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COMBINING PROBABILISTIC VOLUMETRIC AND NUMERICAL SIMULATION APPROACHES TO IMPROVE ESTIMATES OF GEOTHERMAL RESOURCE CAPACITY

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ABSTRACT

Confidence in estimates of geothermal resource electricity generation capacity can be improved by a probabilistic approach that combines numerical reservoir simulation with the classic volumetric estimation based on fluid mass in place. A simplified reservoir simulation model is used to examine the sensitivity of resource performance to changes in the assumptions concerning key reservoir parameters. In particular, this process establishes the expected variability of the volumetric recovery factor with respect to the likely variations in resource thermodynamic and hydraulic characteristics. Recovery factor is defined as the fraction of fluid in place that can be produced as usable steam over the life of the project. In typical volumetric estimates, the recovery factor is treated as an independent variable and is chosen somewhat arbitrarily based on experience with other geothermal fields. The important innovation in this method is a more systematic approach establishing the dependence of recovery factor on certain key reservoir parameters. Probability distributions are assigned to account for the uncertainty in reservoir parameters that affect recovery factor and the volumetric estimation of fluid mass in place. Monte Carlo simulation is then used to assess the probability of occurrence of a given electricity generating capacity based on steam recovery and mass in place. This approach treats recovery factor as a dependent variable. The outcome of this capacity estimation is therefore explicitly linked to the key thermodynamic and hydraulic characteristics of the resource and to their uncertainty level, rather than to volumetric parameters alone.

This method is particularly suited to capacity estimates in the early exploration stages of a geothermal prospect, when only a few deep wells have been drilled and numerical reservoir simulation is not well constrained. It provides a more coherent approach to the estimation of both proven reserves and upside potential, with both being defined in terms of the required confidence level needed for making investment decisions.

1. INTRODUCTION

Geothermal reserves evaluation is typically carried out either by a volumetric approach or by numerical modeling. A probabilistic approach is often utilized to assess the level of confidence of such estimates, and may contribute to a better economic evaluation of a proposed development (Grant and Mahon, 1995).

Volumetric analysis estimates recoverable reserves as a fraction of the fluid mass initially in place within a given reservoir volume. The intrinsic weakness of the volumetric approach lies in the assumption of a fixed recovery factor, usually derived from empirical experience and analogy. In reality, energy recovery strongly depends on the thermodynamic and hydraulic characteristics of the reservoir, for example system temperature, permeability, and recharge. The functional dependency of the recovery factor from the key reservoir parameters cannot be adequately captured if it is considered as an independent variable. This can significantly bias capacity evaluations, in particular those using a probabilistic approach.

Numerical simulation takes into account the physical processes occurring in the exploited reservoir. However, models are typically poorly constrained in the exploration phase of a new prospect. This represents a strong limitation of their practical applicability for initial reserves evaluations, particularly in situations where the field limits have not yet been established by drilling. On the other hand, a probabilistic approach using numerical modeling is computationally impractical.

A method was developed based on Parini and Jarach (1987), that addresses this drawback to simulation and the conceptual limitations of the volumetric approach by combining them. This paper demonstrates the application of the method to an hypothetical reservoir, with assumed reservoir characteristics and related uncertainty levels.

2. METHODOLOGY

The method combines reservoir simulation to predict long-term performance under exploitation with the classical volumetric approach of calculating resource capacity based upon fluid mass in place. The following steps are employed:

- Establish probability distributions for key reservoir parameters
- Define the field abandonment criteria in terms of the minimum bottom hole pressure and enthalpy conditions required to sustain an acceptable wellhead steam deliverability
- Construct a simplified reservoir simulation model, capable of predicting the evolution of reservoir conditions during

exploitation. Quantify the dependence of the "recovery factor" on the key reservoir parameters by modeling the system's exploitation using a wide range of values for the independent reservoir parameters.

- Perform a Monte Carlo simulation to determine the probability distribution of reserves based on the estimated distributions of independent parameters and modeled values of recovery factor.

The systematic use of the model with a wide range of the main reservoir parameters allows establishing a functional dependency of the recovery factor from the reservoir characteristics. The recovery factor is consequently treated as a dependent variable in the probabilistic evaluation. Through this, the outcome of the volumetric capacity estimation is explicitly linked to the key thermohydraulic characteristics of the resource and to their uncertainty level.

3. MAIN RESERVOIR CHARACTERISTICS AND PROBABILITY DISTRIBUTION OF KEY PARAMETERS

For the purpose of modeling, average values, representative of the entire commercial reservoir, must be defined for all parameters potentially affecting the exploitable reserves. Obviously, the ultimate value of every parameter is affected by some level of uncertainty, which can be quantified by means of a probability distribution function. Simple triangular distributions, based upon the most likely, minimum and maximum values, are usually adequate for the description of the uncertainty level of the key reservoir parameters. However, the use of other distribution functions would not affect the applicability of the method.

In a real case, the parameter values and related levels of uncertainty depend on the amount of knowledge gathered by the exploration activity. Typically, the possible range for a specific parameter will narrow with the availability of more detailed and/or extended information. The key reservoir parameters considered in the evaluation of the hypothetical reservoir, whose assumed probability distributions are shown in Figure 1, are:

- Areal extension (Field limits): The minimum value would correspond to the area actually proven by drilling, whereas the most likely and maximum values would be based on geoscientific indications (like geophysical modeling, distribution of surface thermal features, structural features, etc.)

- Elevation of reservoir top and bottom, defining the thickness of the reservoir.

- Reservoir Temperature: In the example, the temperature distribution function partially depends on the areal extension of the reservoir (see Figure 1). For small reservoir areas, there is a narrow range of temperatures corresponding to measured temperatures in the drilled area. For larger areas, there is a wider range of possible values as well as a shift of the most likely average temperature towards a lower value. This accounts for the low degree of uncertainty regarding temperature in the drilled area and probability of encountering lower temperatures in some undrilled areas. The dependency of average temperature on reservoir size could be modified for other specific cases.

- Porosity: The average value of the porosity over the whole reservoir thickness is used as characterizing parameter

- Permeability The assumed values represent the possible range of the "average" permeability for the whole reservoir. The local permeability variability within the reservoir will be significantly higher than the range for the average value.

- Average Fracture Spacing The average fracture spacing is selected as the primary parameter defining the dual porosity nature of the reservoir. High values represent a strongly fracture dominated behavior of the reservoir, whereas low values are typical for single-porosity reservoir types. The other main factor defining the dual porosity behavior of the reservoir rocks is matrix permeability. However, this parameter is kept constant in the example (at 0.001 mD), and its possible variation is believed to be conveniently reproduced by a corresponding change in the average fracture spacing.

- Productivity index The average PI of the wells is another parameter affecting the recoverability of the geothermal fluid, and is accordingly treated as a probabilistic function. Its probability distribution is skewed, to account for the typical lognormal distribution of the PI values. In the example, a correlation coefficient has been introduced between reservoir permeability and well productivity index.

Other factors potentially affecting the reservoir performance are initial pressure and NCG content of the fluid. In the example, it is assumed that these parameters are known without significant uncertainty, and were kept constant throughout all sensitivity runs.

The boundary conditions can range between a perfectly closed reservoir (impervious lateral boundary) and a strong connection with a surrounding cold aquifer. In the example, equal probability distribution is assigned to any condition between these two extremes.

Effects of the exploitation strategy on the overall performance (areal distribution of production and injection, depth of the wells) are also taken into account, as described in Section 4.

In the example, the reservoir is considered to be massive, with a simple, symmetric geometry. If the reservoir shape appears to significantly affect the expected performance, this should be taken into account in the model implementation, by defining an appropriate "shape" factor and applying a probability function to it. This would complicate modeling a bit, but would not conceptually change the method.

4. MODELING

4.1 General Model Characteristics

The geothermal reservoir simulator TETRAD has been applied for this particular evaluation. However, any other code could be used, provided it has the capability to handle 3-D problems and it supports a dual-porosity formulation.

The applied simulation model is essentially a process study model which represents a strong simplification of the real geothermal reservoir. The model is characterized by the homogeneous distribution in space of most petrophysical and thermodynamic properties, representing average expected values for the whole reservoir. A limited degree of variability with depth has been introduced only for the porosity (decrease with depth, according to a predefined function, and resulting in the required average value) and for the temperature (slight decrease in the upper reservoir layers). The model has a limited number of grid blocks which allows multiple forecasts to be efficiently computed to assess the sensitivity of model's results to variations of the key reservoir parameters. For every parameter, the base case value corresponds to the "most likely value", as deduced by the probability distributions discussed in Section 3. The extreme values reflect the complete range of possible values.

4.2 Model Geometry

The areal extension of the reservoir is kept constant at a conveniently defined size. In the example, the model represents a rectangular volume having an extension of 3 x 3 km, as shown in Figure 2. It is important to mention that the selection of the model size doesn't reflect an evaluation of a proven or probable size of the real reservoir. The reservoir extension and its level of uncertainty are described by its probability distribution function, and are adequately taken into account by the probabilistic reserves evaluation. As the model results are interpreted in terms of recoverability of the fluid mass in place, they can be simply extrapolated to any reservoir size within the assumed range. This approach takes advantage of the model characteristics (homogeneous parameter distribution and normalized inflow from the boundary), simplifying the probabilistic computation of the reserves.

Vertically, the model is discretized into 10 layers, with thinner layers at the top which allows the model to reproduce the effects of a falling liquid level and the formation of a two-phase zone or steam cap under exploitation.

4.3 Exploitation Strategy

Horizontally, the model is discretized into four sectors to account for different locations of production and injection, as shown in Figure 2:

- the production area (P)
- the injection area (I)
- a buffer or stand-off zone between production and injection (Ib)
- a sector of the reservoir that is not utilized (N).

Sector N remains hydraulically connected to the other sectors, but does not contain any production or injection activity. This represents areas that would not be targeted for drilling for reasons such as difficult access, uneconomic deliverability or drilling hazards.

In the example, the base case model assumes that the commercial resource area can be developed such that 50% of the area is used for production (P), 30% is used for injection or standoff (I + Ib), and 20% is not utilized for production or injection (N). Sensitivity of the reservoir performance to the extension of the different sectors has been analyzed within an assumed range of plausible values.

Sensitivity analyses also examined alternative exploitation strategies with shallow and deep extraction. Disposal by deep injection into the reservoir of 100% of the separated brine is assumed in all cases

4.4 Boundary Conditions

The upper and lower boundaries of the model are assumed to be closed to both mass and heat flow. In the sensitivity analyses, the lateral boundary can be either impermeable (closed reservoir) or connected to a radial, infinite-acting aquifer at 150^{o}C (open reservoir with cold influx). In the case of an open reservoir, the four horizontal sectors are connected to the surrounding aquifer proportionally to their areal extent (for example, a sector extending over 50% of the total modeled area will share 50% of the connecting surface between geothermal reservoir and external aquifer).

The cold fluid inflow from the aquifer into the different sectors of the model depends on the pressure conditions in the sector itself. It will be higher in the production sector (where the largest pressure drops will be experienced) and lower (or even negative, i.e. fluid will escape from the reservoir) in the injection area. The reservoir and aquifer permeability affects this flow interaction. In order to have reasonably homogeneous conditions, all simulated "open reservoir" cases are "normalized" to an average inflow of 60%, meaning an average substitution of 60% of the net extracted fluid (steam) with cold water during the 30 years of exploitation. Situations with lower inflow rates from the surrounding aquifer can be satisfactorily interpolated between the 0% inflow (closed) case and the 60% inflow (high rate of fluid replacement) case.

5. CRITERIA FOR THE DEFINITION OF RESOURCE CAPACITY

5.1 Field Abandonment Conditions

The first step in defining criteria for the definition of resource capacity was to establish field abandonment conditions related to a minimum practical or economic limit for well deliverability. For the purpose of this study, the minimum acceptable well deliverability was set at 10 kg/s of steam at a wellhead pressure of 10 bar g and a separator pressure of 8 bar g. A wellbore simulator (WELLSIM) was then used to calculate the minimum flowing bottom hole pressure which would yield the required deliverability as a function of discharge enthalpy, non-condensible gas content, and feed zone depth.

Two typical well completions were evaluated in the example: a shallow completion (1450 m TVD), for the model cases with shallow extraction, and a deep completion (1900 m TVD), for the model cases with deep extraction. The hypothesized wells have 16" tie-back, 13 3/8" casing, 10 ¾" and 8 5/8" (below 1350 m VD) perforated liner.

An example of the wellbore simulation results is shown in Figure 3, where the curves define abandonment conditions of flowing bottom hole pressure and enthalpy that correspond to a well deliverability of 10 kg/s steam. Combinations of bottom hole pressure and enthalpy that lie above the curve correspond to conditions that yield steam deliverability in excess of 10 kg/s. Points below the curve correspond to conditions that yield deliverability less than 10 kg/s. The abandonment pressure used here is a flowing bottom hole pressure rather than a reservoir pressure taken outside the dynamic influence of the producing well. This approach takes advantage of a feature of the reservoir simulator that can calculate the dynamic drawdown for the fluid flow towards the well. This allows to include the well productivity index as variable parameter in the reservoir simulation model.

5.2 Determination of Maximum Sustainable Steam Production

With field abandonment conditions established, the reservoir simulation model can be run to determine how reservoir conditions will evolve during exploitation and what rate of steam production could be maintained for a full 30 years.

The model is run specifying a constant steam production rate. The total mass extraction rate, as well as the injection rate, are automatically determined by the simulator based on the resulting enthalpy of the extracted fluid. The steam production rate imposed on the model is successively adjusted until the resulting evolution line reaches the minimum (abandonment) conditions after 30 years of production. Under these extraction conditions, the typical well will have declined to the minimum required deliverability after 30 years of field exploitation.

5.3 Definition of Recovery Factor

For every simulated case, corresponding to a set of the variable parameters defining the reservoir and the adopted exploitation strategy, the reservoir performance can be evaluated based on the resulting recovery factor R, defined as:

$$R = Ms / MIP \qquad (1)$$

where

Ms = total produced steam during 30 years
MIP = initial fluid mass in place

The recovery factor thus becomes an output of the reservoir simulation. Its sensitivity and dependency on the other reservoir parameters is discussed in the next section.

6. EFFECT OF KEY PARAMETERS ON RECOVERY FACTOR

The recovery factor R resulting from the simulation is a complex function of all parameters defining the reservoir and the assumed exploitation scheme. However, through multiple runs with different parameter sets it is possible to define the nature of this function.

For the two extreme cases of closed and open (60% inflow) reservoir, the dependency of the recovery factor R on the key reservoir parameters has been evaluated through sensitivity analysis by: 1) varying each parameter independently, maintaining all others constant, and 2) combining variations of several parameters at once. To facilitate the analysis, the parameters have been grouped into three main categories, namely:

- parameters related to fluid and energy storage: porosity and temperature
- parameters related to fluid recovery: fracture permeability, fracture spacing, and well productivity index
- parameters defining the exploitation strategy: extraction depth and areal distribution of extraction and injection.

Figure 4 shows the effect on recovery of the variation of single reservoir parameters. Sufficient cases were also run wherein more than one parameter was varied in order to create a multi-dimensional picture or map of the effect on recovery factor. A relationship was developed that accounts for the effect of superimposing changes in different parameters to give the correct overall value of recovery factor.

The remaining parameters (reservoir thickness, extraction depth, and exploitation strategy) were found to have a smaller impact on the recovery factor and were best dealt with by applying a correction factor to the superimposed effects of the parameters listed above. For the example discussed in this paper, following variability ranges for R resulted from the performed sensitivity studies :

- reservoir thickness: +/- 15% of the base case value (relating R to the mass-in-place of the base case with 1150 m reservoir thickness).
- extraction depth: +/- 10%
- exploitation strategy: +/- 10%

7. MONTE CARLO EVALUATION OF CAPACITY

The capacity evaluation is based on a volumetric calculation, combined with a probabilistic evaluation of all key parameters defining reservoir characteristics and exploitation strategy. Again, the recovery factor R is not treated as an independent variable, rather it is a dependent variable which is itself a function of key reservoir parameters.

7.1 Capacity Calculation

The fluid mass in place in the reservoir volume (MIP) is calculated as

$$MIP = A \cdot h \cdot \phi \cdot \rho(T) \qquad (2)$$

where

A = extension of the reservoir
h = average reservoir thickness
ϕ = average total porosity
ρ = average fluid density at temperature T

The electrical generating capacity (P) is calculated as

$$P = MIP \cdot R / UF / CF / H \quad (3)$$

where

C = electrical capacity (MW)
MIP = initial mass-in-place (kg)
R = recovery factor (steam over initial mass in place)
UF = steam usage = 7.5 kg/kWh
CF = capacity factor = 85%
H = hours in project life = 30 years = 262,800 hours

7.2 Monte Carlo Simulation

Monte Carlo simulation is a technique that involves random sampling of the independent variables in a complex problem in order to establish a frequency distribution for possible outcomes. The results show the complete range of possible outcomes as well as the probability of occurrence for a given outcome

Reservoir area, reservoir top and bottom, matrix porosity and temperature (affecting fluid density) were treated as independent variables for the purpose of calculating fluid mass in place. Simultaneously, porosity, temperature, fracture permeability, fracture spacing, well productivity index, cold fluid influx, reservoir top and bottom, extraction depth, and exploitation strategy were treated as independent variables for the purpose of calculating the appropriate recovery factor. Thus, the capacity calculation is based on the sampling of 10 variables. The assumed probability distribution functions for the reservoir parameters correspond to those described in Section 3 and shown in Figure 1.

For the described example, the obtained results are shown as a probability distribution curve for the reservoir capacity in Figure 5. This curve indicates that the evaluated reservoir has:

- a 90% probability of having a capacity of 175 MW or higher
- a 50% probability of being as high as 290 MW
- a 10% probability of exceeding 460 MW

8. CONCLUSIONS

The presented method provides a coherent approach to the estimation of "proven" reserves and upside potential of a geothermal prospect. Treating the recovery factor as a dependent variable, the resultiung capacity is linked to the key thermodynamic and hydraulic characteristics of the resource, rather than to volumetric parameters alone. However, maintaining a volumetric formulation allows a straightforward application of probabilistic concepts, which would be quite difficult with a pure simulation approach.

The method improves the confidence in estimates of geothermal generation capacity. It is particularly suited to applications in the early exploration stages of a geothermal prospect, and provides a useful basis for making the appropriate investment decisions for commercial development.

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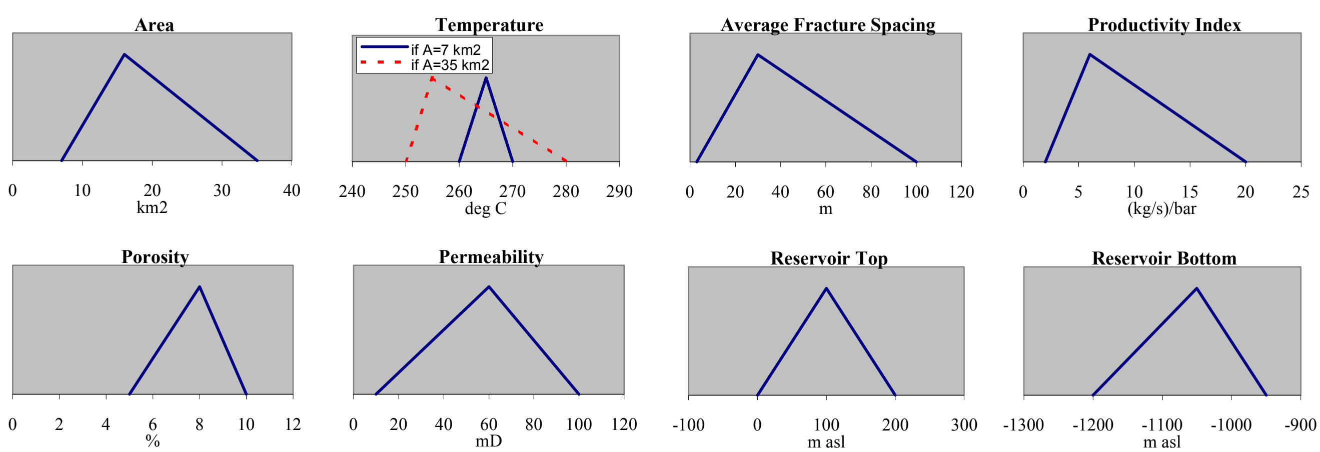

Figure 1. Probability distribution of key reservoir parameters

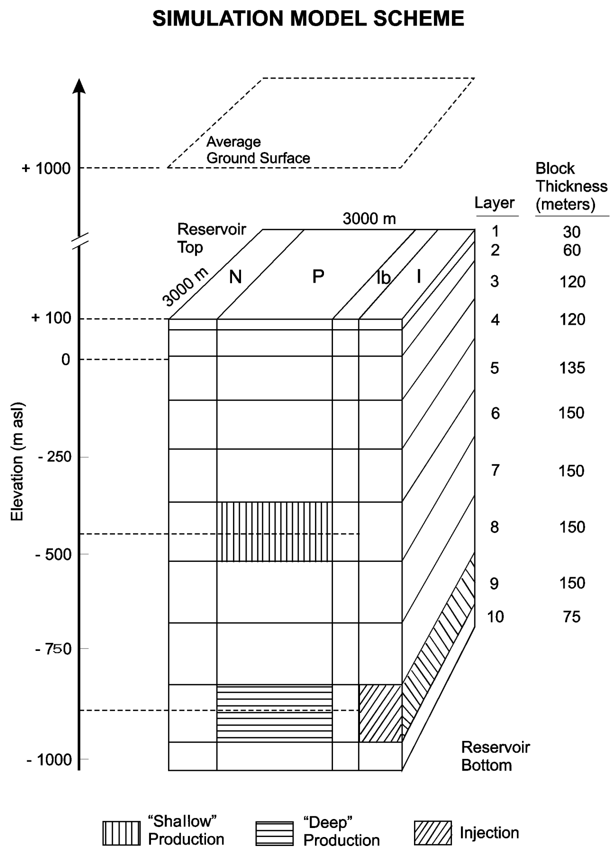

Figure 2. Simulation model

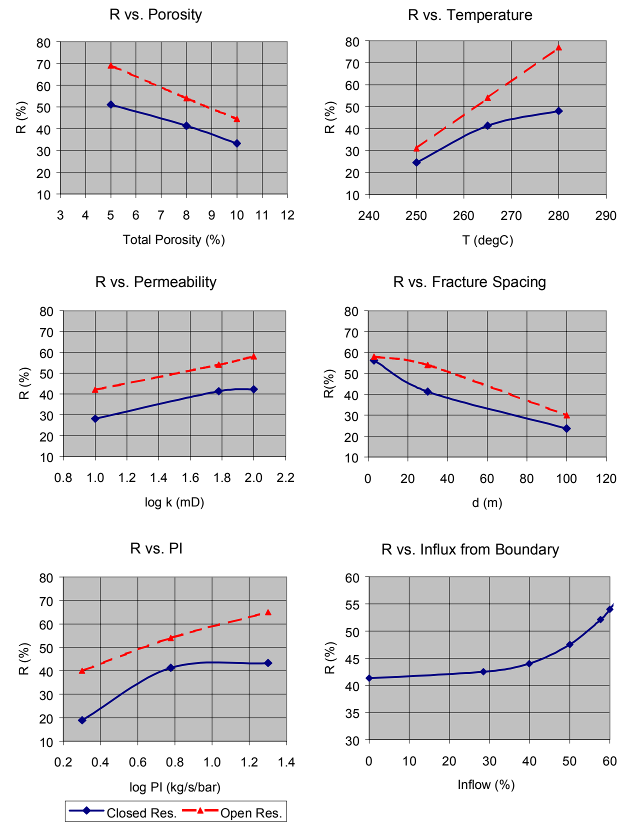

Figure 4. Dependency of recovery factor from key reservoir parameters

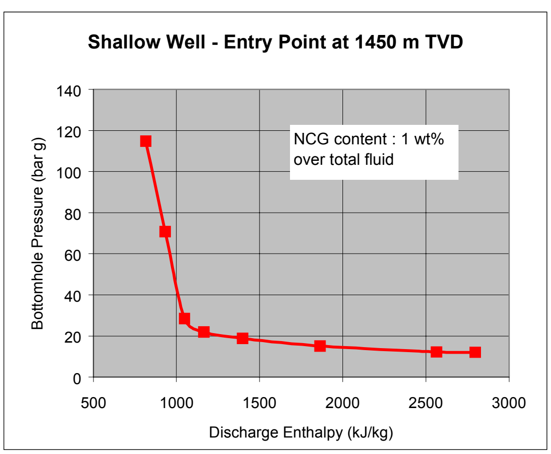

Figure 3. Field abandonment pressure

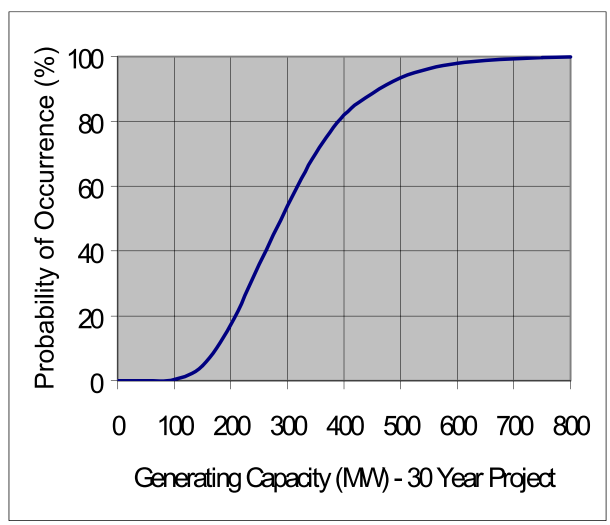

Figure 5. Cumulative probability curve for field generating capacity