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Booking Geothermal Energy Reserves

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Booking, geothermal, reserves, Philippines, proved, probable, possible

ABSTRACT

Formal booking of geothermal energy reserves, for accounting purposes or annual reporting to shareholders or portfolio management, is not yet a common practice among geothermal companies. In the petroleum industry booking of oil and gas reserves is a routine practice, and at least two geothermal operators that are subsidiaries of petroleum companies book geothermal reserves. As in the petroleum industry, the reserves should be booked in appropriate resource uncertainty categories. To this end we propose three reserve categories with reference to the cumulative probability of exceeding the estimated reserves level: “proved” (equivalent to the 90th percentile), “proved-plus-probable” (equivalent to the lesser of the median and most-likely values), and “proved-plus probable-plus-possible” (equivalent to the 10th percentile). However, before any reserves are booked in the proved category, we believe prospects for commercial productivity from the reservoir should be demonstrated. For the purpose of booking, reserves can be expressed in kilowatt-hours and also in equivalent barrels of oil.

The available methods of estimating geothermal reserves are reviewed here as regards their applicability to booking reserves: empirical methods based on analogy, volumetric reserve estimation, decline curve analysis, lumped-parameter modeling and numerical simulation of the reservoir. Of these methods, only volumetric estimation and numerical simulation are concluded to be generally suitable for booking geothermal reserves. While numerical simulation is more sophisticated than the volumetric method, the latter can be readily conducted in a rigorously probabilistic way while the former cannot. Therefore, for booking reserves, volumetric estimation is the most practical approach. Numerical simulation can allow refinement of the proved reserves, approximate

verification of the probable and possible reserves estimated by the volumetric method, and also help in portfolio management. For the purposes of annual updating of booked reserves it usually should be adequate to simply subtract the cumulative amount of energy produced from the initially estimated proved reserves while leaving the probable and possible reserve levels unchanged. Results of step-out drilling or supplemental exploration may call for reassessment of the reservoir volume under the probable and possible categories, whereas monitoring of reservoir performance upon exploitation may indicate the need for reassessment of proved reserves. The proposed approach to booking reserves has been applied to nine producing reservoirs (located in four geothermal fields) in the Philippines, developed and operated by the Philippines National Oil Company-Energy Development Corporation; these fields have a combined installed generation capacity of 1,100 megawatts.

Introduction

Booking geothermal energy reserves, in connection with accounting or annual reporting to shareholders or portfolio management, is not yet a convention in the geothermal industry. Unless it happens to be a subsidiary of a petroleum company, who customarily state booked reserves in their annual report, a geothermal company does not book reserves. Furthermore, there is no standard for booking reserves in the geothermal industry. Even in the petroleum industry the standard is not strict in most countries. For example, petroleum companies book “proved”, “probable” and “possible” reserves of barrels of oil (or standard cubic feet of gas) without all using exactly the same methodology of arriving at these estimates (Ross, 1998). The Society of Petroleum Engineers (SPE) and the World Petroleum Congress (WPC) have jointly proposed definitions of these terms in an attempt at standardization (SPE/WPC, 1997), which is yet to be fully achieved.

Regulatory bodies in some countries, such as the United States, have stricter guidelines for petroleum reserves reporting than some others. In the U.S., all companies producing oil or gas are subject to the regulations of the Financial Account-

ing Standards Board (FASB), and are required to report their proved reserves and a “*standardized measure of discounted future net cashflows to be derived from proved oil and gas reserves*” (otherwise known as SMOG). FASB recognizes that, as SMOG is based on proved reserves only, it does not represent the fair market value, which should include the reserves in all categories: proved, probable and possible (FASB, 1982). Furthermore, as per the guidelines of FASB and the U.S. Securities and Exchange Commission, SMOG is not subject to government audit as would be the financial accounts of the company. Nevertheless, to promote greater investor confidence, many oil and gas companies routinely commission independent audits of their reserves. For geothermal energy, regulatory bodies have not yet required formal booking of reserves in any country that we are aware of. Yet for all practical purposes, proved reserves and some equivalent of SMOG are routinely quoted by geothermal entrepreneurs to attract investors. Probable and possible reserves as well are often included in the description of an entrepreneur’s portfolio without any definition of the terms.

The Energy Development Corporation (EDC) of the Philippines National Oil Company (PNOC) is considering booking geothermal reserves according to the proposed methodology. PNOC-EDC has developed and operates nine commercial geothermal reservoirs in four geothermal fields in the Philippines: Bacon-Manito, Mindanao, Palinpinon and Greater Tongonan (Figure 1); the combined installed generation capacity is 1,100 MWe.

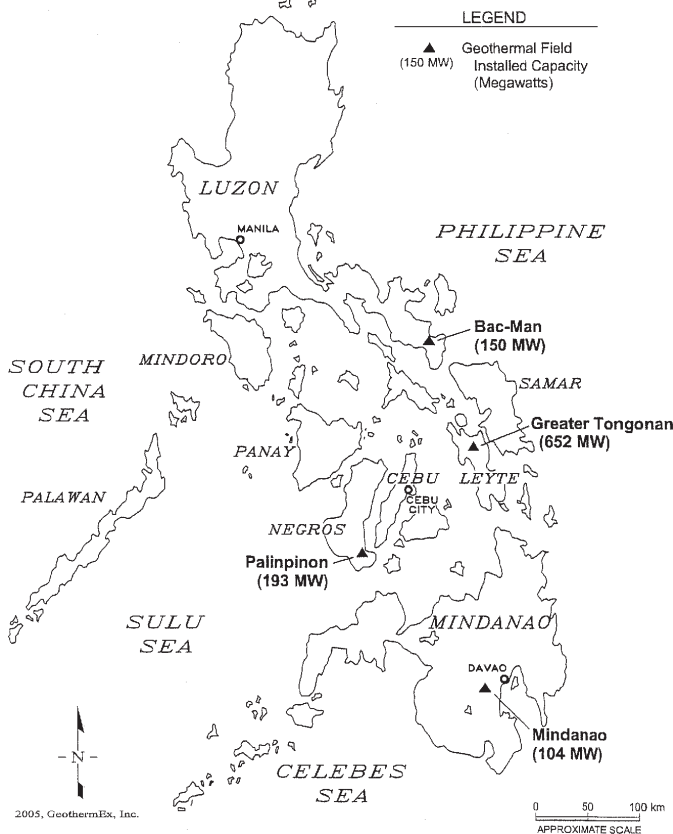


Figure 1. Location of Producing Geothermal Fields of PNOC-EDC.

Reserve Assessment Methodologies

Available methodologies for geothermal reserve assessment can be grouped under two broad categories:

- 1) methods that do not depend on the production history of the field, and as such, can be used to estimate reserves before exploitation begins; and
- 2) methods that require actual production history of the field.

Under the first category fall (a) empirical methods that rely on analogy to case histories of development and operation of similar fields; and (b) volumetric estimation of reserves. Under the second category lie three alternative methods: (a) decline curve analysis; (b) lumped-parameter modeling; and (c) numerical reservoir simulation. These assessment methodologies are considered below as regards their applicability to booking of reserves.

Empirical Methods Based on Analogy

The reserves potentially available from an undeveloped geothermal field can be approximated by at least two empirical methods based on analogy to case histories of developed fields. The first such method defines a “Power Density”, which is the installed megawatt capacity of a producing field divided by the productive area of the field (Grant, 2000). The basis for this method is the expectation of a statistical correlation of increasing power density with increasing resource temperature. In practice, however, the data scatter in a plot of power density versus temperature makes such estimation of reserves questionable. Figure 2 presents a plot of power density versus resource temperature data from 43 fields worldwide; no statistical trend is apparent. The data scatter in Figure 2 is due mainly to two unknown variables, reservoir thickness and recharge characteristics, which are not taken into account in this method.

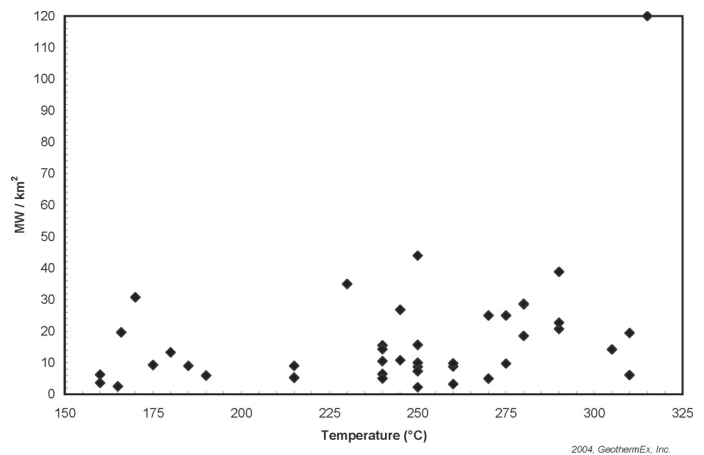


Figure 2. Graph Showing MW/km² versus Temperature at 43 Geothermal Fields World-wide.

Another empirical approach has been proposed based on case histories of producing fields (Sanyal, 2005), which indicate that the sustainable power generation capacity of a field

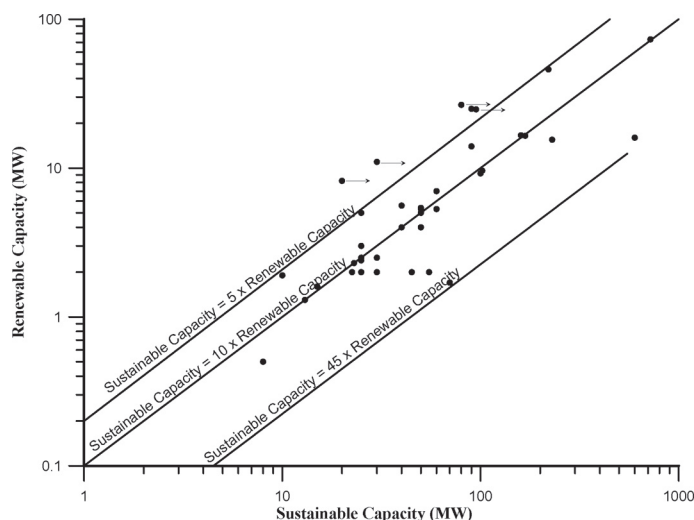


Figure 3. Renewable Capacity versus Sustainable Capacity.

is generally an order of magnitude higher than its renewable generation capacity. The renewable capacity is considered to be the power capacity equivalent of the total rate of heat loss from the thermal anomaly associated with the field. For liquid-dominated reservoirs this heat loss is equal to the steady-state rate of energy recharge prior to exploitation. Therefore, if the heat loss rate over the anomaly can be estimated from surface exploration data (Wisian, et al, 2001), or alternatively, the energy recharge rate prior to exploitation can be quantified from reservoir simulation (Sanyal, 2005), sustainable power capacity can be approximated. Empirical data show that while sustainable energy production capacity is likely to be about 10 times the renewable capacity, it can range from about 5 times to 25 times for non-sedimentary systems; for sedimentary systems, it could be even higher. Figure 3 shows this empirical correlation between sustainable and renewable capacities from 38 fields worldwide. This method can be used to bracket the sustainable generation capacity of a field within a plausible range.

Volumetric Reserve Estimation

In this method, reservoir volume is defined from the estimates of reservoir area and thickness based on exploration and drilling results. Average reservoir temperature is defined based on drilling and well testing data. From estimated reservoir volume and average temperature, the heat-in-place above a reference temperature level (typically ambient temperature or injection temperature) is calculated. Recoverable heat energy reserves are then estimated by using a recovery factor (fraction of in-place thermal energy produced at the wellhead). Electrical energy reserves are then calculated from available thermal energy reserves with appropriate consideration of the energy conversion efficiency. Finally, for a given power plant life and an assumed power plant capacity factor, megawatt capacity of the field is calculated from the estimate of recoverable energy reserves.

The above method can be applied in several different ways, particularly as regards the assumption of the reference

temperature and recovery factor and calculation of electrical energy reserves from thermal energy reserves. The most extensively used such approach, referred to here as the “USGS” approach, was introduced in 1978 by the U.S. Geological Survey (Muffler, 1979). The USGS had proposed a fixed value of 0.25 for recovery factor (r), based on the assumption that 50% of the reservoir volume is porous and permeable and 50% of the heat within the porous and permeable volume is recoverable. However, based on the actual performance of geothermal fields over the three decades since the USGS method was proposed, it has been recognized that the r value in the USGS method should be lower, and in the 0.05 to 0.20 range (Sanyal, *et al*, 2004).

For a steam-dominated reservoir, where steam is the only mobile phase, the above-described USGS method is not applicable. An alternative method of volumetric reserve estimation applicable to steam-dominated systems is presented in Appendix A. PNOG-EDC usually estimates reserves, by the volumetric method, separately for the “liquid-phase volume” (that is, volume without mobile steam) within the reservoir and for the “two-phase volume” in which both water and steam are mobile. Although this approach is reasonable, the additional complication of defining the liquid-phase and two-phase volumes separately does not appear to be warranted; the reason is explained in Appendix B.

Figures 4 and 5, overleaf, show the results of Monte Carlo simulation of reserves, using the volumetric method, in the liquid volume and two-phase volume, respectively, of one of PNOG’s projects (Mahanagdong, Greater Tongonan field, Leyte Island). Figure 6, overleaf, compares the cumulative probability graphs of reserves within the same two-phase volume at Mahanagdong, treating the volume as entirely liquid saturated as well as considering the presence of both phases; the calculated reserves are similar whether the presence of two phases is taken into account or not. In fact, most likely reserves in this reservoir (including both liquid and two-phase volumes) changes by only 3.4% (from 262 to 271 MWe) if the presence of two phases is ignored.

Figure 7 compares the estimated reserves at P90 level (that is, the 90th percentile of cumulative probability of exceeding the estimated reserves level) in nine PNOG reservoirs (within the four fields) with and without considering the presence of steam saturation in the reservoir; the two sets of estimates give similar values. Therefore, explicit consideration of the two-phase volume in a liquid-dominated field is not warranted given the level of accuracy inherent in such estimates. Ignoring the presence of steam saturation in the reservoir appears to have little impact on reserve estimation because (a) the two-phase volume is typically a fraction of the overall reservoir volume, and (b) the amount of heat contained in the fluids in the reservoir is typically much smaller than the amount contained in the rock; this latter issue is elaborated in Appendix B. If, however, a field is initially steam-dominated, the methodology of Appendix A would become applicable for reserve estimation.

Volumetric reserve estimation implicitly assumes that the available reserves can be recovered by drilling as many make-up wells as needed and adopting an optimum production/injection

SUMMARY OF INPUT PARAMETERS

Variable Parameters	Minimum	Most Likely	Maximum
Reservoir Area (sq. km)	9.24	9.74	11.60
Reservoir Thickness (m)	1800	2100	2400
Rock Porosity	0.03	0.06	0.09
Reservoir Temperature (°C)	240	275	290
Recovery Factor	0.05		0.20

Fixed Parameters

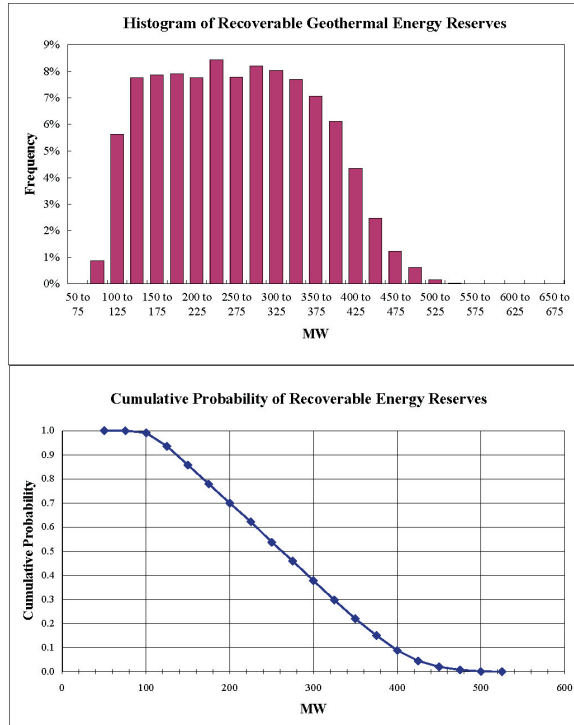
Rock Volumetric Heat Capacity	2475	kJ/cu. m°C
Rejection Temperature	30	°C
Utilization Factor	0.477	
Plant Capacity Factor	0.92	
Power Plant Life	27	years

RESULTS

	Statistics		
	MW	MW/sq. km	Recovery Efficiency
Mean	265	26.0	1.58%
Std. Deviation	96	9.3	0.54%
Minimum (90% prob.)	137	13.5	0.82%
Median (50% prob.)	262	25.8	1.58%
Most-likely (Modal)	252	26.4	2.17%

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Figure 4. Probabilistic calculation of geothermal energy reserves Greater Tongonan field (Mahanagdong – liquid phase volume).



Estimation of Geothermal Energy Reserves
Steam-Dominated Reservoir

SUMMARY OF INPUT PARAMETERS

Variable Parameters	Minimum1	Most Likely	Maximum1
Reservoir Area (sq. km)	9.24	9.74	11.60
Reservoir Thickness (m)	100	150	200
Rock Porosity (fraction)	0.03	0.06	0.09
Initial water saturation (fraction)	0.30		0.90
Recovery Factor (fraction)	0.30		0.70

Fixed Parameters

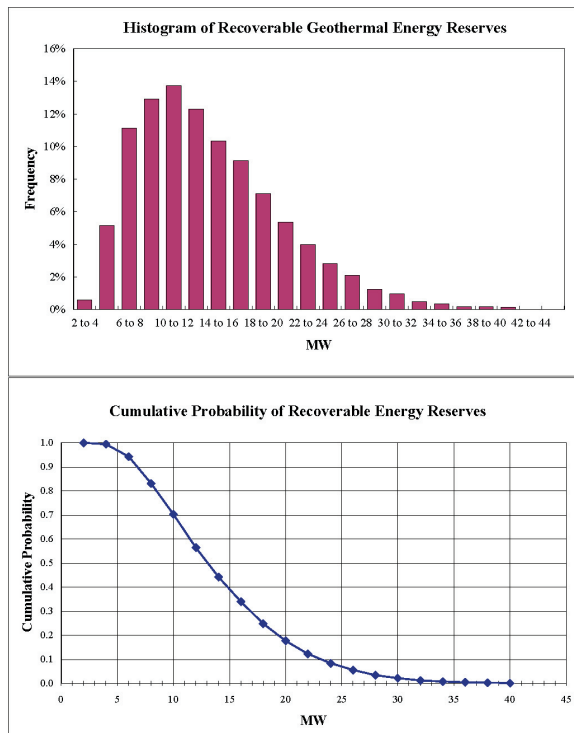
Density of water at initial condition (kg/cu.m)	813.5
Density of steam at initial condition (kg/cu.m)	16.76
Abandonment pressure (MPa)	2.0
Density of steam at abandonment (kg/cu.m)	10.00
Unit steam consumption rate (kg/s/MWe)	2.0
Plant Capacity Factor (fraction)	0.92
Power Plant Life (years)	27

RESULTS

	Statistics	
	MW	MW/sq. km
Mean	14	1
Std. Deviation	6	1
Minimum (90% prob.)	7	1
Median (50% prob.)	13	1
Most-likely (Modal)	10	1

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Figure 5. Probabilistic calculation of geothermal energy reserves Greater Tongonan field (Mahanagdong – two-phase).



based on conservative assumptions of the required calculation parameters.

Decline-Curve Analysis

This is an empirical approach to reserve estimation, in which production rate of a well (or a group of wells) is statistically correlated to time to decipher the productivity decline trend. From an estimated decline rate, one can project the need for make-up wells and cumulative production available before productivity per well becomes too low to be economic. This method is commonly used for forecasting productivity decline for oil, gas and steam wells; for two-phase reservoirs the approach has dubious applicability. This approach has been used historically at The Geysers steam field in California (Sanyal, et al, 1989) and occasionally applied to two-phase reservoirs. Any long-term forecast of well productivity, let alone reserve estimation, from decline curve analysis is constrained by the requirement that field management, and particularly the production/injection strategy, remain unchanged over the forecast period. Reserve estimation would call for forecasting productivity decline over the entire life of a field, and it is unlikely that field management will remain unchanged for so long. As such, reserve estimation from decline curve analysis would be questionable. Even at The Geysers field, decline curve analysis has gradually given way to numerical simulation because the production/injection strategy has been changed substantially in recent years.

Lumped-Parameter Modeling

strategy; in reality, economic and logistical considerations can limit the extent of possible make-up well drilling and optimization of production/injection strategy. As such, volumetric reserve estimation is prone to overestimation, and should be

Lumped-parameter modeling represents the reservoir as a tank without considering the heterogeneity in rock and fluid properties within it or spatial variation in reservoir geometry. Therefore, while lumped-parameter modeling may consider

SUMMARY OF INPUT PARAMETERS

Variable Parameters	Minimum	Most Likely	Maximum
Reservoir Area (sq. km)	9.24	9.74	11.60
Reservoir Thickness (m)	100	150	200
Rock Porosity	0.03	0.06	0.09
Reservoir Temperature (°C)	240	275	290
Recovery Factor	0.05		0.20

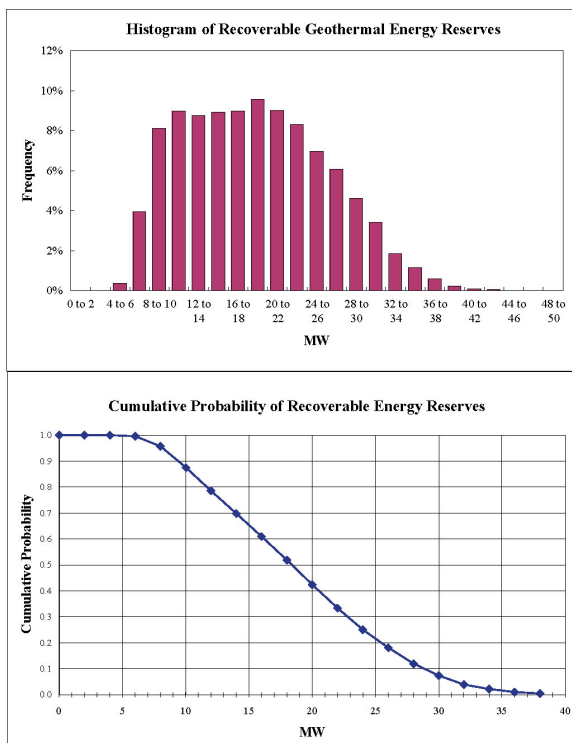
Fixed Parameters		
Rock Volumetric Heat Capacity	2475	kJ/cu. m°C
Rejection Temperature	30	°C
Utilization Factor	0.477	
Plant Capacity Factor	0.92	
Power Plant Life	27	years

RESULTS

	Statistics		
	MW	MW/sq. km	Recovery Efficiency
Mean	19	1.8	1.57%
Std. Deviation	7	0.7	0.54%
Minimum (90% prob.)	9	0.9	0.82%
Median (50% prob.)	18	1.8	1.56%
Most-likely (Modal)	19	2.0	1.45%

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Figure 6. Probabilistic calculation of geothermal energy reserves Greater Tongonon field (Mahanagdong – two-phase volume as liquid phase).



both mass and energy balances as does numerical simulation, it is a less reliable tool for forecasting reservoir behavior. In addition, lumped-parameter modeling, unlike numerical simulation, does not consider fluid flow and heat transfer in response to spatial gradients of pressure and temperature within the reservoir. Therefore, lumped-parameter modeling is a poor substitute for numerical simulation. However, lumped-parameter modeling may still prove useful for studying a specific aspect of the reservoir behavior that can be readily

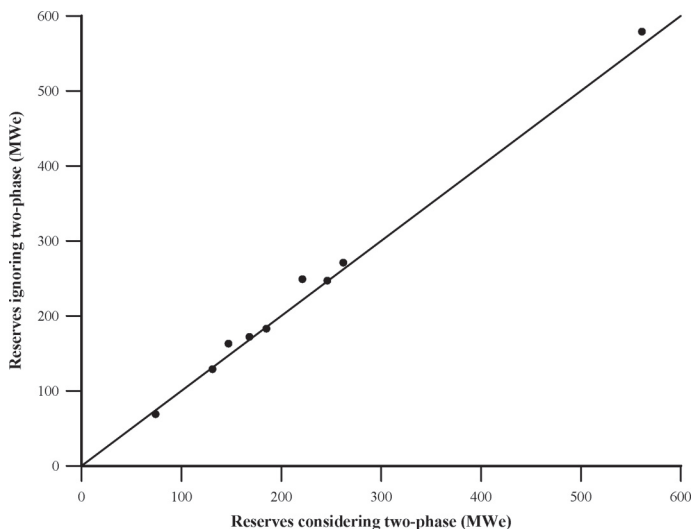


Figure 7. Effect of ignoring steam saturation in volumetric reserve estimation (estimated reserves with 90% cumulative probability).

isolated from the issue of overall reservoir behavior (for example, Sanyal, 2005) of the Wairakei field in New Zealand; but this required the reservoir to be idealized as isothermal.

Numerical Simulation

Numerical simulation is the most sophisticated tool available for forecasting reservoir behavior because it takes into account, in a quantitative way, the variation in reservoir geometry, heterogeneity in rock and fluid properties, physics of fluid flow and heat transfer, and any other physical phenomena (such as, mass transfer) that can affect reservoir behavior. If the numerical model is (a) based on a sound conceptual (hydrogeologic) model and adequate empirical data on rock and fluid characteristics, (b) constructed in sufficient detail, and (c) calibrated adequately against

both the pre-exploitation state of the reservoir and production/injection histories of wells, then it can serve as a reliable tool for forecasting reservoir behavior, which can then be used for portfolio management and estimation of proved reserves (for example, Esberto and Sarmiento, 1999).

Reserve Estimation for Booking Reserves

As discussed before, volumetric estimation and numerical simulation are the only consistently applicable methods of reserve estimation. While numerical simulation is a sophisticated tool for forecasting reservoir performance, estimation of reserves from numerical simulation is deterministic rather than probabilistic; as such, a simulation forecast represents a single reserves value. Furthermore, even arriving at this single reserves value is a trial-and-error process of forecasting reservoir performance under various plausible exploitation levels until the maximum sustainable level is defined. Since numerical simulation is far more involved and time consuming than volumetric estimation of reserves, it is unrealistic to conduct numerical simulation with Monte Carlo sampling of its numerous variables. It is possible to conduct parametric studies of reservoir performance by changing a few variables at a time in the simulation model and re-running it. But this falls far short of a valid probabilistic assessment of reservoir performance. In recent years, sophisticated stochastic approaches have been introduced in the petroleum industry to explicitly consider the simultaneous uncertainty in the important variables in numerical simulation of petroleum reservoirs. However, such approaches have not been attempted in the geothermal industry.

Since booking of reserves under proved, probable and possible categories by definition calls for probabilistic assessment, conventional numerical simulation cannot be the primary basis for such reserve estimation. Numerical simulation can accurately define the proved reserves only; for the other reserve categories volumetric estimation remains the only practicable approach at this time. Conventional numerical simulation is best reserved for portfolio management rather than reserve estimation. Therefore, we believe volumetric reserve estimation to be the preferable basis for booking geothermal reserves.

Categories of Booked Reserves

In the petroleum industry, a consensus has developed that proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves should represent the 90th percentile (P90), median (P50) and 10th percentile (P10), respectively, of the cumulative probability of exceeding the estimated reserve level. We occasionally estimate proved, probable and possible geothermal reserves when the field developer happens to be a petroleum or mining company rather than a utility. In such cases, we have used the above definitions of proved reserves and proved-plus-probable-plus-possible reserves, but we have usually considered the most-likely reserves (rather than P50) to represent proved-plus-probable reserves. We have observed that the histogram of geothermal reserves calculated by Monte Carlo simulation using volumetric estimation tends to be skewed with a mode at less than the 50th percentile level (see for example, Figure 5). In such cases, P50 would be an overestimate of the proved-plus-probable reserves. Therefore, given that volumetric reserve estimation is intrinsically optimistic, we believe the lesser of the most-likely value (“mode”) and median (P50) should be used to represent proved-plus-probable reserves.

It should be noted that in the petroleum industry proved reserves are defined to be those that “... can be estimated with reasonable certainty to be commercially recoverable ...” (SPE/WPC, 1997). We believe the same restriction should apply to proved geothermal energy reserves; that is, before any reserves are booked in the proved category, prospects for commercial productivity from the reservoir should be demonstrated.

For annual updating of booked reserves it should usually be adequate to simply subtract the cumulative amount of energy produced from the initially estimated proved reserves while leaving the probable and possible reserves levels unchanged. However, results of step-out drilling or supplemental exploration may call for reassessment of the reservoir volume initially allocated under probable and possible categories. Likewise, monitoring of reservoir performance upon exploitation may indicate the need for reassessment of the proved reserves. For example, if reservoir performance clearly indicates poorer recharge characteristics than initially expected, recovery factor may have to be reduced. In some situations, reservoir performance may indicate some practical limitations to either reservoir pressure maintenance or to injection without incurring the risk of cooling of production wells. Such situations would reduce proved reserves. However, as indicated before, the growth of a two-phase zone upon reservoir exploitation

should not normally require reassessment of the proved reserves so long as the cumulative energy production is subtracted from it.

Traditionally, geothermal reserves are represented as megawatt capacity (for an assumed project life), and as such, do not represent true reserves, which should equal the MWe capacity multiplied by plant life and capacity factor. At least two geothermal developers, who are also petroleum companies, explicitly report geothermal reserves in both kilowatt-hours of energy and equivalent barrels of oil. A conversion factor of 1 million kilowatt-hours to approximately 1,500 barrels of oil equivalent is reasonable for this exercise. This conversion factor is appropriate considering both the energy content and price of the two resources. For example, using the above conversion factor, a typical price of \$40 per barrel of oil equates to \$0.06 per kilowatt-hour, which is a realistic price level for wholesale geothermal power.

Concluding Remarks

Based on the discussion above, we believe the following procedure is appropriate for booking geothermal energy reserves:

- Estimate volumetrically, using Monte Carlo simulation, recoverable energy reserves in terms of kW-hour at the P90, most-likely, P50 and P10 levels using appropriate assumptions of plant life and plant capacity factor.
- Define proved, probable and possible reserves levels as follows:

$$\text{Proved Reserves} = \text{P90}$$

$$\text{Probable Reserves} = \text{Mode} - \text{P90, if Mode} < \text{P50};$$

$$\text{or P50} - \text{P90 if Mode} > \text{P50}$$

$$\text{Possible Reserves} = \text{P10} - \text{Probable Reserves}$$
- Estimate reserves in barrels of oil equivalent by assuming 1 million kW-hour to be equivalent to 1,500 barrels of oil.

The proved reserves we have thus estimated for the four producing fields of PNOC are as follows:

Field	Installed Capacity (MWe)	Proved Reserves in Million Barrels Oil Equivalent	Proved Reserves in Billion kW-hours of Electricity
Bacon-Manito	150	65.3	43,542
Mindanao	104	54.1	36,105
Palinpinon	193	74.4	49,612
Greater Tongonan	<u>652</u>	<u>145.4</u>	<u>96,940</u>
Total:	1,099	339.2	226,199

Assuming a 90% plant capacity factor, this proved reserves of 226,199 billion kW-hours would be sufficient to supply the installed capacity of 1,099 MWe for 26 years, which is significantly longer than the remaining life of the installed plants.

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Appendix A: Reserve Estimation for Steam-Dominated Systems

We estimate the reserves (E), in terms of MWe capacity, in a steam-dominated reservoir, or within the two-phase volume of a liquid-dominated reservoir, as follows:

$$E = \frac{V\phi[S_{wi}\rho_{wi} + (1 - S_{wi})\rho_{si} - \rho_{s,ab}]r}{UFL}, \quad (A1)$$

where V = reservoir bulk volume,
 ϕ = porosity,
 S_{wi} = initial water saturation,
 ρ_{wi} = density of water initially,
 ρ_{si} = density of steam initially,
 $\rho_{s,ab}$ = density of steam at abandonment condition,

r = steam mass recovery factor,
 U = steam usage factor (steam mass required per MW-hour of generation),
 F = power plant capacity factor, and
 L = power plant life.

In estimating reserves at The Geysers steam field in California (Muffler, 1979), the USGS had assumed a water-filled reservoir volume fraction (that is, ϕS_{wi}) of 0.05. Our numerical simulation studies of the performance of The Geysers field over several decades have confirmed the existence of significant spatial variation in initial water saturation, ranging from 0.5 to 0.9. On the other hand, mobile, saturated steam can exist in vapor-dominated fields with water saturation even lower than 0.5. We have found 0.3 to 0.9 to be a reasonable assumption for the range of S_{wi} values for a vapor-dominated field. The water phase is typically immobile below a saturation of 0.30 (see, for example, Reyes *et al.*, 2004); as such, an S_{wi} of less than 0.30 in the initial state would be unlikely. In an exploited reservoir, water saturation much less than 0.3 would likely cause superheating of the produced steam; such superheating has not been noted in the PNOC fields. As for the assumed upper limit of S_{wi} , steam is likely to be immobile for an S_{wi} significantly higher than 0.9 (Reyes *et al.*, 2004). For a typical porosity value of 0.05, this implies a water-filled reservoir volume fraction (ϕS_{wi}) of 0.015 to 0.045, the range being lower than the value of 0.05 used by the USGS. We have also encountered this range of ϕS_{wi} values in other vapor-dominated fields. While the USGS used a fixed r value of 0.5 for The Geysers, we believe from experience a range of 0.3 to 0.7 to be a more reasonable.

Appendix B: Two-Phase Volume in Reserve Estimation

Let us estimate the ratio of the heat contained in fluid to the heat contained in reservoir rock plus fluid for two extreme cases: (1) a liquid-dominated reservoir from which only liquid is produced (with all wells producing from below the water level), and (2) a liquid-dominated or steam-dominated reservoir from which only steam is produced (with all wells producing from a steam cap).

If only liquid is produced, then (using the nomenclature of Appendix A),

$$\frac{\text{Heat in Fluid}}{\text{Total Heat}} = \frac{\phi C_f [\rho_{wi} S_{wi} - \rho_{s,ab}]}{\phi C_f [\rho_w S_{wi} - \rho_{s,ab}] + (1 - \phi) C_r \rho_r} \quad (B1)$$

and if only steam is produced,

$$\frac{\text{Heat in Fluid}}{\text{Total Heat}} = \frac{\phi [\rho_{wi} S_{wi} + \rho_{si} (1 - S_{wi}) - \rho_{s,ab}] (h_{s,T} - h_{w,T_0})}{\phi [\rho_w S_{wi} + \rho_{si} (1 - S_{wi}) - \rho_{s,ab}] (h_{s,T} - h_{w,T_0}) + (1 - \phi) C_r \rho_r (T - T_0)}, \quad (B2)$$

where $h_{s,T}$ = enthalpy of saturated steam at reservoir temperature, and

h_{w,T_0} = enthalpy of water at ambient temperature.

Let us estimate the ratio of the heat in fluid to total heat in the reservoir for the typical case of a two-phase reservoir at 240°C with 5% porosity and 50% water saturation, assuming the following typical values for the other variables:

$$C_f = 4.99 \text{ kJ/kg}^\circ\text{C}$$

$$C_r = 0.9 \text{ kJ/kg}^\circ\text{C}$$

$$\rho_{wi} = 784.29 \text{ kg/m}^3$$

$$\rho_{si} = 16.76 \text{ kg/m}^3$$

$$\rho_r = 2,750 \text{ kg/m}^3$$

$$\rho_{s,ab} = 10.0 \text{ kg/m}^3$$

$$T_0 = 30^\circ\text{C}$$

$$h_{s,240^\circ\text{C}} = 2,802 \text{ kJ/kg}$$

$$h_{w,30^\circ\text{C}} = 125.7 \text{ kJ/kg}$$

If only liquid is to be produced from the two-phase reservoir, we find from (B1) that only 3.9% of total heat in the reservoir is contained in fluid. If only steam is to be produced from the two-phase reservoir, from (B2) we find that only 9.6% of total reservoir heat is contained in fluid. If a mixture of liquid and steam were produced from the reservoir, somewhere between 3.9% and 9.6% of total heat in the two-phase volume would be contained in fluid. Therefore, explicit consideration of the two-phase volume in reserve estimation is not critical.