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DECISION TREE ANALYSIS OF POSSIBLE DRILLING OUTCOMES TO OPTIMISE DRILLING DECISIONS

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ABSTRACT

The distribution of permeability within geothermal fields is generally lognormal. Using distributions from field data, it is possible to determine expected results of drilling, and expected well performance. Using a decision tree of possible actions (drill/accept/sidetrack), drilling costs, and measurements of well injectivity, decision criteria based on injectivity are defined..

1. INTRODUCTION

During drilling and completion testing, the only information on the permeability of a new well is the injectivity. Productivity is related to injectivity but with considerable scatter. If a new well has low injectivity, it may be more economic to immediately redrill or sidetrack, rather than run liner, warm up and test properly. The immediate sidetrack saves the cost of later mobilising a rig back to site.

Given a known distribution of permeability, the chances of a well meeting economic criteria can be calculated. Using these probabilities, optimal decision criteria can be defined. This paper defines such criteria, and illustrates them for a hypothetical field and with hypothetical drilling costs.

2. PERMEABILITY DISTRIBUTIONS

The first component of the analysis is a description of the possible outcomes in terms of well permeability. This is defined using collected data on a set of wells. Table 1 below gives measured injectivity and productivity data from some NZ wells, from Grant (1982).

Note that injectivity is as reported in the completion test. Injectivity normally increases with injection – this is the value measured before any such extended stimulation. Permeability varies over orders of magnitude, and is positive definite. A lognormal distribution would be a natural form for the distribution to take. Figure 1 shows a cumulative distribution of the injectivity data, and a lognormal and normal distribution to fit the data. The lognormal distribution is clearly better. Apart from the poorer fit in the graph, the normal distribution extends to negative injectivity.

Table 1. Permeability data from NZ wells, t/h.b

Well	Injectivity *II*	Productivity *PI*
NG2	5	9
NG3	22	2
NG4	110	200
NG8	8	12
NG11	42	25
NG18	10	4
BR9	20	1.5
BR13	9	3.3
BR18	8	3.2
BR22	14	12
BR23	26	11
BR25	21	35
BR27	9	5.5
BR28	50	15

Lognormal distributions were fitted to the injectivity, productivity and the ratio $r = PI/II$. The distributions are defined by the mean m and standard deviation s of the natural log of the variable. Table 2 shows these parameters for the distribution of the data in Table 1. Subscripts p, i, r refer to productivity, injectivity and ratio respectively.

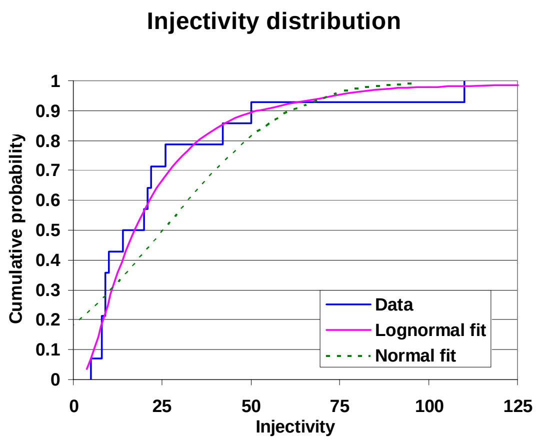

Figure 1. Distribution of injectivity.

Table 2. Permeability distribution parameters

	II	*PI*	*r*
m	2.85	2.21	-0.64
s	0.86	1.28	1.01

Note that there are consistency conditions in these parameters. Because *PI=II*r*,

$$m_p = m_i + m_r$$
$$s_p^2 = s_i^2 + s_r^2$$

The second relation only applies if the different data are uncorrelated, so in practice it will not be exactly observed.

The probability of a productivity value of *PI* or less is given by (in Excel):

$$P = \text{LOGNORMDIST}(PI, m_p, s_p)$$

3. PRODUCTION WELL PERFORMANCE

Given well design, reservoir pressure and temperature, well performance can be computed as a function of productivity. For the present purposes the only flow needed is flow at standard operating pressure, ie the flow on production.

For the purposes of an example, a hypothetical field is used. The reservoir will be assumed to be normally pressured.. A base temperature of 280ºC is assumed, and a gas content of 0.8%. Saturation pressure for this fluid is 77 bar a. The well is cased to 1000m, and produces from a feed zone at 1700m depth. Reservoir pressure at this depth is 150 bar abs. The well has 9-5/8" casing and 7-5/8" liner. Calculations were made using GWELL.

Figure 2 shows calculated well flow at 15 bar g as a function of productivity. It also shows a simple fit to the simulator results, which is given by

$$W = A*PI/(1+A*PI/B)$$

$$A = 110$$
$$B = 600$$

For convenience this fit is used in calculations rather than doing many wellbore simulations. It has been found that a relation of this form usually gives a good fit to the variation of flow with permeability. The fit is specific to the well, reservoir and WHP specified, and needs to be recalibrated against wellbore simulations for any different field or well type.

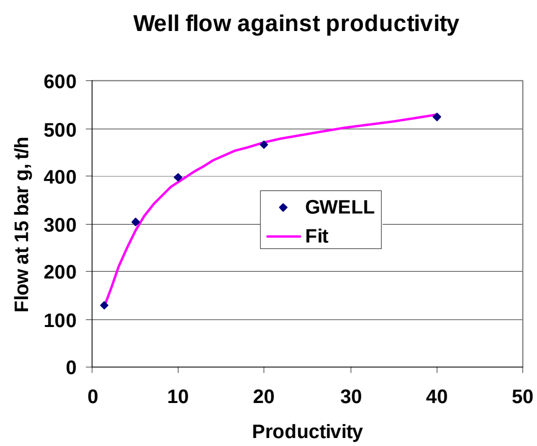

Figure 2. Flow against productivity.

The expectation flow of a new well can now be calculated:

$$E(W) = \int W(PI)\, dF(PI)$$

Where *F* is the cumulative distribution of productivity. For the distribution above, and the hypothetical field, this value is 360 t/h. This is the expectation value of a new well, without any redrills or sidetracks.

4. DRILLING COSTS

There are three drilling cost parameters used in the decision tree:

DC	Drilling cost
SC	Sidetrack cost
MC	Mobilisation cost

The drilling cost is the total cost of drilling a representative well of the specified design. The sidetrack cost is the extra cost of an immediate sidetrack, and the mobilisation cost is the additional cost of calling a rig in to sidetrack. For the purposes of illustration, the following values are used:

DC	=	\$6m
SC	=	\$1.5m
MC	=	\$1m

These are not actual figures for any actual field and differ from current costs. However all that is important is the ratio between the different costs.

There are also many more places where costs may be varied. For example, if a well has just been drilled and has had little loss, so that it is a possible candidate for a redrill, some time and money can be saved by doing a stage test (an injectivity test with the tool at the casing shoe) to measure injectivity before running the liner. If the decision is to keep it, a liner is then run.

5. PRODUCTION DRILLING DECISION

5.1 The decision tree

Now consider the decision at the completion of drilling. Figure 3 decision tree shows the basic decisions made. If a well is successful it costs DC. If unsuccessful and sidetracked immediately it costs $DC+SC$; but if the sidetrack is delayed the cost is $DC+SC+MC$. Immediately after drilling the only information available is the injectivity II_1.

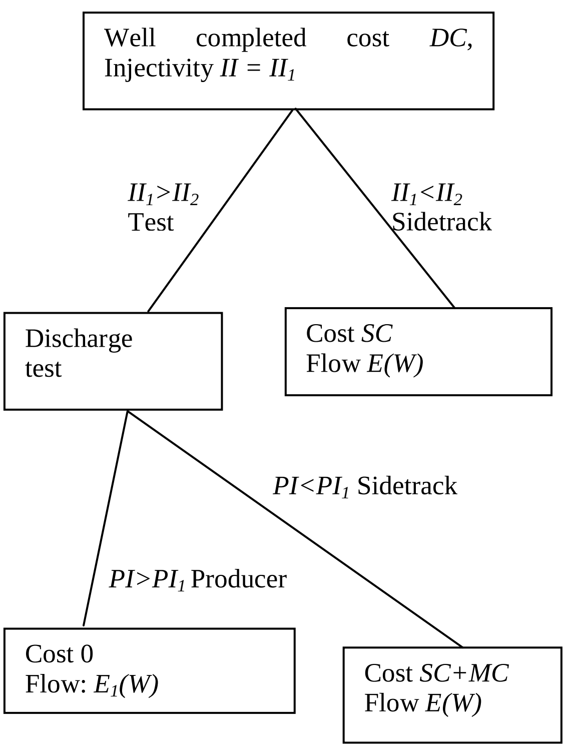

Figure 3. Drilling decision tree.

The decision tree is filled out by working up from the end of all the branches.

5.2 Decision after discharge test

The first decision is the choice made after carrying out a discharge test. This gives a well flow W. Is the well accepted or sidetracked?

If the well is sidetracked, the expected flow is $E(W)$ (=360 t/h), and total cost $DC+SC+MC$ (=\$8.5m). This gives a unit cost of the production as $E(W)/(DC+SC+MC)$ (=42 t/h.\$m).

If the well is kept, the flow is W, and the cost DC, giving a unit cost W/DC. The well is therefore kept if:

$$W/DC > E(W)/(SC+DC+MC)$$

$$W > W_1 = E(W)*DC/(SC+DC+MC)$$

The corresponding productivity is PI_1, and probability P_1. The probability P_1 of this outcome is the lognormal probability of PI less than PI_1, given the distribution parameters m, s.

$$P_1 = \text{LOGNORMDIST}(PI_1,m_p,s_p)$$

In the example case, the cutoff flow is

$$W_1 = 250 \text{ t/h}$$

which corresponds to a productivity of 4 t/h.b. Correspondingly PI_1 is 26%. That is, about one-quarter of all wells should be sidetracked. The expectation flow of the wells that are kept is the expectation over that part of the distribution with productivity greater than PI_1:

$$E_1(W) = \int_{PI>PI_1} W(PI)dF(PI) \Big/ \int_{PI>PI_1} dF(PI)$$

$$= \int_{PI>PI_1} W(PI)dF(PI) / (1-P_1)$$

This value is 425 t/h. This is the expectation value of a successful new well, ie discarding the failures, but without any redrill or sidetrack.

Given this decision, the consequences of the decision to keep and test the well can now be computed.

Summarising, there is probability $1-P_1$ that the well is kept, with total cost DC and flow $E_1(W)$. There is probability P_1 of a sidetrack, with total cost *DC+MC+SC*, and flow *E(W).*

Note that is some fields there may be other criteria. For example, if the reservoir fluid is prone to scaling, it may be desirable to avoid flashing in the formation and a well may be kept if it is sufficiently permeable to flash only in the wellbore. This decision depends upon whether the average permeability is high enough to make this a viable option. It can set a cutoff value of productivity higher than the value PI_1 determined above.

5.3 Decision at completion

After completion there is decision to keep and test the well, or immediately sidetrack. The available information is the injectivity II_1. Given this information, the probability of achieving a productivity PI_1 is given by the probability P of achieving $r_1 = PI_1/II_1$. The parameters of the distribution of r are given in Table 2 above. This probability is a function of the injectivity II_1. The expectation flow and cost of the option to keep the well are then given by:

$$W_2 = P*E_1(W)+(1-P)*E(W)$$
$$C_2 = P*DC+(1-P)*(DC+SC+MC)$$
$$= DC+(1-P)*(SC+MC)$$

which are functions of the injectivity II_1 through the dependence on P.

If the well is immediately sidetracked, the flow is $E(W)$ and the cost is $DC+SC$, independent of II_1. Comparing the unit cost of flow gives the breakeven value of II_1. This break-even value can be calculated by equating the unit cost of the two options:

$$W_2/C_2 = E(W)/(DC+SC)$$

which gives

$$P_2 = E*MC/[(DC+SC)*(E_1\text{-}E)+(SC+MC)*E]$$

Figure 4 shows the optimisation, with a break-even value of 4 t/h.b. For an injectivity less than this, the well should be immediately sidetracked.

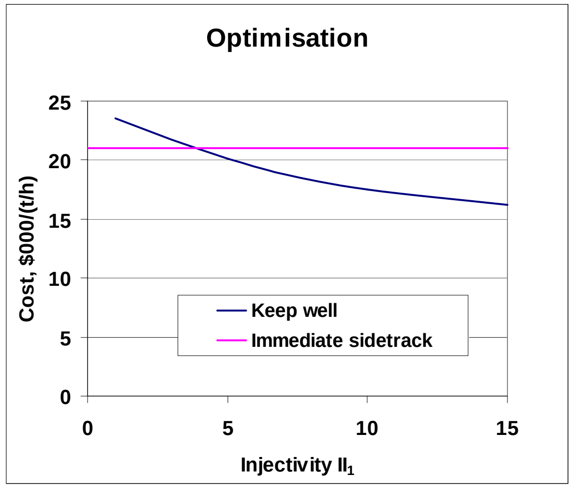

Figure 4. Unit cost of production against injectivity

Explicit formulae for the breakeven value are given by

$$r_2=\text{LOGINV}(1-P_2,m_r,s_r)$$

$$II_2=PI_1/r_2$$

The probability of not achieving this injectivity is

$$P = \text{LOGNORMDIST}(II_2,m_i,s_i)$$

For the values above, this is 4% - ie only 4% of wells require for an immediate sidetrack. It would be expected that only a small proportion of wells would be so much below average that it was not worth carrying out a discharge test.

This has defined a cutoff value for a new production well – an injectivity at which the well should be immediately considered a failure. It must be noted that this result is specific to the costs, permeability distribution and well performance used. Applying the method in a number of situations has shown that the cutoff injectivity differs between fields and drilling costs, although it always seems to lie in the range 3-15 t/h.b.

Figure 5 shows the decision tree with all values evaluated. It is a coincidence that there is the same value for II_2 and PI_1, and in general these are not equal.

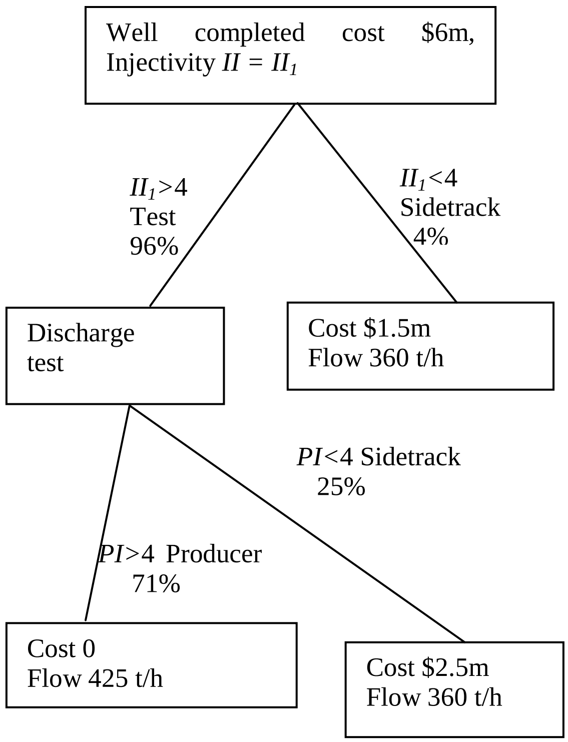

Figure 5. Decision tree for model field

5.4 Chance of an incorrect decision

Of the wells immediately sidetracked, there is a fraction which would in fact have been sufficiently productive. Given an injectivity II, the chance that the productivity exceeds PI_1 is given by

$$1\text{-LOGNORMDIST}(PI_1/II, m_r, s_r)$$

So the chance of productivity exceeding PI_1, over all the wells immediately sidetracked, is

$$P_3 = \int_0^{II_2} [1\text{-LOGNORMDIST}(PI_1/II, m_r, s_r)]\, dF(II)$$

In the model case this is 0.7% - one in six of the wells immediately sidetracked would have in fact made sufficient production to be kept, had they been tested.

5.5 Sensitivity

Experimentation has shown that the cutoff injectivity is quite sensitive to the sidetrack and move costs. The point of an immediate sidetrack is to save the cost of a subsequent move, so naturally a change in the move cost changes the cutoff – a higher move cost means a higher cutoff. A change in the sidetrack cost changes the proportion of wells that should be sidetracked, whether immediately or after discharge testing, and consequently the cutoff injectivity is changed – higher sidetrack cost means a lower cutoff.

INJECTION WELLS

There is a parallel process for decisions on injection wells, following a similar decision tree.

The difference is the alternative after drilling and completion test. This completion test gives an injectivity, which is after all the essential parameter for an injection well. However, experience shows that injectivity normally increases after a period of injection. Thus the decision is to either sidetrack immediately, based upon the completion injectivity, or alternatively to subject the well to a period of injection, which will normally stimulate the injectivity several-fold, and then make a final decision. The structure of the decision tree is the same, but in place of the distribution of the ratio of productivity to injectivity, is the ratio of injectivity after stimulation to the injectivity before stimulation. This requires some statistics on this latter ratio.

SUMMARY

Probability distributions have been defined for well injectivity and productivity. Using these together with drilling costs and well performance, a cutoff injectivity has been derived at which a well should be immediately sidetracked.

The results are field-specific and are sensitive to changes in cost ratios.

ACKNOWLEDGMENTS

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REFERENCE

Grant, M.A., 1982 "The measurement of permeability by injection tests" Proc. 8th workshop on geothermal reservoir engineering, Stanford University, pp111-114.