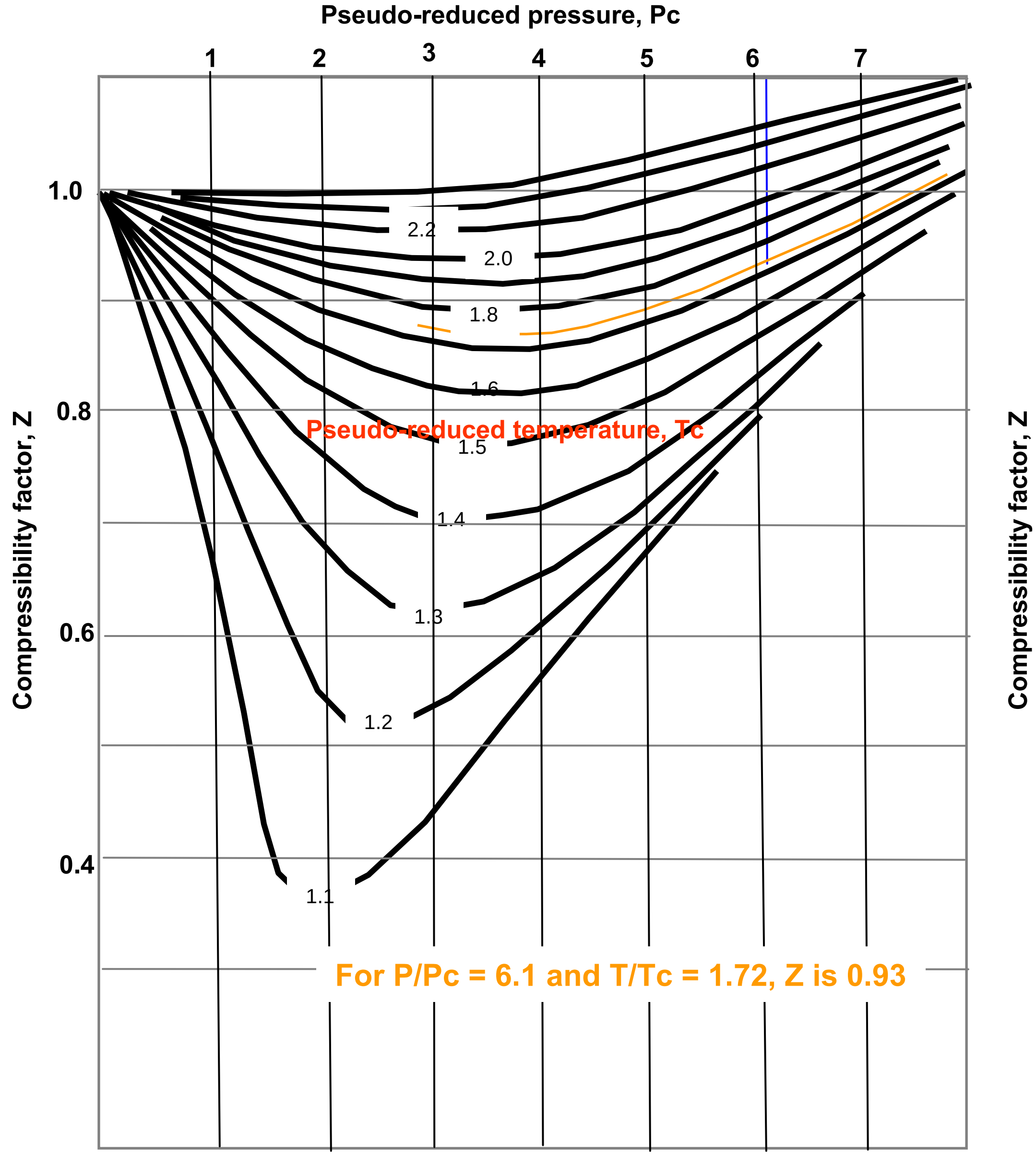
$$P_{pc} = 706 - 51.7\gamma - 11.1\,\gamma 2$$

In this case the density is the sg of the wet gas mixture.

Standing and Katz chart looks basically like this

(Only part of it is drawn, boundary conditions are left out here).

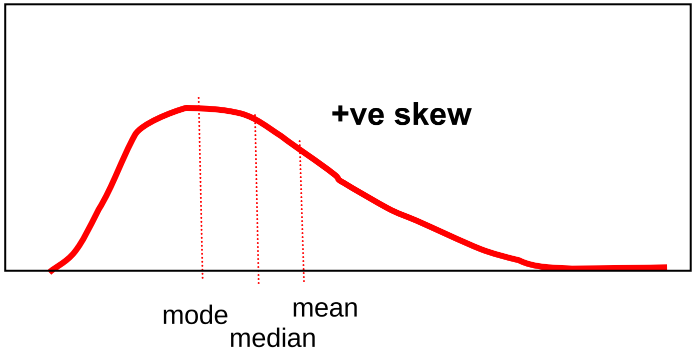
The chart plots "pseudo-reduced" temperatures and pressures, in order that mixtures of gases can be handled.



Lognormal distributions:
Hydrocarbon saturation, pay, gross rock volume

These three data distributions we deal with in prospect analysis are asymmetrical, skewed. The median doesn't correspond to the mode or the mean. It seems this kind of curve is more likely to describe natural data populations. (There is a theory, that a skewed distribution must be the result when the variable is the product of two or more distributions which are independent of each other. If we repeatedly multiply symmetrical distributions together, gradually the result turns into a skewed one. Hence Monte Carlo modelling with thousands of passes will generate a log normal).

To sample skewed data the assumption is typically made that the data are log normal, even if they aren't. For a variable Y, the log normal distribution has the form Y = log(x).



How do you know if a data set really is log normal? If it plots as a straight line on lognormal probability paper, it is. A lognormal p50 is given by root(p10*p90).

Statistics for lognormal curves description

The mode is the value of the random sample that occurs with greatest frequency. In our skewed distribution it isn't necessarily unique, indeed the data might be bimodal. If the data are continuous any particular value might not occur more than once. So the mode probably isn't much use, as a descriptor.

The mean is the "average", its the sum of data points divided by the number of points. It is influenced by end-member extreme values, so its pulled in the direction of skewness, strongly so in the case of gross rock volume.

The median is the value of the point which has half the data smaller than that point. Possibly, its the best of the three options.

What is p50? Some 50 percent of the estimates or outcomes in the distribution are going to be bigger than this value, so its a median. Its said to be the best estimate you can make in the frequency distribution.

P10 and p90 are measures of the range of uncertainty of the estimate. Note, p90 doesn't have 90 percent chance of being correct, its the value which has got 90 percent chance of being exceeded. We are more confident of p90 being exceeded by the outcome of a well because 90 percent of estimates we make are bigger than that number.

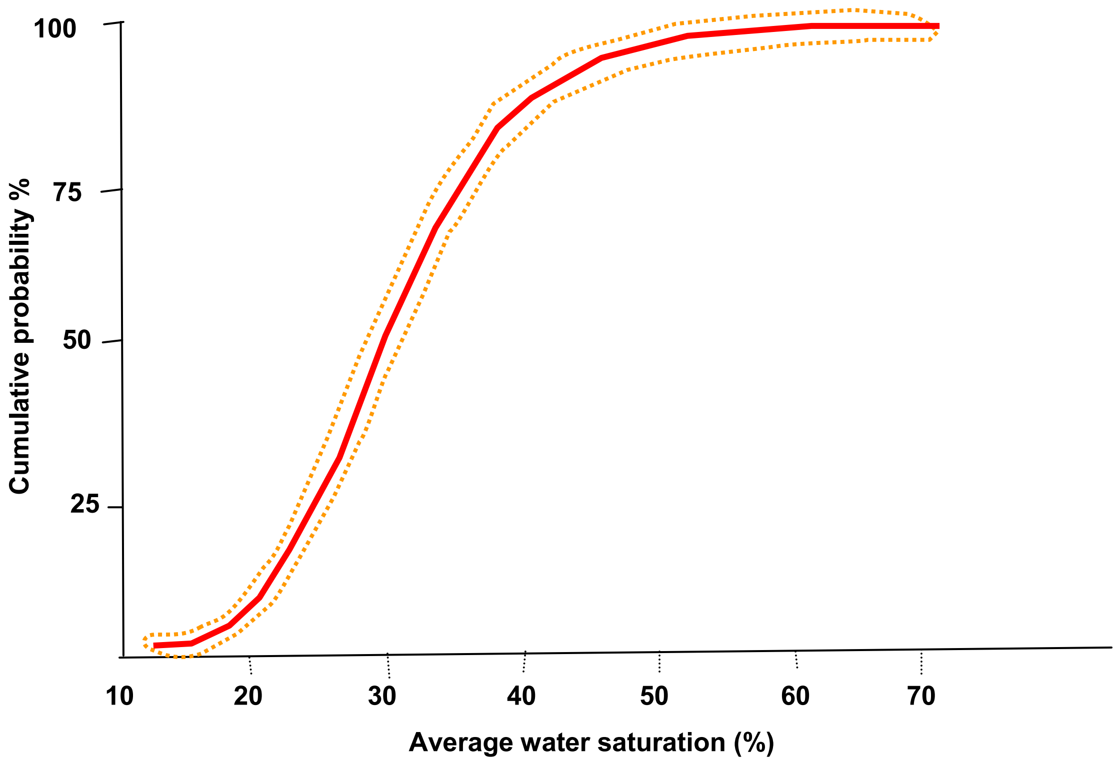
Swanson's Mean

Probably the best summary statistic from a lognormal expectation curve is Swanson's mean. Swanson who worked for Exxon in the 1970s introduced a shorthand way of computing the lognormal mean for modestly skewed distributions, weighting the p50 value at 40% and p10 and p90 values at 30% each (giving them the 10 percent tails). Its a truncated lognormal mean, giving a conservative bias to the analysis by getting rid of huge extreme values, but that's OK for risky frontier plays. The idea of truncating to p90 and p10 is to exclude cases which are hard to visualise or justify. See Hurst et al in AAPG 84(12), December 2000, 1883-1891 for a justification of the formula.

$$\text{Swanson's Mean} = 0.3*p10 + 0.4*p50 + 0.3*p90$$

This does assume log normality.

Water Saturation is commonly lognormally distributed



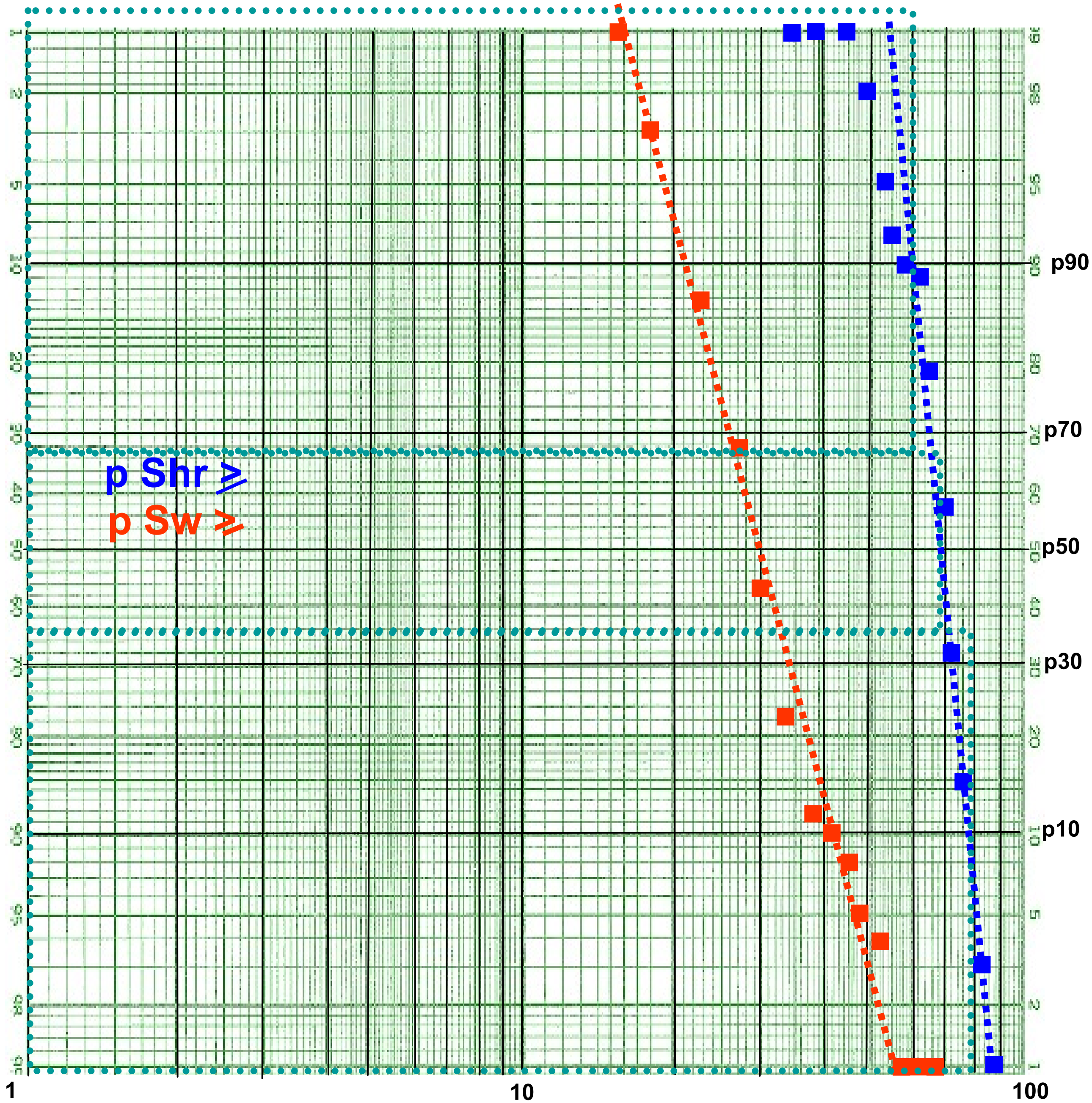
The fourth component for our expectation curve, is the hydrocarbon saturation range. This plot shows lognormal behaviour of water saturation, many areas will similarly show that Sw and therefore So, Sg are lognormally distributed.

Hydrocarbon saturation data inputs

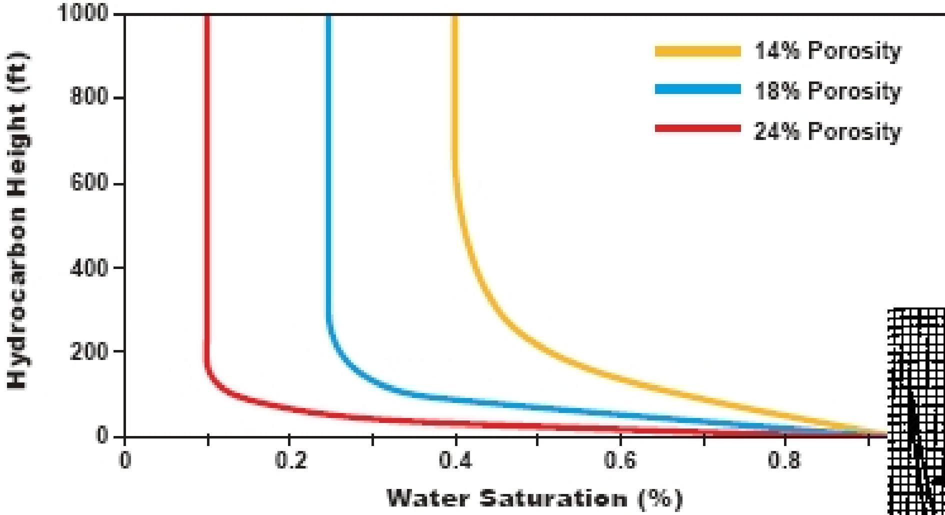
Plotting Sw (red) and Shr (1-Sw, blue) points from the data of the last slide on lognormal probability paper, shows they are indeed lognormal. We scaled off the Sw values from the curve, and there's some noise in doing that. However the Sw is a more or less straight line plot except for the higher-end water saturations reported

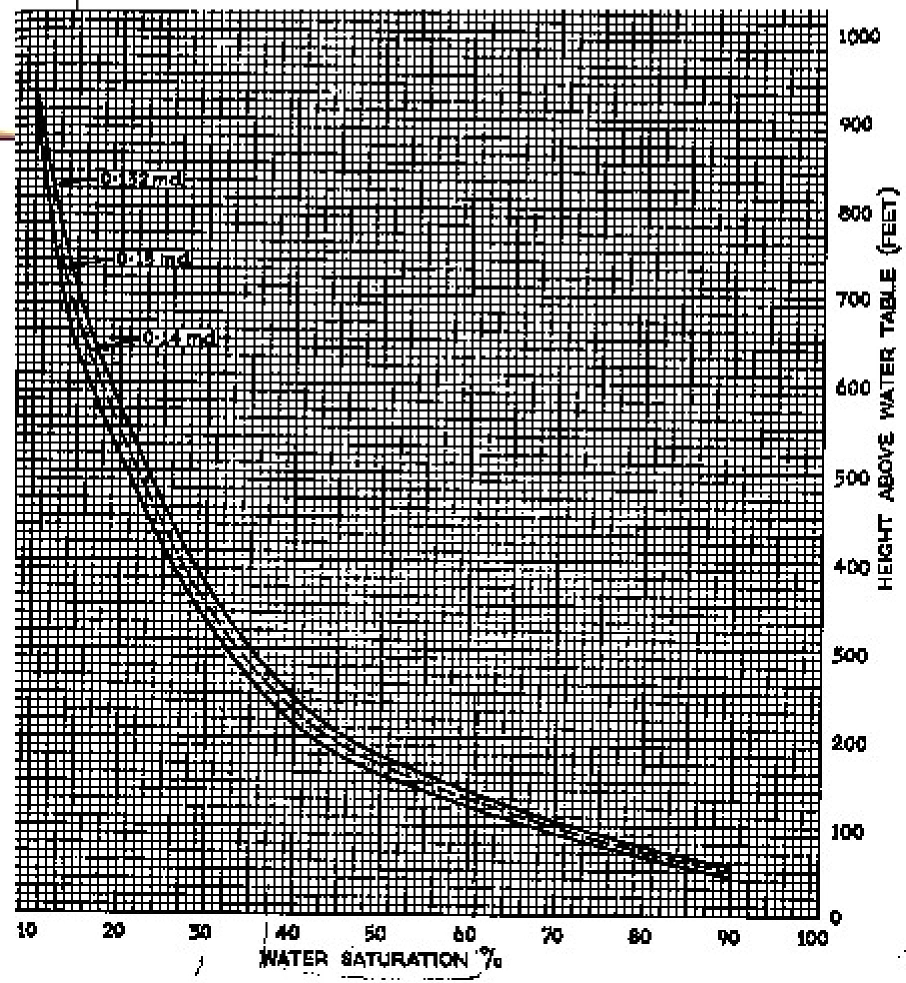
We could assess that if oil or gas are present in that particular reservoir there is very little chance of Shr being less than 40 percent, and no chance of it being greater than 84-85 percent (irreducible water is 15-16 percent). The Shr p50 is around 70 percent for an oil-gas bearing reservoir.

Three Shr equiprobables for this data would be 60/70/80 percent Shr, green dotted construction lines.



Estimating water saturation ranges





Water saturations have a complex relationship with porosity, there is dependence between Sw and phi (Archie equation) but Sw is also controlled by height above water zone, to an extent depending on the permeability. If phi is high, like the red and blue curves above, so will be the permeability and the Sw rise approaching the water contact is relatively abrupt.

In less porous rocks the Sw increases downwards over a longer transition zone; and in very tight rocks like the inset on right, where permeabilities are less than 1 mD, there will be no gas-water contact at all and the transition zone might be hundreds of metres high. Irreducible water saturation can be around 60 percent, even in the crestal area.

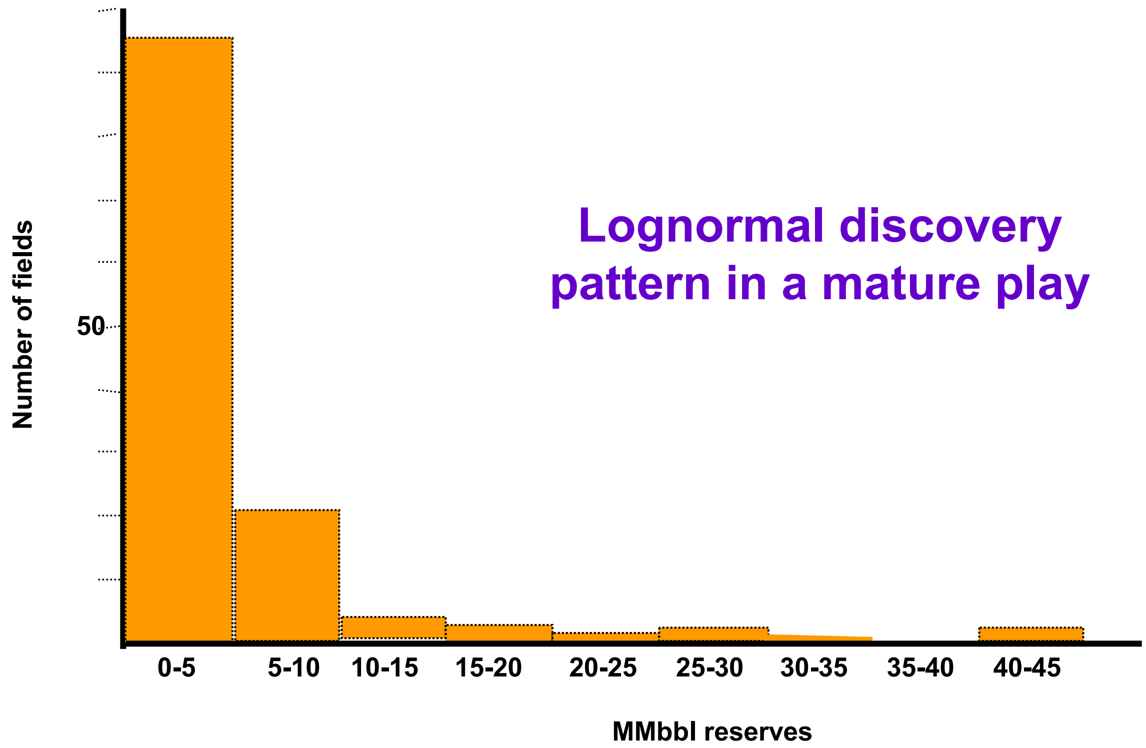
Averaging Oil, Gas Saturations

If there is a well near the prospect and logs are available through the reservoir, you might want to average the known hydrocarbon saturations. Do interval thickness and porosity-weighted saturation values like this:

	Thickness h	Porosity Φ	Φ.h	So	So.Φ.h	Sw	Sw.Φ.h
A	10	0.10	1.0	0.75	0.75	0.25	0.25
B	20	0.15	3.0	0.80	2.40	0.20	0.60
C	10	0.12	1.2	0.77	0.92	0.23	0.28
Sum			5.2		4.08		1.13

So = (So.Φ.h)/ Φ.h = 4.08/5.2 = 0.78

and connate Sw = (Sw.Φ.h)/ Φ.h = 0.22



A lognormal field distribution with a few large fields and many small discoveries lots of which are barely economic, is what many observers expect to see in a basin.

It may be the case that the large fields are found first, but not necessarily so. Until recently Canning Basin onshore Western Australia was an instance where, despite there being three petroleum systems, lots of drilling had achieved only half a dozen finds of only a few mmbbl apiece. Only recently has a significant gas discovery been reported. The opposite picture has come from Inner Moray Basin of UK, where one big field (Beatrice) was found very early and then a long series of dry holes and very minor finds followed, the middle-sized fields are still not known. Explorers just haven't seen the key plays yet. Possible answers: stop drilling the highs and look downflank for structural/stratigraphic plays; drill deeper; drill footwall structures instead of hangingwall anticlines; etc.

Sanity checks are vital

Leads	STOIIP MMstb		GCOS	Unrisked NPV 10% Pretax £MM		EMV £MM
	Low	Mid		Low	Mid	Base Case
A	34.1	61.7	0.16	191.3	464.7	50.4
B	13.3	43.1	0.14	74.0	325.1	25.8
C	22.7	42.7	0.16	99.5	255.9	20.0
D	3.5	8.6	0.14	15.5	68.8	3.7
Recovery Factor	0.25	0.35				

This slide is to make the point that EMV computations need to be checked for sanity by the explorationists before recommendations get as far as Management.

These are real prospects, onshore, analysed by a person who didn't do the mapping and he ranked them in order of supposed attraction as targets after calculation of expected monetary value. The GCOS (geological chance of success) figures are quite different from the chance factors which were derived by the exploration team.

The whole basis of the EMV concept is that you drill the highest EMVs first: so Management should highgrade this play. The ranking suggested prospect A was the most valuable.

The conclusion is disastrously wrong, because prospect A already has a well inside the mapped area of closure, which was a dry hole and the geologist knew that and downgraded the untested volume accordingly: the untested updip-closed volume is very small. But the analyst reworked the risks and his revised GCOS estimates are very different from the original ones.

Structure B is immediately adjacent to a sizable oilfield, the structure is small but much more attractive than A. Is it reasonable that a structural closure next to a producing field has only 14 percent chance of containing <u>any</u> amount of movable oil? It comes out of this work with an expected monetary value half of Prospect A's, which is ridiculous.

Bloopers

"I'll drink every barrel which comes from the North Sea", by a leading oil geologist of the time is famously wrong but a bigger favourite of ours because of personal involvement is a memo from one of our bosses saying that oil fields in Dorset are "lucky freaks" and could only be small. It was sent to us about a year before the Sherwood reservoir at Wytch Farm was discovered with its 500 million barrels, its author had a record of several dry holes in the basin and he had committed himself to a negative opinion on the area, in intra-company reports. New ideas and data in support, did not change his mind.

We can't resist including this following reference, for some reason we kept a press cutting from the Financial Times of June 17th 1987. We found it again recently, in which their resources editor Max Wilkinson quoted the BP Statistical Review of World Energy just published that year:

- World oil reserves will last 32 1/2 years at present rates of consumption.
- Britain's oil reserves at current rates of depletion would last 5 1/2 years.
- North American oil reserves would last 9 years.
- The World's natural gas reserves will last for more than 50 years, but the gas reserves of the USA will hardly last longer than another 11 1/2 years at present depletion rates.

This was a group of experts with a reliable database doing their best to make an unbiased estimate which would be helpful to planners of all disciplines. With so many end users waiting on reliable advice, no doubt that team was anxious to avoid error and they took a conservative approach. This was around the time when buying other companies was more popular than drilling wells: nearly all the Industry went risk-averse.