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USING A LARGE RESERVOIR MODEL IN THE PROBABILISTIC ASSESSMENT OF FIELD MANAGEMENT STRATEGIES

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ABSTRACT

For the probabilistic assessment of exploitation strategies of a geothermal reservoir, alternative numerical simulation models are constructed (most likely, pessimistic and optimistic), in order to represent the uncertainty range of key reservoir properties affecting field performance. While each of these models is calibrated to the initial state and field historical behavior, they significantly diverge in the prediction of future reservoir performance. The entire set of models is used to evaluate some exploitation strategies. However, some uncertain parameters, although not directly related to reservoir properties, can also affect to some extent overall field behavior. Therefore a complete coupling of the reservoir simulation models with a probabilistic evaluation would lead to an unreasonably high number of model runs, making it computationally impractical. To overcome this problem, polynomial approximation functions have been developed for the predicted reservoir performance, based on specially designed model runs and on the recognized relationship between well deliverability and cumulative steam production. The polynomial expressions are incorporated into a complex economic model that allows the combined evaluation of the complete range of uncertainties potentially affecting a given project, without the need of specific, time consuming reservoir modeling runs.

Keywords: reservoir simulation, probabilistic assessment, polynomial approximation

INTRODUCTION

In today's highly competitive energy market, the successful development and use of geothermal resources requires a carefully integrated evaluation of all aspects affecting the economic value of a project. As shown in Figure 1, the economic evaluation must take into account the anticipated reservoir performance in the context of power generation strategies, well performance, and contractual agreements. When faced with strategic decisions that involve significant capital investment, a thorough assessment of the uncertainty level for all parameters that can significantly influence the final economic outcome of a given project is necessary. Because development projects invariably possess some degree of economic risk, alternative options are usually evaluated and compared in terms of risk-based Net Present Value (NPV). Other calculated values such as chance of regret, are also used in the probabilistic evaluation, in order to properly assess the level of risk associated with a project or a particular exploitation strategy, as well as their upside potential.

Resource management specialists are required to develop a consistent set of reservoir performance forecasts that adequately represent the perceived range of uncertainty in future resource behavior. These data are then combined with all other variables and their respective uncertainties in an economic model. Especially in the case of fields under exploitation, the use of relatively complex, three-dimensional simulation models calibrated against the past reservoir performance is considered the most reliable tool for the evaluation of future performance with different exploitation schemes. However, the combination of a probabilistic approach with the use of a large numerical reservoir model is a challenging task that can easily result in a prohibitively high amount of computational work. This is further complicated by the influence on reservoir performance of several project uncertainties unrelated

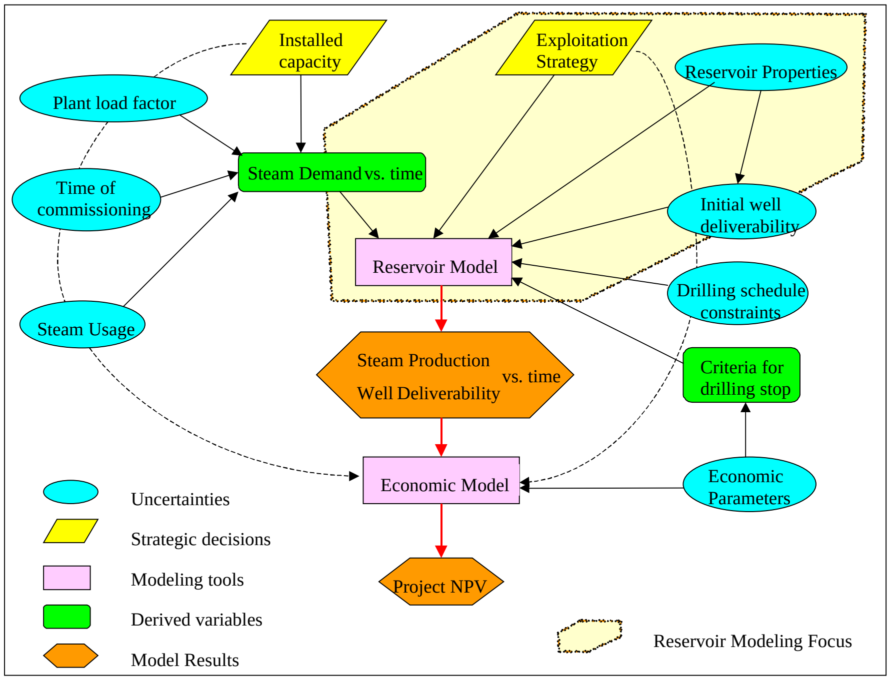


Figure 1. Simplified influence diagram for a geothermal development project.

to reservoir parameters, such as power plant load factors or the timing of plant commissioning (see Figure 1). This creates a strong relationship between the probabilistic economic model and the underlying reservoir model, potentially leading to a very high number of required reservoir model runs.

This paper presents in generic terms the methodology that we adopted in a recent project, aimed at the identification of the optimum strategy for the future exploitation of a mature field. The reservoir under investigation is characterized by a shallow part that has been extensively exploited for several years, overlying a still largely untapped deep part. One of the key issues investigated was the potential benefit of targeting the deep reservoir for future make-up drilling versus the present strategy of exploitation primarily focused on the shallower, more easily accessible reservoir. Information on the deep reservoir is still rather limited, in particular regarding permeability distribution. As a consequence, the existing numerical model of the field is not very well constrained in that sector, and this calls for a proper consideration of the uncertainty level in the model itself.

ADDRESSING KEY UNCERTAINTIES IN RESERVOIR

In the economic model utilized for the probabilistic project evaluation, the uncertainty about the possible range for every relevant parameter is described by a set of three values, defining the "most likely" (P50), "pessimistic" (P10) and "optimistic" (P90) values. These values define the cumulative probability function for that parameter. By definition, the actual value of a given uncertain parameter has 50% chance to be equal to or less than the P50 value. Similarly, there is only a 10% probability that the actual value would be equal to or less than the P10 value. The P90 value represents the opposite extreme, with a 90% probability that the actual value doesn't exceed that limit (in other words, there is only a 10% chance that the real value is higher than that).

To be consistent with this approach, the expected reservoir performance must also be defined in terms of "most likely", "pessimistic" and "optimistic" outcome for every field exploitation strategy that is being considered. For the field under investigation, a detailed numerical model of the reservoir, consisting of a grid with several thousands blocks, had been previously implemented based on the commercially available reservoir simulator TETRAD (Vinsome, 1996). The model accurately reflects the current conceptual model of the field and has been satisfactorily calibrated against initial thermodynamic state, reservoir pressure response to exploitation and well performance (steam deliverability and enthalpy evolution vs. time). As this model is believed to represent a fairly accurate representation of our current knowledge of the reservoir, with all main reservoir properties being set at what we consider the most likely value, it was defined as the "most likely model", or "P50 model". Accordingly, performance forecasts obtained with this model would be used as the "P50", i.e. most likely, prediction of what would happen with a given exploitation strategy.

For the definition of the P10 and P90 cases it was decided to develop "pessimistic" and "optimistic" numerical models in order to obtain distinct reservoir performance forecasts. To do this, we first identified key reservoir parameters or processes that are still poorly constrained and can significantly influence future performance, and tried to define reasonable ranges of uncertainty for them. In our example, the key uncertainties relate to the permeability of the deep reservoir, the strength of aquifers attached to the edges of model, the hot upflow rate and its dependency on reservoir pressure changes, and deep reservoir temperature outside of the already drilled area.

Starting from the existing P50 model, and maintaining the same basic model structure, a trial and error process was initiated by modifying the key parameters described above within the range of evaluated uncertainty. The goal was to obtain models that have a comparable history match to the existing P50 model, while diverging significantly in terms of future performance, both in pessimistic (P10) and optimistic (P90) sense. This process was particularly insightful. For example, when deep permeability was reduced in one of the models, the enthalpy and pressure history match of the shallow reservoir were preserved by increasing the hot basal upflow in the central part of the model. Constraining the uncertainty in the deep permeability in this fashion allows an evaluation of the economic downside and upside to development strategies focused on deep drilling.

At the end of the calibration process, three different versions of the model were available for the evaluation of alternative exploitation strategies that would result in the required P50, P10 and P90 performance forecast. All models can match historic data within reasonable tolerance limits, but the difference in future response to exploitation is significant, reflecting the underlying uncertainty in key model parameters.

EVALUATION OF BASIC ALTERNATIVE STRATEGIES

The numerical model, in its three variations, can be used to evaluate basic strategies for field development. Up to 10 different strategies were proposed that resulted from a combination of the following parameters.
- total target steam production rate
- completion type, location and depth of the make-up wells
- location of injection
- operating conditions of wells (wellhead pressure)

In predictive mode, the reservoir model is coupled with our proprietary wellbore simulator GEOFLOW. Both existing and future make-up wells are defined in the model in terms of location, depth and productivity index of multiple feedzones, and calibrated versus observed performance at the beginning of the forecast run. For future wells, average expected initial deliverability is achieved by proper calibration of the productivity indices. Through the coupling of reservoir and wellbore simulators, well deliverability is calculated explicitly in periodic time intervals based on reservoir conditions, and make-up wells in the reservoir model are activated as needed to meet the specified steam demand. Calculation of separated brine rates to be injected, selection of new make-up well locations according to specific criteria, and shut-in of non-productive wells are also performed automatically. With the adopted approach, the fundamental output of the prediction runs is the well productivity evolution with time, for both existing and future make-up wells. Additionally, the predicted amount of brine vs. time is reported, to determine the requirements for new injection wells. Typically, every prediction run requires a few hours on a top-of-the-line PC to be completed. This is due to the size and complexity of the reservoir model and the coupling with the wellbore simulator (well deliverability calculations are repeatedly performed for more than 150 wells).

Besides the specific uncertainty in reservoir properties (which is represented by the three models P10, P50 and P90), a complete probabilistic evaluation also needs to capture the indirect impact on reservoir performance of several uncertain parameters affecting the overall economic evaluation. Typical examples (see Figure 1) are uncertainties in:
- initial deliverability of make-up wells
- constraints in drilling schedule (such as the maximum number of wells to be drilled per year)
- criteria for termination of make-up drilling
- steam usage and its deterioration rate with time
- power plant load factor
- timing of plant commissioning and/or modification of plant characteristics

Considering only the six uncertainties mentioned above, some 10^4 reservoir simulation runs would be required to calculate the NPV probability distribution for 10 different strategies. A further complication arises from the fact that the criterion for make-up drilling stop is actually affected by several, sometimes significantly uncertain economic parameters. It is evident that the reservoir model is not a practical tool for this type of probabilistic evaluation.

A simplified and more flexible alternative to the reservoir model is therefore needed, that would reproduce its results with an acceptable level of precision. Looking for this alternative, we investigated whether variations within reasonable limits from a selected "base case" (including variations in the total installed capacity) could be handled without the need of repeating the reservoir simulation. After examining in detail the simulation results for several cases, a viable solution to achieve the desired level of generalization was found by using polynomial approximations of key simulation output data, as described below.

BEST FITTING POLYNOMIAL CURVES OF SIMULATION RESULTS

In the following discussion four different cases simulated with one of the three available models are utilized as examples of how a polynomial approximation can be applied to synthesize the model results in a way that will later allow a proper evaluation of effect of several parameter variations.

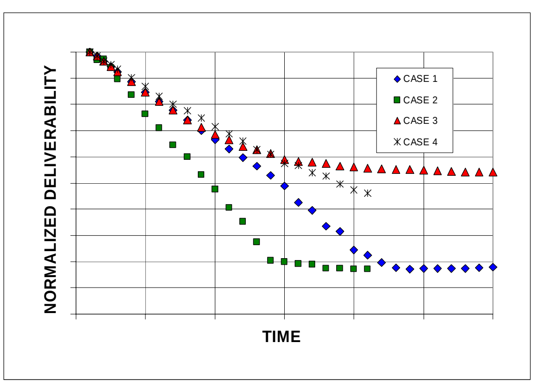
All cases assume the same reservoir exploitation strategy, but they differ as follows:
- Case 1 is the base case, with a given steam extraction rate, to be maintained constant as long as the make-up well deliverability remains above a prescribed minimum limit
- Case 2 is a case with the extraction rate increased by 35% with respect to the base case
- Case 3 has the same extraction rate as the base case, but a make-up drilling stop is imposed at a given time, several years before the deliverability minimum is reached.
- Case 4 is a case where the maximum number of make-up wells is limited to 2 per year.

Figure 2 shows the obtained simulation results for the four cases, both in terms of total produced steam and average well deliverability versus time. Obviously, the observed evolution of well deliverability is different for every individual case, due to the different load imposed on the reservoir. However, if the same data are plotted as a function of cumulative extracted steam, rather than time (Figure 3), they plot on a single curve up to a point corresponding to the time when make-up drilling stops. It is therefore possible to define a single best fitting polynomial that reasonably describes the well deliverability decline as a function of cumulative steam. It is interesting to note that in the specific case under investigation, the best approximation is achieved when two separate functions are defined for the existing and the future make-up wells, respectively. For existing wells, a satisfactory correlation is obtained by plotting deliverability vs. total cumulative steam, while for make-up wells a function of the cumulative make-up steam appears to be more appropriate.

Once make-up drilling stops, the field enters into a declining capacity mode, and the deliverability changes need to be defined with a different approximation. All our cases are characterized by the existence of a final, pseudo-steady state situation in which a certain level of steam production can be maintained almost indefinitely. The analysis of the simulation results shows that a reasonable single approximation for all different cases can be achieved. This is done by plotting the difference between total steam production and the pseudo-steady-state extraction rate (normalized at the beginning of the decline capacity period) versus the cumulative steam produced after the drilling stops. As shown in Figure 4, an exponential decline function appears to be appropriate for the representation of the reservoir behavior during this period.

To complete the description of reservoir behavior, an additional function is needed, defining the performance of the existing wells vs. total cumulative steam, for the case where only the existing wells are

(a)



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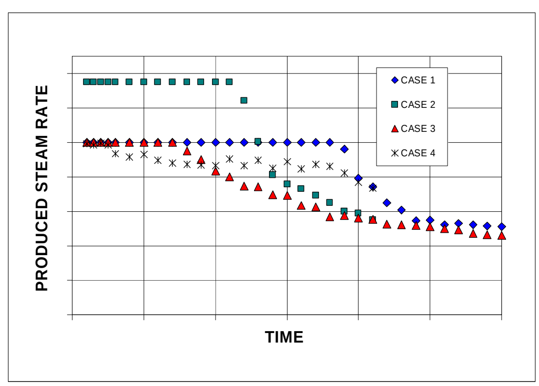

Figure 2. Well deliverability decline (a) and total steam production (b) for different cases as a function of time.

operated, with no additional drilling (Figure 5). This allows considering situations where the make-up drilling campaign is delayed until some future time.

During the process of deriving the approximation

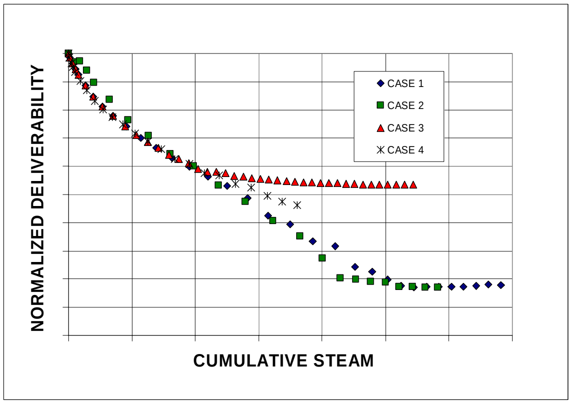

Figure 3. Average well deliverability decline as a function of cumulative steam production

functions, it was found that three model runs are in general sufficient to define the whole set of coefficients required by the different polynomial curves. These cases are:

- the no make-up drilling case
- the case with a constant target production, and an unlimited number of make-up wells
- the case with the same target production, but with a limitation in make-up drilling.

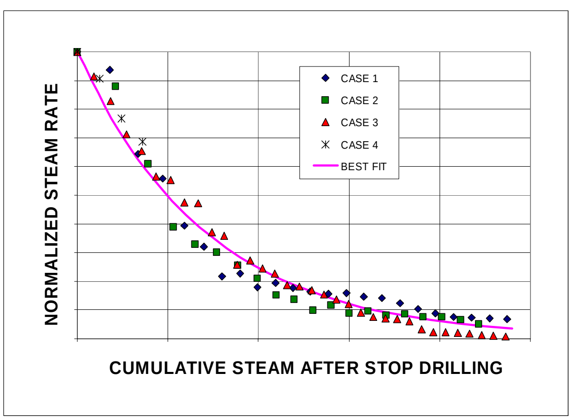

Figure 4. Best fitting exponential curve for the normalized field decline after make-up drilling stops.

For the complete definition of a given reservoir exploitation strategy, considering the three reservoir models P10, P50 and P90, a total of six runs is therefore required, plus the three runs for the no make-up case, which is common to all strategies in any of the three reservoir models.

A spreadsheet has been subsequently developed, that reconstruct the expected evolution with time of well uses the obtained strategy-dependent coefficients to performance and of total produced steam, based on assigned total required steam production, well

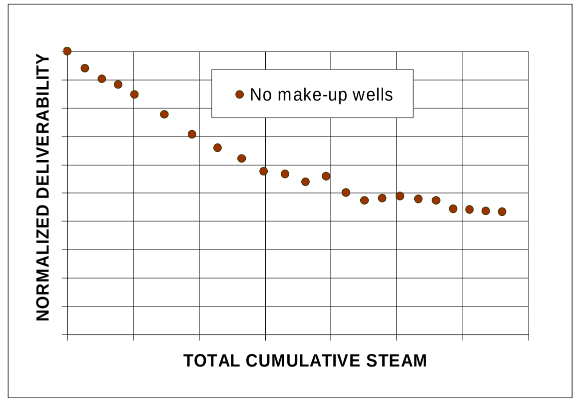

Figure 5. Well deliverability decline vs. total cumulative steam, with no additional make-up drilling.

drilling schedule, initial well deliverability, etc. To demonstrate the ability of this "synthetic" model to satisfactorily reproduce the simulation model results, Figures 6 and 7 show a comparison between the model results and the reconstructed curves of average well deliverability and total produced steam, respectively, for all example cases. It has been verified that a similar approximation quality is

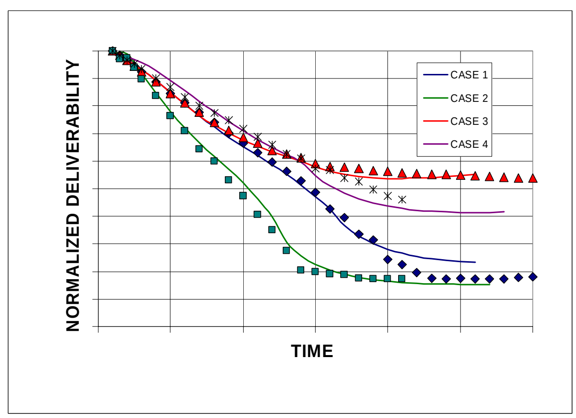

Figure 6. Comparison of well deliverability decline from model results and polynomial approximation

achieved for cases involving total capacity levels different from the base case (see Case 2), as well as for changes in other parameters like load factor, drilling schedule, plant commissioning, etc.

Similar approximation functions have been developed for the expected amount of brine to be disposed of, in order to supply the necessary information about injection well requirements.

This spreadsheet is integrated into the overall economic model, and can easily evaluate the impact of every uncertain parameter on field performance,

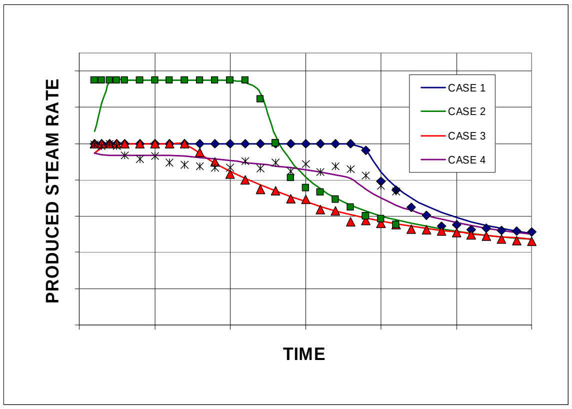

Figure 7. Comparison of total steam forecast from model results and polynomial approximation

including but not being limited to the reservoir model itself. For every combination of all relevant parameters, the spreadsheet returns the corresponding function of produced steam (that determines the revenue stream) and the well deliverability decline (that affects spending for make-up drilling). This allows the application of a consistent probabilistic approach, without a full coupling with the underlying, time consuming reservoir simulations.

CONCLUSIONS

In order to properly assess the potential impact of reservoir-related uncertainties on the expected field performance under alternative exploitation strategies, three different reservoir simulation models have been constructed, representing the "most likely", "pessimistic", and "optimistic" cases. Although these models show a similar quality in the match of historic reservoir evolution, they diverge significantly in the performance forecasts, reflecting significant uncertainty in some key reservoir parameters

Several other parameters that define the overall project indirectly affect the reservoir performance, and are also subject to a certain level of uncertainty. A complete coupling of all these parameters with the reservoir model would require a very high number of simulation runs, and that would make a consistent probabilistic approach virtually impossible, due to computation time limits. Also, the effective integration with economic models developed for project evaluation would be very difficult.

To overcome this limitation, a method has been developed that relies on polynomial approximation of the model results for a limited number of conditions and exploitation strategies. The study has proven that by selection of appropriate relationships for the characterization of the model performance (in particular, well deliverability vs. cumulative produced steam) the performance forecast for each model can be approximately described by a set of polynomial coefficients.

Using this approach, the required number of simulation runs to fully evaluate strategic alternatives from a probabilistic point of view has been maintained within reasonable limits. The polynomial approximation of the reservoir performance allows an efficient integration of this key uncertainty in a complex economic model utilized for project evaluation.

It is suggested that a similar approach could be adopted in the study of other reservoirs. For every particular case, though, a careful analysis of the best possible representation of the field performance will be required, because this at least partially depends on the reservoir characteristics and on the development strategies to be evaluated.

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