Evaluating the Volume Method in the Assessment of Identified Geothermal Resources

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ABSTRACT

In 2008 the US Geological Survey (USGS) updated the 1979 assessment of the electric power generating potential of geothermal resources in the United States associated with natural hydrothermal systems. These resources are concentrated in the states of Alaska, Arizona, California, Colorado, Hawaii, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming, which contain all 248 identified hydrothermal systems located on private or accessible public lands and with temperatures greater than 90 ºC in the US outside of Alaska and greater than 75 ºC in Alaska that have the potential to be exploited for electric power generation. The estimated mean electric power generation potential from identified geothermal resources in the 2008 assessment is approximately 9060 MW-electric (MWe). Recent studies have raised questions regarding the applicability of the volume method, the technique used in USGS assessments of identified resources, in the evaluation of geothermal reserves. A detailed examination of the method as applied in the 2008 assessment, an understanding of the differences between resources and reserves, and a comparison of the assessment predictions with observed power production from geothermal fields in the Great Basin, demonstrate the validity of the volume method for geothermal resource assessments when properly calibrated using field measurements and physical models.

Introduction

Geothermal energy resources are characterized by geologic settings, intrinsic properties, and viability for commercial utilization. Coherent frameworks for classifying these resources are necessary for a number of purposes, including resource assessment, exploration, development, and reporting. The diversity of both the nature of the geothermal resource and its exploitation presents a challenge in the context of resource classification and assessment, as definitions and concepts that serve one purpose may be inadequate for or even counterproductive when used for other purposes. Recent reports examining the viability of various techniques for quantifying both geothermal resources and reserves (Garg and Combs, 2010, 2011; Benoit, 2013) have highlighted the need to revisit the classification concepts and the techniques applied in the assessment of geothermal resources, their validity, and their relationship to the quantification of geothermal reserves.

Comprehensive efforts to assess the geothermal resources of the United States began in the 1970s, and the USGS produced three national geothermal resource assessments in the years following, USGS Circular 726 - *Assessment of Geothermal Resources of the United States-1975* (White and Williams, 1975), USGS Circular 790 - *Assessment of Geothermal Resources of the United States–1978* (Muffler, 1979) and USGS Circular 892 - *Assessment of Low-temperature Geothermal Resources of the United States–1982* (Reed, 1983). These reports developed methodologies for geothermal resource assessments and provided estimates of potential electric power generation that have continued to guide long-term geothermal planning. In 2008 the USGS updated the assessment of conventional geothermal resources in the temperature range above 90 ºC and also produced a provisional assessment of EGS potential (Williams et al., 2008a), adapting the methodologies applied in the earlier assessments based on observed characteristics of geothermal reservoirs, observed production histories, and theoretical considerations on the recovery of heat from fractured geothermal reservoirs (Williams et al., 2008b). The 2008 assessment for power generation potential yielded a mean total of 9057 MWe with a 95% probability of 3675 MWe and a 5% probability of 16,457 MWe from 240 identified geothermal systems located in 13 states (Alaska, Arizona, California, Colorado, Hawaii, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming; Williams et al., 2008a). These results represent a significant decrease relative to the 1978 assessment, which estimated the mean power generation potential from identified geothermal systems at approximately 23,000 MWe (Muffler, 1979) but is much larger than the current installed capacity of approximately 3000 MWe.

Geothermal Resource Classification

This paper follows other USGS geothermal resource studies in using the terminology adopted by Muffler and Cataldi (1978) for the subdivision of the geothermal resource base. These subdivisions are easily illustrated through a simplified McKelvey diagram (Figure 1), in which the degree of geologic assurance regarding resources is set along the horizontal axis and the economic/technological feasibility (often related to depth) is set along the vertical axis (Muffler and Cataldi, 1978). USGS geothermal assessments consider both identified and undiscovered systems and utilize the following definitions. The "geothermal resource base" is all of the thermal energy in the Earth's crust beneath a specific area, measured from the local mean annual temperature. The "geothermal resource" is that fraction of the resource base at depths shallow enough to be tapped by drilling at some reasonable future time. Similarly, the "geothermal reserve" is the identified portion of the resource that can be recovered economically and legally at the present time using existing technology (Muffler and Cataldi, 1978; Williams et al., 2008b).

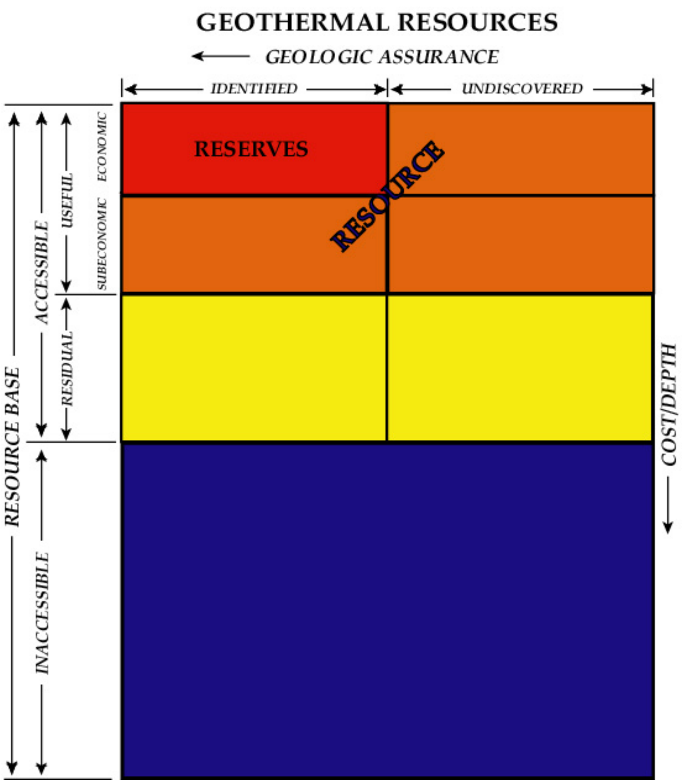

Figure 1. McKelvey diagram representing geothermal resource and reserve terminology in the context of geologic assurance and economic viability. Modified from Muffler and Cataldi (1978).

The distinction between resource and reserve is critically important in understanding the differences between resource assessments and industry reports of reserves, as well as evaluating the viability of various techniques for determining the production potential from identified geothermal systems. Reserves are naturally a subset of identified resources, constrained by current conditions of land status, regulations, and economics. Both resources and reserves are characterized by different levels of confidence regarding the information available to quantify production potential. For example, the Australian Geothermal Reporting Code (AGCC, 2008), following the example of Muffler and Cataldi (1978), subdivides geothermal resources among the categories Inferred, Indicated, and Measured, in order of increasing geological knowledge and confidence, and GeothermEx applies a letter ranking system for geothermal fields from A (operating power plant) to D (limited exploration information) (Lovekin, 2004). The USGS 2008 assessment followed a similar scheme, characterizing identified geothermal systems as Producing (the reservoir is currently generating electric power), Confirmed (the reservoir has been evaluated with a successful flow test of a production well), Potential (there are reliable estimates of temperature and volume for the reservoir but no successful well tests to date), and Prospective (a hydrothermal system has been identified but there is insufficient information to provide quantitative estimates of reservoir temperature and volume) (Williams et al., 2008a). Only information from the Producing, Confirmed, and Potential systems was used for quantitative production estimates in the assessment.

All of these measures of confidence highlight the difference in scope between resource and reserve assessment. Only the systems associated with higher levels of confidence in these resource classification systems are used in reserve estimates. For example, reserves estimates cannot be derived from Inferred resources in the Australian Geothermal Reporting Code (AGCC, 2008). However, both geothermal resources and reserves are commonly assessed using the same methods. The volume or "heat-in-place" method used in the USGS assessments and in many commercial applications, and the modifications applied to it for the 2008 assessment, are discussed in the next section.

Geothermal Resource Assessment Methodology

An important component of geothermal resource assessment methodology is the development of geothermal resource models consistent with the production histories of exploited geothermal fields. The primary method applied in USGS assessments for evaluating the production potential of identified geothermal systems is the volume method (Nathenson, 1975; White and Williams, 1975; Muffler and Cataldi, 1978; Muffler, 1979; Williams et al., 2008b), in which the recoverable heat is estimated from the thermal energy available in a reservoir of uniformly porous and permeable rock using a thermal recovery factor, R_g, for the producible fraction of a reservoir's thermal energy. The basics of the volume method have been discussed in detail elsewhere (Nathenson, 1975; Muffler and Cataldi, 1978; Muffler, 1979; Lovekin, 2004; Williams et al., 2008b), so only a brief summary of the relevant aspects is presented here.

Both the direct use and electric power generation potential from an identified geothermal system depends on the thermal energy, q_R, present in the reservoir, the amount of thermal energy that can be extracted from the reservoir at the wellhead, q_{WH}. Once the reservoir fluid is available at the wellhead, the thermodynamic and economic constraints on geothermal applications can be determined. The challenge in the resource assessment lies in quantifying the size and thermal energy of a reservoir as well as the constraints on extracting that thermal energy. In the volume method, the reservoir thermal energy is calculated as:

$$q_R = \rho C V (T_R - T_0)\,, \tag{1}$$

where ρC is the volumetric specific heat of the reservoir rock, V is the volume of the reservoir, T_R is the characteristic reservoir temperature, and T_0 is a reference, or dead-state, temperature. The thermal energy that can be extracted at the wellhead is given by

$$q_{WH} = m_{WH}(h_{WH} - h_0)\,, \tag{2}$$

where m_{WH} is the extractable mass, h_{WH} is the enthalpy of the produced fluid, and h_0 is the enthalpy at some reference temperature (15ºC in Circular 790). The wellhead thermal energy is then related to the reservoir thermal energy by the recovery factor, R_g, which was defined in Circular 790 as

$$R_g = q_{WH} / q_R \tag{3}$$

Inherent in equations (1) and (2) is a geometrical concept of the reservoir that allows calculation of a volume and an estimate of the ability to extract hot fluid from the volume. In general, through a heat sweep process using injection, it is possible to produce many times the original volume of fluid from the reservoir in order to recover the thermal energy from the reservoir rock. In the 2008 USGS resource assessment R_g for fracture-dominated reservoirs was estimated to range from 0.08 to 0.2, with a uniform probability over the entire range. For sediment-hosted reservoirs this range was increased from 0.1 to 0.25 (Williams et al., 2008b).

From estimates of R_g and measurements of reservoir volume and properties, the exergy, E, (DiPippo, 2005), referred to as the available work, $W_{A,}$ in Circular 790, for a geothermal reservoir can be determined as

$$E = m_{WH}[h_{WH} - h_0 - T_0(s_{WH} - s_0)]\,, \tag{5}$$

where s_{WH} is the entropy of the produced fluid and s_0 is the entropy at the reference temperature. In the actual implementation of this approach the mean values for the input variables are replaced with a range of values corresponding to estimated uncertainties, and these values are then used in Monte Carlo simulations to define the reservoir properties and productivity, along with the associated uncertainties (for example, Muffler, 1979; Williams et al., 2008b). For systems sufficiently hot relative to ambient surroundings to be utilized for electric power generation, the electric energy, W_e, for a given period of time (typically 30 years) is then determined through multiplying the exergy over the same period of time by a utilization efficiency, η_u, which is generally well-constrained for a reservoir of a specified fluid state and temperature (Muffler and others, 1979).

$$\dot{W}_e = \dot{E}\eta_u \tag{7}$$

For power generation above 150°C, Muffler and others (1979) used a constant value for η_u of 0.4 down to the minimum reservoir temperature for electric power production of 150ºC. Lovekin (2004) increased this to 0.45. A compilation of η_u for existing geothermal power plants producing from liquid-dominated systems over a wide range of temperatures confirms η_u equal to approximately 0.4 above 175°C (Williams et al., 2008b). There is an approximate linear decline in η_u below 175°C as reservoir temperatures approach the reference state in binary power plant operations. In the 2008 assessment and the work described here the 150ºC lower limit is revised downward to include binary power production from lower temperature systems. Developments in binary power plant technology have led to electric power generation from systems with temperatures as low as 94ºC in the lower 48 states (Amedee, California) and 75ºC in Alaska (Chena Hot Springs), and production from lower temperatures is possible, if not always economically viable at the present time.

Given the relatively well-established technology for power generation, the key uncertainties in assessment of identified geothermal systems are the temperature, reservoir volume, and geothermal recovery factor. The determination of values for these variables and the associated uncertainties are discussed in the following sections.

Temperature Estimates

Geothermal reservoir temperatures can be determined from in situ measurements in exploration and production wells where available, but in order to characterize the thermal state of a geothermal reservoir when in situ temperature measurements are not available, chemical geothermometers can be applied as proxies. The calculation of chemical geothermometers rests on the assumption that some relationship between chemical or isotopic constituents in the water was established at higher temperatures and this relationship has persisted when the water cools as it flows to the surface. The calculation of subsurface temperatures from chemical analyses of water and steam collected at hot springs, fumaroles, geysers, and shallow water wells is a standard tool of geothermal exploration and fills the need to estimate the subsurface temperature of a geothermal prospect area for resource assessment before any deep wells are drilled.

Interpretation of the calculated temperatures requires knowledge of the most likely reactions to have occurred between the water and the surrounding rocks. Geothermometer-based temperature estimates in USGS geothermal resource assessments rely primarily on silica and cation geothermometers. In natural environments, it is often difficult to choose the correct silica geothermometer because it is not clear which mineral is controlling the dissolved silica concentration. Below 180°C, there is a choice between geothermometers for chalcedony and quartz, since each of these minerals may control the dissolved silica in different rock environments. As noted by Reed and Mariner (2007), the Giggenbach (1992) equation works well to approximate the calculated temperature in the transition zone between the chalcedony solubility control at low temperatures and the quartz solubility control at high temperatures. This smoothed curve eliminates the ambiguity of calculations between 20°C and 210°C.

The cation geothermometers use ratios of cation concentrations to represent the hydrothermal, steady-state reactions that take place within mineral groups such as the feldspars, micas, zeolites, or clays. The use of concentration ratios rather than the actual concentrations makes these geothermometers less sensitive to changes in strength of the solution due either to boiling or to dilution. The cation geothermometers normally use sodium, potassium, calcium, magnesium, and lithium in various relationships that are temperature dependent. For the Na-K-Ca-Mg geothermometer, these relationships are based on several different mineral equilibria, and these different reactions result in a discontinuous function for this geothermometer and an underreporting in the number of systems in the range between 100ºC and 130ºC (Reed and Mariner, 2007).

Although control from calibration well samples is limited, the K-Mg geothermometer provides estimated temperatures reasonably close to temperatures measured in drilled geothermal systems within the 90ºC to 130ºC range. The potassium-magnesium geothermometer relates temperature to the logarithm of the ratio of potassium concentration squared to magnesium concentration, $c_{(K)}^2/c_{(Mg)}$. Because the potassium to magnesium ratio is consistently representative of the subsurface temperature, the K-Mg geothermometer has been the preferred cation geothermometer in recent USGS assessments (Williams et al., 2008b). The Na-K-Ca geothermometer is preferred in Cl-rich waters and used where Mg data are unavailable.

For each identified geothermal system included in the 2008 assessment, the silica and cation geothermometers were applied when in situ temperature measurements were not available. USGS geochemists determined the geothermometer most appropriate for the system in question, assigning the resulting temperature as the “most likely” value in the triangular probability density function for temperature shown in Figure 2. They assigned minimum and maximum values based either on other geothermometers or estimated uncertainties associated with the preferred geothermometer used for the most likely value. In some cases measured discharge temperatures from thermal springs and wells were used for minimum values (Reed and Mariner, 2007). Estimated uncertainties vary considerably from one system to the next depending on data quality and availability, but the minimum and maximum values generally deviate less than 20% from the most likely value.

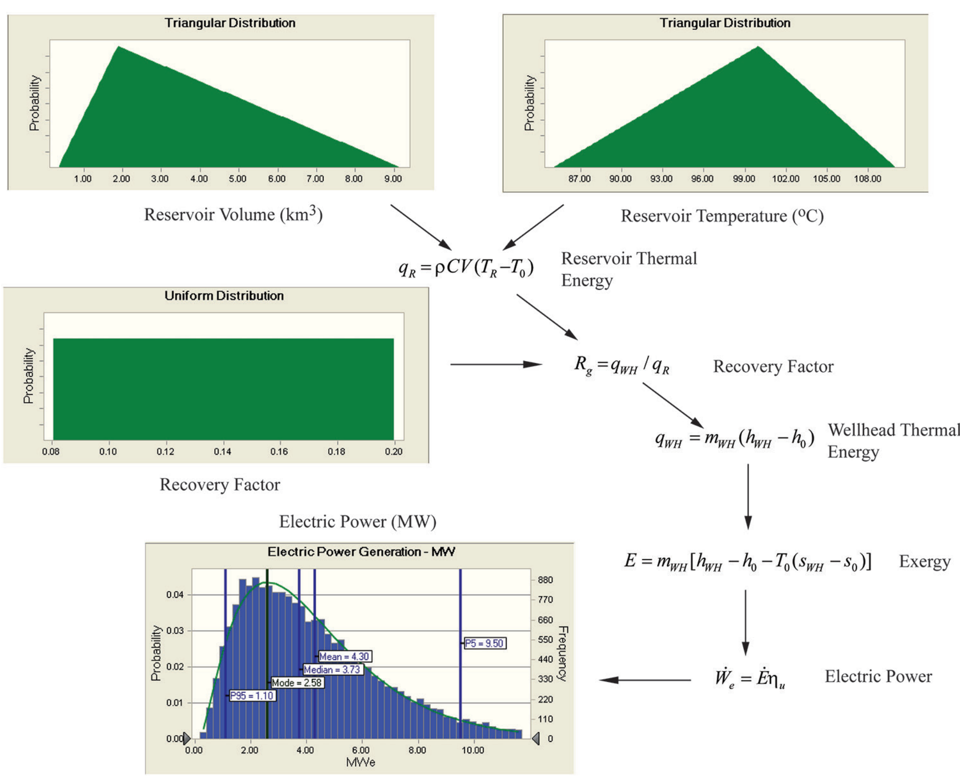

Figure 2. Schematic of the Monte Carlo uncertainty analysis applied in the calculation of reservoir thermal energy, wellhead thermal energy, and electric power generation potential for liquid-dominated geothermal systems in the national resource assessment.

Reservoir Volume

The difficulty of developing accurate estimates for the volumes of unexploited geothermal reservoirs varies depending on the geologic setting and the availability of data from exploration and development drilling. Many geothermal reservoirs in the United States are dominated by fracture porosity, which can be characterized by high permeabilities but relatively low fluid volumes. In addition, fracture permeability is sensitive to relatively rapid (in geologic time) temporal variations in the state of stress and fluid chemistry, and this can lead to heterogeneous permeability distributions within the fracture-dominated reservoirs (for example, Melosh and others, 2008). Estimates of reservoir volumes in the 2008 assessment were derived from production histories, drilling results, chemical tracer tests, and exploratory geological and geophysical investigations.

In some cases information on a geothermal system is limited to the temperature, flow rate and chemical composition of a thermal spring. Under these circumstances, reservoir volumes are estimated by applying constraints from well-characterized geothermal reservoirs in analogous geologic settings. For example, for hot springs emerging from range-front faults in the Great Basin, the width of the fault damage zone (typically 100 to 500 m) constrains one horizontal dimension of the geothermal reservoir, and the temperature of the reservoir fluid relative to the background geothermal gradient defines the maximum depth of circulation. The greatest uncertainty in the estimated reservoir volume for a range front fault system lies in the lateral extent of the reservoir along strike. In the absence of geophysical or structural constraints, the upper end of possible along-strike extents is defined by the examples of producing geothermal reservoirs and other well-explored geothermal systems. Based on these examples, the default along-strike extent of a fault-hosted geothermal reservoir ranges from 1 to 5 km, with a most likely extent of 2 km. The largest volumes determined from this range of reservoir dimensions are consistent with larger, producing fault-hosted reservoirs such as Dixie Valley and Beowawe. The smallest volumes are consistent with simple vertical conduits of limited spatial extent and doubtful viability for commercial power production.

Geothermal Recovery Factor

Hydrothermal systems capable of generating electrical power require the presence of both high temperatures and locally high permeabilities (for example, Bjornsson and Bodvarsson, 1990). Although the volume method provides a means of estimating the heat content of a geothermal reservoir, it does not explicitly predict the reservoir permeability. The presence of permeability adequate for production is determined from the existence of an active hydrothermal system (for example, hot springs, flowing wells, anomalously high heat flow) and the geothermal recovery factor applied in calculating the potential thermal energy recovery from the reservoir incorporates an estimate of the effective reservoir permeability and porosity. Reservoir models and production histories are generally consistent with the predictions of the volume method when the reservoir volume and the spatial distribution of permeability are well-constrained (for example, Parini and Riedel, 2000; Williams, 2004). Potential problems arise when both the volume of a reservoir and its flow properties must be estimated. Many geothermal reservoirs are dominated by fracture porosity, which can be characterized by high permeabilities but relatively low fluid volumes. In addition, fracture permeability is sensitive to relatively rapid (in geologic time) temporal variations in the state of stress and fluid chemistry.

In the USGS national assessment of low-temperature geothermal resources, Reed (1983) applied models for the recovery of heat and fluid from large, low-temperature sedimentary reservoirs using constraints on drawdown at production wells. Production-related pressure declines have posed significant problems in geothermal reservoirs, and, despite the risk of thermal breakthrough, injection has become a common procedure for sustaining production (Axelsson, 2003). Consequently, USGS estimates of reservoir production potential from hydrothermal systems evaluate longevity from the perspective of injection and eventual thermal breakthrough. Theoretical models for the recovery of heat from uniformly porous, homogeneous, and liquid-phase reservoirs using injection indicate that R_g can reach values of 0.5 or higher (for example, Nathenson, 1975; Garg and Pritchett, 1990; Sanyal and Butler, 2005).

To allow for uncertainties in the distribution of permeability in a producing geothermal reservoir, the resource estimates in Circular 790 were based on a Monte Carlo uncertainty model with a triangular distribution for R_g with a most-likely value of 0.25 and a range from 0 to 0.5 (Muffler et al, 1979). More recent analyses of data from the fractured reservoirs commonly exploited for geothermal energy indicate that R_g is closer to 0.1, with a range of approximately 0.05 to 0.2 (Lovekin, 2004; Williams, 2004, 2007). In general this apparent discrepancy in R_g reflects the contrast in thermal energy recovery from complex, fracture-dominated reservoirs compared to the uniform, high-porosity reservoirs considered in the early models. The original values for R_g were derived from models of the effects cooling in a geothermal reservoir due to reinjection or natural inflow of water colder than pre-existing reservoir temperatures (for example, Nathenson, 1975; Bodvarsson and Tsang, 1982; Garg and Pritchett, 1990; Sanyal and Butler, 2005). This is consistent with the optimal extraction of thermal energy from a reservoir, as in general it is possible to produce many times the original volume of fluid from the reservoir in order to recover the thermal energy from the reservoir rock. The challenge is to extend these results to evaluate the thermal effects of injection and production in reservoirs varying from those containing a few isolated fracture zones to those that are so pervasively fractured as to approach the idealized behavior of uniformly porous reservoirs.

The contrast in thermal energy recovery between uniformly reservoirs and fractured reservoirs can be illustrated by the fracture flow model of Bodvarsson and Tsang (1982). This model provides a means of predicting the propagation of a thermal front for liquid-dominated reservoirs with different rates of production and fracture spacing and highlights the sensitivity of thermal energy recovery to average fracture spacing. For representative geothermal reservoir rock and fluid properties, the Bodvarsson and Tsang model predicts that fractured reservoirs approach the uniform energy sweep possible in porous reservoirs when the average fracture spacing is approximately 50 m. As the average fracture spacing grows, a progressively larger fraction of thermal energy in the formation is bypassed by cooler water moving along fracture paths, and the geothermal recovery factor drops (Williams, 2007; Williams and others, 2007).

Although these results are suggestive of the factors that determine why less heat may be recoverable from naturally-fractured reservoirs, the Bodvarsson and Tsang model fails to replicate other important features of geothermal production from fractured reservoirs. In particular, analyses of tracer tests in active geothermal fields, as well as variations in recorded flow rates from producing fractures, clearly indicate significant variation in permeability and path length among fractures connecting injection and production wells (Shook, 2005; Reed, 2007). The chemical tracer tests yield information on the variability of flow in a reservoir that can be plotted as a curve relating flow capacity to storage capacity, or the productivity of each portion of the reservoir. Examples for the Beowawe and Dixie Valley geothermal fields are shown in Figure 3. In the Beowawe field approximately 50 percent of the flow comes from the most productive 10 percent of the permeable fractures, and in the Dixie Valley field approximately 35 percent of the flow comes from the most productive 10 percent of the permeable fractures. By contrast, the uniform fracture model requires an equal distribution of flow across the entire permeable fracture network (Figure 3). The spatial distributions and hydraulic properties of real fracture networks are highly heterogeneous, and the heterogeneity manifests itself in the fundamental production characteristics yielded by the

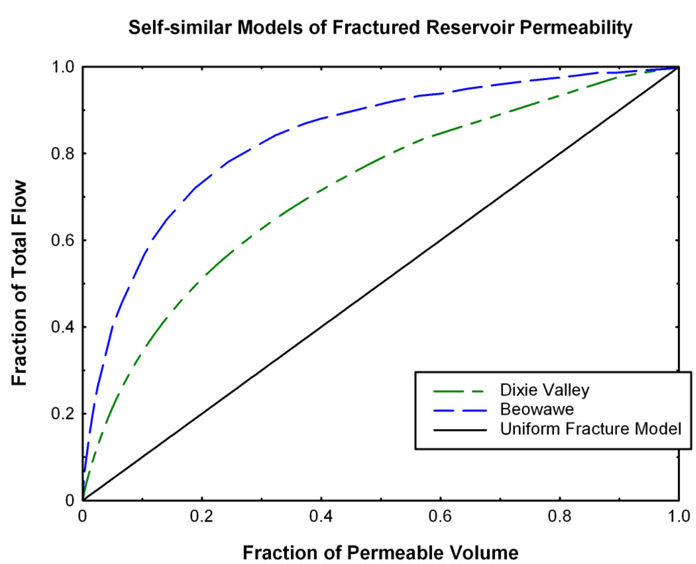

Figure 3. Distribution of flow capacity across the reservoir permeable volume for the fractured reservoir model of Bodvarsson and Tsang (black) and the Beowawe (Shook, 2005) and Dixie Valley (Reed, 2007) geothermal fields.

moment analysis of tracer tests. Any accurate characterization of injection and production from fractured reservoirs must be able to account for this heterogeneity.

Williams (2007) investigated the use of self-similar fracture distributions in a modification of the Bodvarsson and Tsang (1982) model as a means of better representing the actual fracture flow characteristics and variations in R_g observed in producing reservoirs. One simple and effective way of characterizing this heterogeneity has been through the use of models that characterize fracture properties such as permeability through a self-similar distribution (for example, Watanabe and Takahashi, 1995). If, for example, the productivity of fractures intersecting a production well follows a self-similar distribution, this distribution is described by

$$N_k = C_k k^{-d_k}, \tag{6}$$

where k is a reference permeability, N_k represents the number of fractures intersecting the well with permeability greater than or equal to k, C_k is a constant, and d_k is the fractal dimension.

Although there is some direct evidence for fractal dimensions of properties that are relevant to permeability, such as fracture aperture, fracture length, and fracture density, the fractal dimensions for permeability may vary over a wide range (for example, Watanabe and Takahashi, 1995; Dreuzy and others, 2001). For the purpose of this analysis, the fractures of interest are those that contribute significant volume to flow in the well and thus span a permeability range of approximately two orders of magnitude (Bjornsson and Bodvarsson, 1990). These will be a relatively small subset of the total population of fractures with measureable permeability. This analysis also equates the productivity of individual fracture sets with their permeability, an approach consistent with observations in producing geothermal fields (for example, James and others, 1987). Records of flow from producing fractures in geothermal wells confirm the varying contribution of individual fractures or fracture sets to geothermal production,

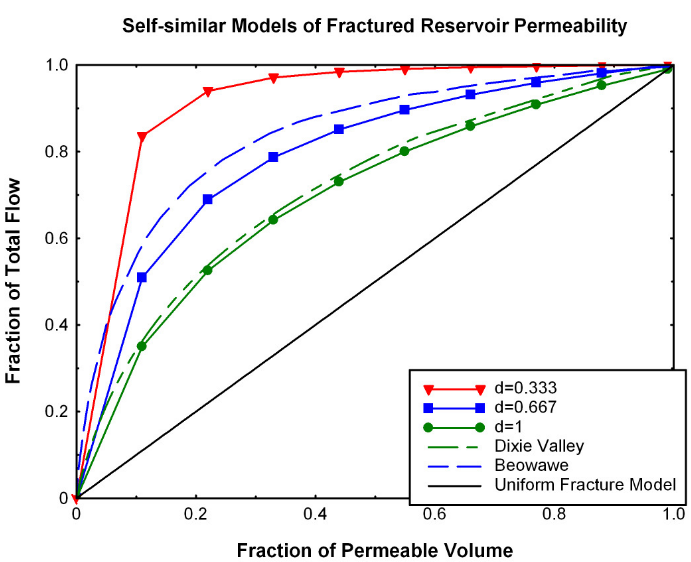

Figure 4. Distribution of flow capacity from Figure 3 with the predictions of self-similar models with three different fractal dimensions (after Williams, 2007).

and also demonstrate the range of fractal dimensions necessary to characterize the observed variations in flow (Williams, 2007; Williams et al., 2008b).

Figure 4 compares flow capacity/storage capacity curves from self-similar models for three different fractal dimensions with the Beowawe, Dixie Valley and uniform fracture model curves from Figure 3. (For details see Williams, 2007.) The distribution of flow for the Dixie Valley field is consistent with the modeled distribution for d=1, and the distribution for the Beowawe field is consistent with the modeled distribution for d=0.667. The smaller value for d in the Beowawe field reflects the dominance of a single fracture or fracture system in the permeability tapped by the chemical tracer test. Like the uniform fracture model, the self-similar fracture flow models yield a range of values for R_g that depends both on average fracture spacing and on the dimensionality of the spatial distribution of fractures (Figure 5).

These results indicate that the self-similar models for fracture permeability reproduce the behavior of producing geothermal reservoirs and provide a physically-based justification for the

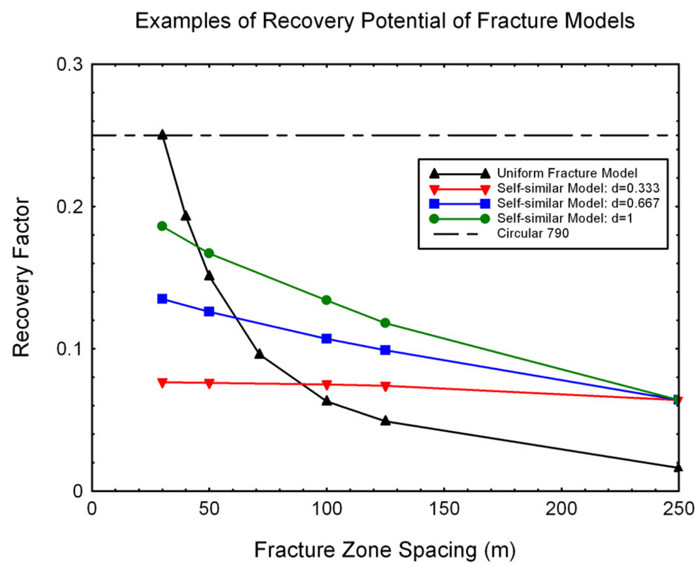

Figure 5. Variations in recovery factor with fracture spacing for example models incorporating planar fractures with uniform flow properties (black) and fractal distributions of flow properties among the producing fractures (green, blue and red).

observed variation in R_g. Given the observed variability in fracture flow properties, the likelihood that most natural fractures will match these varied flow properties with diverse fracture spacings and orientations, and the range of recovery factors determined from production histories of geothermal reservoirs, it is not possible to assign a single value, or even a narrow range, for R_g for unexploited geothermal systems. Taking the above analysis as a guide, in the 2008 resource assessment R_g for fracture-dominated reservoirs was estimated to range from 0.08 to 0.2, with a uniform probability over the entire range. For sediment-hosted reservoirs this range was increased from 0.1 to 0.25.

Uncertainties in the Volume Method - Reservoir Permeability, Reservoir Volume, and Thermal Breakthrough

According to Garg and Combs (2010), uncertainties associated with application the volume method to geothermal systems early in the exploration and development process mandate modification of the range of recovery factors to include the possibility of $R_g = 0$. In their view, until the viability of production has been verified through well testing (the Confirmed category in the USGS 2008 assessment) "it may eventually prove impossible to produce fluids from a geothermal reservoir" (Garg and Combs, 2010). This statement may be true in the context of geothermal reserves but it is not correct for the assessment of geothermal resources. As noted above, there may be many reasons why a given geothermal system cannot be produced either economically or legally, but, in the context of the volume method and reservoir evaluation for the purpose of quantifying resources, the primary concern is attaining a flow rate capable of sustaining production. This in turn depends on well productivity, which is a reflection of reservoir permeability, and sustained high temperature, which depends on avoiding premature temperature decreases, from either inflow of cooler, shallow groundwater due to decreasing reservoir pressure or, more commonly, thermal breakthrough to production wells of cooler injection well water. As long as a permeable reservoir of any measureable size exists, R_g is greater than zero from a technical (i.e., resource) perspective, regardless of commercial and legal factors that may constrain development.

In the context of a resource (as opposed to reserve) assessment, the production histories and well tests available for Producing and Confirmed geothermal systems provide sufficient confirmation of reservoir permeability to establish that R_g cannot be zero. For geothermal systems in the Potential category, the question centers on whether simply the existence of a geothermal system, with its natural flow to a thermal spring or well, demonstrates sufficient permeability to support production, whether

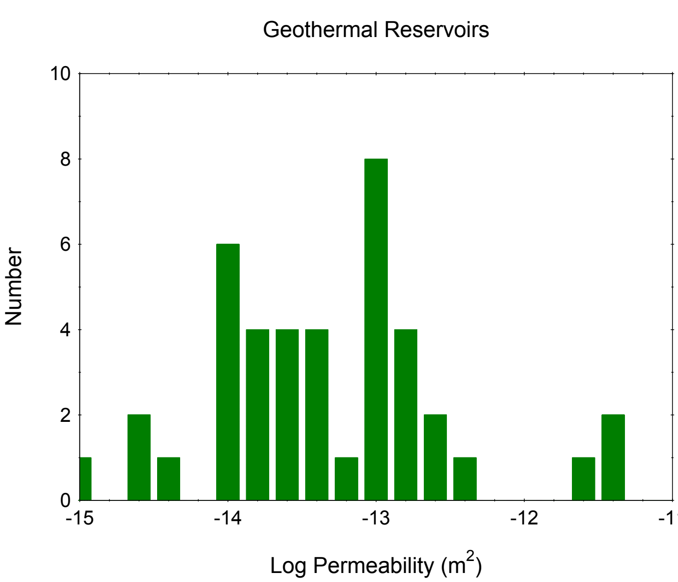

Figure 6. Histogram of measured permeability in producing geothermal fields, after Bjornsson and Bodvarsson (1990).

economically viable current conditions or not. According to the compilation published by Bovardsson and Bjornsson (1990), measured permeability in producing geothermal reservoirs generally exceeds 10^{-14} m^2, although there are some exceptions in the range between 10^{-15} and 10^{-14} m^2 (Figure 6). For amagmatic geothermal systems formed through upflow along high angle faults in the Great Basin, models presented by Williams (2013) indicate that fault zone permeability must fall in the range of 10^{-15} to 10^{-13} m^2 in order to account for observed flow rates and associated thermal anomalies. Consequently, for geothermal systems in the Potential category, measurable characteristics clearly demonstrate that R_g is nonzero.

Given a range of representative values for R_g and the relative accuracy of temperature estimates from either in situ measurements or the careful application of appropriate chemical geothermometers, a remaining concern regarding the volume method relates to estimates of reservoir volume. As noted by Williams (2004), reservoir volume can be determined accurately for fully-developed fields covered by extensive drilling programs (e.g., The Geysers, Coso), but is not well-constrained by field measurements for almost all unexploited and many partially exploited systems. However, the most likely USGS reservoir volume estimates for identified geothermal systems in the Great Basin are consistent with the swept pore volumes determined from chemical tracer test models (Shook, 2005; Reed, 2007) and the estimates of thermal heat recovery provided by the Bodvarsson and Tsang (1982) model, which indicates that over the reference 30 year life span of a geothermal field the circulation of fluid between injection and production wells will extract significant amounts of heat from impermeable rock 10's of meters on both sides of permeable fractures. There are significant uncertainties regarding the minimum and maximum potential reservoir volumes and whether the triangular distribution properly captures the actual probabilities. Potential revisions to the reservoir volume distribution function are a focus of ongoing research.

Finally, observations of the adverse effects of thermal breakthrough in some producing geothermal fields led Benoit (2013) to question the viability of the volume method for geothermal systems in the Great Basin, despite his fundamental observation that systems with reservoir temperatures near 210 C produce approximately 10 MWe per km of fault length, a result consistent with both the USGS 2008 assessment parameters and similar observations by Williams (2004) for the Dixie Valley geothermal system. Benoit (2013) does note that for the Blue Mountain geothermal reservoir, premature thermal breakthrough from injection wells led to a power production far below values predicted by the volume method before full development of the field. However, the injection wells at Blue Mountain are located approximately 1 km from the production wells, compared to injection-to-production well distances of 1.5 km or more at other producing fields in the Great Basin (Benoit, 2013). In addition, the injection rates at Blue Mountain were approximately 3 times greater than those applied at other fields (Benoit, 2013). According to the fractured reservoir flow model presented by Bodvarsson and Tsang (1982) and utilized in determining recovery factors for the 2008 USGS assessment, avoiding premature thermal breakthrough for increased flow rates requires maintaining the ratio (d^2/Q) constant, where d is the injection-production well distance and Q is the flow rate. Based on this model, thermal breakthrough could be avoided at Blue Mountain by increasing the injection-production well distance to approximately 2.5 km. Consequently, observed problems with injection and thermal breakthrough do not invalidate the volume method approach provided that investigators account for both the natural variability of permeability in these systems as well as the potential need to relocate injection and production operations to optimize reservoir productivity and longevity.

Summary

Recent studies have raised questions regarding the accuracy of the volume method, the technique used in USGS assessments of identified resources, in the evaluation of geothermal reserves. A detailed examination of the method as applied in the 2008 assessment, an understanding of the differences between resources and reserves, and a comparison of the assessment predictions with observed power production from geothermal fields in the Great Basin, demonstrate the validity of the volume method for geothermal resource assessments. However, as the accuracy of the method depends in part on calibration against geothermal field production histories, observations from development of new fields as well as continued production in existing fields need to be included in application of the volume method in future assessments.

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