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RELIABILITY OF EARLY MODELING STUDIES FOR HIGH-TEMPERATURE RESERVOIRS IN ICELAND AND THE PHILIPPINES

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ABSTRACT

A 10-30 years long operation history of various geothermal steam fields in the Philippines shows that initial, simple model capacities are still being sustained. Volumetric heat reserve models therefore provide assurance that the resource in question can deliver necessary output to generate forecasted revenues. When applying the simple model approach to Icelandic resources, it appears that detailed numerical models conservatively estimate maximum generating capacities. Simple models, on the other hand, likely lead to aggressive production strategies. They also neglect risk of undesired resource behavior, such as cooler fluid invasion or fast pressure drawdown rates. Both can be mitigated at later stages in utilization history by make-up drilling and changed reinjection strategies. Initial costs are lower for aggressive power production but greater at later times, for maintaining steam flow rates. The reverse appears the case when intense green field development and detailed modeling are basis for conservative generating capacities. Interestingly, financial risks may be similar. Geothermal industries, which adopt aggressive production schemes, must prepare for higher steam field maintenance cost and should ensure that human and technical resources for the task are available. Detailed reservoir models should be preferred when it comes to address environmental issues like sustainable development and renewable power generation. Reason is that detailed models include boundary recharge; a reservoir property which allows successful utilization of a resource for generations.

INTRODUCTION

Reliability of simple and detailed reservoir models, that provide initial generating potential estimates for steam fields in the Philippines and Iceland, is the scope of this paper. Geothermal power producers face a need to estimate maximum generating capacity at early stages in their green field development. Reason is that environmental awareness and lengthy permitting procedures push for a licensing culture that maximizes allowed generating capacity, while at the same time it minimizes environmental impact of green field activities.

The Philippines geothermal industry has successfully developed many high-temperature reservoirs under strict environmental rules. Decision making for new projects has relied on surface exploration and 2-3 deep wells. Simple volumetric heat calculations provide basis for initial resource assessments. The Icelandic geothermal industry, on the other hand, has evaluated generating potential of green fields by intense drilling and years of flow testing. Generating capacity estimates are put forward when all relevant field data have been calibrated against 3-D numerical models. These models have matured with time and are used for assessing feasibility of adding new units to existing power plants.

The phenomenal growth of geothermal energy development in the Philippines, now ranked second to the US with 1931 MW installed, has been attributed to many factors. First was a government impetus to reduce the country's dependence on imported oil, especially in aftermath of the 1973 oil crisis. Second was abundance of geothermal resources. Third, but not the least, was a non-traditional and bold decision making strategy adopted by pioneers in the geothermal industry. To achieve self-reliance in energy requirements the government resorted to fast-tracking and acceleration of development projects, to immediately displace imported oil and save foreign currency costs. During early periods of geothermal development, the Philippines decided to change initial strategy from drilling shallow and slim holes to that of deep and big exploratory wells. If successful, the period of time needed to shift a field status from exploration to production stage could be shortened. The government put on a little more risk capital by shortening the evaluation period but did so by availing foreign expertise and contractors to adopt from new technologies and avoid costly mistakes.

This aggressive development strategy has been adopted in the Philippines ever since. One of the most important aspects, which concern long term impact of such decisions are to be reviewed in this paper. Part of this strategy was shortening of the evaluation period, which casts doubts on the long term viability of a project given such a scarce volume of field data and short testing period for a reservoir.

The Icelandic geothermal industry is currently building up speed and has several reasons for. Firstly environmental policies impose constraints on maximum number of exploratory wells in green field development. Secondly, success of current production drilling and exploration activities contributes to more optimistic and aggressive decision making. Thirdly, larger power units are more economical than the smaller ones. Fourthly there is substantial demand for electricity by aluminum industry. These factors have, altogether, led to the situation that the Icelandic geothermal industry is revising its development strategy, from conservative to more aggressive. This paper is a part of that revision.

The paper is structured as follows. First, geothermal development strategies for Iceland and the Philippines are reviewed. Then a nearly 25 years history of simple, volumetric modeling in the Philippines is presented, emphasizing early generating capacities and present power plant installations. Detailed reservoir models in both countries are briefly addressed, pointing out how recalibration efforts often result in increased generating capacities. We revise a volumetric heat reserve model for the 100 km^2 Hengill system in Iceland, this time applying the Philippine approach. A special chapter is devoted to operating performance of high-temperature reservoirs in Iceland and the Philippines. Potential risk factors are identified and examples given on management strategies that counteract steam field problems. Finally, we discuss sustainable development and renewable power generation strategies, and suggest what type of early reservoir models best address these critical environmental issues.

PHILIPPINE DEVELOPMENT STRATEGY

A common signature of most high temperature geothermal fields in the Philippines is their association with Pliocene-Quaternary volcanoes, situated along a discontinuous belt from Northern Luzon to Mindanao. This belt is referred to as the Philippine Fault, an active, left-lateral, strike slip fault. It extends more than 1,300 km parallel to offshore subduction zones. The Philippines has about 71 known surface thermal manifestations associated with decadent volcanism (Alcaraz et al., 1976). These are seen as hot spouts, mudpools, clear boiling pools, geysers, and hot or warm altered grounds. Most of these features have been identified with 25 volcanic centers. Malapitan and Reyes (2000) discussed the occurrences of these thermal features which form as the exclusive base for regional identification of prospects in the Philippines.

The local geothermal industry has explored in an advanced stage 22 distinct resources in the Philippines. Their development history has a general trend. Upon integration of multi-disciplinary exploration data from geology, geochemistry and geophysics for a selected area, a preliminary conceptual model is proposed. Drilling of 2-3 exploration wells follows, to validate and revise the conceptual model. First well is usually directed towards a postulated upflow zone, drilled to probe the existence of a high temperature resource. Second and third well are then drilled to explore other targets, still within the perceived resource boundaries. The exploration wells are generally targeted to collectively test a resource block with an area of 5 km^2 (Barnett et. al., 1984), delineating a wellfield area equivalent to at least 50-100 MWe in generating potential. Well test results should dictate development size. When risks are considered, a buffer zone is reserved for possible overestimation.

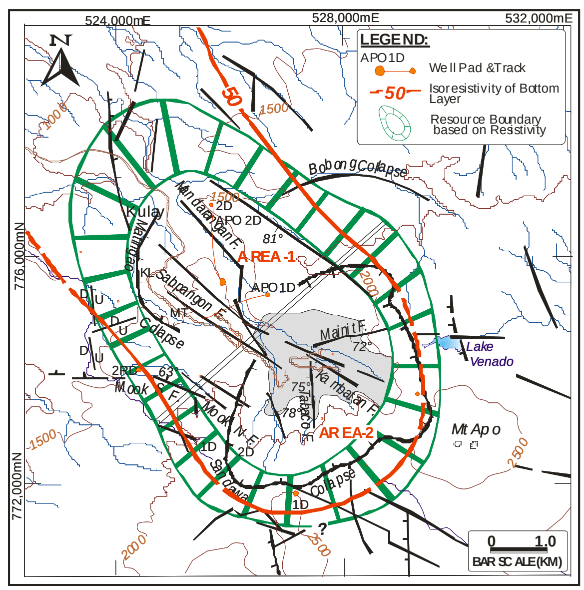

Figure 1: *Exploratory well location map showing provisional resource boundary for Mindanao geothermal field* ***(****Modified from Delfin et. al., 1992)*

Figure 1 provides an example on green field development for the Mindanao project where a power plant of 100 MW was committed after drilling the first two wells and environmental permits were obtained. The wells were drilled inside a resource with a provisional boundary enclosed by resistivity anomaly.

When delineation and development drilling resume with favorable results, additional capacities are programmed. This was the case in Bacman I/II and Mindanao I/II, where commissioning dates for the two stages are only 1-2 years apart. In some cases, plant size comes finally from turbine design and economics of the project. As an example, in Mahanagdong 3x60 MW units replaced the initially proposed 3x55 MW.

ICELAND DEVELOPMENT STRATEGY

The Icelandic geothermal industry has had a more precautious and conservative approach in resource assessment. The development strategy has, until recently, been strongly affected by two factors. Firstly that the population was pro-geothermal, meaning that environmental constraints during green field activities used to be minimal. This resulted in more extensive exploratory drilling and flow testing than for example in the Philippines. Secondly, early construction phase of the 60 MW Krafla power station in N-Iceland was severely impacted by a volcanic episode, injecting magma and gasses into the wellfield (Björnsson et al., 1977). To worsen the situation, a preliminary conceptual reservoir model was incomplete, resulting in different steam field characteristics than anticipated from drilling of first three wells (Stefansson, 1981).

The first 30 MW Krafla turbine was commissioned in 1978, generating 7 MW by 11 wells. Only in 1984, after drilling of 24 wells, the unit finally generated at full capacity. The Krafla project fully recovered in 1999, when 11 additional wells provided ample steam to operate 60 MW (Nielsen et al., 2000). Learning curve for Krafla drilling proved therefore exceptionally long (Stefansson, 1992). The inverse is the case for the Svartsengi geothermal field. There, first 2 units of a cogeneration power plant were successfully up and running in 1981 with only 12 wells drilled (Gudmundsson and Thorhallsson, 1986).

We feel that the lengthy and troublesome Krafla project made Icelandic geoscientists more precautious in their field appraisal work than colleagues abroad. For example, first stage of the Nesjavellir power plant was commissioned in 1990, only after drilling 18 wells, years of flow testing and detailed reservoir modeling (Bodvarsson et al., 1990a, 1990b; Gunnarsson et al, 1992). With 6 additional wells the power plant is currently generating 120 MW electric and 300 MW thermal (Ballsuz et al., 2000; Gislason et al, 2005). Recently the new Hellisheidi 90 MW project took 7 exploratory wells prior to graduating from a green field status to a large scale steam field project (Gunnlaugsson and Gislason, 2005)

SIMPLE VOLUMETRIC MODELS

Volumetric models quantify amount of heat available in a reservoir volume that could be mined for a specified period, usually 25 years. The underlying concept and assumptions are discussed by Bodvarsson (1974), Nathenson (1975) and Muffler and Cataldi (1978). This method has been accepted worldwide in determining initial generation potential at end of green field development studies. Funding and lending institutions together with BOT contractors also often accept the methodology.

Table 1 shows reserve estimates for various geothermal fields in the Philippines, based on volumetric methods. Figures are taken from Horton et al. (1981), Maunder et al. (1982), Tolentino (1986), Ogena and Freeston (1988), Bayrante et al. (1992), and Delfin et al. (1992). Learning from the experience in Tiwi, MakBan, Tongonan and Palinpinon, the number of exploratory wells were reduced into half from 4-6 to 2-3. With a reserve estimate of 3000 MW-years equivalent to 120 MW (Imrie and Wilson, 1979), Tongonan was developed after completion of a discovery well 401. Operation of a 3-MW pilot plant started in 1977. At the time of decision to construct a 112.5 MW Palinpinon I plant, calculated energy reserves of the steam field had increased to 9000 MW-years or ~360 MW for 25 years (Maunder et al., 1982). The estimate was based on data from 2 wells, Okoy-4 and Okoy-5 where temperatures of 299°C and 310°C respectively were observed.

Table 1*: Initial reserves estimates on various fields in the Philippines, based on volumetric models.*

Year	Field	Area (km^2)	Reserves (MW)	Comments
1974	Tiwi	13	110*	4 wells
1975-6	Makban	7.5	220*	6 wells
1978	Tongonan I	-	120	3 MW on-line
1980	Mahiao-Malitbog	5-22	720-1000	112.5 MW on-line
1982	Same	5-22	400-570	Lower temp.
1982	Mahanagdong		138	2 wells
1988	same	-	138	3 wells
1990	same	-	80-109	conservative
1991	same	9.8	107-167	3 wells
1992	same	6-10	100-180	Monte Carlo
1978	Palinpinon-I/II	11	360	2 wells
2005	Palinpinon II	-	100	20 MW opti
1982	BacMan I & II		160	Feas. study
1985	same	12	150	
1992	Mindanao I	8	117-220	2 wells
1992	Mindanao II	8	175-328	-
2001	N.Negros	6-9	42-63	4 wells

*) Data from Tiwi and MakBan were inferred from various references and timing of plant commissioning.

Here we point out large variations on estimates obtained in 1980 and 1982 for Mahiao-Malitbog. These were caused by uncertainties on use of recovery factor (25-50%), notwithstanding the lack of sufficient knowledge of the reservoir. Recent simulations indicate that up to 28% of the heat reserve can be recovered in Tongonan I for 25 years by reinjection, and higher if no brines return to production fields (Bayrante et al., 1992). An over estimation may bias porosities in the volumetric models. Later simulations namely indicate that porosities range 6-10%, in order to match flowing enthalpies. Nevertheless, with all the extensive studies and modeling of the fields in Table

1, keeping in mind that each one has unique characteristics and responses during production, a more congruent and consistent assessment using volumetric models is currently achieved.

It should be noted that total installed capacities approximate the initial reserves estimate for all the cases in Table 1. Exceptions are Palinpinon and Mindanao where problems on reinjection returns and presence of acidic fluids deter immediate expansion.

DETAILED MODELING IN ICELAND

The Icelandic geothermal industry has practiced a step-wise development strategy of high-temperature resources. Decision on building new power plants was only made after drilling of 5-10 full size production wells and months to years of flow testing. Development of 3-D numerical reservoir models held hand-in-hand with field activities, resulting in frequent mesh expansion and recalibration phases. This account in particular for the Hengill model which has been maintained and recalibrated for 18 years (Björnsson et al., 2006). Table 2 highlights milestones in development history of the large Hengill model.

Table 2: *Milestones in Hengill reservoir model development (Björnsson et al., 2006)*

Year	Model	Generating capacity	Comment
1988	Tough2, 4 layers, 12 x 12 km	300 or 400 MWt	1st thermal unit in Nesjavellir
1992	Same, extended to 100x100 km	400 MWt	Better pressure support
1998	Same, wellfield modifications	60 MWe 200 MWt	2nd Nesjav. unit on line in 1999
2000	Same, minor changes, iTough2	90 MWe 300 MWt	3rd Nesjav. unit on line in 2001
2003	Large scale 3-D, iTough2, cluster	240 MWe 700 MWt	4th unit in Nesjav. New plant Hellish.
2005	Nesjavellir 30 MWe expansion	270 MWe 700 MWt	5th unit in Nesjav. rejected
2005	Hellisheidi 150 MWe expansion	400 MWe 700 MWt	Double plant size in Hellisheidi

The Hengill models are developed in TOUGH2 and later iTOUGH2 environment, single porosity, EOS1 and fully accounting for all downhole and production histories gathered in wells around the massive Hengill volcano. As can be seen in the table, recalibration phases have in general resulted in expanded generating capacities. Part of the reason is that model area extent has increased. More important is, however, a better pressure support from model boundaries than indicated by early production and pressure drawdown data. Modelers are therefore in general conservative when simulating early field data, resulting in pessimistic generation capacities.

Currently there are two power plants in full operation in Hengill region. Figure 2 shows location of these fields and other prospective subfields of the Hengill system. The older plant is sited in the Nesjavellir region and dates back to 1988. Current capacity is 120 MW electric and 300 MW thermal. The Hellisheidi power plant was commissioned in October 2006. It is presently rated at 90 MW electric and firm plans to expand to 300 MWe and 400 MWth by year 2010.

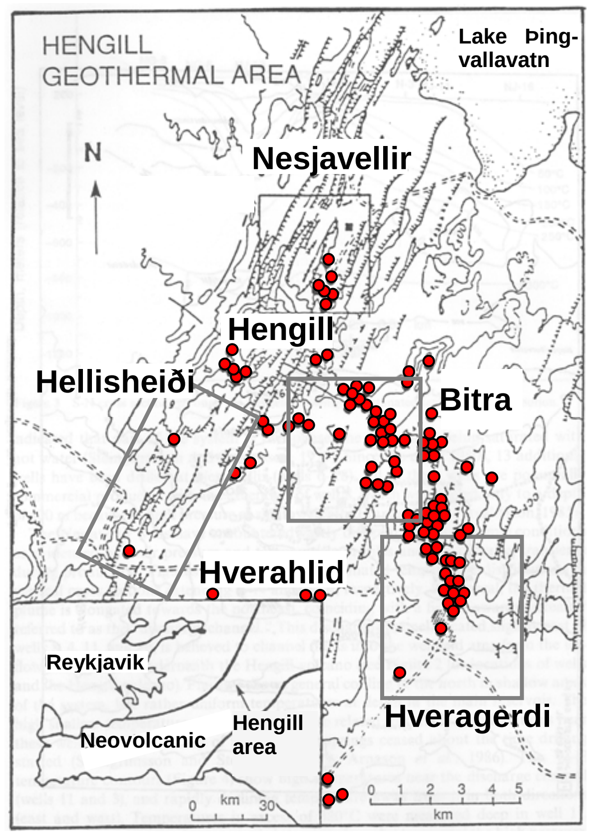

Figure 2*: Location of the Hengill central volcano and Nesjavellir, Hellisheidi, Hveragerdi, Bitra and Hverahlid subfields. Hot springs and fumaroles are shown by bullets (•) and major faults by tagged lines (from Bodvarsson et al., 1990).*

Both projects have in common ample supply of steam and separate from their respective wellfields, with 16 wells feeding the Nesjavellir plant and only 6 in Hellisheidi. A gentle pressure drawdown of around 10 bars is observed in the Nesjavellir reservoir and continues to increase at slow rate. The numerical model predicted a loss in mean enthalpy if reservoir pressure is stabilized by reinjection. Reinjection is therefore not yet a part of the resource management. The inverse appears the case in Hellisheidi, where 100% reinjection of the separated brine is planned due to favorable performance of the numerical model.

Prior to the Hengill modeling effort, a pioneering modeling study was carried out for the Krafla geothermal reservoir in N-Iceland (Bodvarsson et al., 1984; Pruess et al., 1984). Similar to the early Hengill model, the Krafla model was calibrated against only a few years of production data. The resulting generating potential was estimated rather low (~50 MW). Both Krafla and the Hengill reservoirs are liquid dominated but follow the boiling point with depth profile. Under these circumstances early pressure drawdown and enthalpy data lead to generally low numerical model permeabilities. As time progresses, better than anticipated boundary pressure support impacts collected field data. Consequently estimated generating potential becomes higher the often a detailed reservoir model is recalibrated.

It is of interest here to note that the Svartsengi reservoir behaved initially as a single phase, liquid dominated system. Observed pressure drawdown rates were high, in 1-2 bars/year range. Early reservoir models, based on conventional, isothermal hydrology, simulated and predicted reservoir pressure with accuracy. A dominant production mechanism was identified as drainage of an unconfined reservoir with rather tight boundaries (Gudmundsson and Thorhallsson, 1986). Due to pressure drawdown and formation of a steam cap, shallow wells eventually changed to a dry steam flow behavior. The deep reservoir pressure also stabilized, thanks to storativity provided by the shallow steam cap (Björnsson, 1999). New units have therefore been successfully added to the Svartsengi power plant. Once again it appears that model calibration against early field data results in a pessimistic reservoir performance estimate. Although this time the higher generation capacity relies on internal reservoir boiling and local mining of the heat reserve.

DETAILED MODELING IN THE PHILIPPINES

Table 3 gives an overview of various detailed modeling studies conducted so far in the Philippines by Aunzo et al., (1986), Salera and Sullivan, (1987), Aquino et al., (1990), Amistoso et al., (1990), Sarmiento et al., (1993), Urmeneta (1993), Sta Ana et al., (2002), Esberto (1995) and Esberto and Sarmiento (1999). These studies have mainly been used as management tools to predict future reservoir performance and reevaluate earlier estimates on the fields' generating potential under current generation and future expansion level.

Detailed modeling in the Philippines started in 1986 for the Tongonan sector of Leyte, dealing with calibration of natural state data and brief production history of the field (Aunzo et al., 1986 and Salera and Sullivan, 1987). Continuing studies focused on strategies and optimization of the field capacity (Aquino et al., 1990; Sarmiento et al., 1993). The latter simulation was to study field sustainability at pressures higher than turbine inlet pressure of 0.55 MPa. Motivation was to increase plant efficiency while reducing steam consumption and, hence, the total field mass withdrawal. If the high pressure is not sustained in the future, it would be addressed by retrofitting the power plant. The modeling study concluded that the field could operate at 1.0 MPa wellhead pressure for another 25 years provided make-up wells are drilled. The Tongonan I turbine inlet pressure was consequently raised and the field capacity optimized installing topping turbine (Sarmiento et al, 1993).

Table 3: *An overview of detailed reservoir modeling studies in the Philippines. See text for references.*

Field	Year	Area (km^2)	Generat Capacity (MW)	Comments
Tongonan	1986	16	112.5	First simulation (CHARGR)
Tongonan	1987	60	112.5	MULKOM
Tongonan	1990	50	112.5	Development strategy expansion
Tongonan	1992	50	112.5	Optimization
Tongonan	1999	-	500*	Tedrad forecasting
Mahanagdong	1993			Nat. state MULKOM
Same	2002		200	Field Mgt. TETRAD
Palinpinon I/II	1990	650**	112.5	MULKOM Forecasting
Mindanao I/II	1995			First detailed modeling
Mindanao II	1996			Detailed model expansion
Mindanao I/II	1999	60	106	Forecasting

*Excludes Mahanagdong ** Extended Recharge Block

A detailed modeling study further showed that 130 and 240 MW units for Upper Mahiao and Malitbog respectively could be sustained for 25 years (Sarmiento et al., 1993). Subsequent studies indicated that the field generating potential could be raised by even another 50 MW, via bottoming units in Malitbog and topping units in Mahanagdong. These modeling studies, altogether, were a base for the decision to raise total generating capacity of Leyte power plants from the initial value of 112.5 to 700 MW in 1993.

Other detailed modeling studies were made on Mindanao, to deal with a concern on brine returns from the planned 50-70 MW expansion, and on Mahanagdong, where negative effects of cold fluids are being experienced. The need for follow-up study on Palinpinon 1990 model and a model for Bacman is minimal. Fast reinjection returns have been of concern in Palinpinon (Macario, 1991). These are managed by revision of conceptual reservoir model; revisions that are based on field studies like tracer tests, chloride level monitoring and relocation of injection sites. At present, there is no major problem that would require detailed modeling in Bacman.

MONTE CARLO SIMULATION FOR THE LARGE HENGILL SYSTEM

Generating capacity estimates for Nesjavellir and Hellisheidi subfields of the large Hengill complex are based on a detailed 3-D numerical reservoir model, (Table 3). New green fields in Hverahlid and Bitra are currently up for additional development and licensing (Figure 2). Due to a change in environmental policies, exploratory drilling appears limited to only 3 wells at each site. This number of wells is considered, by us, insufficient for reliable calibration of the detailed reservoir model. Instead, we choose to coarsely estimate generating capacity of the whole Hengill complex, by applying the Philippine volumetric model. This approach should provide a generating potential for each km^2 of the Hengill resource. Surface exploration studies and 3 exploratory wells then delineate potential area extent of green fields. A product of the two, unit area generating capacity and wellfield extent, serves as a base for preliminary generating capacity estimate.

Such volumetric generating capacity estimates already exist for the Hengill resource (Palmason et al, 1983; Ministries of Industry&Commerce, 1994). These studies suggest a generating potential of 690 MW electrical for 50 years. Study assumes a boiling point with depth temperature conditions, resource down to 3 km, 20 % recovery factor and low porosity.

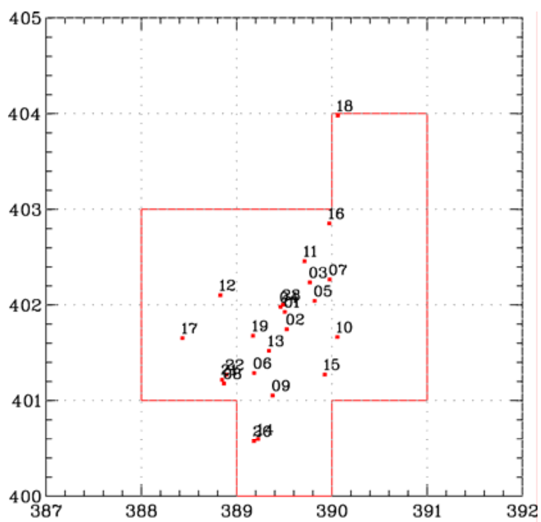

Figure 3: *Nesjavellir wellfield area, based on counting number of 1 km^2 squares that contain productive wells (red line). Distance in km.*

Another study suggested an area based generating potential for the Nesjavellir field to be about 15 MW/km^2, an embarrassingly simple number derived by the 120 MW installed and wellfield area of 8 km^2 (Figure 3). The area based generation capacity is sensitive to delineation of productive wellfields. Taking this uncertainty into account yielded a maximum capacity of 13 MW/km^2 for resources in the Hengill area (Björnsson, 2005). For comparison, we calculated power densities from installed capacities and resource areas reported for the various fields in the Philippines. This yielded 29 MW/km^2 for Tongonan, 18.5 for Tiwi, 34 for Makban, 9.7 for Mahanagdong, 9.8 for Mindanao and 7 MW/km^2 for Northern Negros. It could thus be stated that the area based capacity of Hengill is underestimated relative to similar size reservoirs in the Philippines.

For the purpose of this paper, we ran again a volumetric reserve estimation of the Hengill field by using Monte Carlo style simulation. The method determines probability distribution of capacities based on inferred range of input parameters. This is a statistical approach, accounting for uncertainties in resource properties, which are built-in to the stored heat calculation. Table 3 shows input parameters, as defined by the authors.

Table 3: *Input data for Hengill Monte Carlo simulation*.

Input	Unit	Most Likely	Min	Max	Prob. Dist.
Area	km^2	100	80	120	Triangular
Thickness	km	1.5	1.0	2.0	Triangular
Rock dens.	kg/m^3	3000			Sing. value
Rec. Fac.		0.25			=f(por)
R. Sp. Heat	J/kg/°C	850	840	900	Triangular
Temp.	°C	280	240	320	Triangular
Fluid Den.	kg/m^3	754			f(temp)
F. Sp. Heat	J/kg/°C	5300			f(temp)
Conv. Eff.		0.13	0.12	0.14	f(temp)
Load Factor		0.95	0.9	1	
Rej. Temp	°C	180			Fixed
Most Likely Capacity	MW	1820 @25 years			
Most Likely Capacity	MW	830 @50 years			
Most Likely Capacity	MW	475 @100 years			

Porosity: Mean = 10%, Std. Dev. = .02 Prob. Dist. Log Norm

Note that Table 3 also presents most likely generating capacities for 50 and 100 years of production. The 830 MW estimate is, for example, to be compared with the 690 MW derived earlier for 50 years of continuous generation. Obviously, as more years add to a project life, the more important is boundary recharge in reservoir performance. Long time intervals in volumetric models should therefore be questioned.

Figure 4 illustrates a relative frequency histogram taken from total occurrence of each range of interval out of possible 1000 events in a single run. It shows that the mode or the *most likely* capacity of the Hengill field for 25 years plant life is 1820 MW. The mode is that occurrence where there is no optimism or conservatism using a deterministic evaluation. Additional statistics indicate a minimum field capacity of about 630 MW and that the P90 corresponding to the proven capacity (90 percentile, as used in the petroleum industry) is 1090 MW. Following the Philippines strategy, a 600 MW project could have been rapidly developed in Hengill subject to market demand and favorable results of delineation drilling.

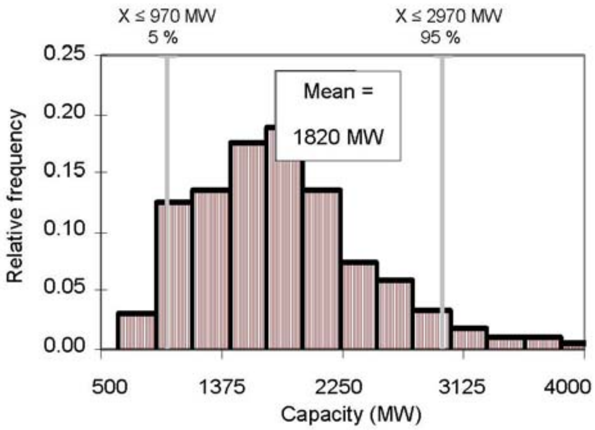

Figure 4: *Relative frequency plot of the volumetric reserves estimation of the Hengill field*

LONG TERM RESERVOIR PERFORMANCE

Large scale geothermal development in the Philippines can be divided into two major periods:

- 1979-1984 - operation of the first 800 MW power plants in Tiwi, Makban, Tongonan and Palinpinon
- 1993-1997 – operation of BacMan and expansion in Palinpinon and MakBan, and operation of the BOT power plants of PNOC-EDC in Leyte and Mindanao totaling 1100 MW.

It has been 28 years since first large scale production testing commenced in Tiwi in December 1978 which has reached a total of 330 MW installed capacity. Up to present, major challenges faced in Tiwi's field management have been reservoir pressure and fluid level decline, and seepage of cold ground waters to the production wells. This influx of cold fluids find its way through hot springs conduits in Naglangbong sector, eventually mixing with shallow reservoir fluids and causing many wells to become non-commercial (Alcaraz et al, 1989). A campaign to cement suspected channels or pathways of cold fluids and inject treated saline water to induce precipitation was not effective. The cold water seepage had spread to whole Naglangbong and eastern edge of Kapipihan sectors. As of late 2003, main production has been coming from Kapipihan, Bariis and Matalibong, ultimately resulting in the abandonment of Naglangbong production sector. To further improve field utilization, rehabilitation of 4 power plants were conducted. The field is now expected to operate at 232 MW, still 70 % of the total installed capacity. A financial NPV (net present value) analysis indicates that net cash flows, including avoided oil cost, have paid for the project by itself since 1986 (Benito et al., 2005).

Initial response of MakBan during first 5 years of operation was marked by a fall in the interface level between vapor and liquid dominated columns in the reservoir, from 600 to 1070-1220 meters (Benavidez et al, 1998). Since then vapor pressure has stabilized and brine pressure drawdown slowed down. Unlike in Tiwi and due to land-locked position of Makban, reinjection has been part of reservoir management since early operation, injecting both hot brines and excess cold condensates from power plants.

Except for a minimal reinjection breakthrough during early periods of MakBan operation, remedied by moving edgefield injection load further to the west, the field has been performing well to date. A slowdown of reservoir pressure decline is related to influx of deeper reservoir fluids and reinjection returns (Benavidez et al, 1998). As of 2003, 71 production wells and 15 reinjection wells were in service. Make-up wells were targeted at deeper portions of the reservoir. These tap hotter rocks and higher pressures and are believed to ensure long term sustainability of the field (Benito et al, 2005). Six wells had been drilled to >2800 meters vertical depth. Accounting for a recent turbine rehabilitation project, which raised their output from 55 to 63 MW each, it is projected that Makban can continue to operate at a 402 MW base load. This amounts to 96% of the installed capacity.

Reservoir response to production in the Tongonan sector of Leyte has been very pronounced when large scale operation of BOT power plants ensued in 1996. Prior to this period, Tongonan I operated without any major problem. A gradual rise in produced enthalpies was observed, due to normal pressure drawdown. The Tongonan example features an in-field injection case; due to low permeability encountered in an intended peripheral injection sink. Steam production from high enthalpy wells has become a priority, aimed towards minimizing injection returns. Resource management is therefore focusing on drilling new wells in high enthalpy portions of the field, even with excess steam from existing wells.

Figure 5 shows historical mass withdrawal in the Tongonan field, depicting a significant increase in 1996-1997. A steady supply of steam is evident since beginning of commercial operation, the level of which is being maintained up to present time by drilling make up wells, acidizing and work-over.

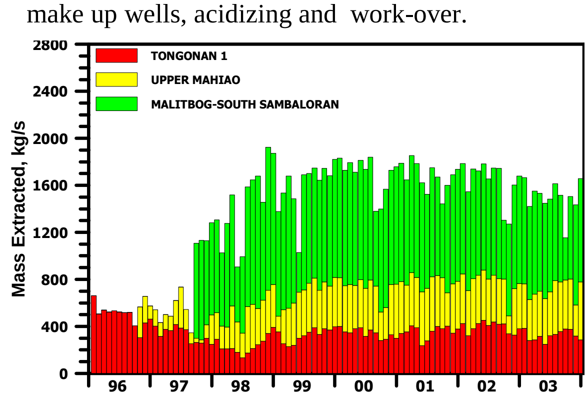

Figure 5: *Historical mass withdrawal in the Tongonan sector of Leyte (After Aleman et al, 2005)*

Figure 6 displays pressure histories of monitoring wells in the Tongonan field. They all follow identical pattern, an indicator for a rapid pressure communication among the various sectors. With expansion of a two phase zone propagating throughout the entire field, a 5-5.5 MPa leveling in reservoir pressure is observed. This pressure level is sufficient for sustaining the required wellhead pressure.

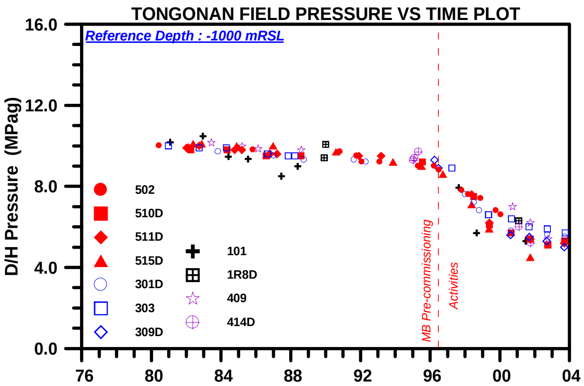

Figure 6: *Reservoir pressure trend in the Tongonan wellfield. (Modified from Aleman et al, 2005)*

To date the Tongonan borefield continues to divert steam via steam highway to Mahanagdong. This is to supplement steam shortfall in the latter area, brought about by cooling in some wells (Aleman et al, 2005). This strategy will continue until long-term measures are put in place. Sharing of excess steam across the various Leyte sectors has allowed for operational flexibility in case unexpected problems occur. It also allows for time to put in place long term solutions to sectors affected. In the Mahanagdong case, a long term solution is to convert existing reinjection wells into production wells. This project has a lead time of 3-5 years due to right of way negotiations, site construction and pipe-laying activities.

The Palinpinon field, after 23 years of operation, has had a stable output of close to 100 MW. The output should be higher if power plant efficiency were maintained properly. Here, most make-up drilling is for relocating reinjection wells, not for additional steam production. Despite rapid communication between production and reinjection wells, the brine returns provide a good pressure support but only minor cooling (Amistoso et al., 2005). Current management strategy is to balance reinjection load, thereby minimizing thermal effects of brine returns. This has been very effective in maintaining power production levels, even after commissioning of the 80 MW Palinpinon II power plants.

Figure 7 illustrates pressure and steam availability trend in the Palinpinon field since commissioning of the 112.5 and the 80 MW phases. The latter part of the pressure history indicates that a steady state level has now been attained in the reservoir; recharge has approximated the mass withdrawal. The good and stable performance of the reservoir now justifies additional 20 MW expansion of Palinpinon II, in order to make use of excess wellhead capacities staying idle for last ten years.

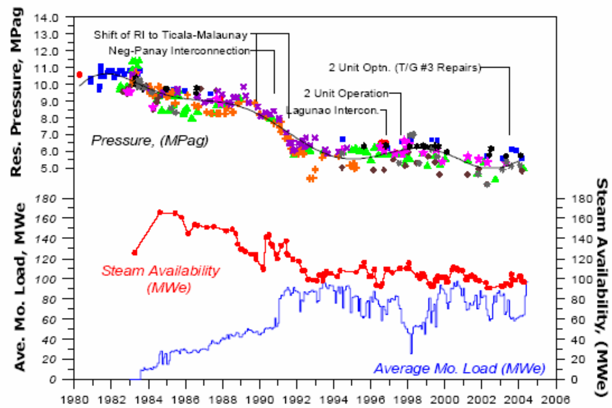

Figure 7: *Pressure trend and steam availability in the Palinpinon field (After Aqui et al, 2005)*

Mass extraction in the Bacman I reservoir has been steady for the last 10 years even though the 110 MW Bacman I plant has been plagued by operational and maintenance problems. Many of the wells could not be shut due to risk of mineral deposition. Reservoir status is characterized by minimal pressure drawdown in Cawayan and Botong sectors, at 0.03 to 0.8 MPa respectively in 1999, where the loading has been very high in the initial 7 years. (Fajardo et al, 1999). Highest pressure drawdown recorded yet is in one pad of Palayang Bayan where ~half of the production is taken, reaching 3.8 MPa after 6 years and slowly declining. No reinjection returns have been traced after 10 years, unlike in other fields (See et al., 2005). This field behavior is attributed to location of injectors farther into the reservoir outflow zone. Additional generating capacities of 40-50 MW could be derived in Tanawon-Rangas sector, further to the SSE (Fajardo and Malate, 2005).

In Mindanao, excess wellhead capacities have endured for more than 10 years of generation, despite presence of calcite deposition in wells. Installation of calcite inhibition system has stabilized production from affected wells, while also replacing mechanical workover. With an average 48-50 MW continuous production from each of the Mindanao I and II sectors, boiling and two-phase expansion has reached southern side of the reservoir. There, a large area of acidic fluids was earlier delineated. Two older wells drilled in this sector have now turned highly two-phase, allowing fluids to be extracted without unduly corroding casings and wellheads. An additional 50 MW unit is planned in the field.

The Icelandic tradition of conservative generating capacity estimates has shifted priorities in steam field management from stabilizing field output to that of expanding. New units are therefore being added to existing power plants. Make-up drilling is virtually unheard of. Some of the oldest production wells have been cemented, due to mechanical problems. Reservoir temperatures are stable and so is fluid chemistry. Maximum reservoir pressure drawdown is on the order of 30 bars. Most well produce at 5-20 bars higher pressure than that of steam gathering systems. Highly convenient for field operators and may explain why make-up drilling is scarce. But good and hot pressure support from outer reservoir boundaries is also contributing to the operating success.

SUSTAINABLE AND RENEWABLE PRODUCTION

Icelandic regulatory authorities find resource generating capacity estimates, which only cover pay-back time periods, unacceptable for environmental licensing procedures. Reservoir modeling studies in Hengill have, therefore, addressed time periods much longer than the 20-40 years needed to recover investment. These studies conclude that future generation needs, in Nesjavellir and Hellisheidi, tap fluid and heat out of wellfields at higher rates than replenished by outer boundaries. Long-term resource management, say for 100-300 years, therefore needs to prepare for resting periods. By resting, the mass reserve recovers to initial state in similar time as production resided, while the heat reserve needs 500-1000 years to fully recover (Björnsson et al., 2006). This conclusion is based on a precautious modeling culture, where uncertainties are interpreted in favor of nature, not the model.

Although the present generating strategies for wellfields in Hengill may not necessarily qualify as renewable power production, the modeling study concluded that these projects should qualify as sustainable development (Björnsson et al, 2006). Main reason is that technical and scientific achievements follow intense geothermal development. This appears to be the case for a developer like Reykjavik Energy, which operates under an open data policy and supports many geoscientific and drilling related technology projects in Hengill. Next generations in Iceland should therefore have same or better change to utilize the geothermal resource as the present one.

The definition of sustainable production of energy from an individual geothermal system has been addressed for example by Axelsson et al (2004) as (Figure 8): "*For each geothermal system, and for each mode of production, there exists a certain level of maximum energy production, E_0, below which it will be possible to maintain constant energy production from the system for a very long time (100-300 years). If the production rate is greater than E_0 it cannot be maintained for this length of time. Geothermal energy production below, or equal to E_0, is termed sustainable production while production greater than E_0 is termed excessive production*".

Our review of historic performance of geothermal power projects in the Philippines has shown that generating capacity estimates, based on simple models, have worked quite well; with security on the recovery of field investments and rate of returns. When viewed in the scope of Figure 8, the question arises if the current level of geothermal production in the Philippines has exceeded the sustainable production level. In light of extensive field management programs described in previous chapter, like make-up drilling, deeper drilling, relocation of injection sites and less acidity of steam-caps, we conclude that E_0 is a highly transient number. Furthermore it may have risen drastically from what was technically possible in the Philippines in 1978 when first large scale production testing took place in Tiwi. Very likely present and next generation will continue to explore and learn new techniques at an early stage to push production levels away from being excessive to being sustainable.

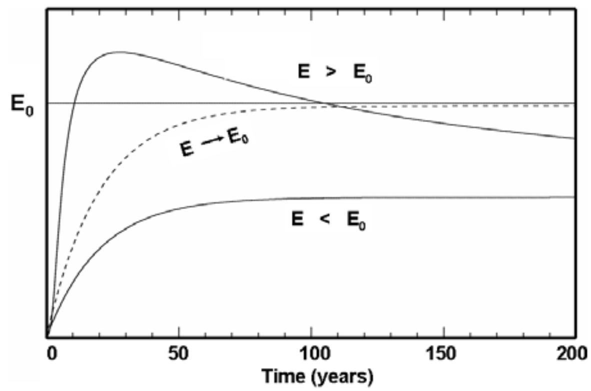

Figure 8: *A schematic illustrating difference between sustainable ($E=E_0$) and excessive production ($E>E_0$). Modified from Axelsson et al (2004).*

Stefansson (2002) has proposed a stepwise development strategy as a suitable method for securing a cost-effective way for development of geothermal power plants. The power plants are to be built in 20-30 MW steps and generating capacity of steam fields revised every 6 years or so by modeling studies. The geothermal industry appears not attracted to this style of development, possibly due to the fact that upfront cost is similar for small and large projects.

The correlation between level of sustainable production, on one hand, and technology and science, on the other, places governmental regulatory and licensing authorities in a complex situation. For the Philippines, as an example, the rapid development between 1979-1984 and later 1993-1997 probably should have been defined as excessive production at time of decision. But since then the industry has been able to manage its geothermal reservoirs at near full capacity, and may continue to do so for another 50-100 years. The current activities should therefore qualify as sustainable development. By failing, the reverse is the case. This example should show that a sustainable production criterion is quite tricky. The Philippines experience, nevertheless, indicates that generating potential estimates, based on simple models, are likely to fulfill the sustainable development criterion. But this requires that the industry is willing and able to develop, both technically and scientifically. Not mentioning publishing its findings.

The issue of renewable production rates clearly is badly addressed by volumetric heat reserve models. Reason is simple, there is no recharge. Here detailed models should be preferred, in particular when 10-20 years of field data constrain boundary recharge rates. We are unable at this time to pick early field indicators for good and hot boundary recharge. Experience and similarity with known resources are most likely of help in this respect.

CONCLUSIONS

Long-term performance of high temperature geothermal power plants in the Philippines attests to the reliability of simple volumetric calculations as a method of providing early estimates on generating potential of a green field. Undoubtedly, the most prudent way to develop a field is to conduct detailed reservoir testing and modeling, requiring some 6-8 wells to get a wide coverage of the green field. However, if project economics would accommodate drilling of future make-up wells, the risk taken in accelerating development could be absorbed by generating early revenues that pay back any drastic change in field management. Tiwi, Makban, Palinpinon I and Tongonan I have been operating for an average of 25 years. Their output is in general still within 80% of installed capacity. These fields will continue to supply steam requirements of the power plants, which in the case of Tiwi and MakBan have been rehabilitated to extend their economic life.

The Upper Mahiao and Malitbog sectors in Leyte, which are connected to Tongonan I, as well as the Mahanagdong block, also are expected to continue to be exploited for another 15 years or more. By drilling make-up wells, they are expected to sustain current production level. Expansions in Palinpinon, Bacman and Mindanao by an aggregate 110 MW are highly probable, based on stable reservoir response from 10 years of production. The current states of these fields and their continuous production have been commensurate for the unprecedented risks that the Philippine government had taken in rapidly developing these geothermal resources.

The results in this paper also present a case for planners and regulators worldwide that development of geothermal resources could be shortened without undergoing detailed reservoir testing and modeling, provided prudent management strategies are incorporated in the operation of the field. The case for the Hengill field shows that adopting a conservative development approach does not necessarily result in better prediction of maximum generating capacity. Main reason is that boundary effects only manifest after several years of exploitation, and respond differently under various exploitation levels. Modeling studies in Svartsengi and Krafla similarly indicate that early generating capacities were on pessimistic side. Today's modeling should, however, be more accurate in this respect as boundary permeabilities are better known than during early detailed modeling phases of 1980-1988.

The mode of a maximum sustainable production is an ideal choice for developers as well as government regulatory and licensing authorities. Problem is that the concept is hard to define at early stages in field development. As an example, it may take 10 years of aggressive operation to determine this level, while it takes only 5 years to recover cost from the same period of excessive production. Each society therefore needs to decide if aggressive generation scenarios are worth the risk. Furthermore they must be prepared to later reduce production rates to a sustainable level. This is exemplified clearly by Palinpinon where capacity has not declined significantly and the reservoir manifested quasi-steady state condition after 10 years of aggressive production. The same is probably true with the MakBan reservoir when they decided later to put up additional 80 MW in 1996.

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