Proceedings World Geothermal Congress 2010
Bali, Indonesia, 25-29 April 2010

What is the End Point for Geothermal Developments: Modeling Depletion of Geothermal Fields

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Keywords: Resource Estimation, Stored Heat, Reservoir Modeling, Reinjection, Corrosion, Scaling

ABSTRACT

Any finite quantification of the capacity of a geothermal resource implicitly involves a start point and an end point for energy extraction. The issue addressed here is, why does commercial energy extraction cease from a geothermal resource, and what are the implications for resource capacity estimation?

In a simple stored heat estimate with no natural heat or fluid recharge over the project lifetime, the implicit assumption is that the project will cease when all of the available energy has been extracted. So the "failure mode" is a temperature decline. Even that is a significant oversimplification - in a system with reinjection, energy extraction will have to cease when the fluid coming out of the production wells drops below the minimum inlet temperature requirement of the power plant. But at that time there will be a temperature and pressure gradient laterally through the reservoir from the reinjection to the production wells, so the average resource temperature at that time will be less than the power plant inlet temperature. Further considerations to take into account are: heat loss up production wells, which could be considerable; heat loss between the wells and power plant; heat loss between the separators and power plant and reinjection wells; and heat gain down the reinjection wells. There are power systems aspects to consider as well as parasitic pumping etc. loads. Furthermore, if the production temperature declines over the lifetime of the project the power plant efficiency would drop and the production pumping requirements will change.

With dynamic reservoir simulation the failure mode is often found to be pressure decline rather than temperature. Based on practical experience of geothermal systems that have been exploited for a long period of time, there are other possible failure modes including: premature reinjection returns leading to a low percentage energy recovery; fluid depletion; groundwater incursion causing undesirable chemical effects such as scaling and corrosion as well as enthalpy decline; or excessive environmental effects on the surface.

1. INTRODUCTION

Any finite quantification of the "capacity" of a geothermal resource implicitly involves a start point and an end point for energy extraction – the alternative being an infinitely sustainable energy extraction rate. The issue addressed in this paper is, at what time and why does commercial energy extraction cease from a geothermal resource, to what extent is this predictable, and what are the implications for resource estimation methodology?

The point of cessation can be referred to as the "end point" and the reason for cessation (somewhat pessimistically) as the "failure mode". The objective of this paper is to define the various ways that geothermal energy extraction development might have to cease, and then look at to what extent these can be built into predictive models. A significant outcome is that recovery factors for energy may in practice be much less than would be assumed on a theoretical basis.

As yet very few whole geothermal resources anywhere have been rendered unusable due to the resource reaching the end point and failing (though a number of individual plants have ceased to operate for various reasons). Fushime in Japan (Akaku 1990) may be an exception. However, cessation will eventually be the case, and it is implicit in most resource estimation.

Useful insights can be gained from experience in geothermal projects based on high temperature naturally convective systems with long operating histories, in excess of 50 years in some cases. To some extent those insights can be applied to other types of projects. However not all end points will apply equally to every type of resource. For example, fluid depletion is much more of an issue for dry steam resources than for others. Table 1 shows which effects are most applicable to which resource types. Practical examples are given it Table 2.

To a large extent many of the possible effects are manageable, and this is the art of successful geothermal project operation. For example, premature reinjection returns can be dealt with by adjusting the reinjection well locations or spacing. But this means that defining the project concept at an early stage has got to be a significant part of resource capacity estimation, quite apart from the obvious issues such as different conversion efficiencies for different types of power plant. For example, use of a high separator pressure could be adopted for a flash-steam only project, and will avoid silica deposition, but will imply lower ultimate energy recovery than if chemical dosing and a binary bottoming plant is also adopted. Therefore it will affect the resource estimation.

A factor leading to production of this paper has been the establishment and implementation of the Australian Code for reporting geothermal reserves and resources (Australian Geothermal Code Committee 2008, Williams et al. 2010). A unique feature of the Code is that it applies to both "conventional" high temperature magmatic-hydrothermal systems and other geothermal resource types such as modest temperature deep sedimentary aquifers and EGS. Application of the Code to projects with few data and hence in which only Inferred Resources can be declared is comparatively straightforward and to date has been based largely on stored heat estimates. But as geothermal projects within the emergent geothermal industry in Australia advance to the point where higher resource and reserves categories can be declared, a need has arisen to more rigorously examine the principles of resource capacity estimation. Such considerations equally apply to resource estimation elsewhere in the world as the recent re-inventory of geothermal resources in the USA has demonstrated (Williams 2008).

2. STORED HEAT ESTIMATES

"Stored heat" estimation is an appropriate method for resource estimation at an early stage of project development, such as pre-drilling or when only a few exploration wells have been drilled and tested (Muffler and Cataldi 1978). It is admittedly crude, but has the advantage of providing a means of comparing geothermal resources on a consistent basis and with some degree of calibration against actual examples of project with a production history (e.g. Sanyal et al. 2004, Sarmiento and Steingrimsson 2007). It can also be readily adapted to different resource types.

In a simple stored heat estimate with no natural heat or fluid recharge over the project lifetime, the implicit assumption is that the project will cease to operate when all of the available energy, subject to a suitable recovery factor (Sanyal et al. 2004), has been extracted. So the "failure mode" is a temperature decline.

In such assessments the "cut off temperature" represents the minimum isotherm for defining the resource volume. This is often based on an assumed power plant inlet temperature, and the "base temperature" which the available energy is referenced to is based on the plant rejection temperature. But even those apparently straightforward assumptions can be significant oversimplifications of what will actually happen through the project life.

In a system with reinjection, practically speaking energy extraction will have to cease when the fluid coming out of the production wells drops below the minimum inlet temperature requirement of the power plant. At that time there will be a temperature and pressure gradient laterally through the reservoir from the reinjection to the production wells, so the average resource temperature at that time will be less than the power plant inlet temperature (Williams 2007). That average temperature should more logically be the cut off temperature to define the resource volume for the stored heat assessment.

The next level of refinement is to consider that the lateral pressure and therefore temperature gradient between the reinjection and productions wells will definitely not be linear, which means the fraction of the resource volume from which energy can usefully be extracted is not just a simple proportion. This is because of the change in water properties with temperature, and multiple flow paths of different permeability. Those issues could readily be addressed by a dynamic reservoir model, provided suitable data on the formation properties are available for calibration, but that will not be the case re-drilling.

Further considerations to take into account are: heat loss up production wells, which could be considerable where wells are deep and flow rates small (e.g. in EGS); heat loss between the wells and power plant heat loss between the separators (high temperature resources utilizing flash steam only) and power plant and reinjection wells; and heat gain down the reinjection wells. There are also power systems aspects to consider such as process and thermodynamic issues as well as parasitic pumping etc. loads which for a low temperature project with deep wells of modest permeability could be as high as 30%. Site-specific ambient temperatures and humidity will dictate practical cooling options and hence efficiency.

Furthermore, if the production temperature declines over the lifetime of the project which is what would be expected in a heat mining operation (e.g. EGS in particular) and is therefore implicit in a stored heat estimate, the power plant efficiency would also drop. This will be an issue in particular for binary plants which can operate across a wider range of temperatures compared to a condensing steam turbine which would usually operate over a smaller range of possible inlet pressures and therefore a fixed efficiency in so far as the energy in the steam fraction is concerned (though if the reservoir enthalpy declines, more liquid will have to be taken to produce the same amount of steam). We are not aware of any stored heat estimate where the effect of decline in temperature with time on conversion efficiency has been explicitly taken into account. The production pumping requirements also will change as the fluid density and viscosity changes, exacerbated by any reservoir pressure changes. All of these factors can and ideally should be modeled as resource assessments become more accurate.

3. DYNAMIC RESOURCE ESTIMATES

Unlike a "static" stored heat estimate, dynamic resource estimates allow for changes in the reservoir characteristics over time, including in some cases the assumption that the exploited part of the reservoir is not a closed system. This can include substantial hot fluid recharge from greater depth, and fluid lost to the system through surface discharge, evaporation or outfield injection. It can also include cool inflows.

Rather than assuming a fixed amount of available energy in a resource which can be depleted within a certain length of time, if there is sufficient recharge an alternative approach is to assume that a certain rate of extraction is indefinitely physically sustainable on a human time scale, in which case the field "capacity" is better expressed as MW_{th} or MW_e (making suitable assumptions as to conversion efficiency) rather than $PJ_{thermal}$ or $MW_{thermal}$-years in place and recoverable. This appears to be the case with fields such as Wairakei in New Zealand, where the amount of hot recharge has increased as a result of pressure drawdown (Allis and Hunt 1986) and reservoir modeling predicts that extraction will be physically sustainably for at least 100 years – which is perhaps simply an expression of the fact that our perception of the "resource' is too limited in that it does not include the deeper heat source. But even there other factors may come into play which could mean the project cannot in fact sustain output for all of that period.

Based on practical experience of geothermal systems that have been exploited for a long period of time, there are other possible failure modes as follows:

With dynamic reservoir simulation, which is the most common means of assessing appropriate capacity in advanced existing conventional schemes without pumping, the "failure mode" is often predicted to be **pressure decline** rather than simply temperature decline to the point where the thermal energy is depleted.

In a single phase (liquid) reservoir, pressure decline will be due to draw down in liquid pressure, as in a groundwater aquifer. In a two-phase reservoir such as Wairakei in New Zealand, Cerro Prieto in Mexico (Puente and Rodriguez 2000), or many of the other high temperature "conventional" projects worldwide which have been exploited, pressure draw down will to some extent be buffered by boiling, but if wells tap two-phase zones, pressures will be linked to temperatures, so can decline if cool water invades the reservoir. This has happened at Ohaaki for example (Bixley 1990).

In a dry steam system such as The Geysers in California pressure decline can be due to the reservoir drying out through insufficient injection (Sanyal 2000). Subsurface water loss within EGS projects is an obvious parallel though of a different origin.

Reservoir pressure decline has two important physical consequences. Initially it will cause declines in well mass output (though that may be compensated for by rising enthalpy if boiling occurs, so the available energy output may actually increase). It is also possible that pressures may eventually fall to the point where steam turbines become inoperable. In both cases considerable unrecovered thermal energy may remain within the reservoir.

To some extent these effects can be countered by drilling make up wells or adopting pumping , but a point of no return may be reached at which drilling further wells is not considered economic.

In the extreme case, reservoirs may dry out to the point where HCl is produced from the residual salinity, causing severe **corrosion** of wells and pipelines. This is most common in dry steam resources such as The Geysers but has also been observed in resources which are initially two phase or liquid, such as Tiwi in the Philippines (Santos and Carandang-Racela 1993).

Linked to and synergistic with reservoir pressure declines, there can be **incursion of groundwater**, either laterally or from above. This has been well documented and studied in New Zealand resources such as Wairakei, Ohaaki and Kawerau (Bixley 1990) as well as in some fields in the Philippines (e.g. Gambill and Beraquit 1993) and elsewhere. As well as chemical monitoring of well production physical and chemical parameters, repeat micro-gravity measurements are an appropriate tool for tracking fluid movements (Allis and Hunt 1986; San Andres and Pederson 1993).

Incursion of cool ground waters may be severely detrimental by reducing well enthalpies, as at Ohaaki. But it can also causing undesirable chemical effects such as **scaling and corrosion** (Clotworthy et al. 1995). The ground water above and around high temperature geothermal systems may be high in species such as bicarbonate and sulphate and of low pH, developed by separation, absorbtion and oxidation of gas phases. Wells have failed in New Zealand field due to external corrosion by such secondary fluids. They can also contribute to scaling in production wells by anhydrite from the admixed sulphate and/or more commonly calcite from the bicarbonate.

Premature reinjection returns to production wells are a common limiting factor, and can leading to a low percentage energy recovery though not usually total failure of the project (Aleman and Saw 2000; Esberto et al. 2001; Horne 1982; Inoue and Shimada 1985; Sarmiento 1986; Vasquez 1987).

Excessive **environmental effects** on the surface can limit geothermal energy extraction well before thermal energy depletion. At Wairakei in New Zealand for example, 50 years of geothermal fluid extraction with very limited reinjection have caused severe localised surface subsidence (possibly up to 21m) and increases in thermal activity including hydrothermal eruptions. The possibility of such effects extending into populated areas has been a constraint on further development (White et al, 2005). At Rotorua in New Zealand, power generation is effectively precluded because of concerns over effects on thermal activity which is crucial to the tourist industry.

4. ECONOMIC ISSUES

A fundamental definition not only in the Australian Geothermal Reporting Code, but also in the mineral and petroleum reporting codes from which it is derived, underlying formal resource and reserve reporting is that a **reserve** is what is considered to be economic to exploit today, and a **resource** is where is a reasonable expectation of economic development in the near future.

Therefore, even the lowest category of resource capacity estimation (Inferred Resources in the Australian Code) needs to have some consideration of the economics of a hypothetical project. At the simplest level this is implicitly done by appropriate choice of a cut off temperature, but it is preferable for it to be done more explicitly in terms of an assumed energy conversion process. Practically speaking, any geothermal power plant is not the most thermodynamically efficient possible: rather it is the most efficient that the project economics will sustain. Thus compromises often have to be made in terms of aspects such sizing of cooling and gas extraction systems, use of binary bottoming plant, and separator pressure including whether or not chemical inhibition of silica deposition is adopted. Similarly, Sanyal et al. (2007) make the point that there is an inevitable trade-off between drilling depth and drilling and pumping costs, leading to the conclusion that there is a optimum depth for drilling in any geothermal project which may be significantly less than the technical limits. This will provide a limitation on the assumed resource volume.

Consideration of the power price including any direct or indirect subsidies is also important. In Germany long term power sales contracts for renewable energy projects can be obtained for about 35 US cents/KWh, and there are additional incentives available such as drilling success guarantee schemes. It is therefore economic to drill to about 4km and obtain water at 140 -160 °C for power generation from aquifers of modest permeability. Those aquifers constitute a geothermal resource. In contrast, in New Zealand long term power sales contracts are for about 5 US cents/KWh and there are no incentives. Unpublished analysis by SKM, not surprisingly, demonstrates that fluids at similar temperatures cannot be produced economically even from existing abandoned oil wells with zero drilling cost to the project. The corresponding aquifers in New Zealand are therefore not a geothermal resource at this time. In terms of the Australian Code they would be termed a “geothermal play”.

For more advanced projects the interplay between end points and economics should be made explicit. For example in Figure 1 are shown the results of a numerical reservoir simulation for a fictitious geothermal project. This plot demonstrates that it is possible to sustain sufficient steam supply for about 70 MWe net production for the lifetime of the project, but the saw-tooth pattern of well flows at the bottom shows that it is only by drilling almost one make up well per year. In reality it would probably not be considered economically viable to drill make up wells during the last few years of the project life, and so the resource capacity (which in this case is best expressed as a rate in MWe rather than MWe-years) would decrease over time even though it is physically sustainable. Analysis over a longer time scale predicts that a lesser level of production is sustainable almost indefinitely, without make up drilling (Figure 2) though with declining enthalpy. Re-configuring the project to this lesser level of production would almost certainly be economic.

5. ABILITY TO PREDICT FAILURE MODES AND MODEL END POINTS

The ability to predict what will be the failure mode of a geothermal project and hence its end point for resource estimation varies both according to the nature of the reservoir and the amount of knowledge available. At an early (pre-drilling) stage stored heat with its implicit assumption of temperature depletion is the most appropriate tool.

Once exploration wells are drilled and tested, stored heat estimates can be refined, but data may start to become apparent which indicate other possible end points, such as premature reinjection returns or pressure decline. At this stage such effects can be qualitatively modeled by analogies and dynamic reservoir simulation, but probably as a series of “what if” scenarios rather than a definitive quantitative prediction.

Some factors are more readily predictable than others. For example, the large degree of subsidence that has occurred at Wairakei and Ohaaki would not have been predictable pre-production based on experience elsewhere, as Figure 2 shows. It is due to the occurrence there of unusual geological conditions making the formations there unusually sensitive to pressure change.

It is only once some production history becomes available either through operation of a small scale initial power generation scheme or long term well testing, that dynamic reservoir simulation can really come into its own and be used to give reliable forward predictions. Even then, reservoir simulation is only going to be as reliable as the information that is available to define the model and the scenarios modeled. Changes in field management have to be explicitly input to a model. At The Geysers, the rate of reservoir pressure run down fitted a harmonic decline curve and it would have been reasonable to extrapolate that into the future (Menzies and Pham 1995). Once supplementary injection was adopted, however, there was a rapid change in the rate of response and the power output increased substantially.

6. IMPLICATIONS FOR RESOURCE ESTIMATION

The methodology for meaningful resource and reserves estimates will change over time as projects become more advanced. While stored heat estimates are adequate for Inferred Resource estimates, more advanced projects and higher resource categories should take into account other possible end points and adjust the estimates accordingly, in many instances through numerical reservoir simulation.

In many cases this approach will cause the later resource estimate to be lower than the initial ones – though strictly speaking that should not be so if the risks and uncertainties have been considered properly in the initial estimates. That is not always necessarily the case however. At Wairakei for example a significant stimulation of heat and fluid recharge has occurred which has increased the resource available.

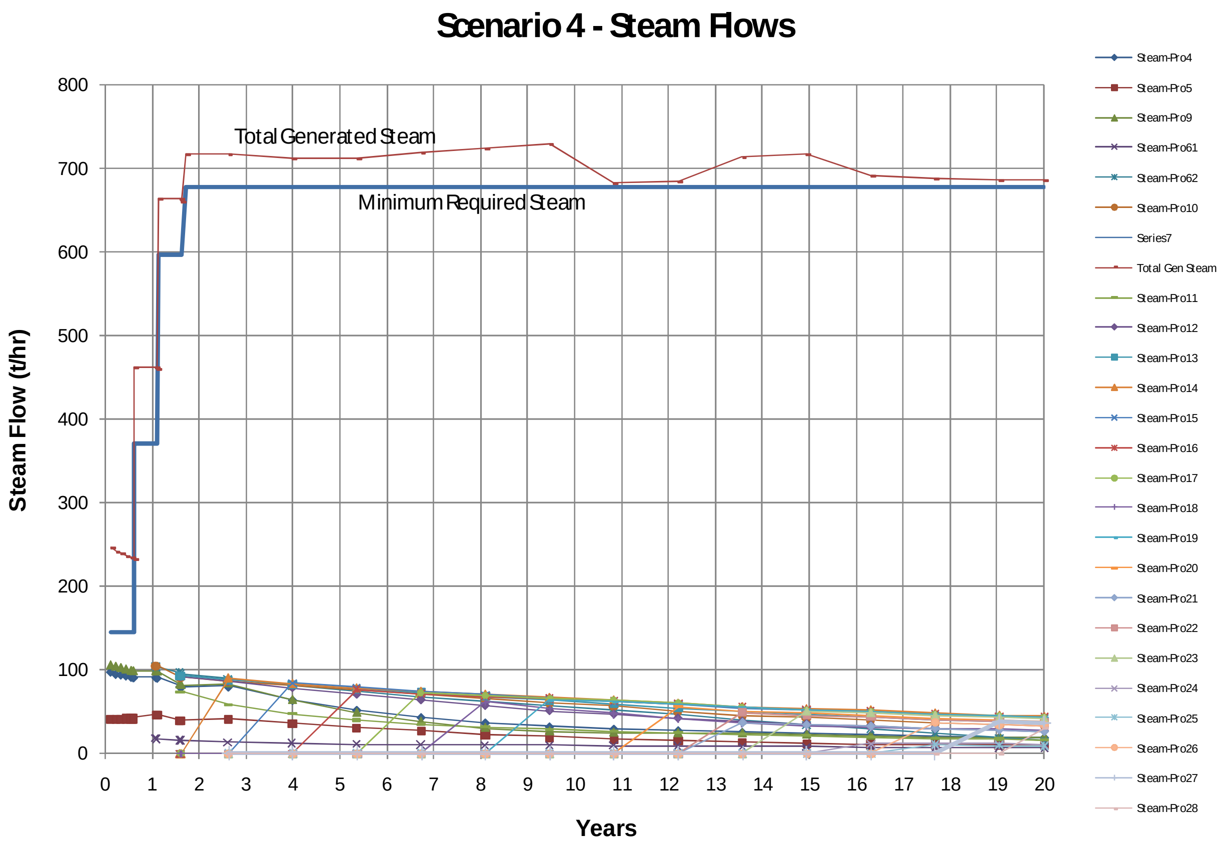

Figure 1: Required and predicted steam flow for 3 x 24 MWe units for 20 years at the “Inferno” project

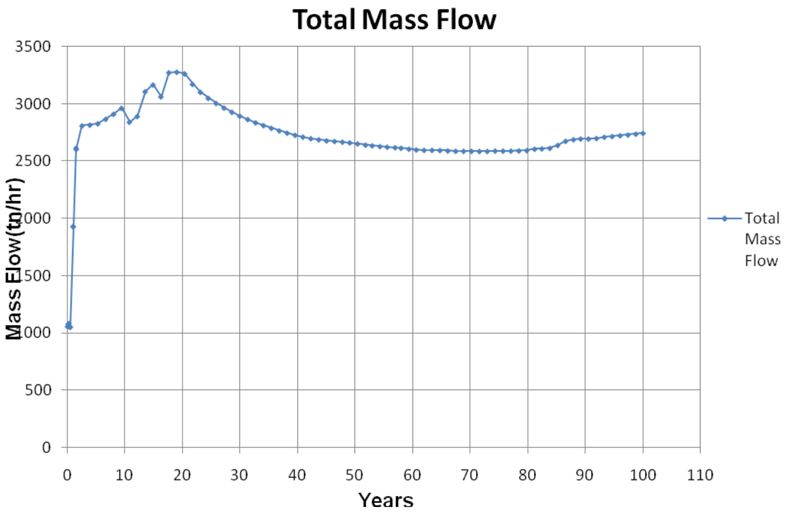

Figure 2: Predicted mass for 100 years at the "Inferno" project

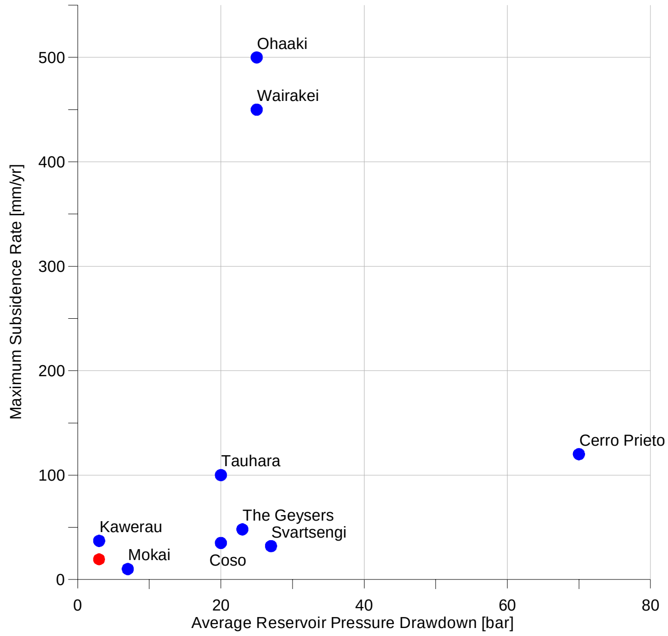

Figure 3: Comparison of subsidence rate vs. pressure draw down at various geothermal projects

7. CONCLUSIONS

When undertaking an estimate of geothermal resource "capacity", it is preferable to link the methodology and assumptions adopted to previous experience in analogous exploited resources, by way of considering the ultimate "failure mode" of the project. At an early stage, when few data are available, a stored heat estimate will probably be the most appropriate, where the implied end point is through energy depletion. The meaningfulness of the estimate can be improved by undertaking the estimate probabilistically.

As more data are accumulated and it becomes possible to categorise resources and reserves more accurately, the possibility of other end points should be considered. Dynamic reservoir simulation is a more appropriate method but it needs to be constrained by a consideration of what will ultimately cause the exploitation to cease, which is very unlikely to be simple heat depletion with uniform energy recovery throughout the reservoir. Recovery factors may in practice be much less than initially assumed.

Consideration of alternative end points will often, but not always, reduce the size of the stated resource capacity with time. It is possible for it to increase if there is evidence for substantial hot recharge, if the production history demonstrates that initial estimates of recovery factor were too low, or if there are changes in the operational regime.

In all cases economic practicalities need to be taken into account, along with the assumptions about the method for producing the fluid from wells and energy conversion that will affect overall ability to extract energy from the reservoir.

More rigorous recent use of the Australian Code for reporting geothermal reserves and resources has led to the conclusion that these issues need to be more explicitly expressed in resource estimates than has often been the case.

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Table 1: Factors which could provide practical limits to extraction in different system types

System Type	Possible Effects						
	Cooling (by production only)	Fluid depletion	Pressure decline	Cooling by groundwater incursion	Premature cooling by reinjection	Chemical effects	Environmental concerns
High temperature hydrothermal liquid	M	M	I-S	M-S	M-S	S	M-S
Dry steam	M	S	S	M	M-S	M	M-I
HSA	M		I	I	M-I	M-I	M
EGS	M	I	M		M-S	M	M-I

Key (Tables 1 & 2): **Effects**: M = Minor, I = Intermediate, S = Severe. **Predictability**: H = Highly predictable, I = Intermediate, L = Low degree of predictability

Table 2: Some examples of limiting factors observed in various projects, and the degree to which would have been considered predictable pre-production and after some years of production. All of these are high temperature hydrothermal projects

Project	Effects Observed							Predictability	
	Cooling (by production only)	Fluid depletion	Pressure decline	Cooling by groundwater incursion	Premature cooling by reinjection	Chemical effects	Environ-mental concerns	Pre-production	Post-production
Ohaaki NZ	M		M	S	M	S	M	I	H
Wairakei NZ	M		I	M			S	L	H
Kawerau NZ	M		M	I		I	M	L	M
Tongonan, Philippines	M	M	I	M	I			L	M
Palinpinon Philippines	M	M	M	M	I			L	H
Tiwi Philippines	M	I	M	I	M	M	I	L	M
Hatchobaru Japan					S			M	H
The Geysers USA	I	S	S			I	M	L	H