Updated U.S. Geothermal Supply Characterization and Representation for Market Penetration Model Input

C. Augustine

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The results of this report were summarized and presented at the 35th Stanford Geothermal Workshop, held February 1-3, 2010 (Augustine, Young, et al. 2010). This report serves to provide thorough documentation of the methodology used to create the supply curves presented.

Acronyms and Abbreviations

\$M	millions of U.S. dollars
%ile	percentile
Recovery Act	American Recovery and Reinvestment Act
BLS	Bureau of Labor Statistics
^{o}C	degrees Celsius
cm	centimeters
DOD	U.S. Department of Defense
DOE	U.S. Department of Energy
EGS	enhanced geothermal systems
EIA	Energy Information Administration
ft	feet
GEA	Geothermal Energy Association
GETEM	Geothermal Electricity Technology Evaluation Model
GIS	geographical information system
GPRA	Government Performance and Results Act of 1993
GTP/the Program	Geothermal Technologies Program
GW_e	gigawatt (electric)
in	inches
k, km	kilometers
kg/s	kilograms/second
kW_e	kilowatt (electric)
kWh	kilowatt-hour
LCOE	levelized cost of electricity
MARKAL	Market Allocation Model
MIT	Massachusetts Institute of Technology
MW_e	megawatt (electric)
MYRD&D Plan	Multi-Year Research Development and Deployment Plan
NEMS	National Energy Modeling System
NGDS	National Geothermal Data System
NREL	National Renewable Energy Laboratory
O&M	operation and maintenance
PPI	producer price index
psi	pounds per square inch
RD&D	research, development, and demonstration
ReEDS	Regional Energy Deployment System
SEDS	Stochastic Energy Deployment System
SMU	Southern Methodist University
TPM	technology performance metric
U.S.	United States of America
USGS	U. S. Geological Survey
$W\text{-}h/lb_m$	watt-hours per unit pound (mass) of geofluid

Executive Summary

The U.S. Department of Energy (DOE) Geothermal Technologies Program (GTP) tasked the National Renewable Energy Laboratory (NREL) with conducting the annual geothermal supply curve update. The purpose of this project is to characterize and represent the supply of electricity generation potential from geothermal resources in the United States. The principal products of this task are quantitative estimates of the potential electric capacity of U.S. geothermal resources and the cost to develop those resources. The two products are integrated to generate geothermal supply curves. The supply curve data are used primarily as input into the annual Government Performance and Results Act of 1993 and DOE portfolio development support processes and are also used extensively as input for market penetration models. The results of this study were used for the Fiscal Year 2011 DOE planning cycle. This report documents the approach taken to identify geothermal resources, determine the electrical producing potential of these resources, and estimate the levelized cost of electricity (LCOE), capital costs, and operating and maintenance costs from these geothermal resources at present and future timeframes under various GTP funding levels. Finally, this report discusses the resulting supply curve representation and how improvements can be made to future supply curve updates.

The general approach and flow of information used to develop supply curves and incorporate the results as input into market penetration models is shown in Figure ES-1. The primary steps in generating a supply curve and model input were estimating the resource potential and the cost of developing the resource. Estimating the cost of electricity from the geothermal resources required the resource characteristics, the assumptions under which resource development would take place, and component technology cost and performance data.

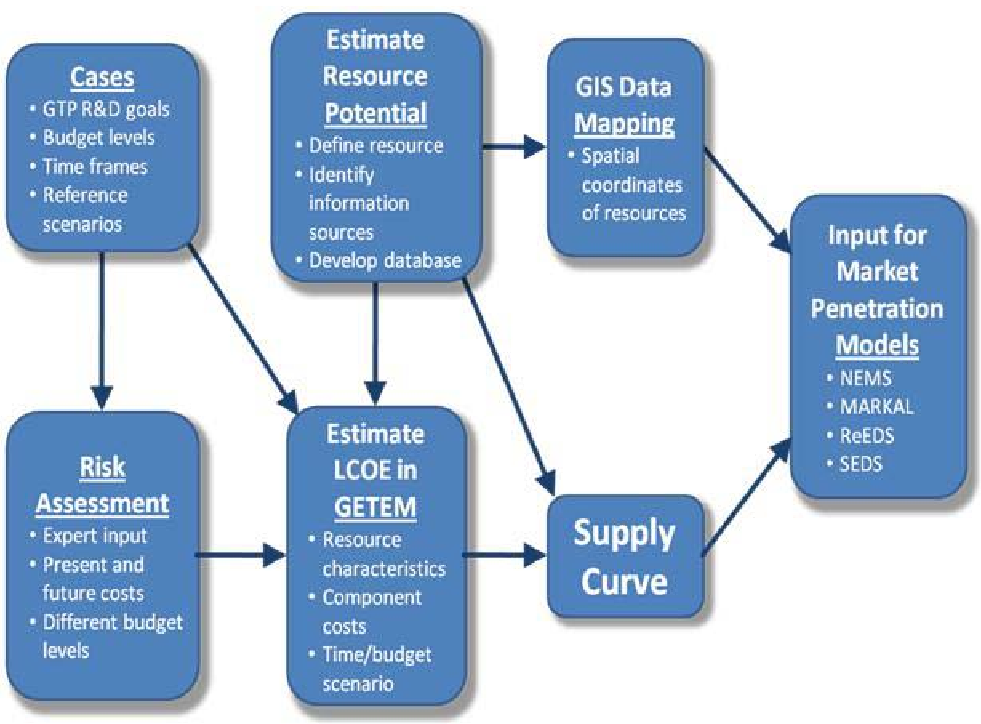

Figure ES-1. Supply curve information flow diagram.

Schematic of general approach used to develop geothermal resource supply curve and incorporate results as input into market penetration models. Arrows show flow of information.

For this study, the geothermal resource was broadly split between two technologies: conventional hydrothermal and enhanced geothermal systems (EGS). Conventional hydrothermal technologies utilize naturally occurring hydrothermal resources and have been commercially developed for decades, while EGS is an emerging technology in which geothermal reservoirs are engineered to extract economical amounts of heat from geothermal resources that have low permeability and/or lack natural *in-situ* fluids for heat extraction. The resource was further subdivided into four categories: identified hydrothermal, undiscovered hydrothermal, near-hydrothermal field EGS, and deep EGS. The geothermal resource characterization took advantage of published or available resources whenever possible, and made assumptions as necessary to estimate geothermal resource potential. The characterization benefited greatly from the recent geothermal resource assessment performed by the U.S. Geological Survey (USGS) in 2008 (Williams, Reed, et al. 2008b) and also uses methodologies and data from the Massachusetts Institute of Technology *Future of Geothermal Energy* report to characterize EGS resources (Tester et al. 2006). The results of the resource potential estimate and a brief description of the sources and methodology used are given in Table ES-1.

Table ES-1. Summary of Results for Geothermal Resource Potential Estimate

Resource		Resource Potential	
		Capacity (GW_e)	*Source(s) and Description*
Hydrothermal	Identified Hydrothermal Sites	6.39	USGS 2008 Geothermal Resource Assessment[1] • Identified hydrothermal sites • Sites ≥110°C included • Currently installed capacity excluded
	Undiscovered Hydrothermal	30.03	USGS 2008 Geothermal Resource Assessment[1]
Enhanced Geothermal Systems (EGS)	Near-Hydrothermal Field EGS	7.03	Based on data from USGS 2008 Geothermal Resource Assessment[1] and methodology developed at NREL • Regions near identified hydrothermal sites • Sites ≥110°C included • Difference between mean and 95%ile hydrothermal resource estimate
	Deep EGS	15,908	NREL 2006 Update[2], MIT Report[3], SMU Data[4] • Based on volume method of thermal energy in rock 3-10 km depth and ≥150°C • Does not consider economic or technical feasibility

[1](Williams, Reed, et al. 2008b)
[2](Petty and Porro 2007)
[3](Tester et al. 2006)
[4](Richards 2009)

When developing supply curves, two cases based on GTP budget funding and EGS technology advances were considered: (1) the "base" or "no-funding" case, which assumes a business-as-usual case where there is no GTP budget for geothermal research, development, and demonstration so that only modest improvements are made in EGS reservoir performance from current benchmarks, and (2) the "target" case, which assumes DOE funding of $50 million/year and that the targets for GTP EGS reservoir performance in the *Multi-Year Research Development and Deployment Plan* (Geothermal Technologies Program 2008) are met. The EGS reservoir technology assumptions for each case are summarized in Table ES-2.

Table ES-2. EGS Technology Assumptions Used in Base and Target Cases

Enabling Technology	Base Case Value	Target Case Value
RD&D Funding	$0 M/year	$50 M/year
Production Well Flow Rate	30 kg/s	60 kg/s
Thermal Drawdown Rate	3.0 %/year	0.3 %/year
Production/Injection Well Ratio	2:1	2:1

Project development costs for each resource site in the supply curve were estimated using the Geothermal Electricity Technology Evaluation Model (GETEM). GETEM is a highly detailed Microsoft Excel-based techno-economic modeling tool that estimates the LCOE and capital costs associated with a hydrothermal or EGS project based on the user-defined inputs of the project's resource attributes and component costs and performance levels. Geothermal technology component costs and performance inputs required by GETEM to estimate total project costs were based on probability distributions elicited from experts as part of the GTP's annual risk assessment (Young, Augustine, et al. 2010). Risk analysis software was used to run Monte Carlo simulations in GETEM incorporating these expert input distributions. The incorporation of technology component uncertainty results in a distribution of probable project costs rather than a single value. Based on conversations with geothermal drilling contractors, drilling costs were assumed to be discounted 30% from the 2008 index value used in the GETEM model to account for significant declines from recent record-high values that were related in part to a rapid rise in crude oil costs starting in 2004.

Supply curves based on the median, 10^{th}-percentile, and 90^{th}-percentile estimates of the LCOE were generated for each of the resource categories. The individual supply curves were combined to create aggregate supply curves for the base and target cases, shown in Figure ES-2, that include all geothermal resources in the supply curve. The aggregate supply curves are truncated to show the most cost effective 50 GW_e of geothermal resource. Capital costs by project phase for the different technologies were also calculated and presented. Future cost multipliers for years 2015 and 2025 that account for the effect of technology improvements and cost reductions with time for each geothermal technology were calculated based on expert risk assessment input and GETEM results.

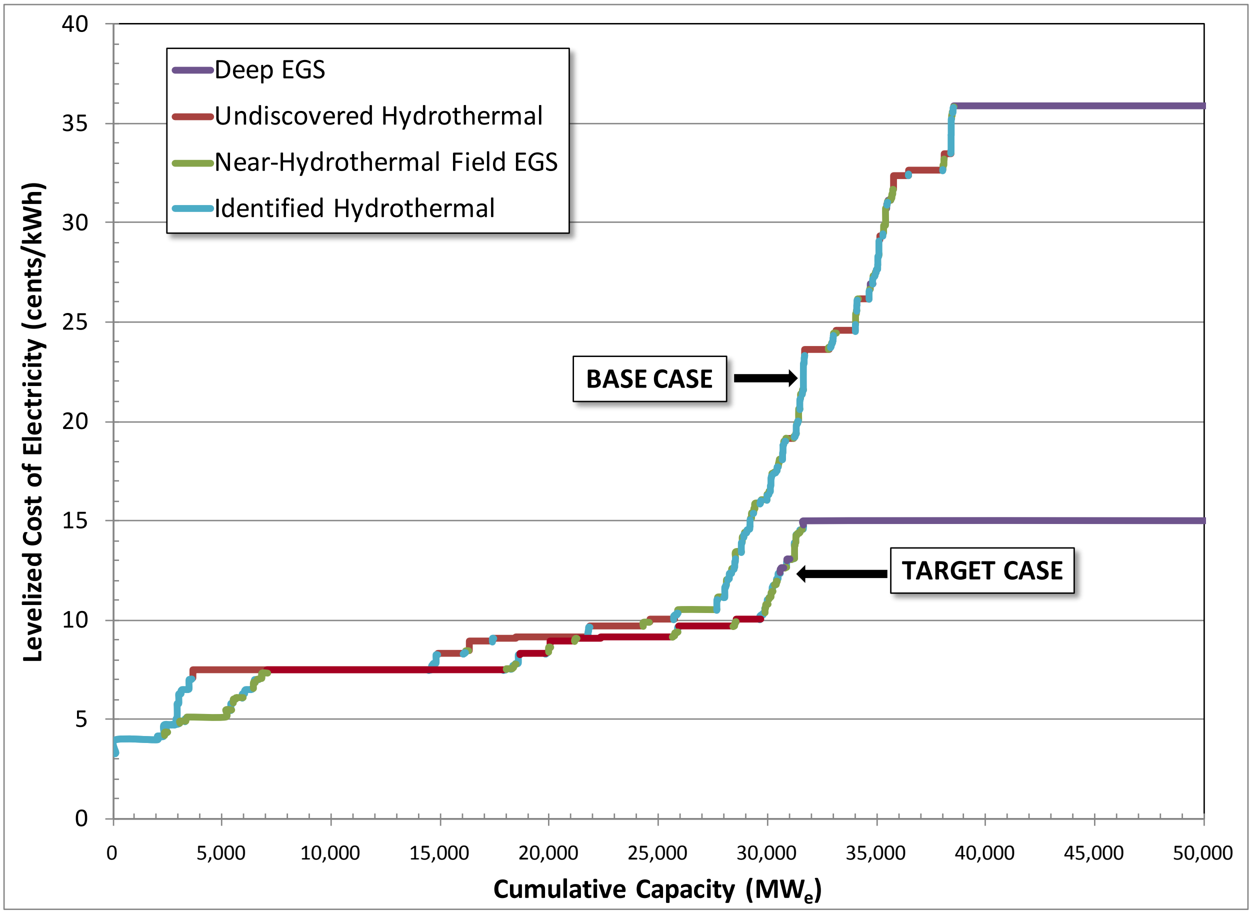

Figure ES-2. Combined supply curves of all geothermal technologies for base and target cases.

For the base case, identified and undiscovered hydrothermal resources dominate the lower part of the curve, with some EGS present at higher LCOE values. For the target case, hydrothermal projects still dominate the lower part of the curve, but a significant amount of near-hydrothermal field EGS resource is visible. The cost level at which a large amount of deep EGS resource is found in the supply curve is significantly lower for the target case than in the base case, indicating that meeting GTP goals could have a significant impact on deep EGS deployment. For the hydrothermal and near-hydrothermal field EGS resources, power plant costs tend to account for a significant portion of capital costs since these resources tend to be shallow with relatively low drilling costs. Exploration/confirmation and plant costs are comparable for hydrothermal and near-hydrothermal field EGS resources, with the major difference in capital costs for the two resources stemming from the need to stimulate the EGS reservoir. For the deep EGS resource, capital costs are dominated by drilling costs. LCOE and capital costs were generally higher for all geothermal resources in this update than in the last NREL study (Petty and Porro 2007), mainly due to a significant increase in drilling costs over the past several years. A sensitivity analysis confirmed that binary power plant costs and drilling costs most significantly affect the LCOE of hydrothermal and EGS projects, respectively. Since probability distributions were not used for EGS reservoir performance factors such as thermal drawdown rate and well production flow rate, they were not included in the sensitivity analysis. The differences between base and target case EGS costs indicate variations in their values could also have a large impact on the LCOE for EGS projects.

An analysis of the minimum LCOE for the deep EGS resource by location was performed. Regions were grouped by favorability, with regions having the lowest LCOE identified as the most favorable and those having the highest as the least favorable. By grouping the data, the transition between resources is smoothed and the classification generalized; the results should apply even with some variation in the underlying costs (e.g., drilling or power plant costs) or assumptions (e.g., EGS reservoir performance, fixed charge rate) used in this study. The resulting analysis was mapped and the location of the identified hydrothermal sites (and hence the assumed near-hydrothermal field EGS resource) was also included. The resulting map, shown in Figure ES-3, summarizes many of the results from the supply curve study.

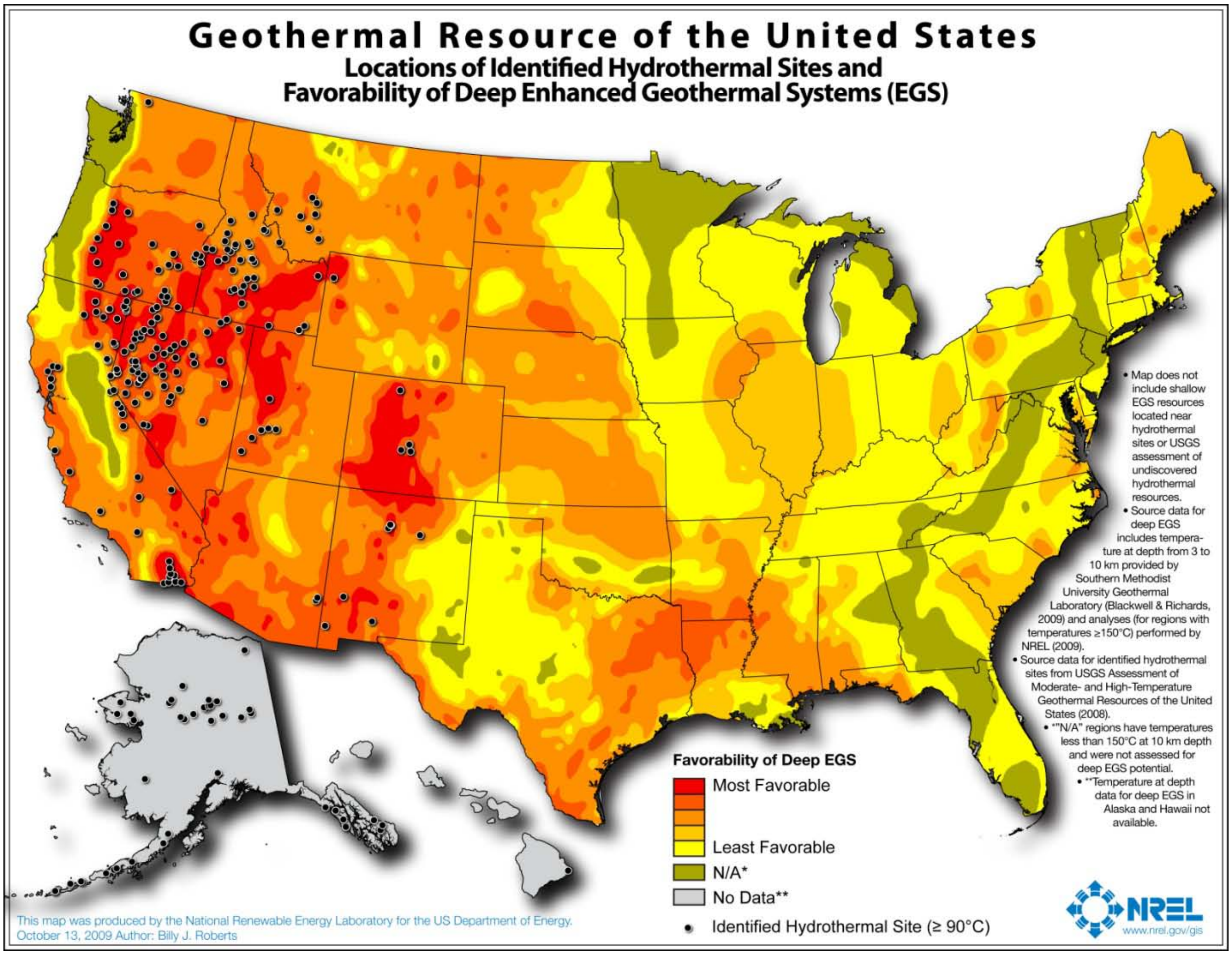

Figure ES-3. Geothermal resource of the United States.

Locations of identified hydrothermal sites, the co-located near-hydrothermal field EGS resource, and the relative favorability of the deep EGS resource. Undiscovered hydrothermal resources and other geothermal resources, such as co-produced fluids, are not represented.

Although the best efforts were made to accurately assess the geothermal resource and estimate project development costs for the supply curve, there is room for improvement of both the resource potential and project development cost estimates. The report conclusions identify key findings and recommend actions for improving future reports.

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1 Introduction and Purpose

This report documents the approach taken as part of the U.S. Department of Energy (DOE) Geothermal Technology Program's (GTP or the Program) annual supply curve update to characterize and represent the supply of electricity generation potential from geothermal resources in the United States. The geothermal supply curve is used as the basis for input into market penetration models for an array of tasks that analyze the competitiveness of geothermal electricity generation against other forms of electricity generation and forecast the penetration of geothermal technologies into the national electricity generation market. The primary use of data from the supply curve is to provide cost input for the annual Government Performance and Results Act of 1993 (GPRA) and DOE portfolio development support processes. The National Energy Modeling System (NEMS) and Market Allocation Model (MARKAL) market penetration models are used for these exercises. Geothermal supply curve data are also supplied to the Regional Energy Deployment System (ReEDS) and Stochastic Energy Deployment System (SEDS) market penetration models developed at the National Renewable Energy Laboratory (NREL). The results of this study were available for DOE use starting in August 2010 and were used for the Fiscal Year 2011 DOE planning cycle.

The primary purposes of this report are to:

1) Document the approach taken in identifying geothermal resources and determining the electrical producing potential of these resources;
2) Document the approach taken to estimate the levelized cost of electricity (LCOE), capital costs, and operating and maintenance (O&M) costs from these geothermal resources at present and future timeframes assuming various GTP funding levels;
3) Discuss the resulting supply curve and how improvements can be made to future supply curve representations.

While a geothermal resource is broadly characterized by the ability to extract heat from the ground and convert it to electricity, different technologies are used to achieve this task. The technologies are defined by the specific characteristics of the resource and methods used to extract the thermal energy and convert it to electricity. For this study, the geothermal resource was broadly split among two technologies: conventional hydrothermal and enhanced geothermal Systems (EGS). The hydrothermal resource consists of the naturally occurring geothermal sites conventionally used to produce electricity. EGS are artificial geothermal systems created by drilling into formations of hot rock, hydraulically stimulating the formation to open and extend fractures, intersecting the fractures with at least one more drilled hole, and then circulating fluid through the fractures. Injected fluid is heated by the hot rock as it is circulated through the reservoir, brought to the surface, and then used to produce electricity in a power plant before being re-injected into the reservoir, forming a closed-loop system. To develop the supply curves, the hydrothermal and EGS resources were further subdivided into four geothermal categories: identified hydrothermal, undiscovered hydrothermal, near-hydrothermal field EGS (EGS in regions near identified hydrothermal sites), and deep EGS (EGS at depths >3 km).

In defining the geothermal resource, published and available resources were used whenever possible. In particular, the supply curve update benefited greatly from the recent geothermal resource assessment performed by the U.S. Geological Survey (USGS) in 2008 (Williams, Reed, et al. 2008b). The study also drew upon methodologies and data from the Massachusetts Institute of Technology (MIT) *Future of Geothermal Energy* report to characterize U.S. EGS resources (Tester et al. 2006). The LCOE of the geothermal resources used to generate the supply curve were estimated using the Geothermal Electricity Technology Evaluation Model (GETEM), with cost input elicited from experts as part of a recent GTP geothermal risk assessment (Young, Augustine, et al. 2010).

The approach used to characterize and create the geothermal supply curve in this report enables updates to the geothermal resource to be quickly incorporated into the supply curve and input into market penetration models. The approach takes advantage of geographical information system (GIS) mapping methods to categorize and assess resources, to generate illustrative maps of the resulting resources, and to generate regional input for the various market penetration models. The incorporation of expert input on the present and future costs and performance levels of geothermal technology components from the risk assessment is a critical step in accurately assessing geothermal project costs and integrating uncertainty into the supply curve. A sensitivity analysis of the impact of technology components on project development costs performed as part of the study also identifies critical areas where research, development, and demonstration (RD&D) efforts can be focused to reduce overall system costs.

Although the best efforts were made to accurately estimate the geothermal resource and project development costs for the supply curve, there is ample room for improvement of both the resource potential and project development cost estimates. The report conclusions identify key findings and recommend actions for improving future reports.

2 General Approach and Assumptions

Figure 1 shows the general approach and flow of information used to develop supply curves and incorporate the results as input into the various market penetration models. The same approach was used for each of the geothermal resource categories considered. The primary steps in generating a supply curve and model input were the resource characterization and the estimation of the cost to develop the resource. For the resource characterization, the category and scope of the geothermal resource were defined. Next, information sources were identified and gathered from the literature and other available sources and were assembled into a database of the potential electrical generating capacity of the resource. The characterization of each category of geothermal resource considered is described in detail in Section 3.

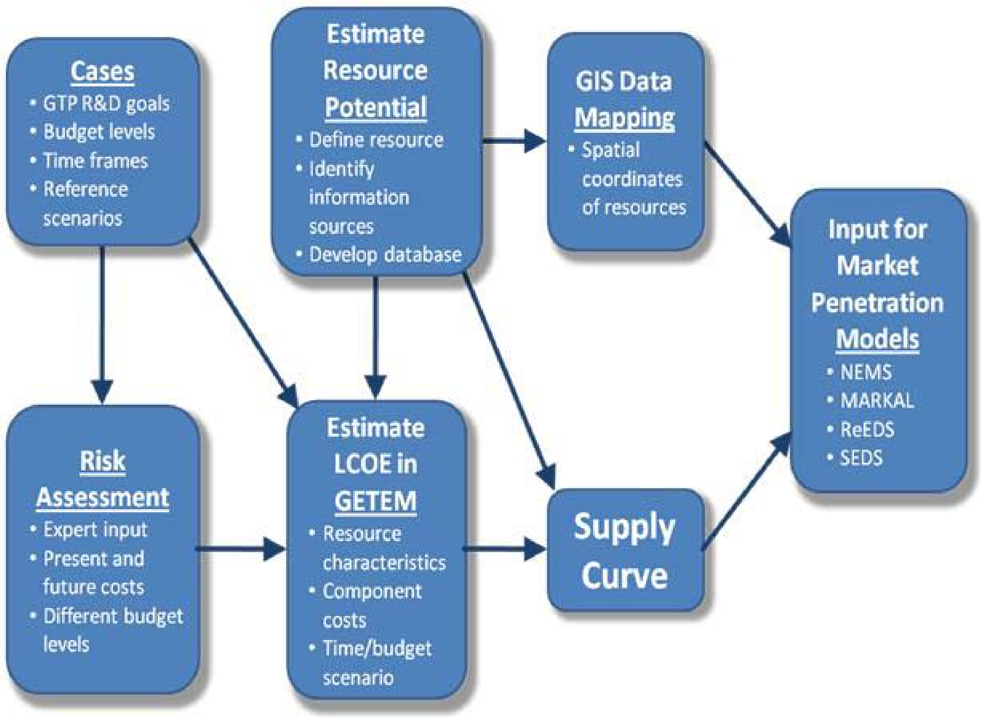

Figure 1. Supply curve information flow diagram.

Schematic of general approach used to develop geothermal resource supply curve and incorporate results as input into market penetration models. Arrows show flow of information.

The cost of developing each category of geothermal resource was estimated based on the resource characteristics from the characterization, the technology components required to develop the resource, and any factors or assumptions included in the funding case under which the resource would be developed. First, the various cases under which the resource is developed were defined. This included specifying budget and technology assumptions and the time frame under which the resource would be developed, as described in Section 2.1. Next, the cost of the technology components required to develop the resource were estimated, taking into account time frame and budget level. For this study, component cost and performance data were elicited from experts in the geothermal field as part of the geothermal risk assessment performed in 2009 (Young, Augustine, et al. 2010). Expert input consisted of probability distributions of performance metrics for key technology components. The aggregated component cost and performance data was used as input into GETEM to provide a range of probable LCOE for each geothermal resource; a Monte Carlo approach was used to sample the distributions by coupling GETEM with risk analysis software. The component cost data provided by experts are discussed in Section 2.3, along with general assumptions and inputs used for estimating the costs of all the geothermal resources considered. Resource-specific assumptions are described in detail in Section 3.

The potential electrical generating capacity from the resource characterization was combined with the estimated cost of developing that capacity to generate the supply curve. In order to be used as input in regional market penetration models, the supply curve data were matched to geospatial coordinates and assigned to regions specific to each market penetration model. This was accomplished using GIS mapping methods, as described in Section 2.4.

2.1 Supply Curve Cases

Two cases based on GTP budget funding and EGS technology advances were considered when developing supply curves. The two cases are (1) the "base" or "no-funding" case, which assumes a business-as-usual case where there is no GTP budget for geothermal RD&D, and (2) the "target" case, which assumes DOE funding of $50 million/year and that GTP EGS reservoir performance targets are met. The cases were driven by input required of all DOE energy technologies for annual GPRA reporting, which analyzes the benefits of RD&D funding for DOE programs. An "overbudget" case was initially considered but not included since it was not used in Fiscal Year 2011 GPRA analysis.

The budget for the target case was set based on historic GTP funding levels, shown in Figure 2, and on the assumption that these budget levels would likely increase in coming years as indicated by the $400 million allocated to GTP as part of the American Recovery and Reinvestment Act (Recovery Act). The assumed $50 million/year budget level does not reflect any guaranteed future budget levels. Both the base case and target case include the one-time allocation of funds in the Recovery Act and assume that the funds enabled GTP to allocate $350 million of the $400 million for RD&D of EGS and other geothermal-related technologies.

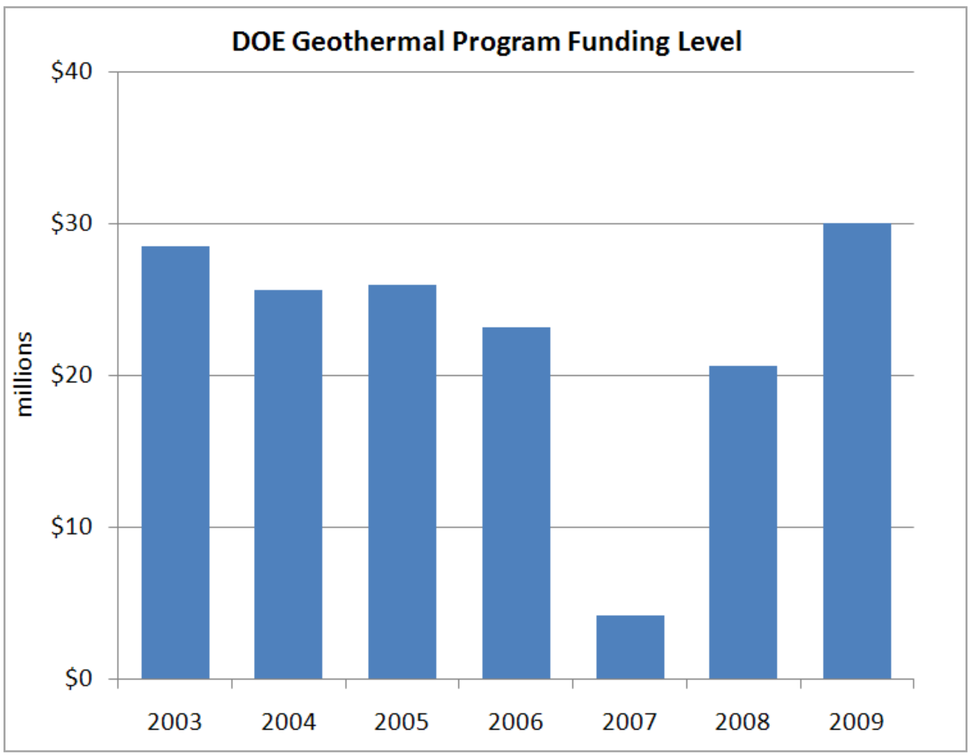

Figure 2. Historical GTP funding levels.

Along with budget levels, different assumptions about advances in enabling technologies for EGS were made for the two cases considered. The technology assumptions are based on major performance goals for EGS in the Program's Multi-Year Research Development and Deployment (MYRD&D) Plan (Geothermal Technologies Program 2008). By 2015, the Program plans to demonstrate the ability to create an EGS reservoir capable of producing 5 MW_e. By 2020, they plan to validate the ability of such a reservoir to sustain 5 MW_e of power generation over a 5-year period. The assumptions in each case apply to three EGS enabling technology performance metrics (TPM) identified as part of the 2009 technical risk assessment (Young, Augustine, et al. 2010): the production well flow rate (kg/s), the thermal drawdown rate of the reservoir (%/year), and the ratio of production wells to injection wells in the reservoir.

In the base case, where no funding is available from the Program for geothermal RD&D, expensive EGS demonstration projects were assumed to be too risky for private industry to undertake on a large scale, so that only modest improvements were made in EGS reservoir performance from current benchmarks. The base case assumed a production well flow rate of 30 kg/s, a thermal drawdown rate of 3.0%/year, and a production-to-injection well ratio of 2:1. A thermal drawdown rate of 3.0%/year corresponds to the EGS reservoir having to be re-drilled and re-stimulated once every 4-6 years, depending on its initial temperature, due to temperature declines in the produced fluid.

In the target case, where $50 million/year funding for RD&D projects is available, it was assumed that GTP MYRD&D goals were met, indicating that significant advances were made in EGS reservoir technology. The target case assumed a production well flow rate of 60 kg/s, a thermal drawdown rate of 0.3%/year, and a production-to-injection well ratio of 2:1. A thermal drawdown rate of 0.3%/year corresponds to an EGS reservoir that can produce fluid without significant produced-geofluid temperature decline over the 30-year lifetime of the power plant and does not require re-drilling or re-stimulation of the reservoir. The EGS reservoir technology assumptions match those used in the risk assessment and are summarized in Table 1.

Table 1. EGS Technology Performance Assumptions Used in Base and Target Cases

Enabling Technology	Base Case Value	Target Case Value
RD&D Funding	$0 M/year	$50 M/year
Production Well Flow Rate	30 kg/s	60 kg/s
Thermal Drawdown Rate	3.0 %/year	0.3 %/year
Production/Injection Well Ratio	2:1	2:1

For both the base and target case, it was assumed that EGS would not be commercially viable until after 2020. At this point, construction of commercial EGS plants would commence, with the first plants coming online in 2024-2025. For the target case, the vast majority of RD&D funding would be spent on EGS enabling technologies until 2020. After, RD&D funds would be focused on technologies that reduce the costs associated with geothermal power plant projects. These assumptions were required as input for GPRA benefits analysis and for annual market penetration modeling, and are discussed in greater detail in Section 5.

To account for the effect of technology improvements and cost reductions with time on overall geothermal project costs, two future year time frames were also considered. The risk assessment asked experts to estimate technology component costs and performance levels in target years of 2015 and 2025. The component technology data and methods used for updating the present-day geothermal supply curves for the base and target cases to 2015 and 2025 are described in Section 5.

2.2 GETEM and @Risk

GETEM was used to estimate costs for all geothermal resources considered in this study. GETEM is a Microsoft Excel-based techno-economic systems analysis tool for evaluating and comparing geothermal project costs. GETEM is a highly flexible tool with more than 180 user-defined inputs that can be used to tailor cost estimates to a resource. GETEM was developed for the Program by Princeton Energy Resources International (Entingh 2006) in collaboration with researchers at DOE national laboratories and external consultants. GETEM is currently maintained by the Idaho National Laboratory and is periodically updated with corrections, current cost indices, and additional modeling capabilities. This study used GETEM Version 2008-A6. The most current version of GETEM is available for download from the GTP website (Geothermal Technologies Program 2009a).

GETEM is a deterministic model that uses a bottoms-up analysis to calculate the LCOE and capital costs of geothermal and hydrothermal projects based on a set of user-specified variables. The user defines the resource characteristics (e.g., hydrothermal or EGS, temperature, depth), project details (e.g., plant type and size, pump types, well productivity), and other required parameters. GETEM then calculates the individual component costs associated with each phase of the project, such as exploration, well field development, power plant construction, and O&M costs, based on user-defined cost inputs, embedded cost and system performance correlations, and cost indices to account for the year the project is developed. Total project costs are calculated assuming a user-defined fixed charge rate for project financing. GETEM's primary output is the LCOE for the project, but also provides the total capital costs and a breakdown of capital costs and LCOE contributions from the project phases. GETEM was designed to examine the impact of technology improvements and cost reductions on geothermal power costs. The user can specify technology or cost improvements in the model input parameters and GETEM quantifies the changes in project costs in a side-by-side comparison of the two cases. For this study, a baseline year of 2008 (the most current available in GETEM at the time) was used.

2.2.1 Use of @Risk in GETEM

Since GETEM is a deterministic model, each set of user input results in a single cost output. However, the technology cost and performance data used as input for GETEM for this study comes from the 2009 technical risk assessment in the form of probability distributions, so that there is a range of possible input values for several of the key input parameters in GETEM. To accommodate these distributions, @Risk Version 5.0 software was used. @Risk is a Monte Carlo simulation add-in for Microsoft Excel available from Palisade Corporation that links directly to Excel to add risk analysis capabilities. For each geothermal resource in the supply curve, @Risk was used to run a Monte Carlo simulation in GETEM in which the technology cost and performance probability distributions were sampled. The Monte Carlo simulation computes a probability distribution of the LCOE for a geothermal power plant project based on the probability distributions of the inputs. For each simulation in this study, 1,000 Monte Carlo iterations were performed.

2.3 Technology Cost and Performance Data from Risk Assessment

2.3.1 Risk Assessment Process

Geothermal technology cost component data for estimating geothermal energy costs in GETEM were elicited from experts as part of the Program's 2009 technical risk assessment. The goal of the risk assessment was to quantitatively assess the projected risk of geothermal RD&D in terms of the Program's primary performance metric: the LCOE for geothermal resources. The experts were asked to estimate the probable range of technology performance metrics for the present and future times under different GTP funding levels. A team of geothermal experts comprised of industry experts, academic researchers, DOE laboratory researchers, and laboratory contractors was assembled during the 2009 Stanford Geothermal Workshop. Experts were divided into four geothermal technology areas: (1) exploration; (2) wells, pumps, and tools; (3) reservoir engineering; and (4) power conversion. The experts were trained on how the risk assessment process worked and, after lengthy discussions, converged on a set of reference scenarios, assumptions, and current status of technology on which to base their future technology performance estimates. Based on these discussions and their personal knowledge of the industry, each expert then provided a triangular probability distribution (compromised of the high, low, and most likely values) for each performance metric in their technology area. Input was elicited for future years of 2015 and 2025 assuming GTP RD&D budgets for each individual performance metric of $0/per year (business-as-usual), $30 million/year, and $60 million/year. The preliminary input was analyzed and, in the case of outliers, experts were asked to justify their responses to eliminate any potential unintentional or erroneous input. The verified input was then combined to produce an aggregated distribution of the expert input. A description of the risk assessment process, the risk geothermal plant reference scenarios assumed while eliciting expert data, and results are detailed in Young, et al. (2010).

2.3.2 Assumptions and Parameter Values Used in GETEM

The expert aggregated distributions of TPMs from the risk assessment were applied independently as input to GETEM in determining the LCOE for geothermal resources. As part of the initial discussion, the experts agreed on the current point values or distributions of the TPMs. Experts were given an EGS reference scenario on which to base their component cost estimates. A summary of the risk EGS plant reference scenario is shown in Table 2. Several of the values, such as well cost and binary power plant costs, are specific to the EGS power plant reference scenario assumed as part of the risk assessment. Experts were also asked to estimate several TPMs for hydrothermal exploration technologies. In all, distributions for 10 geothermal technology performance metrics were used to estimate the current LCOE for geothermal resources using GETEM for the supply curve study. The TPMs and the mean, 10^{th}%ile , and 90^{th}%ile values of the expert distributions for the risk reference scenario are listed in Table 3. These reference distributions were applied when determining the supply curve in current (2008) US$ for both the base and target cases, so that only the enabling technology assumptions differed for the two cases. The future-year data was used to predict future costs of geothermal resources under the cases in Section 2.1 as described in Section 5.

Table 2. Risk Assessment EGS Reference Scenario Parameters

Parameter	Value
Geothermal Resource	EGS
Plant Type	Binary, air-cooled
Net Output	20 MW_e
Resource Temperature	225°C
Plant Design Temperature	200°C
Well Depth	6 km
Production Well Flow Rate	60 kg/s
Thermal Drawdown Rate	3.0%/year
Production/Injection Well Ratio	2:1

This reference scenario was used when determining technology performance metric distributions. Note that the risk assessment EGS reference scenario differs slightly from reference scenarios used in this supply curve study.

Table 3. Summary of Expert-Elicited Geothermal Technology Performance Metric Input

TPM			Value		
Technology Area	Name	Units	10^{th} %ile	Mean	90^{th} %ile
Exploration	Non-Well Exploration Costs (EGS)	$M	0.42	1.41	2.53
	Non-Well Exploration Costs (Hydro)	$M	0.51	1.22	2.00
	Exploration Well Success Rate (EGS)	%	50.0	64.1	83.4
	Exploration Well Success Rate (Hydro)	%	20.1	34.8	50.0
Well Pumps & Tools	Well Drilling/Construction Cost	$M	15.0	22.3	30.0
	Production Pump Cost (per well)	$M	1.0	1.5	2.0
Reservoir Engineering	Stimulation Cost (per triplet)	$M	2.7	8.4	15.1
Power Conversion	Binary System Capital Cost	$/kW	2,200	2,500	2,800
	Binary System O&M Cost/Yr	¢/kWh	-	2.2	-
	Brine Effectiveness	W-h/lb_m	-	9.50	-

Input shown is expert-consensus present-day values or distributions of TPMs for the EGS risk reference scenario in Table 2 and for hydrothermal exploration technologies. The mean, 10^{th}%ile, and 90^{th}%ile values of the TPM distributions are listed.

Wherever possible, the distributions and assumptions used by the experts for the reference scenarios were used as guidance for inputs to parameters and values in GETEM when estimating geothermal energy costs for this report. However, some assumptions had to be made when providing input to GETEM when the resource characteristics of the geothermal resource for the supply curve differed from those assumed for the risk reference scenario, when no relevant guidance was provided in the risk reference scenario, or when the guidance in the risk reference scenario resulted in unreasonable or unrealistic results when applied to the geothermal resource in the supply curve.

A complete list of the input parameters and assumptions used for the hydrothermal and EGS supply curve reference scenarios is given in Appendix A (note: supply curve reference scenarios used in this report differ slightly from risk reference scenarios used in Young, et al. (2010)). Similar parameters and assumptions were used for all GETEM runs in this report. GETEM inputs specific to each geothermal technology are discussed in Section 3, while key assumptions and adaptations of expert input to the geothermal resource used in the supply curve applied to all GETEM runs are listed below.

2.3.2.1 Well Cost

The well cost distribution given by the experts assumes a 6 km-deep well for an EGS project. However, wells considered for the hydrothermal and EGS resources in the supply curve range from 0.3 to 10 km (1,000 to 33,000 ft) in depth. It was assumed that the distribution given by the experts applied to all well depths. The well cost distribution for the 6 km well was normalized by the GETEM drilling cost correlation value for a medium-cost 6 km-deep well. The well cost input for GETEM was calculated during simulations by taking the value from the normalized distribution sampled by @Risk and multiplying by the default GETEM value for the cost of a well at the depth of the geothermal resource being considered.

When the risk assessment workshop was conducted in February 2009, drilling costs were near historic highs due to the scarcity of steel and cement and increased rig rental rates caused by high crude oil and natural gas prices (which led to increased demand for oil and gas drilling). The drilling costs used by the experts in the risk assessment represent drilling costs at a single point in time based on market conditions and reflect these high costs. The decreases in future drilling costs from RD&D and the learning-by-doing projected by the experts in this report indicate cost reductions relative to the assumed drilling costs, and do not consider market volatility. However, since drilling costs are a significant factor in the overall cost of a geothermal project, changes in drilling costs have a significant impact on LCOE. GETEM uses the Bureau of Labor Statistics (BLS) Producer Price Index (PPI) to adjust its drilling cost correlations from the year the cost correlations were developed to the model year. As Figure 3 shows, drilling costs have declined significantly from these recent record highs in the past year. When the supply curves in this study were generated in late summer 2009, it was obvious that drilling costs had decreased significantly from the values assumed during the risk assessment, but only preliminary values from the BLS PPI were available. Based on conversations with geothermal drilling contractors, drilling costs for this report were assumed to be discounted 30% from the 2008 BLS PPI index value in GETEM.

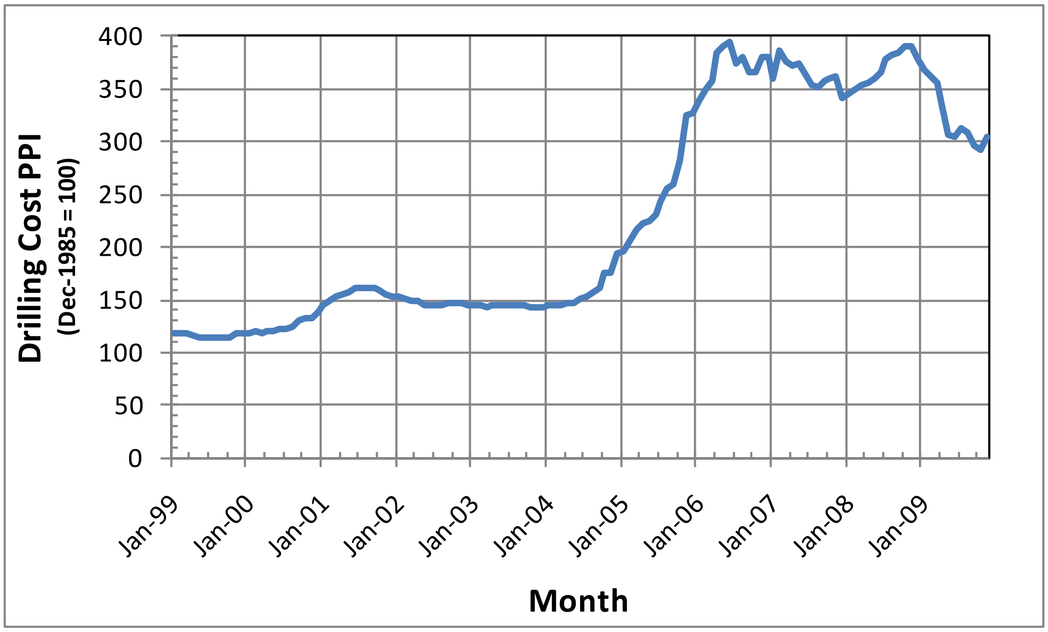

Figure 3. BLS drilling cost PPI.

Index values from August 2009 onward are projected (Bureau of Labor Statistics 2009).

2.3.2.2 Geofluid Pumping

Pumping of the injection and/or production wells is often required for geothermal resources. For hydrothermal resources, pumping may be required in production wells to increase the flow rate of geofluid to the surface, and in injection wells to overcome friction losses or the natural pressure of the formation the fluid is being injected into. For EGS resources, it is theoretically possible to form a thermosiphon in which the density difference between the cool injected geofluid and heated produced geofluid is great enough that the difference in the hydrostatic head between the injection and production wells causes the system to flow naturally. In this case, no pumping would be required. In reality, pressure losses in the wellbores and in the reservoir must be overcome, and these pressure losses increase as the geofluid flow rate increases, so some degree of pumping will likely be required.

To be conservative, it was assumed for this study that both the injection and production wells must be pumped for all types of geothermal resources. The pumping power requirements were calculated by GETEM based on the injection/production well flow rates assuming a well casing inner diameter of 7.0 in (17.8 cm), a bottom hole pressure of 150 psi (10.3 bar) in the injection well, and pressure losses in the reservoir calculated assuming a simple permeability-multiplied-by-surface-area model. Although the cost of the production pump had little impact on the overall LCOE, it was observed that the depth the production pump was set at, and hence its power requirements, could significantly impact project economics, especially for resources with low reservoir temperatures. Therefore, the cost of the production pump was based on expert input, but the production pump depth and power requirements were calculated by GETEM.

2.3.2.3 Power Plant Costs

Similar to well costs, the power plant costs given by experts assumed the risk reference scenario of a binary power plant operating under a particular set of conditions while the geothermal resources in the supply curve cover a wide range of operating conditions. The experts estimated the cost of a binary power plant operating at a design temperature of 200^oC with 20 MW_e of net power output, while the supply curve includes geothermal resources ranging from 110^o to 350^oC. As with well costs, the distribution of binary power plant costs from the experts was normalized by the power plant cost calculated by the GETEM power plant cost correlation for the risk reference scenario, and power plant cost inputs were calculated during @Risk runs from the values sampled from the normalized distribution multiplied by the GETEM-calculated binary power plant costs. Since expert input was not elicited for flash plants, the GETEM-calculated values were used. Sites with plant design temperatures less than 225^oC were assumed to be binary plants, while those with design temperatures of 225^oC and higher were assumed to be flash plants.

2.3.2.4 Power Plant Performance/"Brine Effectiveness"
The power plant performance or “brine effectiveness” measures how much electricity the power plant produces per unit mass of geofluid. The power plant performance has a thermodynamic maximum value and is a strong function of temperature. Although a high brine effectiveness increases power plant output, power plant costs tend to increase with plant performance so that there is an optimum brine effectiveness that minimizes LCOE. GETEM contains a macro that can be used to find this optimum for binary power plants. However, for this study, expert input was used to determine binary power plant performance. Since the power plant performance given by experts assumed a single risk reference scenario, the expert distribution was normalized by the theoretical maximum value in GETEM for the risk reference scenario and applied across the range of geothermal resources in the supply curve in the same method as for well costs and power plant costs. Since expert input was not elicited for flash plants, GETEM-calculated values were used.

2.3.2.5 O&M Costs
The O&M costs given by experts assume the risk reference scenario. Therefore, the same methodology described above for well costs, power plant costs, and power plant performance was used to apply the expert estimated O&M costs across the range of geothermal resources in the supply curve. The normalized distribution was applied to both binary and flash plants.

2.4 GIS Mapping
GIS mapping methods were used to incorporate results from the supply curves generated in this study into market penetration models. GIS is a system used to manage, analyze, and present information associated with a location. The market penetration models divide the United States into different regions and require data input on a regional basis. The regions differ according to the market penetration model being used. For example, the SEDS model has only one region that covers the entire United States. MARKAL uses either one or 10 regions, while NEMS uses 13 regions. The ReEDS model requires input for 134 “power control authority” regions. The supply curve data must be broken down by region to provide input for each of the market penetration models.

The GIS analysis was performed based on data from the resource potential estimates. For geothermal resources associated with a specific location, such as a hydrothermal site, the latitude and longitude was used to identify the site and determine which region it was in. For resource potential estimates based on the characteristics of a region, such as the temperature and depth data associated with the deep EGS resource, the resource was mapped and then overlain with the model regional maps. GIS methods were also used to generate maps showing the potential geothermal power capacity of the United States and analyze the results of the deep EGS supply curve.

3 Supply Curves

For this study, two types of geothermal resources were considered—hydrothermal and EGS. Supply curves were generated for each of the geothermal technologies using project costs estimated with GETEM. Costs are in 2008 US$. Future cost multipliers for each technology are discussed in Section 5.

The hydrothermal resource consists of the naturally occurring geothermal sites used conventionally to produce electricity. The hydrothermal resource potential is based on the recently completed geothermal resource assessment of the United States performed by the USGS (Williams, Reed, et al. 2008b). The USGS resource assessment is an update of USGS Circular 790 (Muffler 1979) and is the first major update by the USGS to the geothermal resource assessment in almost 30 years. The assessment divides the resource into identified sites and "undiscovered" resources.

EGS are geothermal reservoirs that have been engineered to extract economical amounts of heat from geothermal resources that have low permeability and/or lack natural *in-situ* fluids for heat extraction. An EGS reservoir is created by drilling into a formation of hot rock, hydraulically stimulating the formation to open and extend fractures, intersecting the fractures with at least one more drilled hole, and then circulating fluid through the fractures. Injected fluid is heated by the hot rock as it circulates through the reservoir, is brought to the surface, and is then used to produce electricity before being re-injected into the reservoir, forming a closed-loop system. In theory, since temperatures increase with depth, EGS can be developed anywhere. However, technological and economic considerations will limit the sites where EGS can be practically deployed. The cost of electricity from an EGS site depends heavily on the depth and temperature of the reservoir to be developed. For this study, the EGS potential resource is divided into two groups: the near-hydrothermal field EGS resource and the deep EGS resource.

3.1 Identified Hydrothermal Sites

3.1.1 Resource Potential

The USGS 2008 geothermal assessment identifies 241 moderate- and high-temperature (>90^{o}C) sites on private or accessible public lands in the United States (Williams, Reed, et al. 2008b). The sites are concentrated entirely within 13 states in the western United States, Alaska, and Hawaii. The methodology used to estimate the recoverable energy from each site identified in the 2008 USGS assessment is similar to that used in the previous USGS Circular 790 assessment (Muffler 1979), and is described in Williams, Reed, et al. (2008a). The volume method is used to calculate the amount of thermal energy in the reservoir, and a recovery factor is applied to determine the amount of thermal energy that can be recovered from the reservoir. The amount of useful energy that can be extracted from the thermal energy in the fluid produced from the reservoir is limited by the laws of thermodynamics as measured by the exergy of the fluid. The exergy of the recovered fluid is calculated based on the resource temperature and the reference (ambient) temperature. The electric energy potential is then determined by multiplying the exergy by the plant utilization efficiency, assuming a reservoir lifetime of 30 years. To account for uncertainties in the estimate of the potential electric power generation, Monte Carlo simulations were conducted. For each site, triangular distributions of the probable reservoir volume and temperature were made using estimates of the minimum, maximum, and most likely values for these parameters. A uniform distribution ranging from 0.08 to 0.20 (0.10 to 0.25 for sediment-hosted reservoirs) was assumed. The result of the Monte Carlo simulations is a distribution of probable electric power generation potential for each site.

Based on this analysis, the USGS 2008 resource assessment predicts a mean total of 9,057 MW_e of power generation potential from identified hydrothermal systems on private or accessible public lands, with a 95% probability of only 3,675 MW_e and a 5% probability of up to 16,457 MW_e being available (Williams, Reed, et al. 2008b). This mean value is significantly lower than the 23,000±3,400 MW_e potential from only 52 identified sites listed in the USGS Circular 790 assessment (Muffler 1979). The primary reason for this decline was a change in the assumed recovery factor for geothermal systems. The Circular 790 assessment assumed an average recovery factor of 0.25 based on experiences at the Geysers field in California, whereas the USGS 2008 assessment used much lower values based on more recent experiences from a large number of sites. Additionally, the more recent assessment assumes smaller reservoir volumes for some of the large hydrothermal sites and lower temperatures at others than those used in Circular 790, contributing further to the apparent reduction in the overall power producing potential (Williams 2009a).

The total mean value of 9,057 MW_e for the recoverable electric power generation potential from the USGS 2008 assessment was adopted as the starting point for the identified hydrothermal resource in this study. The site-specific data for the identified hydrothermal resources was obtained from the USGS (Williams 2009b). A cut-off temperature of 110°C was adopted based on limitations in the range of power plant operating temperatures validated in the GETEM code. This results in the removal of 106 identified hydrothermal sites representing 460 MW_e of power producing potential. The USGS 2008 assessment does not exclude currently installed generating capacity at hydrothermal sites. An assessment of installed hydrothermal capacity was made based on data from the Energy Information Administration (EIA) (Energy Information Administration 2009) and Geothermal Energy Association (GEA) (Geothermal Energy Association 2009) databases. The power plant capacity data from the EIA and GEA databases do not match directly, neither in names of plants, their listed capacities, nor the plants and locations included on each list. The existing plants from the two databases were matched as well as possible based on plant names, locations, and year that operation began. The selection and assignment of current power plant capacities to identified hydrothermal resources is complicated by the differences in the reported capacities between the two databases and the variations in the types of reported capacities (nameplate, summer, and winter) within the databases. The EIA database was chosen as the primary source for plant capacity and, following their convention, the summer capacities were used in the assignment of power plant capacities to identified hydrothermal sites. As shown in Table 4, total hydrothermal summer capacity in the EIA database, with the addition of several plants in the GEA database and recent plant additions reported by the media, is 2,480 MW_e. According to the installed capacity, some sites, such as the Geysers in California, have a greater existing production capacity than potential capacity, so their potential was completely removed from the assessment. When current capacity and sites with temperatures <110°C are removed from the USGS 2008 mean power producing potential, the subsequent remaining mean potential capacity for identified hydrothermal sites in the United States used in this study is 6,394 MW_e.

Table 4. Existing Capacity at Identified Hydrothermal Sites (EIA, 2009; GEA, 2009)

Identified Hydrothermal Site Name	State	Installed Summer Capacity (MW_e)
Heber Shallow	CA	119.2
East Mesa	CA	101.0
North Brawley	CA	64.0
Salton Sea Area	CA	298.0
Coso Area	CA	229.3
Long Valley	CA	42.9
Geysers	CA	1,121.9
Amedee	CA	2.2
Medicine Lake (Glass Mt.)	CA	99.8
Puna Geothermal Venture	HI	31.0
Raft River	ID	19.6
Lightning Dock	NM	10.0
Wabuska Hot Springs	NV	0.9
Steamboat Springs and Steamboat Hills	NV	85.6
Brady HS	NV	26.0
Desert Peak	NV	17.5
Stillwater Area	NV	8.5
Soda Lake Area	NV	10.9
Dixie Valley Geothermal Field	NV	56.0
Dixie Valley Power Partners	NV	25.0
San Emidio Desert Area	NV	3.5
Beowawe HS	NV	12.8
Cove Fort - Sulphurdale	UT	16.0
Roosevelt HS	UT	68.0
Thermo Hot Springs	UT	10.0
	Total	2,479.6

3.1.2 LCOE Estimates

The present-day LCOE in 2008 US$ for the identified hydrothermal resource was estimated using GETEM on a site-by-site basis. First, site-specific resource definitions were input into the GETEM model. The reservoir temperature and capacity were obtained from the USGS 2008 resource assessment (Williams 2009b). Hydrothermal sites with reservoir temperatures below 110°C were excluded. The net power sales from the plant in GETEM were set equal to the potential capacity of the identified hydrothermal site. The plant size was capped at 100 MW_e and it was assumed that sites with larger potential capacities would have multiple power plants. The reservoir depth and production well flow rates for each site were not included in the USGS data. Therefore, flow rates and depths used for sites in a previous NREL supply curve update (Petty and Porro 2007) were used. As in the previous NREL update, a reservoir depth of 1.524 km (5,000 ft) and a production well flow rate of 44.19 kg/s (350,000 lb/hr) were assumed when site-specific estimates were not available.

Once the hydrothermal site resource was defined, the cost of power was calculated in GETEM using the TPM inputs elicited from experts discussed in Section 2.3. For all hydrothermal sites, a 3:1 production/injection well ratio and a thermal drawdown rate of 0.3%/year were assumed. These values are consistent with those at a typical hydrothermal power plant. The resulting supply curve is shown in Figure 4. The median (50th%ile), 10th%ile, and 90th%ile LCOE values shown illustrate the range of likely values for the hydrothermal power plants given the current state of technology based on expert input. Since the base and target case assumptions are identical for hydrothermal resources, the supply curve is identical for hydrothermal for both cases.

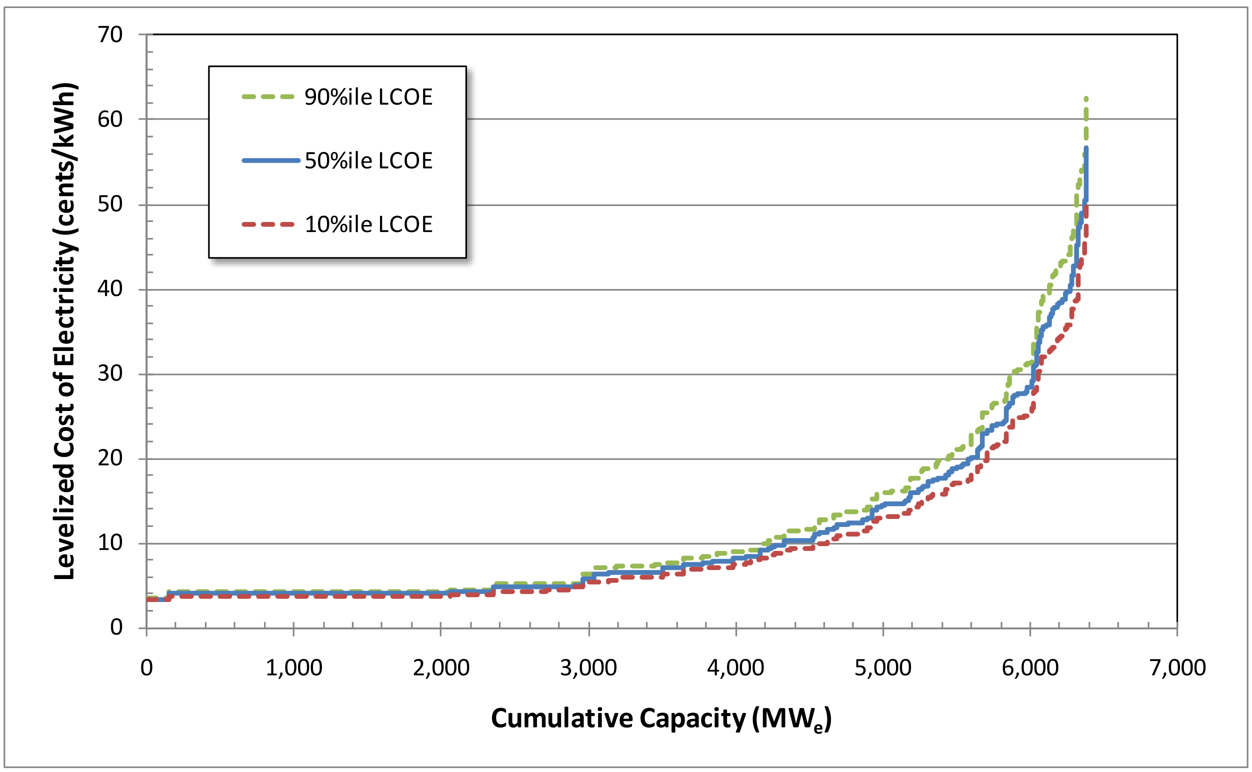

Figure 4. Supply curve for identified hydrothermal resource.

Present-day median (50th%ile), 10th%ile, and 90th%ile LCOE estimates in 2008 US$ from GETEM shown.

It should be noted that because of the large number of hydrothermal sites, detailed site information was not considered when estimating the LCOE in GETEM. For example, the corrosive nature of the geofluid at the Salton Sea site in California was not taken into consideration when estimating well construction and power plant equipment costs. The remote nature of the Puna site in Hawaii, which would increase rig mobilization and equipment shipping costs, was also not taken into consideration. For all sites, a single drilling costs curve was assumed, even though drilling costs can vary considerably based on the lithology of the reservoir. The use of @Risk to calculate LCOE distributions based on a probable range of technology cost and performance captures these cost variations somewhat. Ideally, project cost estimates would consider each site in detail, but the time required to incorporate such detail was deemed time-prohibitive for this study. Some of the sites with characteristics that would significantly affect costs, such as the Salton Sea and Puna, have been identified; future supply curve updates will attempt to incorporate these factors into GETEM.

3.2 Undiscovered Hydrothermal

3.2.1 Resource Potential

In addition to identified hydrothermal resources, the USGS 2008 geothermal resource assessment also estimated the power production potential from undiscovered geothermal resources. The undiscovered resource was estimated using GIS-based statistical methods to analyze the correlation between spatial datasets and existing geothermal resources to derive the probability of the existence of geothermal resources in unexplored regions (Williams and DeAngelo 2008). The undiscovered geothermal resource power generation potential from the study has a mean value of 30,033 MW_e, with a 95% probability of 7,917 MW_e and a 5% probability of 73,286 MW_e. For this study, the mean value (30,033 MW_e) was used. The distribution of the undiscovered hydrothermal resource was broken down by state as shown in Figure 5.

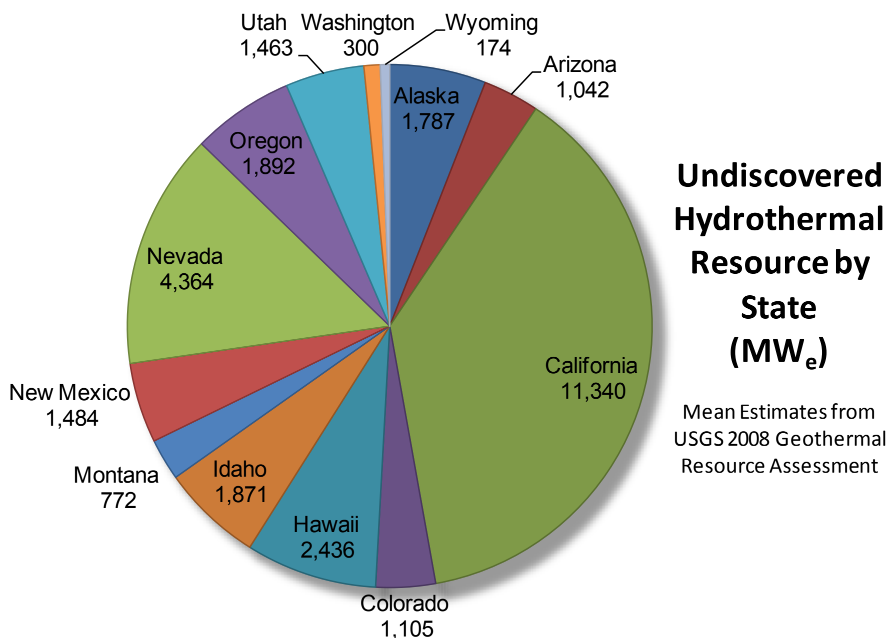

Figure 5. Undiscovered hydrothermal resource by state.

Power producing potential in MWe based on mean estimates in USGS 2008 Geothermal Resource Assessment (Williams, Reed, et al. 2008b).

3.2.2 LCOE Estimate

Estimation of the LCOE in GETEM requires characterization of the geothermal resource. However, the actual resource characteristics of the undiscovered hydrothermal resource, such as reservoir depth and temperature, are unknown. In the absence of actual data, it was assumed that the undiscovered resources would be similar in nature to identified hydrothermal sites in the same region. Since the 2008 USGS resource assessment breaks down the undiscovered hydrothermal resource by state as shown in Figure 5, the undiscovered hydrothermal resource attributed to each state was assumed to look like the hydrothermal resource already identified within each state.

To characterize the undiscovered hydrothermal resource, identified hydrothermal sites were first divided up by state. The identified sites were then further divided into two subgroups—those with reservoir temperatures $\geq 150^{o}C$ and those with temperatures $<150^{o}C$—and the mean potential capacity from identified hydrothermal resources in each subgroup was totaled. The undiscovered hydrothermal resource in each state was apportioned between the designated temperature ranges based on the percentage of identified hydrothermal resource in each subgroup. For several states, such as Colorado, the entire undiscovered resource was assumed to have a temperature $<150^{o}C$ since all the identified hydrothermal sites in those states have estimated reservoir temperatures of $<150^{o}C$. Only Hawaii, with one identified site at Puna, had all its potential resource appropriated to the $\geq 150^{o}C$ subgroup.

A single reservoir temperature, depth, and production well flow rate was assumed for the undiscovered resource in each subgroup. The temperature, depth, and flow rate of the undiscovered hydrothermal resource in each subgroup was determined by calculating the mean-capacity-weighted average of each of these parameters from the identified hydrothermal sites in each sub-group. Because the reservoir characteristics were determined using the potential power-capacity-weighted average, the undiscovered resource is assumed to be more similar to the large identified hydrothermal sites in each state that have large power producing potential. This means, for example, that the high-temperature undiscovered resource characteristics in California are heavily influenced by the characteristics of large sites such as the Geysers and the Salton Sea.

By the nature of the resource, the methodology used to characterize the undiscovered hydrothermal resource is somewhat arbitrary. A range of other techniques could have been used to characterize the resource. On one extreme, the entire undiscovered resource could have been treated uniformly and assumed to have the properties of a "typical" hydrothermal site, so that a single estimated LCOE would apply for the entire undiscovered hydrothermal resource. On the other extreme, a wide range of possible reservoir temperature, depth, and production well flow rate distributions could have been estimated and the undiscovered resource could have been divided amongst the possible combinations using a Monte Carlo simulation. Whether either of these methodologies, or any other that can be imagined, is more "correct" than another is unknowable since the resource remains undiscovered. The methodology used attempted to make the best use of the information at hand to produce a reasonable approximation of the nature of the undiscovered resource. The undiscovered hydrothermal resource estimate would have benefited from greater knowledge of how the USGS arrived at their undiscovered hydrothermal capacity estimates. A report detailing how the undiscovered resource assessment was performed is scheduled to be published in the near future. Future supply curve updates should take this document into consideration once it is available.

Once the undiscovered hydrothermal resource characteristics were defined in GETEM, the process and assumptions used to estimate the LCOE were nearly identical to that used for the identified hydrothermal resources, with the following exceptions. The power plant net power output was assumed to be 20 MW_e for each plant. To account for the added expenses of locating and identifying the undiscovered sites, exploration costs were assumed to be 150% of those for identified hydrothermal resources. The resulting supply curve consisting of the median (50^{th}%ile), 10^{th}%ile, and 90^{th}%ile LCOE values is shown in Figure 6. As with identified hydrothermal sites, the same supply curve applies to both base and target cases.

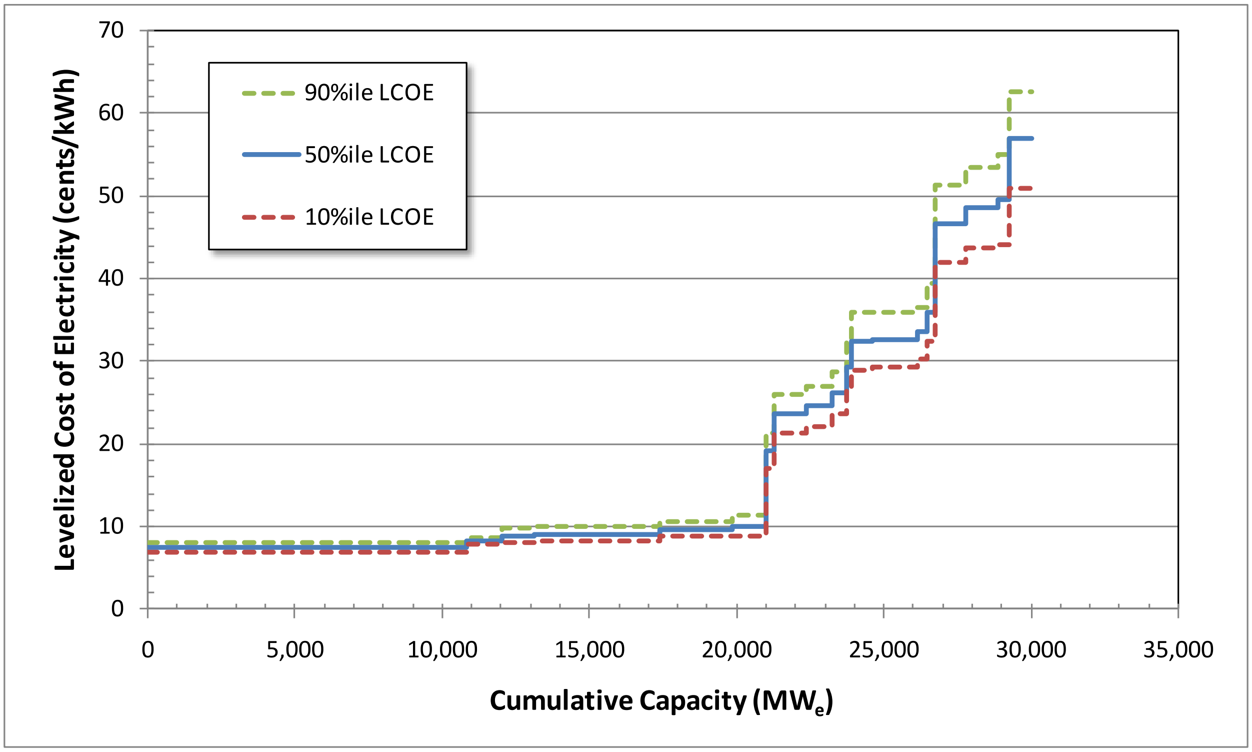

Figure 6. Supply curve for undiscovered hydrothermal resource.

Present-day median (50th%ile), 10th%ile, and 90th%ile LCOE estimates in 2008 US$ from GETEM shown.

3.3 Near-Hydrothermal Field EGS

3.3.1 Resource Potential

The near-hydrothermal field EGS resource consists of the areas around hydrothermal sites that lack sufficient permeability and/or *in-situ* fluids to be economically produced as a conventional hydrothermal resource. These resources require the application of EGS reservoir engineering techniques to become economic producers of electricity. Because these resources are around existing hydrothermal sites, they tend to be relatively hot and shallow, and are likely to be the least expensive and first EGS resources to be commercially developed, as demonstrated by the EGS demonstration projects DOE is funding to develop near-hydrothermal fields at the Geysers, CA; Raft River, ID; Desert Peak, NV; and Brady Hot Springs, NV (Geothermal Technologies Program 2009b), all of which are home to conventional hydrothermal power plants.

A formal assessment of the near-hydrothermal field EGS resource has not yet been completed. However, if it is assumed that the rock in and around identified hydrothermal sites are at high temperatures, but lack sufficient permeability or *in-situ* fluids to be developed commercially, then a reasonable estimate of the near-hydrothermal EGS resource can be made. This approach assumes that the difference between the mean and high-end estimates of the electricity-generating potential capacity for each identified hydrothermal site from the USGS 2008 geothermal assessment (Williams, Reed, et al. 2008b) represents a part of the reservoir that could be made to economically produce electricity using EGS reservoir stimulation techniques. When the difference between the 5% probability and mean power producing potential values for each identified hydrothermal site in USGS 2008 geothermal assessment sites is taken, and a reservoir cut-off temperature of 110^{o}C applied, the resulting estimate for the near-hydrothermal field EGS resource is 7,031 MW_e. The near-hydrothermal field EGS potential resource around the undiscovered hydrothermal resource discussed in Section 3.2 was not considered for this study.

3.3.2 LCOE Cost Estimates

Estimation of the LCOE of the near-hydrothermal field EGS resource was done on a site-by-site basis in GETEM similar to the approach taken for the identified hydrothermal resource. It was assumed that the reservoir temperature and depth for each near-hydrothermal field EGS site was the same as the corresponding identified hydrothermal site. The plant net power sales were set equal to the potential power capacity calculated for each site in the same manner as for the identified hydrothermal sites. Although the resource characteristics for each site were the same as for the hydrothermal scenario, the resource type in GETEM was designated EGS so that well stimulation costs were included. The non-well exploration costs and exploration well success rate for EGS were also used, and a 2:1 production-to-injection well ratio was assumed. The production well flow rate and thermal drawdown rate of the reservoir were set to the values assumed in the base and target funding case. For the base case, a production well flow rate of 30 kg/s and a reservoir thermal drawdown rate of 3.0%/year were assumed, and for the target case, values of 60 kg/s and 0.3%/year, respectively, were assumed. The resulting supply curves for the base and target cases are shown in Figure 7. The 10th%ile and 90th%ile LCOE values are shown in gray to illustrate the range of likely values for the hydrothermal power plants given the current state of technology based on expert input.

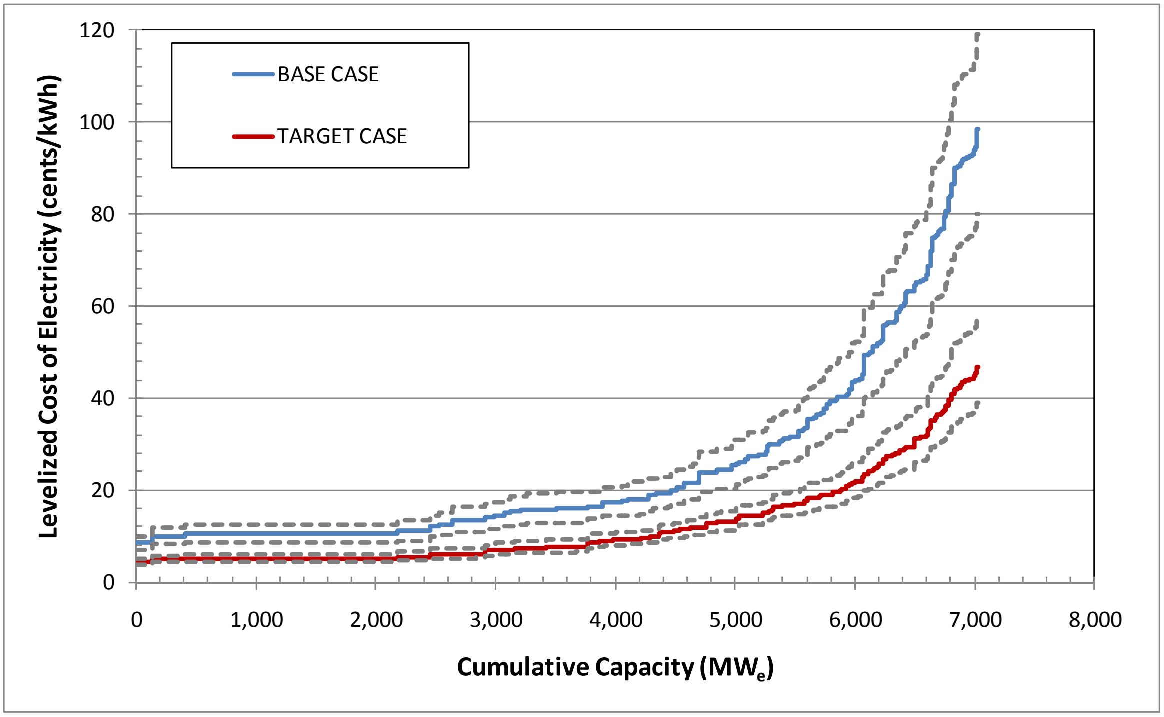

Figure 7. Supply curve for near-hydrothermal field EGS resource.
Present-day median (50th%ile) LCOE estimates in 2008 US$ from GETEM shown for base and target cases. 10th%ile and 90th%ile values for each curve shown in gray.

3.4 Deep EGS

3.4.1 Resource Potential

The deep EGS resource consists of all the thermal energy stored deep in the Earth's crust at depths accessible using drilling technology. The deep EGS resource is not associated with localized hot spots around hydrothermal sites, but instead relies on the natural thermal gradient in the Earth's crust to achieve reservoirs with temperatures high enough to economically produce electricity. Because these reservoirs tend to require deeper drilling and the creation of completely artificial engineered reservoirs, they likely will not be developed until EGS technologies have been proven at near-hydrothermal field EGS sites and the technology has matured somewhat. Because of this and its vast size, the deep EGS resource represents the long-term future of geothermal technology.

The deep EGS resource potential is based on the thermal energy stored at depths 3-10 km below the Earth's surface in the continental United States. The same methodology described in a previous geothermal supply curve update performed by NREL (Petty and Porro 2007) was used to determine the electricity-generating potential of the EGS resource. The supply available is based on the amount of thermal energy contained in a volume of rock. The thermal energy in place for each of these volumes, Q_{rock}, is determined based on the rock density, ρ, heat capacity, C_p, volume, V, and the average temperature decline of the rock over production, ΔT, as shown in Eq. (1).

$$\boldsymbol{Q_{rock} = \rho C_p V \Delta T} \qquad \textbf{Eq. (1)}$$

The temperature decline of the fluid produced from the reservoir over its productive lifetime is limited by the surface power plant equipment. The power plant is designed to work under a relatively narrow range of operating conditions, the temperature of the circulating fluid being one of the key parameters. The power plant becomes less efficient as operating conditions stray from their design values, placing a practical limit on the allowable temperature decrease in the circulating fluid over the lifetime of the plant. In keeping with the methodology used in the previous study (Petty and Porro 2007), an average reservoir temperature decline of $\Delta T = 10^{o}$C was assumed. Since this is the *average* temperature decline of the reservoir, localized regions of the reservoir near flow fractures will experience a much larger temperature drop than those regions far from the flow.

Because of temperature gradients in the reservoir, only a fraction of the thermal energy stored in the reservoir can be recovered and carried to the surface by circulating fluid through it. This fraction is defined by the recovery factor, R_g. A model of flow in fractured systems by Sanyal and Butler (2005) found that beyond a stimulated volume of $1\text{x}10^8$ m^3 the percentage of recoverable heat from an EGS reservoir is nearly constant at about 40%. Therefore, the conservative recovery factor of $R_g = 20\%$ assumed in the previous study (Petty and Porro 2007) was used. This recovery factor lies at the upper end of that assumed by the USGS for hydrothermal systems in its 2008 assessment (Williams, Reed, et al. 2008a; Williams, Reed, et al. 2008b) as discussed in Section 3.1.1. Eq. (2) shows the amount of recoverable thermal energy, Q_{th}, available for conversion to electricity.

$$\boldsymbol{Q_{th} = Q_{rock} R_g} \qquad \textbf{Eq. (2)}$$

The recovered thermal energy is converted to electric energy by a power plant at the surface. The potential power capacity of the plant is determined by assuming a plant lifetime over which the energy is extracted from the reservoir and converted to electricity. The conversion efficiency of the power plant is limited by the laws of thermodynamics and is determined by the temperature of the recovered fluid and the ambient, or dead-state, temperature to which heat is rejected by the power plant. The conversion of thermal energy to electrical energy, W_e, was calculated from Eq. (3) using an analysis of binary cycle efficiency by DiPippo (2004) that considers the net electrical output based on all of the thermal energy from the circulating fluid to determine the net total cycle efficiency, η_{net}.

$$\boldsymbol{W_e = \eta_{net} Q_{th}} \qquad \textbf{Eq. (3)}$$

The electricity-generating potential for a given volume of rock was determined by applying Eq. (1)-Eq. (3). A plant lifetime of 30 years was assumed. Table 5 shows the results of these calculations as a function of the EGS reservoir temperature. Constant values were assumed for the rock density and heat capacity. The table shows that using this methodology, the amount of recoverable heat is independent of the resource temperature. However, the amount of electricity-generating capacity of the EGS resource is greatly affected by its temperature.

Table 5. Potential Electric Capacity Per Unit Rock Volume for Deep EGS Resources as a Function of Temperature

Resource Temp Range	Rock Density	Rock Heat Capacity	Average Reservoir Temp Decline	Heat in Place	Recovery Factor	Recoverable Heat	Plant Life	Plant Efficiency	Potential Electric Capacity
(^oC)	(kg/km^3)	($kJ_{th}/kg\text{-}^oC$)	(^oC)	(MJ_{th}/km^3)	%	(MJ_{th}/km^3)	(years)	%	(MW_e/km^3)
T	ρ_{rock}	C_p	ΔT	Q_{rock}	R_g	Q_{th}		η_{net}	W_e
150-200	2.55E+12	1	10	2.55E+10	20%	5.1E+9	30	11%	0.59
200-250	2.55E+12	1	10	2.55E+10	20%	5.1E+9	30	14%	0.76
250-300	2.55E+12	1	10	2.55E+10	20%	5.1E+9	30	16%	0.86
300-350	2.55E+12	1	10	2.55E+10	20%	5.1E+9	30	18%	0.97
>350	2.55E+12	1	10	2.55E+10	20%	5.1E+9	30	22%	1.19

The deep EGS resource potential estimate was made using temperature vs. depth data obtained from the Southern Methodist University (SMU) Geothermal Laboratory (Richards 2009) featured in MIT's *The Future of Geothermal Energy* report (Tester et al. 2006). The data consist of the maps showing the estimated temperatures at depths of 3-10 km in 1-km intervals for the entire continental United States. Insufficient temperature and depth data were available to include Alaska and Hawaii. The thermal energy in place was calculated for 1-km thick volumes at depths of 3-10 km (centered at 3.5, 4.5, 5.5, 6.5, 7.5, 8.5, and 9.5 km depths). Temperature data was binned in 50°C increments ranging from 50°-350°C as shown in Figure 8.

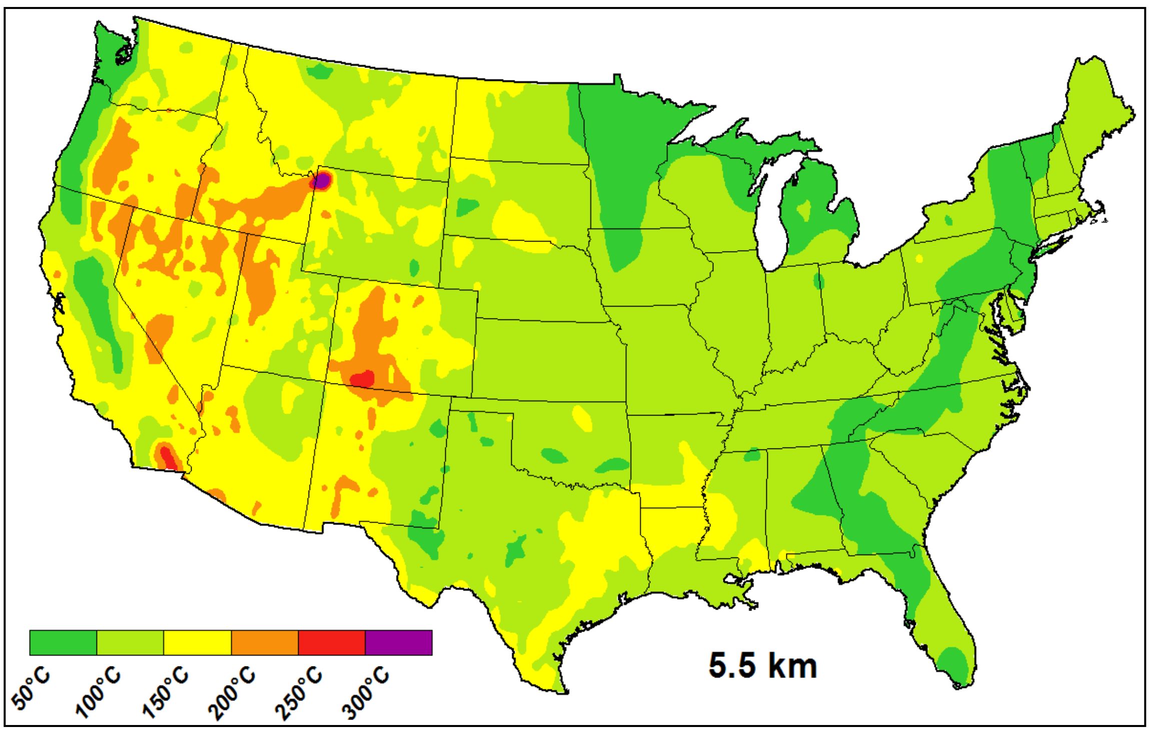

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Figure 8. Temperature at depth of 5.5 km (Tester et al. 2006).

The areal extent of each temperature bin at each depth was determined from the maps using GIS methods. Federally protected and U.S. Department of Defense (DOD) lands were excluded. The resulting rock volume for each temperature bin at each depth interval was multiplied by the corresponding volumetric potential electric capacity in Table 5. The resulting EGS electricity potential for the continental United States for each temperature/depth interval is shown in Table 6. The reservoir is assumed to extend to the bottom of each 1-km slice, so that the resource estimate for the rock centered at 3.5 km has a reservoir depth of 4 km. The resource estimate identifies 15,908 GW_e of electricity producing potential, although the amount of this resource that can be economically produced is likely much smaller.

Table 6. Potential Electric Capacity (MWe) of Deep EGS Resource for Continental United States by Temperature-depth Combination

Potential Electric Capacity (MW_e)						
		Resource Temperature (^{o}C)				
		150-200	*200-250*	*250-300*	*300-350*	*>350*
Reservoir Depth (km)	*4*	92,500	117	0	0	
	5	591,000	26,500	134	0	0
	6	1,140,000	228,000	7,680	50	0
	7	1,340,000	724,000	86,100	631	0
	8	1,540,000	1,130,000	345,000	33,000	320
	9	1,880,000	1,160,000	762,000	138,000	9,920
	10	1,910,000	1,250,000	1,020,000	434,000	69,300

The results of the deep EGS resource estimate in the study differ slightly from the previous NREL supply curve update (Petty and Porro 2007) due to the use of more accurate GIS methods when considering excluded federally protected and DOD lands. The previous study used the average value of excluded lands on a state-by-state basis and removed this percentage uniformly from all resources in a state, while this study takes into account the actual resource beneath the excluded areas. Since much of the excluded area lies beneath high-quality (high temperature and shallow depth) deep EGS resources, such as Yellowstone Park, the previous study overestimated the quantity of high-quality resource. This is evident from the many zero-valued potential electricity capacity entries in Table 6 (gray boxes) for resources in the >250^{o}C and <7 km range. On the other hand, this study estimates a much larger deep EGS resource than the 500 GW_e estimate reported in the USGS 2008 geothermal assessment (Williams, Reed, et al. 2008b) or the 100 GW_e figure commonly cited from the MIT report (Tester et al. 2006). Aside from the use of different resource estimate methodologies, this is because the USGS 2008 assessment only considered 11 states in the western United States, and only depths between 3-6 km, whereas this resource estimate includes the entire continental United States (48 states) and depths between 3-10 km. Much of the almost 16,000 GW_e deep EGS resource reported in this study is attributed to heat stored deep in the Earth at depths >6 km, as seen in Table 6. The MIT number of 100 GW_e was a goal for geothermal deployment for 2050 given sufficient RD&D investments, and was not a total resource estimate.

3.4.2 LCOE Cost Estimates

The LCOE of the deep EGS resource was estimated using GETEM for each temperature and depth interval combination listed in Table 6. First, the resource was defined in GETEM for each combination. The reservoir depths, and the wells drilled into the reservoir, were assumed to extend to the full depth of each 1-km slice, so that the 3-4 km region is assumed to have a reservoir depth of 4 km. The reservoir temperature was conservatively assumed to be 12.5^{o}C

(1/4 of interval) above the lower end of the interval (e.g., 150°-200°C temperature interval was assumed to have a reservoir temperature of 162.5°C). The production well flow rate and thermal drawdown rate of the reservoir were set to the values assumed in the base and target funding case. For the base case, a production well flow rate of 30 kg/s and a reservoir thermal drawdown rate of 3.0%/year were assumed, and for the target case, values of 60 kg/s and 0.3%/year, respectively, were assumed.

Once an LCOE was estimated for each temperature/depth interval combination, the results were coupled to the resource estimate in Table 6 to generate the deep EGS resource supply curve. The resulting supply curves for the base and target cases are shown in Figure 9. The 10th%ile and 90th%ile LCOE values are shown in gray to illustrate the range of likely values for the hydrothermal power plants given the current state of technology based on expert input. The supply curve has been truncated to show only the first 100 GW_e of potential electric power capacity to enable the reader to more clearly see the details of the most cost effective power sources. Even at this truncated scale, many of the smaller, higher quality, more cost effective resources are not discernible. For this reason, the deep EGS supply curve was also plotted using a semi-logarithmic scale, shown in Figure 10. This graph extends out to 1,000 GW_e of power capacity.

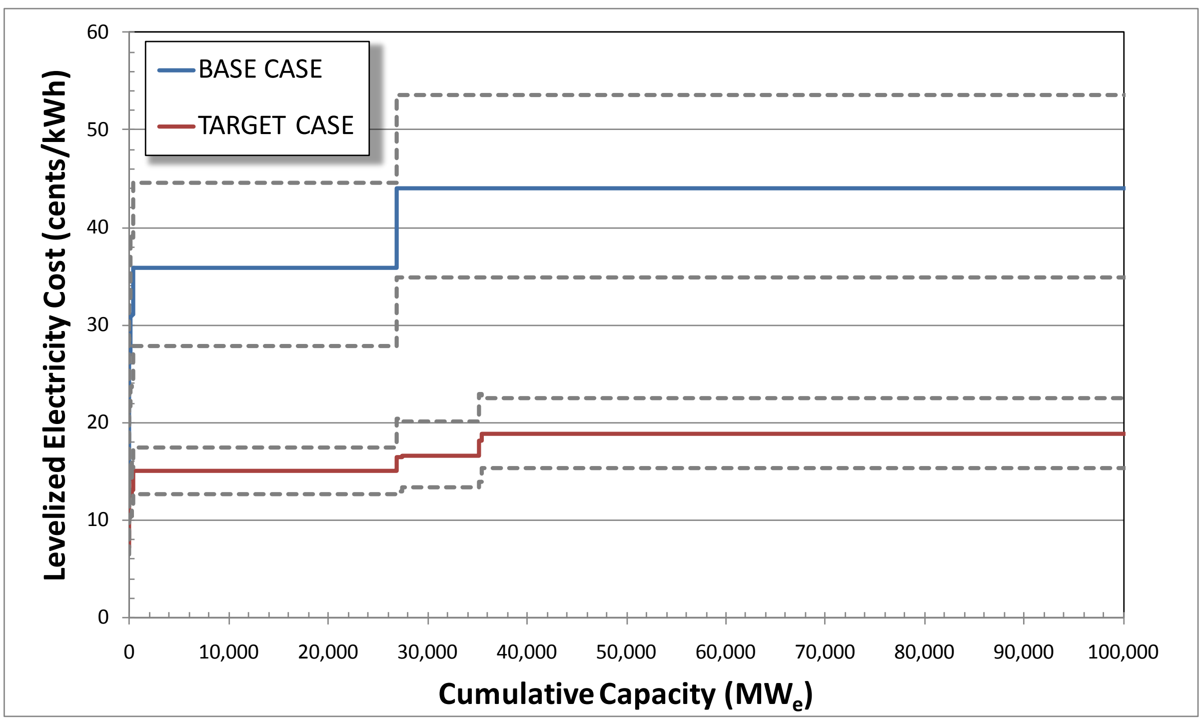

Figure 9. Supply curve for deep EGS resource.

Present-day median (50th%ile) LCOE estimates in 2008 US$ from GETEM shown for base and target cases. 10th%ile and 90th%ile values for each curve shown in gray. Supply curve truncated to first 100 GW_e of potential power capacity.

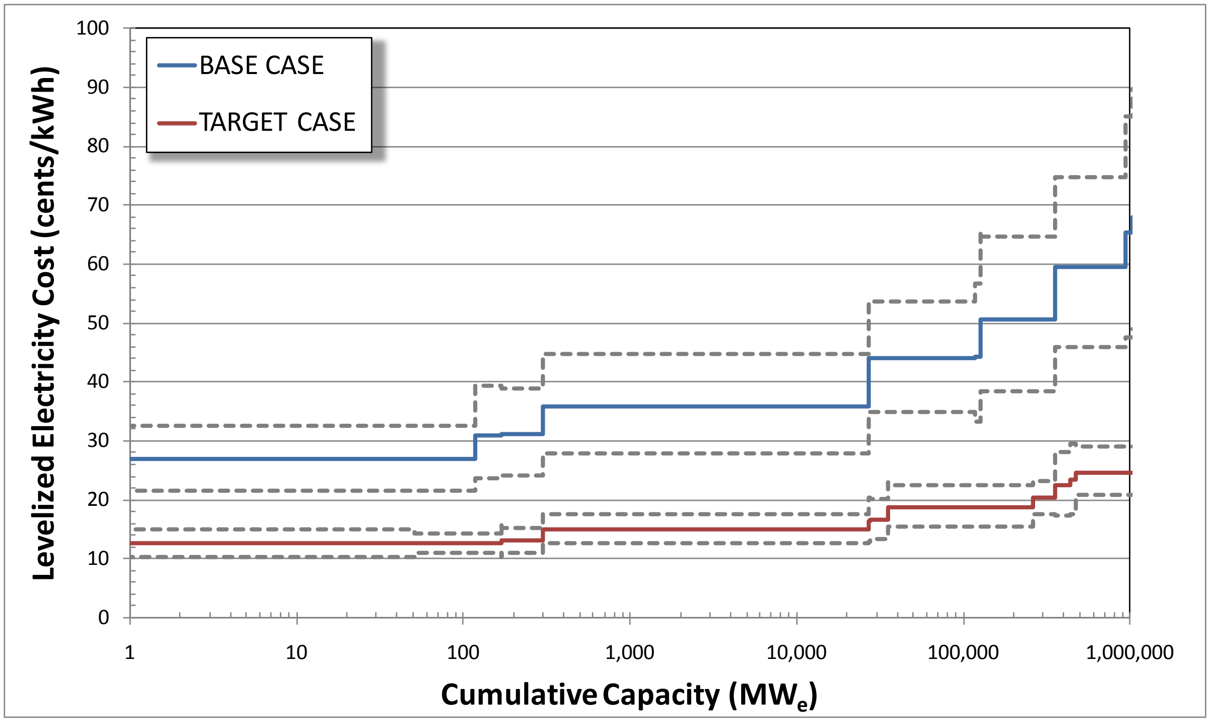

Figure 10. Supply curve for deep EGS resource using semi-logarithmic scale.

Present-day median (50th%ile) LCOE estimates in 2008 US$ from GETEM shown for base and target cases. 10th%ile and 90th%ile values for each curve shown in gray. Supply curve truncated to first 1,000 GW_e of potential power capacity.

3.5 Co-Produced and Geopressured Resources

The resource potential estimate only took into consideration conventional hydrothermal and EGS technologies and did not address all geothermal technologies that can be used to produce electricity. In particular, an assessment of electricity generation potential from fluids co-produced during oil and gas production and "geopressured" resources was not included. The co-produced fluid resource estimate in the last NREL supply curve update (Petty and Porro 2007) was based on the volume of water produced during oil and gas production (Curtice and Dalrymple 2004) and electricity generating potential assuming a range of co-produced fluid temperatures (Tester et al. 2006, pp. 2-29, 2-48), not actual temperature data. Also, the study triple-counted the size of the resource by treating the different temperature assumptions in the MIT report as individual resources. The author of this report felt that there was insufficient data to make a reasonable estimate of the co-produced and geopressured geothermal resource. An effort to perform an assessment of the co-produced fluid geothermal resource is planned and will be included in future assessments.

4 Results and Discussion

4.1 Summary of Results

A summary of the results of the geothermal resource potential estimate is given in Table 7. A detailed listing of the resource potential estimate for each of the geothermal resources included in the supply curve, including site specific data, and capital and O&M cost estimates, is given in Appendix B. Although estimates of the geothermal resource were made using the best available data, future values will likely differ as new hydrothermal sites are discovered and better data and methodologies become available for estimating the capacity of the geothermal resources. The electricity producing potential of hot fluids co-produced with oil and gas, referred to as co-produced fluids, and of geopressured resources, were not included in this study. The available information was deemed inadequate to make an informed estimate of these resources. An effort to perform an accurate assessment of the co-produced fluid resource is planned and will be included in future updates. Future resource assessments will also be aided by the recently established National Geothermal Data System (NGDS). The goal of this Recovery Act project is to assess and classify all geothermal resources and facilitate access to geothermal data sets for developers to lower the development risk associated with geothermal projects.

Table 7. Summary of Results for Geothermal Resource Potential Estimate

Resource		Resource Potential	
		Capacity (GW_e)	*Source(s) and Description*
Hydrothermal	Identified Hydrothermal Sites	6.39	USGS 2008 Geothermal Resource Assessment[1] • Identified hydrothermal sites • Sites ≥110°C included • Currently installed capacity excluded
	Undiscovered Hydrothermal	30.03	USGS 2008 Geothermal Resource Assessment[1]
Enhanced Geothermal Systems (EGS)	Near-Hydrothermal Field EGS	7.03	Based on data from USGS 2008 Geothermal Resource Assessment[1] and methodology developed at NREL • Regions near identified hydrothermal sites • Sites ≥110°C included • Difference between mean and 95%ile hydrothermal resource estimate
	Deep EGS	15,908	NREL 2006 Update[2], MIT Report[3], SMU Data[4] • Based on volume method of thermal energy in rock 3-10 km depth and ≥150°C • Does not consider economic or technical feasibility

[1](Williams, Reed, et al. 2008b)
[2](Petty and Porro 2007)
[3](Tester et al. 2006)
[4](Richards 2009)

The supply curves presented in Section 3 for the separate geothermal technologies were combined to produce an aggregated supply curve for all geothermal technologies and are shown for the base case in Figure 11 and for the target case in Figure 12. The base case assumes current benchmarks for EGS reservoir performance and the target case assumes advanced reservoir technologies consistent with Program MYRD&D goals. The supply curves for identified and undiscovered hydrothermal are the same for both cases. The supply curves have been truncated to show the first 50 GW_e of potential capacity to emphasize the lowest cost resources that are likely to be developed first. The combined supply curve shows the likely order in which resources would be developed based on the LCOE estimated by GETEM. Because market penetration models consider a wider range of factors, such as capital costs, O&M costs, technology readiness time frames, future cost multipliers, and model-specific assumptions about financing and project development times to calculate the cost of developing resources, models differ slightly from each other and from the figures below in the order they build out the resources. However, the LCOE of a resource gives a good approximate measure of the most economical resource to build.

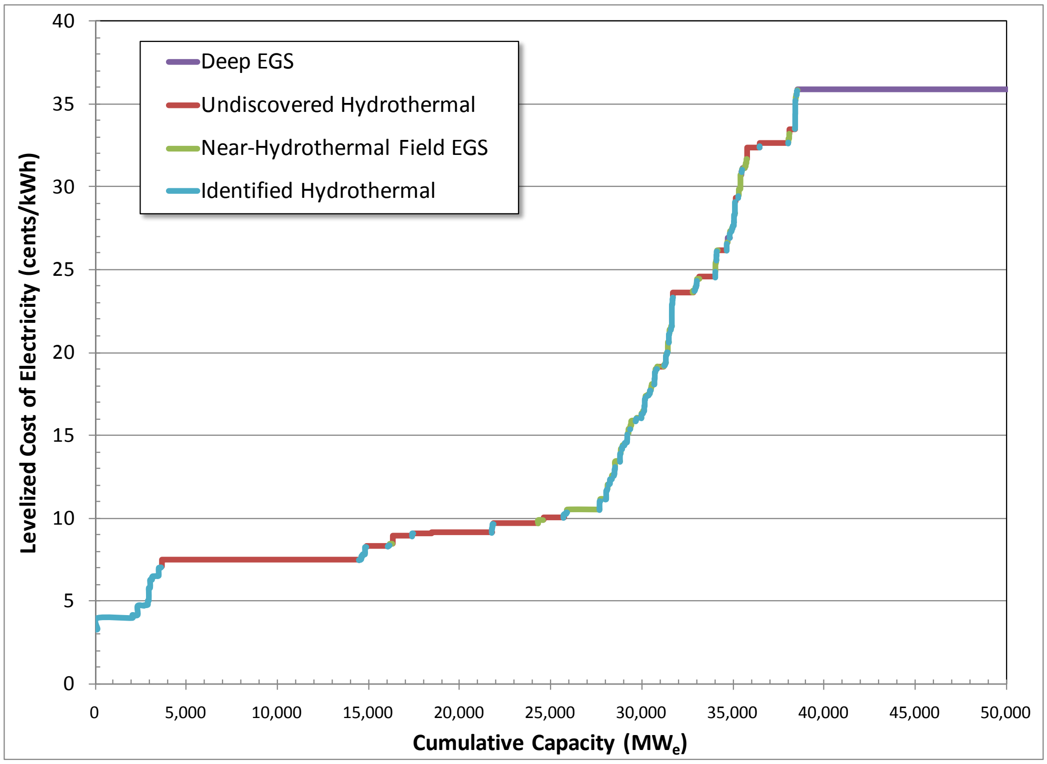

Figure 11. Base case aggregate supply curve of the four geothermal technologies analyzed.

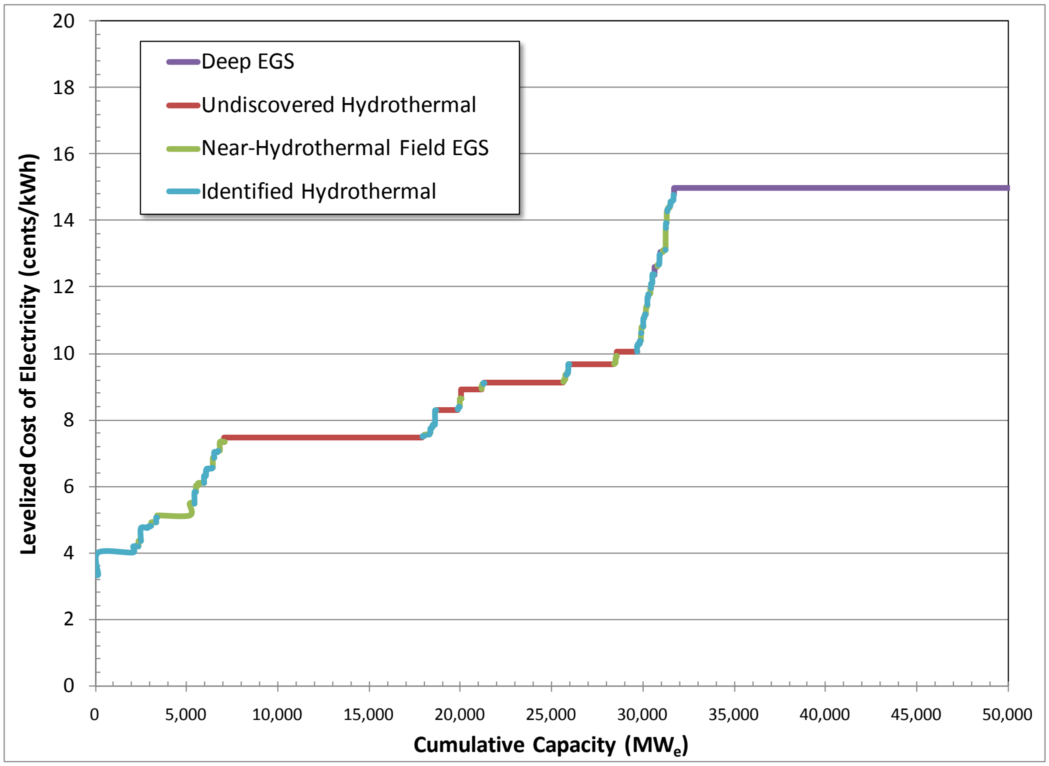

Figure 12. Target case aggregate supply curve of the four geothermal technologies analyzed.

Compared to the base case, the target case shows an increase in the number of near-hydrothermal field EGS projects included in the most cost-effective 50 GW_e of potential capacity. The target case also contains a large amount of deep EGS at a significantly lower LCOE than in the base case. There are two small amounts of deep EGS capacity that are barely discernible in the figures, and a large amount of capacity that extends beyond the scale of the graph. This represents the 5km-200°C depth-temperature combination for the deep EGS resource. It consists of more than 25,000 MW_e of potential capacity. The target case assumes that EGS reservoir technology has advanced to the point where reservoirs can be reliably engineered with production well flow rates of 60 kg/s and thermal drawdown rates of 0.3%/year (versus 30 kg/s and 3.0%/year, respectively, for the base case). The large decrease in costs in the target case for the EGS projects is due to advances in EGS reservoir performance that require fewer wells to be drilled for the power plant and no additional costs incurred for drilling and stimulating new reservoirs over the lifetime of the power plant.

Supply curves can also be shown as a function of the total capital costs of the project. The geothermal supply curves as a function of the 50^{th}%ile capital costs for each technology are shown for the base and target cases in Figure 13 and Figure 14, respectively.

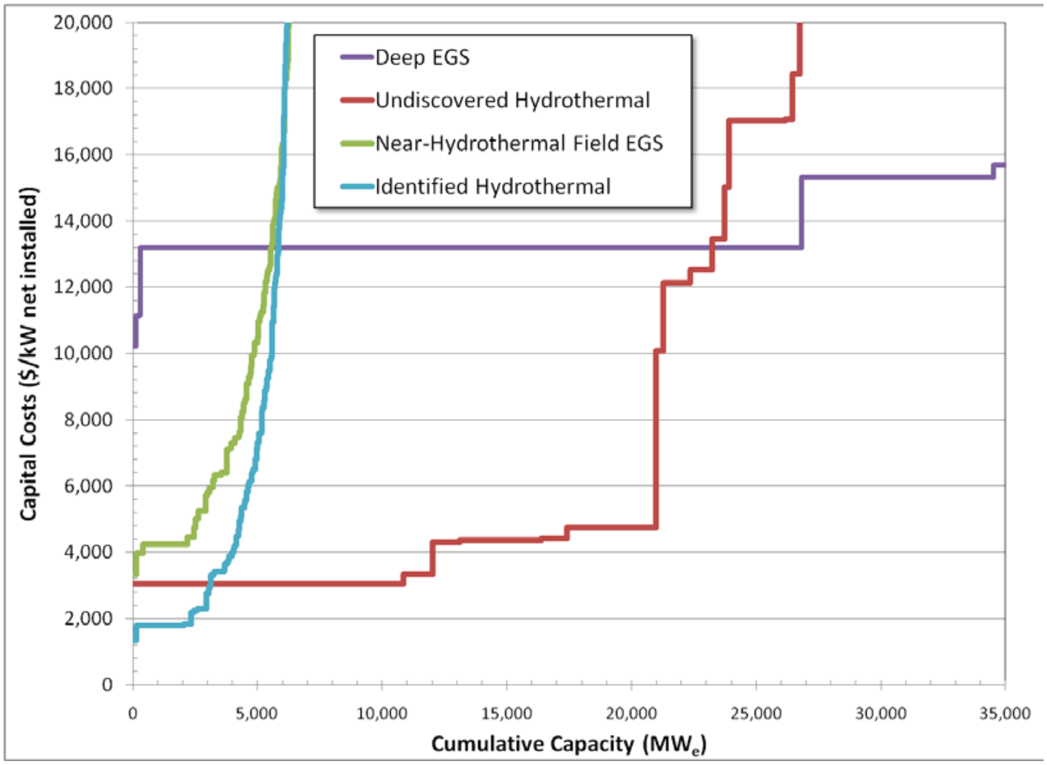

Figure 13. Base case supply curve by capital costs of the four geothermal technologies analyzed.

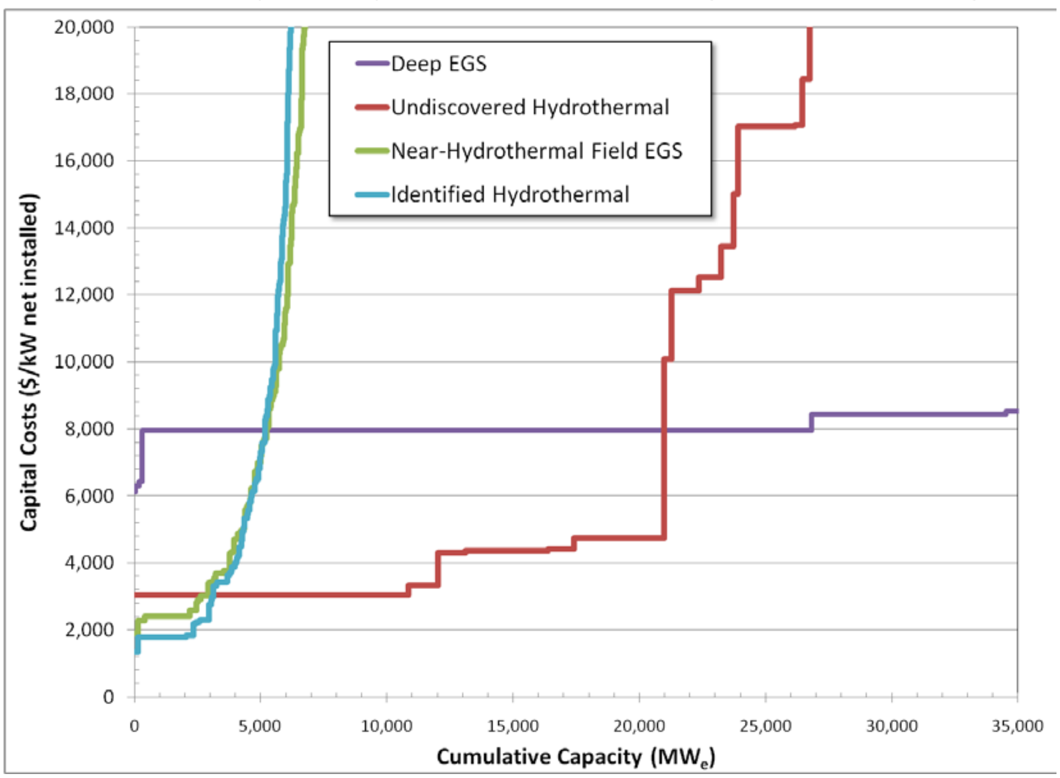

Figure 14. Target case supply curve by capital costs of the four geothermal technologies analyzed.

All geothermal technologies, especially EGS, saw increases in costs compared to those in the previous NREL supply curve update (Petty and Porro 2007) due to increases in drilling costs. The previous update had assumed 2004 drilling costs, which were much lower than current drilling costs (see Figure 3). Even though drilling costs in this study were assumed to be 30% less than the 2008 drilling cost index value in GETEM, drilling costs were still 64% higher than the index value used in 2004. This added significantly to the capital costs of geothermal projects. The capital costs estimated by GETEM for each of the geothermal technologies were broken down by project development phase. Four project development phases were identified:

1) Exploration/Confirmation Costs
    - Non-well exploration costs
    - Exploration well costs
    - Confirmation well costs (two required to prove the resource, used as production wells)
2) Drilling Costs
    - Costs to drill remaining injection and production wells
3) Other Wellfield Costs (non-drilling)
    - Injection and production pumps
    - Reservoir stimulation costs (for EGS sites)
4) Power Plant Costs
    - Costs of equipment and construction

The breakdown of capital costs follows the phases of development for a geothermal project. The early phases, especially during the drilling of exploration and confirmation wells, carry a much higher risk of failure (Deloitte 2008). Acquiring capital for these early phases before the resource is confirmed is more difficult and carries a higher cost of capital, usually equity financing. Once exploration and confirmation is completed, the success rate of the project increases and capital can be acquired at lower interest rates, usually as debt financing. The capital costs for the individual geothermal technologies, as well as other results from the supply curve study, are discussed individually below.

4.2 Hydrothermal Resource

4.2.1 Resource Potential

Like in the oil and gas industry, where advances in exploration and production continue to expand the recoverable resource base, hydrothermal sites are still being discovered and new geothermal technologies will increase the amount of energy that can be recovered from existing sites. This study supplements identified hydrothermal sites with the estimated undiscovered geothermal resource from the USGS 2008 geothermal resource assessment to represent the expected increase in the future identified geothermal resource. The undiscovered geothermal resource estimate was based on the assumption that the undiscovered resource looks like currently identified sites on a state-by-state basis. A forthcoming paper from the USGS should shed more insight on the methodology used to estimate the undiscovered hydrothermal resource. This methodology should be incorporated into future updates to more accurately reflect the likely distribution and nature of the undiscovered resource.

4.2.2 Capital Costs and LCOE

The capital costs estimated by GETEM for the identified and undiscovered hydrothermal resources were broken down by project development phase. Since project costs were estimated for nearly 150 hydrothermal sites, it is not practical to show the capital costs of every single project. Instead, project costs for a number of hypothetical hydrothermal plants representative of the sites in the hydrothermal resource were estimated in GETEM. Reservoir temperatures for the hypothetical sites ranged from 150^{o}-$300^{o}C$ and reservoir depths ranged from 1-3 km. All other resource characteristics and GETEM parameters for the hypothetical plants were set equal to those for the supply curve reference hydrothermal plant (summarized in Table 9 of Section 5 and described in detail in Appendix A). Actual hydrothermal sites can be compared to hypothetical sites with similar resource characteristics to determine a ballpark estimate of capital costs.

The breakdown of capital costs for the hypothetical plants is shown in Figure 15. The base and target case assumptions for the hydrothermal resource are identical, so the data shown in the figure apply to both cases. For the hydrothermal resource, the highest project risk occurs in the exploration/confirmation phase, but the majority of capital costs are from power plant construction. This is because conventional hydrothermal resources tend to be shallow and have relatively low drilling costs. Drilling costs increase non-linearly with depth. GETEM uses a drilling cost correlation in which drilling costs increase exponentially with depth. Higher temperature reservoirs require fewer total geothermal wells per net capacity output, so a lower number of injection and production wells are required for a given plant's power output. Plant costs also decrease with resource temperature since more electricity can be extracted per unit mass of geofluid at higher resource temperatures.

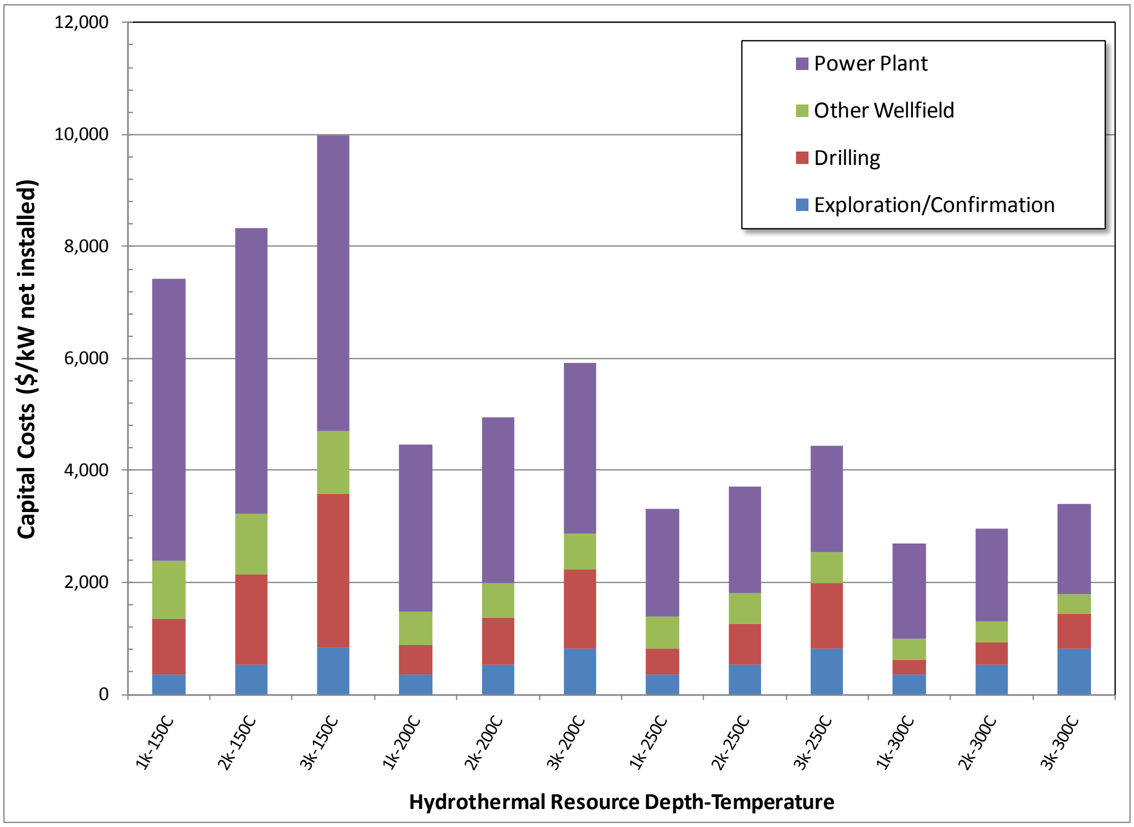

Figure 15. Hydrothermal resource capital costs by project phase.

4.3 Near-Hydrothermal Field EGS Resource

4.3.1 Resource Potential

The near-hydrothermal field EGS resource estimate was made using many assumptions to give a reasonable order-of-magnitude estimate of the size of the resource. However, a formal assessment of the potential to use EGS techniques to develop marginal areas around identified hydrothermal resources is needed to give an accurate estimate of this resource.

4.3.2 Capital Costs and LCOE

As with the hydrothermal resource, the number of potential near-hydrothermal field EGS sites was too numerous to list capital costs for all of them, so project costs for hypothetical fields with a range of reservoir temperatures and depths were modeled in GETEM to study how capital costs vary with the quality of the resource. The same methodology used for hydrothermal resources above was applied, except GETEM values for near-hydrothermal field EGS resources were used. Reservoir temperatures ranged from 150^{o}-300^{o}C and reservoir depths ranged from 1-3 km. All other resource characteristics and GETEM parameters for the hypothetical plants were set equal to those for the supply curve near-hydrothermal field EGS reference plant as summarized in Table 9 of Section 5 and described in detail in Appendix A. The largest difference was that reservoir stimulation was required to engineer the EGS reservoir. Capital costs were estimated for both the base and target cases using the base and target case values for production well flow rate and thermal drawdown rate and a 2:1 production/injection well ratio.

The breakdown of capital costs by project phase for the base and target cases is shown in Figure 16 and Figure 17, respectively. Exploration/confirmation and power plant costs are comparable between the hydrothermal plants above and the near-hydrothermal field EGS plants for both cases since the steps in these phases of the projects are nearly identical for both geothermal technologies. The major difference is that the near-hydrothermal field EGS sites have higher stimulation/other wellfield costs due to the need to stimulate and create the EGS reservoir. Drilling costs differ due to differences in the assumed production well flow rates and production-to-injection well ratios among the technologies and cases. Drilling costs are significantly higher for the near-hydrothermal field EGS base case than for the target case because a larger number of wells are needed to produce enough geofluid for the given power plant's output.

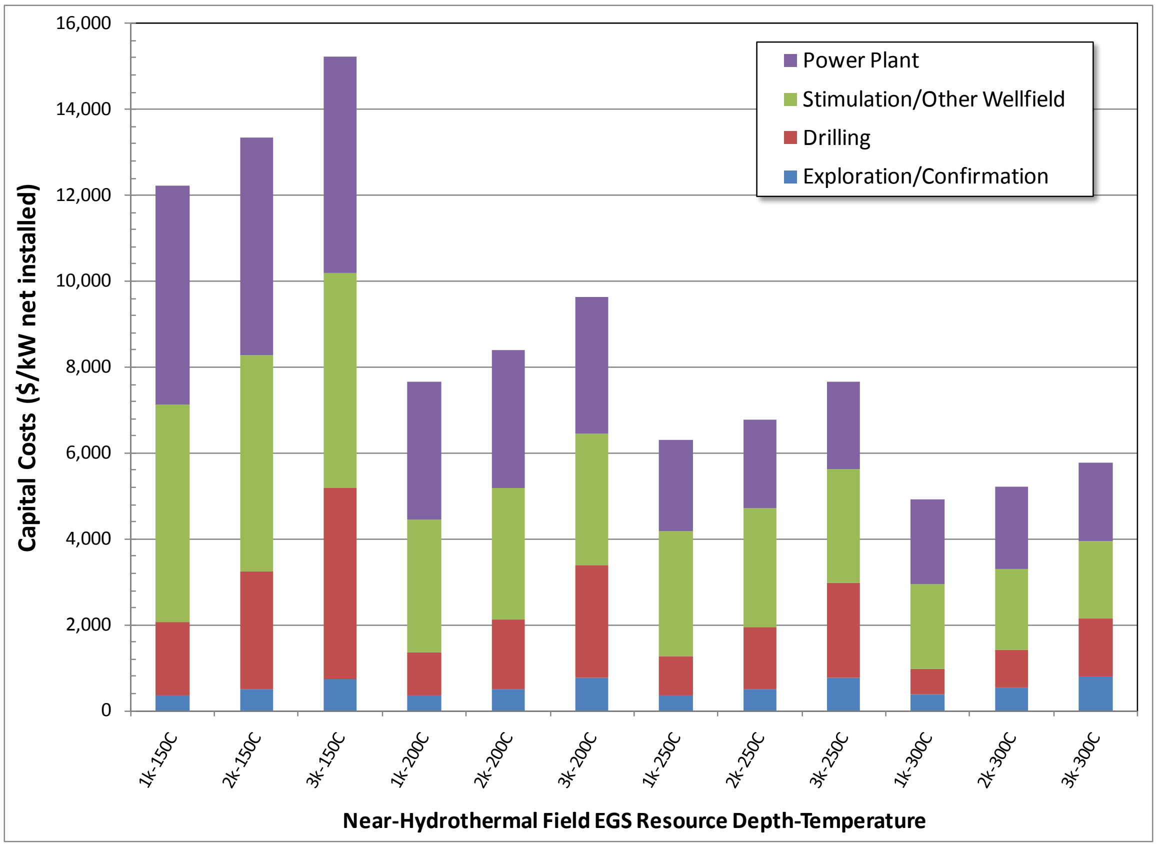

Figure 16. Base case near-hydrothermal field EGS resource capital costs by project phase.

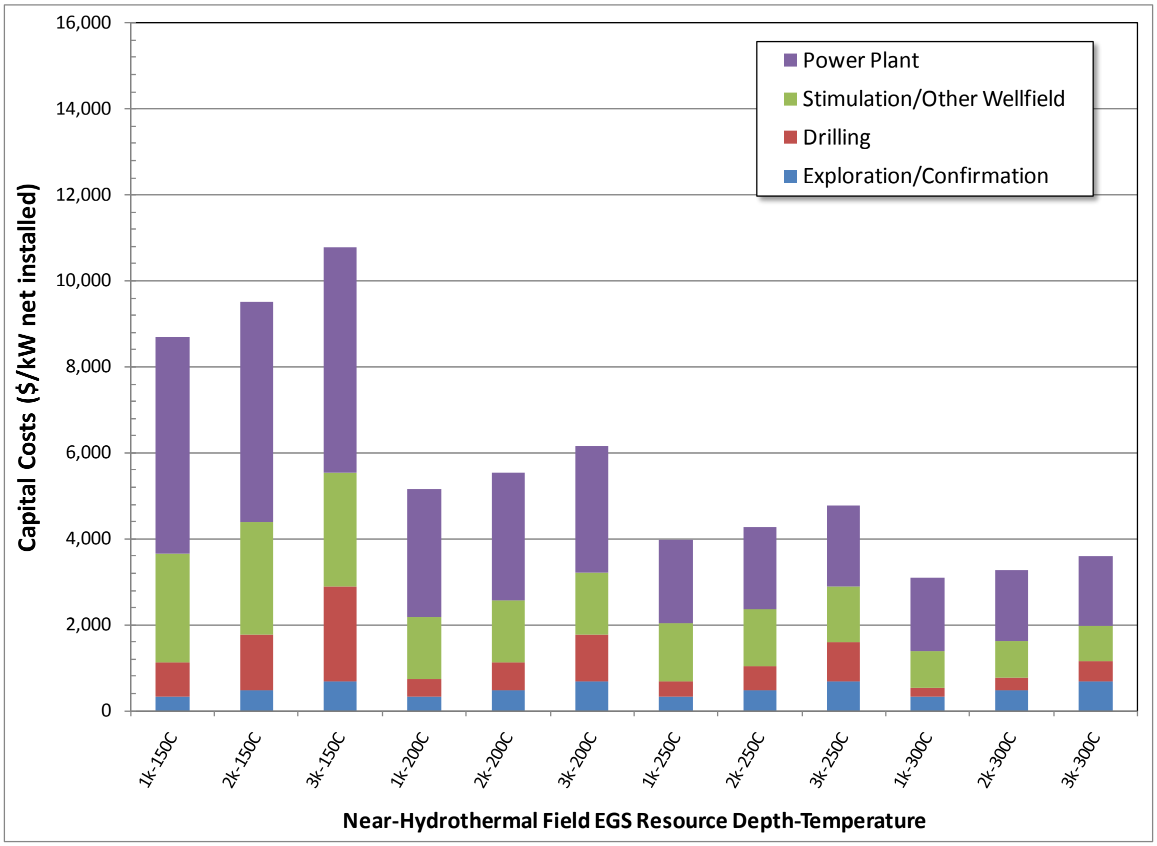

Figure 17. Target case near-hydrothermal field EGS resource capital costs by project phase.

The stimulation capital costs in the figures above only include the creation of the initial EGS reservoir. The base case requires several reservoirs to be re-drilled over the lifetime of the plant because of its high thermal drawdown rate. These costs are included in the wellfield O&M costs, which subsequently are 3-10 times greater for the base case than for the target case, depending on the temperature and depth of the reservoir. The LCOE includes O&M costs in addition to the cost of project capital over the lifetime of the project.

4.4 Deep EGS Resource

4.4.1 Resource Potential

Like the hydrothermal and near-hydrothermal field EGS estimates, the deep EGS estimate has room for improvement. First, it is based on incomplete temperature versus depth data. Many regions, especially in the eastern United States, lack significant amounts of data. For example, there is not a single data point in the state of Kentucky—the estimates in this region are extrapolated from distant neighboring points. More temperature versus depth data for the continental United States is needed to increase the accuracy of the estimate. Second, the resource potential methodology needs further refinement. The assumption of a 10^{o}C average reservoir temperature drop does not adequately capture how heat is transferred from the rock to the fluid and how the reservoir cools over its lifetime. This leads to the conclusion that the same amount of thermal energy can be recovered from a reservoir regardless of initial temperature. Future data collected by the NGDS, advanced reservoir models and results from early demonstration plants should help to refine the methodology used in future updates.

4.4.2 Capital Costs and LCOE

A breakdown of the capital costs for the deep EGS resource temperature/depth combinations in Table 6 for the base and target cases are shown in Figure 18 and Figure 19, respectively. Even for deep EGS resources with relatively low capital costs, most of the capital costs are associated with drilling exploration, confirmation, and injection and production wells due to the depth of the resource. The stimulation and power plant costs are relatively small in comparison except for the highest quality resources. The target case has significantly lower drilling costs because a production well flow rate of 60 kg/s (versus 30 kg/s for the base case) is assumed, so that fewer wells need to be drilled for a given power plant output. The exploration and confirmation costs remain constant between the two cases because the majority of these costs are tied up in the cost of drilling the exploration and confirmation wells; the same number of exploratory and confirmation wells are required in each case. The magnitude of the drilling costs is exacerbated by high drilling costs in recent years (see Figure 3). Despite their recent declines, there is a continuing debate in the geothermal community about whether drilling costs will continue to decrease to pre-2004 levels or will stabilize at a higher level. Decreasing drilling costs will be an important step in developing the deep EGS resource at a large scale in the future. GETEM assumes the same drilling cost curve for all locations, whereas actual drilling costs will vary with lithology.

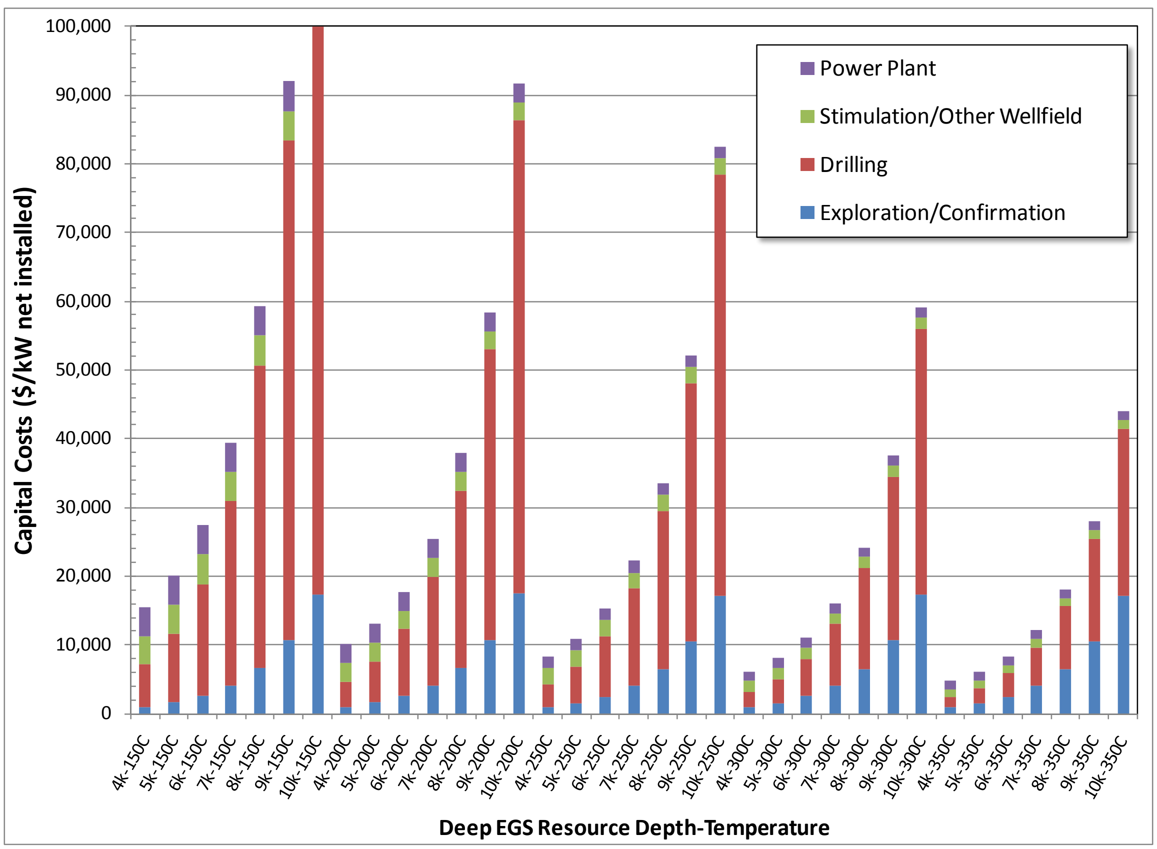

Figure 18. Deep EGS resource capital costs for base case.

The breakdown of the capital costs by project phase is given for each temperature/depth combination listed in Table 6. The lower bound of the reservoir temperature in each depth interval was used to identify the resource, so that “4k-150C” represents the deep EGS resource with a reservoir depth of 4 km and temperature of 150°-200°C.

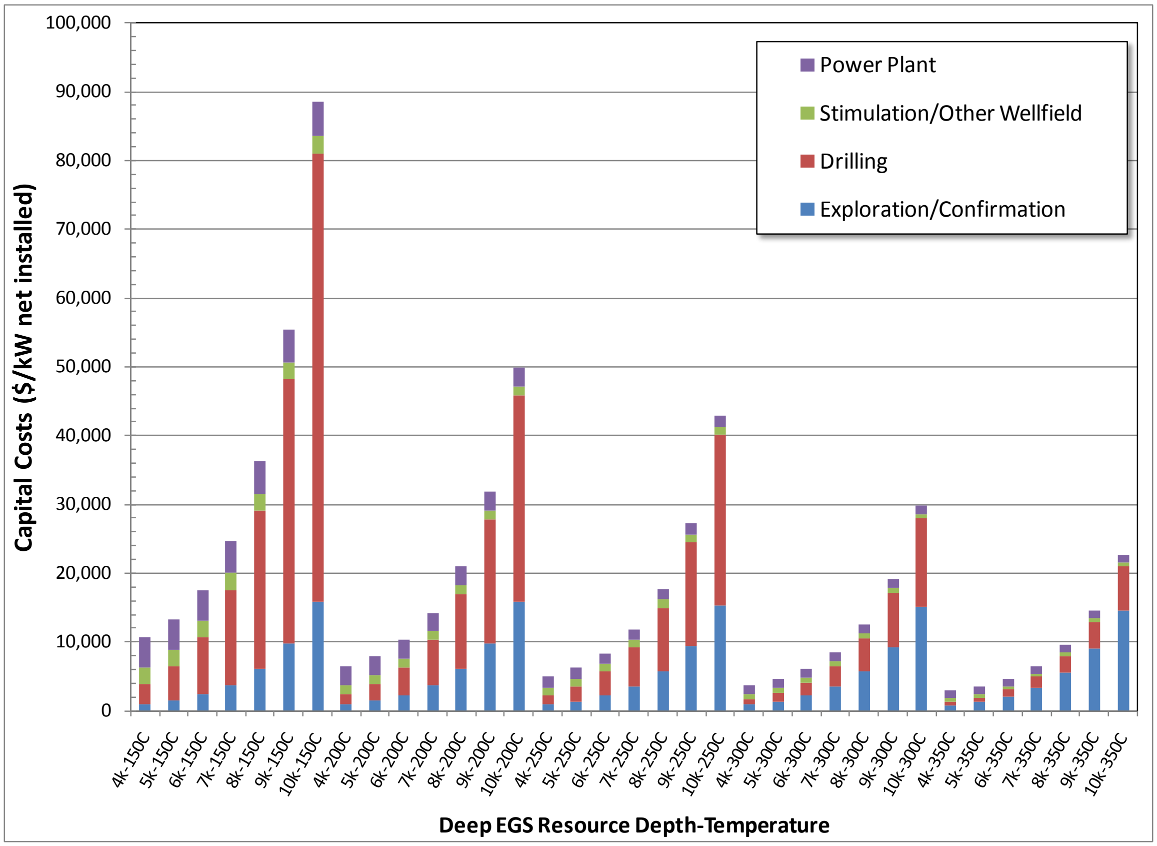

Figure 19. Deep EGS resource capital costs for target case.

The breakdown of the capital costs by project phase is given for each temperature/depth combination listed in Table 6. The lower bound of the reservoir temperature in each depth interval was used to identify the resource, so that "4k-150C" represents the deep EGS resource with a reservoir depth of 4 km and temperature of 150°-200°C.

As with the near-hydrothermal field EGS resource, stimulation capital costs in the figures above only include the creation of the initial EGS reservoir. The base case requires several reservoirs to be re-drilled over the lifetime of the plant. Field O&M costs for deep EGS include the cost of having to redrill the reservoir. Plant O&M costs are nearly identical for the base and target cases, but field O&M costs for the base case range from 10-50 times greater than those for the target case, depending on the resource, due to the need to periodically drill and stimulate a new reservoir.

4.4.3 Optimum Deep EGS Resource Depth

The supply curve assumes that the deep EGS resource can be developed at all depths at a given location. If a deep EGS resource is developed at one depth in a given location, the supply curve does not remove the resource at the remaining depths in that location from potential development—it assumes that if a reservoir is artificially created at 4 km depth, another reservoir could still be developed below it at 5 km, 6 km, 7 km, etc. as well. Given the current state of the technology, the likelihood of this type of development is questionable. It is more likely that the most-economical deep EGS resource at a location would be developed based on the temperature vs. depth profile at that location, and its presence would preclude the development of the remaining resource in that location for the lifetime (assumed to be 30 years) of the power plant. The optimum reservoir depth by location in the continental United States was determined based on the LCOE values estimated by GETEM for the target case using GIS mapping methods. At each data point in the map, the LCOE for the deep-EGS resources at depths from 3-10 km (in 1-km increments) were compared and the minimum was selected. The reservoir temperature and depth associated with the minimum LCOE at each data point was noted and then mapped. The optimum reservoir temperature by location is shown in Figure 20, and the optimum reservoir depth by location is shown in Figure 21. The LCOE was not assessed in regions where the temperature was not above 150°C at the maximum considered depth of 10 km, so no optimum temperature or depth was chosen. Excluded areas are shown in white.

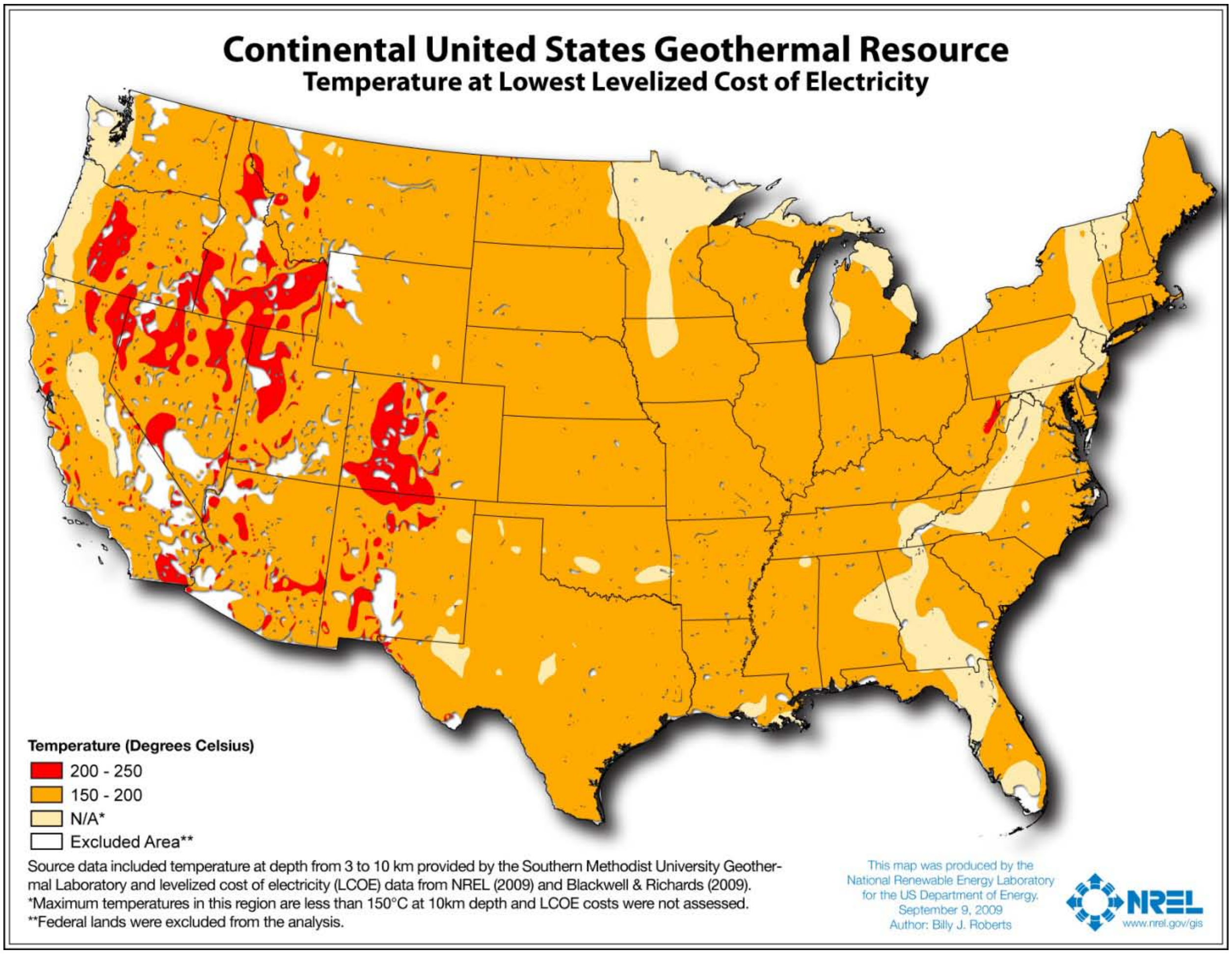

Figure 20. Optimum reservoir temperature for deep EGS resource by location for target case.

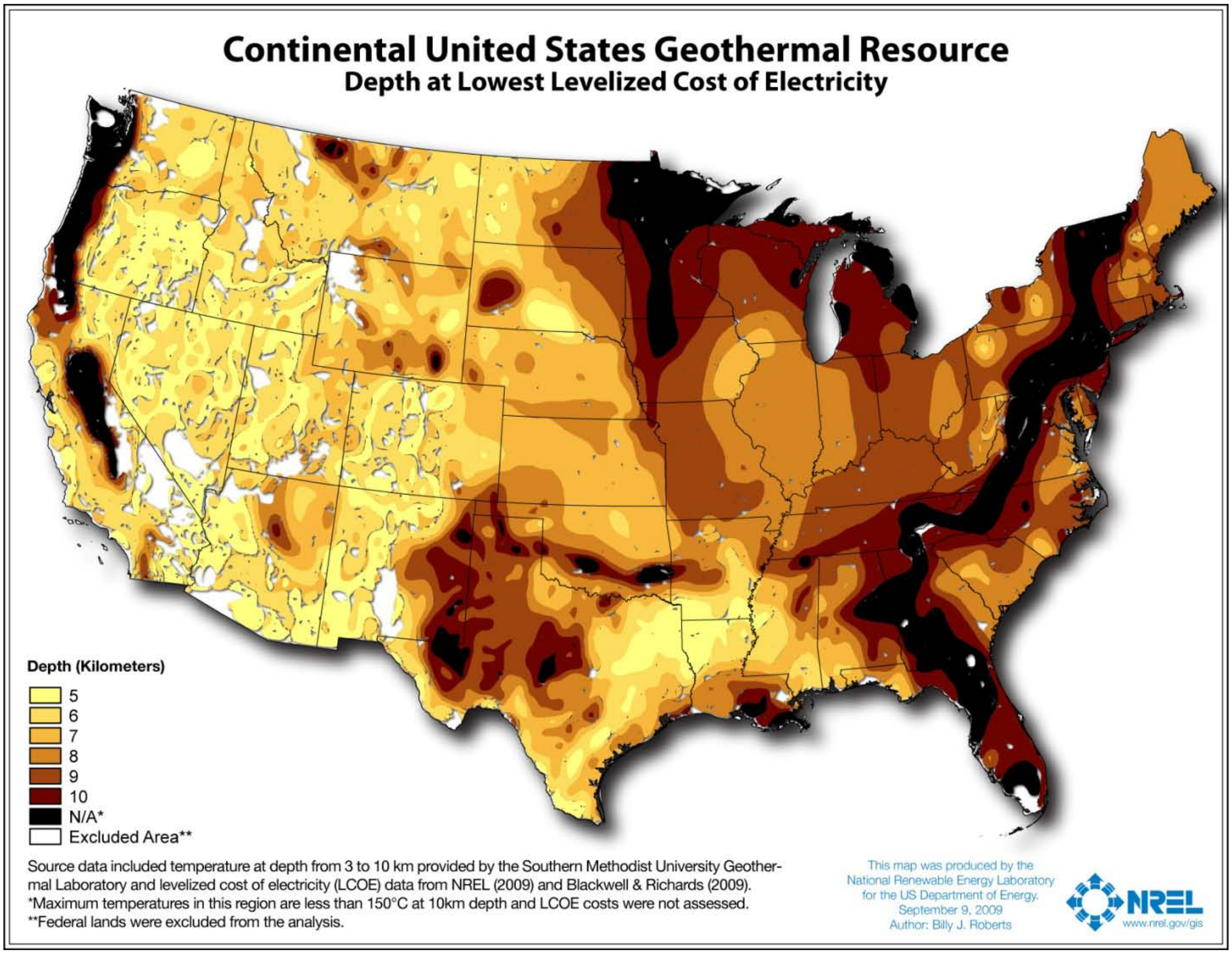

Figure 21. Optimum reservoir depth for deep EGS resource by location for target case.

Because federally protected lands were excluded from the resource estimate, the highest quality resource (high temperature, shallow depth), which exists around Yellowstone National Park was not included in the estimate. The result is that for the remaining resource, the optimum reservoir temperatures are all between 150^{o}-250^{o}C[1]. The vast majority of the optimum resource is in the 150^{o}-200^{o}C range. Although higher temperature reservoirs exist, they are at greater depths so that the drilling costs associated with developing them result in a higher estimated LCOE. Another interesting result is that all optimum reservoir depths are 5 km or deeper[1]. According to the results of this study, there are no locations where the optimum reservoir depth is 4 km. The deep EGS supply curve analysis determined that it was more economical to continue drilling at least 1 km more to encounter higher temperature reservoirs; the increase in plant power output justified the higher drilling costs.

[1] GIS mapping of the assessment actually found small areas where the optimum reservoir depth and temperature were 4 km/150^{o}-200^{o}C and 6 km/300^{o}-350^{o}C. Table 6 indicates that the potential capacity of these areas is small. Moreover, the regions are extremely close to the federal exclusion zones around Yellowstone National Park and, given the accuracy of the mapping, are likely within the park. Because of their small size and proximity to excluded areas, these areas are not shown in Figure 20 or Figure 21.

The results of the analysis above are not definitive and come with significant caveats. First, the results are unique for the EGS reservoir technology performance levels assumed in the target case. Achieving higher production well flow rates or a higher production-to-injection well ratio could lower drilling costs and change the landscape. A change in drilling costs due to natural market forces could also affect the results of the optimum LCOE analysis. Second, the underlying temperature-depth data used in the deep EGS estimate is applied over large areas and is not very accurate. There are likely localized hot spots not captured by the data used in the estimate where high reservoir temperatures exist closer to the surface. Third, a single drilling cost curve was used for the entire continental United States. Regions of easy or difficult drilling will affect drilling costs and change the contour of the maps. Given these caveats, the analysis suggests that future deep EGS RD&D should focus on drilling wells 5 km and deeper and power plants operating in the 150^{o}-250^{o}C range.

Although Figure 20 and Figure 21 show the reservoir temperature and depth at the optimum LCOE, there is no guarantee that the optimum at a location is economically viable. Based on Figure 19, it is unlikely that any of the deep EGS resources with reservoir depths of 8-10 km would be cost effective in the foreseeable future. Therefore, a map based on the target case minimum LCOE by location for the U.S. deep EGS resource was made to illustrate the location of the most cost effective regions for developing the deep EGS resource based on the analysis in this study. A decision was made to avoid mapping all of the separate LCOE regions from the analysis. As discussed above, using raw data from the analysis can be misleading since changes in the assumptions used, changes in drilling costs (due to either market variations or local conditions), or improvements to the underlying temperature vs. depth data could easily alter the rank of the “best” regions. Instead, regions were grouped by favorability, with regions having the lowest LCOE identified as the most favorable and those having the highest as the least favorable. By grouping the data, the transition between resources is smoothed and the classification generalized, so that the results should apply even with variations in some of the underlying costs or assumptions. For this map, excluded areas were included. The location of the identified hydrothermal sites (and hence the assumed near-hydrothermal field EGS resource) was also included. The resulting map, shown in Figure 22, summarizes the majority of the geothermal resource of the United States.

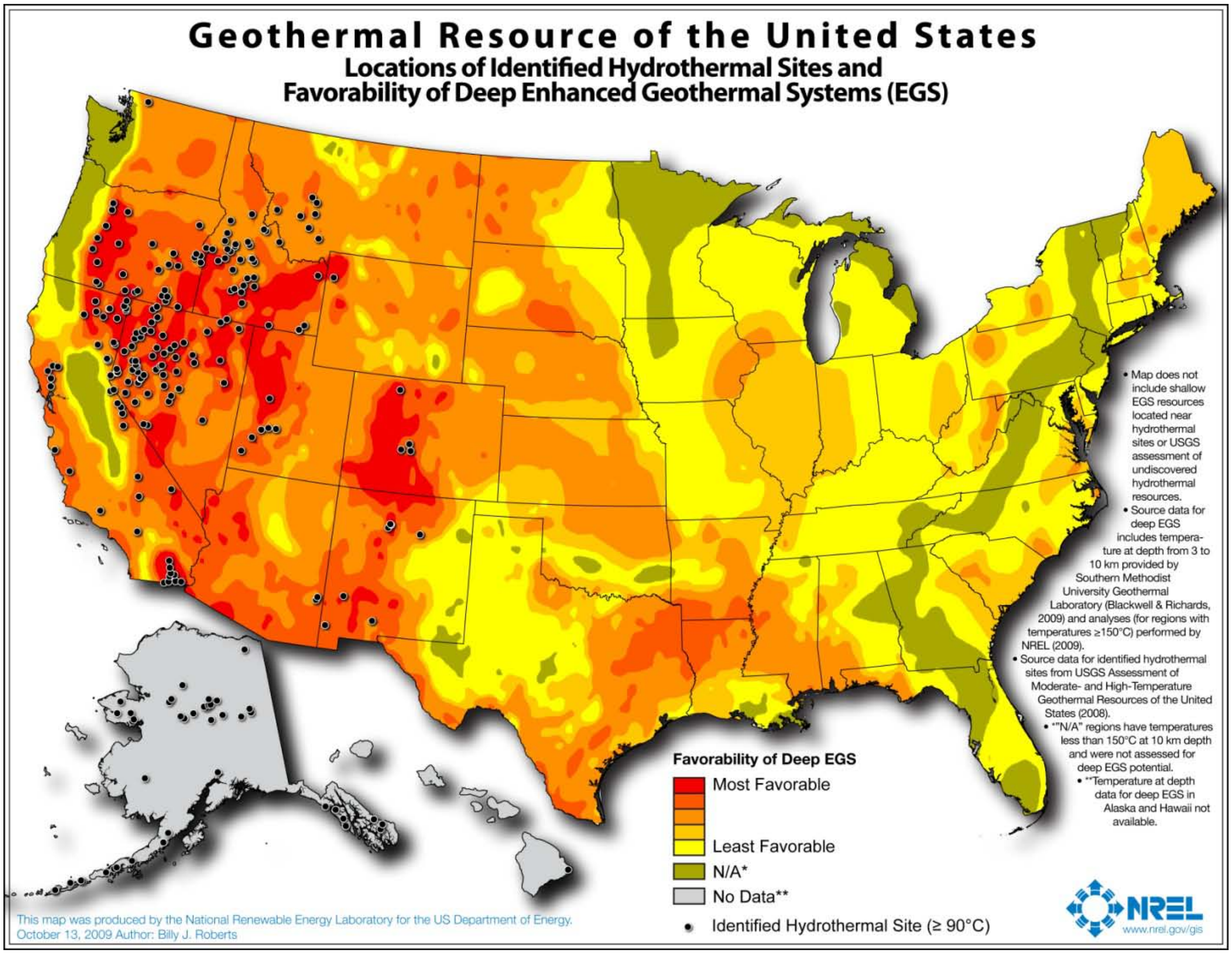

Figure 22. Geothermal resource of the United States.

Figure shows the location of identified hydrothermal sites, the co-located near-hydrothermal field EGS resource, and the favorability of the deep EGS resource by location. The undiscovered hydrothermal resource and other geothermal resources, such as co-produced fluids, are not represented.

4.5 Sensitivity Analysis

The use of TPM distributions based on expert input in Table 3 and the @Risk Monte Carlo Excel add-in during GETEM runs resulted in a distribution of probable LCOE values as output. Examples of the output LCOE distributions from Monte Carlo simulations of the hydrothermal and target case deep EGS reference plants (Appendix A) are shown in Figure 23 and Figure 24, respectively. Each Monte Carlo simulation consisted of 1,000 iterations. The supply curves in Section 3 show the median (50^{th}%ile) LCOE values, as well as 10^{th}%ile and 90^{th}%ile values presented in the figures. The incorporation of the results from the risk assessment and use of risk analysis software for the supply curve gives a more complete picture of the range of possible geothermal project costs based on the uncertainty of technology costs and performance levels.

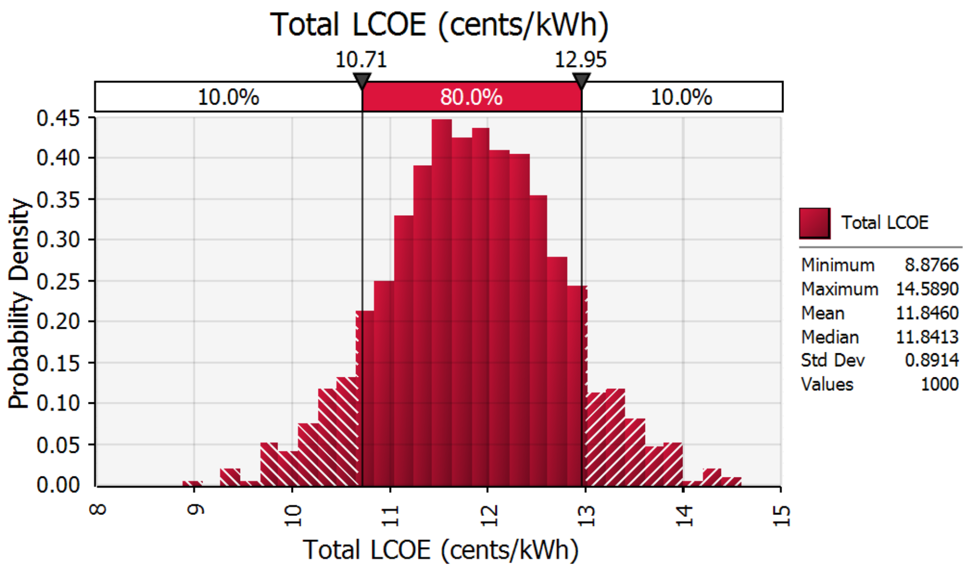

Figure 23. LCOE distribution for hydrothermal reference plant.

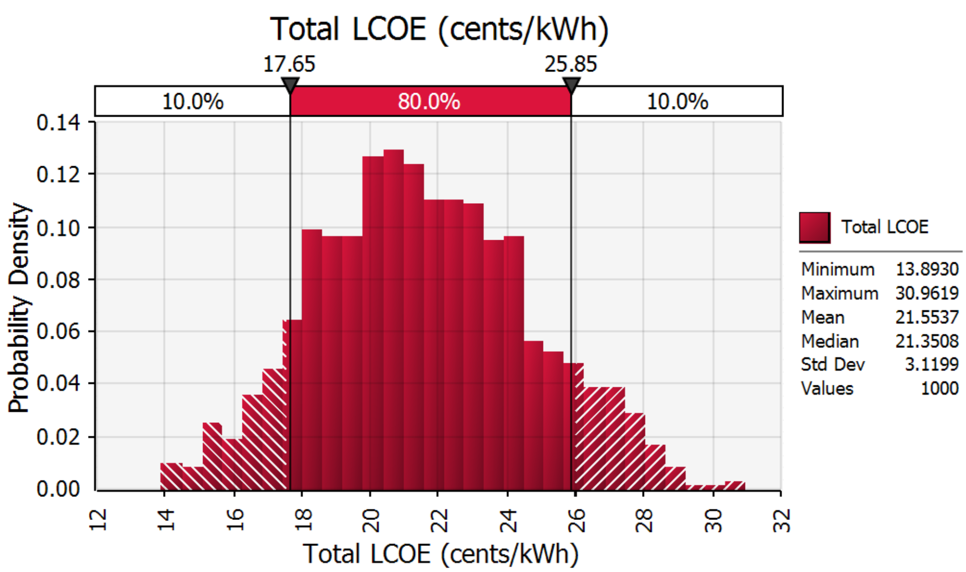

Figure 24. LCOE distribution for deep EGS reference plant (target case).

Along with a probable distribution of the LCOE, the use of risk analysis tools allowed a study of the sensitivity of the LCOE to the GETEM inputs. Sensitivity analysis is used to identify the most significant parameters that affect the output of a model. An analysis was performed of the sensitivity of LCOE for deep EGS and hydrothermal sites to the TPM distributions given by geothermal experts as part of the risk assessment. The hydrothermal and target case deep EGS reference plants described in Appendix A were used to perform the analysis. The results of the sensitivity analysis are displayed as "tornado" charts in Figure 25 and Figure 26. The longer bars at the top represent the most significant inputs of those tested. The results indicate that, of the TPM distributions used, the binary system capital costs and well or drilling costs have the largest impact on LCOE for the hydrothermal reference plant. For the deep EGS reference plant, well costs are by far the most significant variable. For the deep EGS plant, the input distributions for the stimulation costs and binary power plant costs have roughly the same impact on the LCOE. These results could also be inferred from the capital costs for the geothermal resources given above. The results of the sensitivity analysis indicate that RD&D efforts focused on lowering drilling costs and binary power plant costs would have the largest impact in lowering the overall costs associated with the geothermal technologies considered in this study.

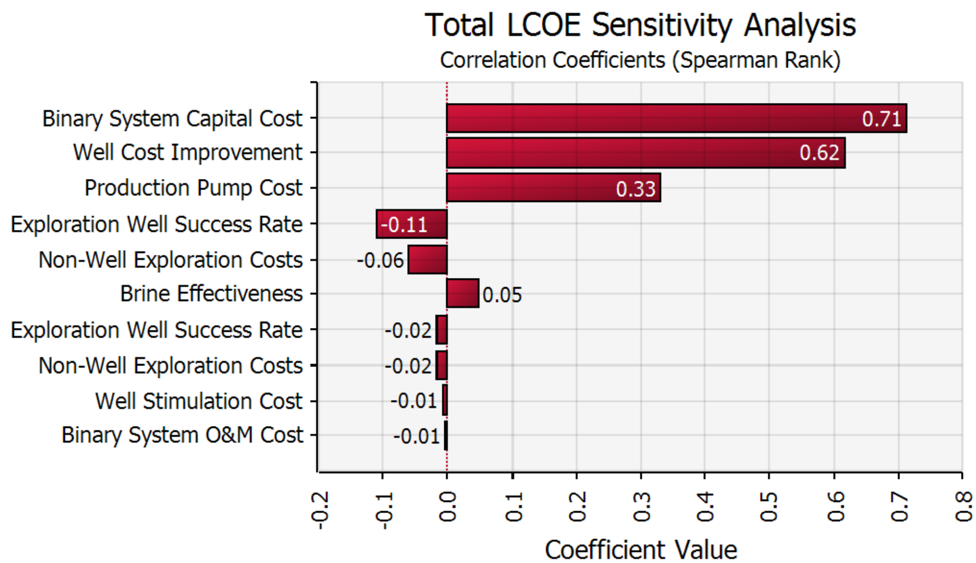

Figure 25. Sensitivity analysis results for hydrothermal reference plant.

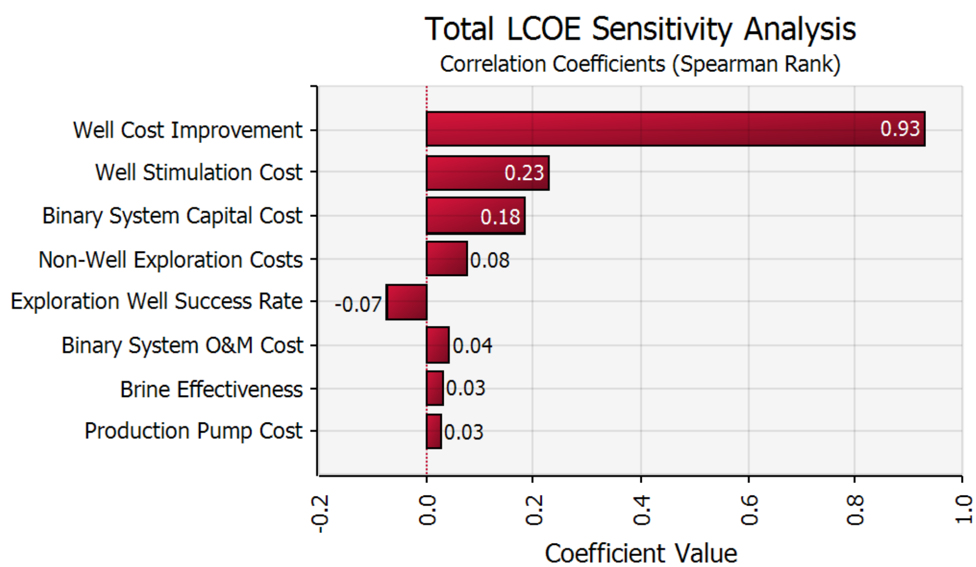

Figure 26. Sensitivity analysis results for deep EGS reference plant (target case).

During the supply curve analysis, constant values for geothermal resource characteristics such as reservoir temperature, depth, and reservoir volume were used. The exact values of these resource characteristics are not known and there is some uncertainty to their value. The USGS 2008 resource assessment used triangular distributions to represent these values and used a Monte Carlo approach to give a range of probable resource capacities (Williams, Reed, et al.

2008a; Williams, Reed, et al. 2008b). These resource characteristic distributions should have been used as inputs for @Risk during GETEM modeling and incorporated into the supply curve analysis to better gauge the uncertainty around the size and cost of developing the geothermal resources in the assessment. However, since the mean values for reservoir temperature and capacity from the USGS 2008 geothermal assessment were used for most inputs, the median LCOE values are likely close to what they would have been had the resource characteristic distributions been used. However, future supply curve studies should incorporate resource characteristic distributions into the risk analysis.

Likewise, distributions for the EGS reservoir performance characteristics, such as production well flow rate and reservoir thermal drawdown rate, should have been used. The sensitivity analyses above do not take into account the significance of these parameters and how changes in them affect LCOE. During preliminary supply curve analysis, it was seen that these factors can greatly affect the project costs for developing a geothermal resource. An attempt was made during the risk assessment to gather distribution data for reservoir performance from the experts, but the reservoir engineering expert discussions in the risk process were never concluded. Consequently, the resulting reservoir TPM distributions were inconsistent, conflicted with input from previous EGS studies, and were deemed invalid (Young, Augustine, et al. 2010). Future risk assessments and data from EGS demonstration projects should provide better reservoir performance data for future supply curve studies.

5 Future Costs of Geothermal Resources

The supply curves in Section 3 show the estimated LCOE for geothermal technologies in 2008 US$ assuming current technology and, for the target case, the LCOE for EGS technologies assuming current technology and that the reservoir technology performance goals proposed for EGS were met today. The risk assessment described in Section 2.3 also elicited input from experts of probable distributions for TPMs in the future. The purpose of the risk assessment was to estimate advances in geothermal technologies under different levels of RD&D funding from the Program, and to use these results to predict the effect Program spending could have on technology improvements, analyze the risk involved in project funding and guide Program funding strategies. The experts were asked to estimate likely distributions for the TPMs in the years 2015 and 2025 assuming funding levels of $0, $30M and $60M per year per technology component. The distributions from the experts were then aggregated into a single probability distribution. The mean values for the aggregated distributions in the present and future years under the assumed budget levels are shown in Table 8. A description of the process and methodology used to gather the expert input and results is given by Young et al. (2010).

Table 8. Mean Values from Aggregated Distributions of Expert-Elicited Geothermal TPM Input for Future Years

TPM			Year / Budget Level						
Technology Area	Name	Units	2008	2015			2025		
			---	$0	$30M	$60M	$0	$30M	$60M
Exploration	Non-Well Exploration Costs (EGS)	$M	1.41	1.14	1.06	0.97	1.10	0.94	0.82
	Non-Well Exploration Costs (Hydro)	$M	1.22	1.18	1.13	1.07	1.16	1.06	0.90
	Exploration Well Success Rate (EGS)	%	64	64	66	68	66	69	73
	Exploration Well Success Rate (Hydro)	%	34	37	41	43	40	45	49
Well Pumps & Tools	Well Drilling/Construction Cost	$M	22.3	21.6	20.3	19.0	20.6	18.3	16.6
	Production Pump Cost (per well)	$M	1.5	1.5	1.3	1.2	1.4	1.2	1.0
Reservoir Engineering	Stimulation Cost (per triplet)	$M	8.4	7.9	7.5	6.8	7.3	6.4	5.8
Power Conversion	Binary System Capital Cost	$/kW	2,500	2,470	2,380	2,010	2,390	2,250	1,870
	Binary System O&M Cost/Yr	¢/kWh	2.2	2.2	2.1	1.9	2.2	2.1	1.8
	Brine Effectiveness	W-h/lb_m	9.5	9.5	9.7	10.0	9.6	10.0	10.4

Note: Budget levels assume RD&D funding per year per technology component. All dollar values assume 2008 US$.

The future TPM data from the risk assessment was used to estimate improvements in future costs of the geothermal technologies in this study for the future year base and target cases described in Section 2.1. The base case assumes "business as usual" for industry with no GTP RD&D funding. For the target case, an RD&D budget of $50M/year was assumed. Future costs were estimated for four future cases—two time frames and two budget levels:

1) 2015 Base Case ($0/year GTP RD&D budget)
2) 2025 Base Case ($0/year GTP RD&D budget)
3) 2015 Target Case ($50M/year GTP RD&D budget)
4) 2025 Target Case ($50M/year GTP RD&D budget)

A sensitivity analysis of GETEM inputs using the TPMs listed in Table 8 found that well drilling/construction costs and binary system capital costs have the largest impact on the LCOE for the hydrothermal reference scenario, and that well costs dominate LCOE for the EGS reference scenario (see Figure 25 and Figure 26). The same conclusion was found when the effect of individual component costs was studied as part of the risk assessment (Young, Augustine, et al. 2010, Table 3). Based on these results, this study assumed that for the target case, the Program split its $50M/year budget evenly between funding RD&D to reduce well costs ($25M/year) and binary power plant costs ($25M/year). These budget levels differ from the $30M/year and $60M/year budget levels considered by experts in the risk assessment. Linear interpolation between the $0 and $30M/year budget levels was used to estimate technology benefits at the $25M/year RD&D level. Benefits from RD&D to well cost and binary power plant cost improvements were applied for all geothermal technologies in this study since well and power plant technology improvements would be applicable in both hydrothermal and EGS technologies. It was assumed that all other TPMs received no RD&D funding, so that their future year improvements followed those predicted by the experts for the $0/year budget level.

The LCOE for each of the geothermal technologies was calculated using GETEM for the four cases using the future year TPM distributions described above. It was not practical to calculate the LCOE under each of the four future cases for every hydrothermal site and EGS resource. Moreover, several of the market penetration models only allow generic cost multipliers that are applied broadly to a technology type, so cost multipliers on a site-by-site basis would not be usable. Instead, reference scenarios representative of a typical plant were assumed for each technology type. Improvements to LCOE under each case were calculated for each reference scenario, and were assumed to apply to all the resources in each technology type. The resource characteristics for reference scenarios and LCOE output for each technology are summarized in Table 9. Hydrothermal covers both the identified and undiscovered hydrothermal resource. The reservoir technology parameters used for the EGS reference scenarios differ in the base and target cases. The near-hydrothermal field EGS reference scenario is a combination of the hydrothermal and deep EGS cases. Unless otherwise stated, GETEM parameter inputs and assumptions for the reference scenarios were the same as those used for each technology type in the supply curve. Detailed input used in GETEM for each of the reference scenarios is listed in Appendix A.

Table 9. Summary of Supply Curve Reference Scenarios
Detailed GETEM input for reference scenarios is listed in Appendix A.

Parameter	Technology Type		
	Hydrothermal	Near-Hydrothermal Field EGS	Deep EGS
Plant Type	Binary, air-cooled	Binary, air-cooled	Binary, air-cooled
Net Output	20 MW_e	20 MW_e	20 MW_e
Resource Temperature	175 °C	175 °C	225 °C
Well Depth	1.52 km	1.52 km	6 km
Production Well Flow Rate	44.2 kg/s	Base Case: 30 kg/s Target Case: 60 kg/s	Base Case: 30 kg/s Target Case: 60 kg/s
Thermal Drawdown Rate	0.3%/year	Base Case: 3.0%/year Target Case: 0.3%/year	Base Case: 3.0%/year Target Case: 0.3%/year

Based on the results of the GETEM runs for each reference scenario, future cost multipliers were calculated for each geothermal technology. The future cost multipliers are based on the LCOE and are calculated by dividing the LCOE under a future case for the reference scenario by the present day LCOE for the reference scenario. Future costs for each technology are determined by multiplying the present value LCOE by the future cost multiplier for a given year. The future cost multipliers are shown in Figure 27.

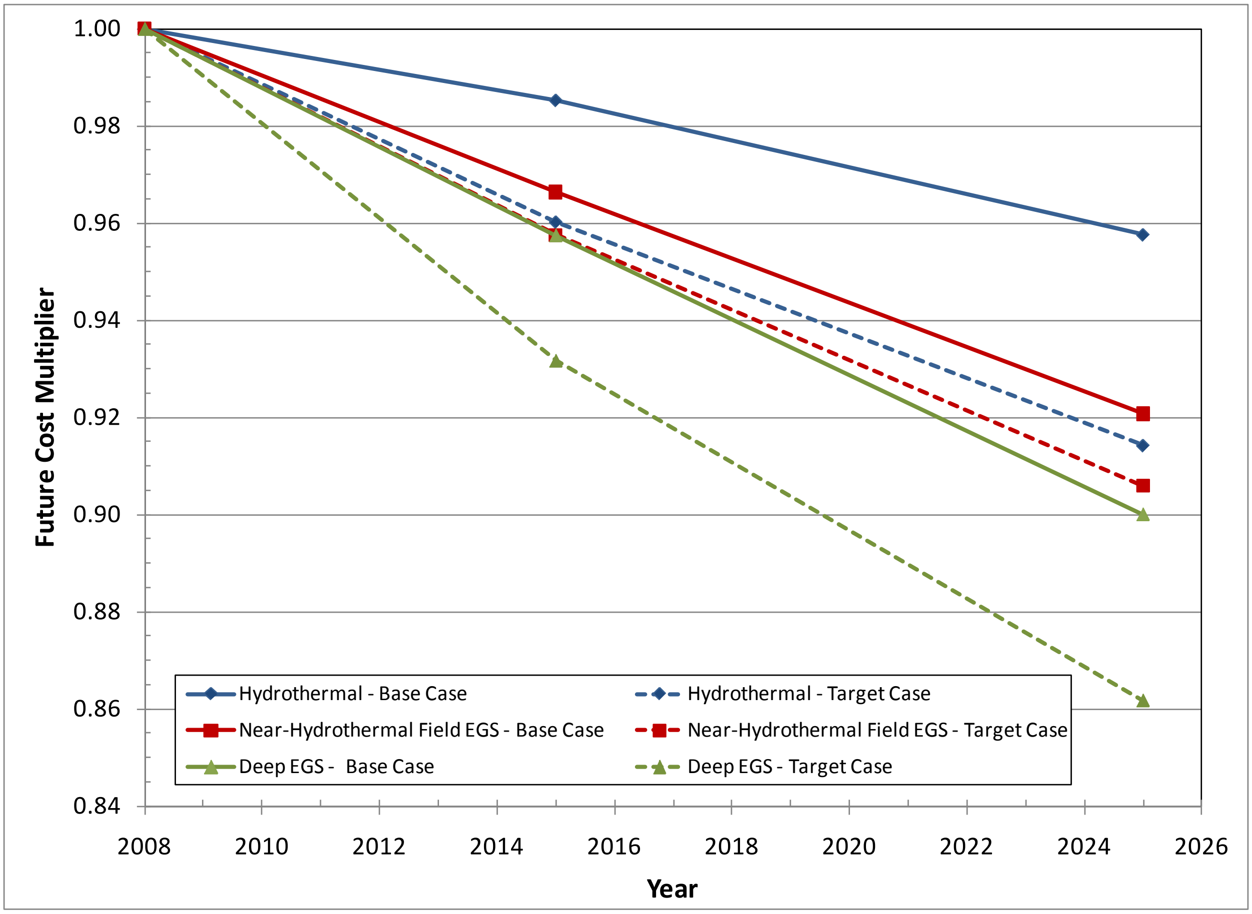

Figure 27. Future cost multipliers for geothermal technologies.

For EGS technologies, the base and target cases make different assumptions about production well flow rate and thermal drawdown rate. The future cost multipliers consider the effect of RD&D budget levels on future costs, not the assumed enabling technology advances from the base case to the target cases. This means that the current year values of LCOE for the EGS base and target cases differ from each other. The effect of the enabling reservoir technology advances assumed for the target case on LCOE can be seen by studying the EGS supply curves in Section 3.

GTP MYRD&D goals call for a functioning EGS demonstration reservoir by 2015 and proven sustainable production from a reservoir by 2020. In the target case, it is not realistic to think that the Program could spend their RD&D funding solely on drilling and power plant technology improvements and still achieve the reservoir performance goals at same time (or vice versa). Therefore, when cost multipliers were calculated for input into market penetration models for annual GPRA benefits analysis, it was assumed that the entirety of the budget was spent on enabling technologies for EGS through 2020—achieving assumed program reservoir technology goals of 60 kg/s production well flow rate and 0.3%/year thermal drawdown rate. After 2020, it was assumed that the Program had reached its MYRD&D goals and that EGS is commercially viable. After 2020, it was assumed that GTP splits its budget equally on funding RD&D for reducing well costs ($25M/year) and binary power plant costs ($25M/year). Such a funding scenario was not presented to the experts during the risk assessment process. The cost multipliers for market penetration model input were estimated using a combination of the base and target cost multipliers shown in Figure 27. The base case multipliers were used through 2020, and then the slope of the future cost multiplier curves from 2015 to 2025 was used to construct the future cost multiplier curves from 2020 onward. For these market penetration model runs, it was also assumed that EGS power plants were not commercially available until 2020.

6 Conclusions

The 2009 geothermal supply curve study updated the geothermal supply curve of the United States for use as input into market penetration models and GPRA benefits analysis. The study established an approach and methodology for performing future supply curve updates when new resource and cost data become available. The potential resource estimates made use of published and available data on geothermal resources, in particular the results of the USGS 2008 geothermal resource assessment. When sufficient information was not available, methodologies and assumptions were established for estimating geothermal resource potential.

The geothermal resource was divided among two technologies—conventional hydrothermal systems and EGS. Resources were further divided into four categories, two for each technology. The resource categories and the electricity generation potential capacity determined for each were:

1) Identified Hydrothermal Resource: 6.39 GW_e
2) Undiscovered Hydrothermal Resource: 30.03 GW_e
3) Near-Hydrothermal Field EGS Resource: 7.03 GW_e
4) Deep-EGS Resource: 15,908 GW_e

The costs of developing the geothermal resources were estimated using GETEM. Two budget levels were considered: a base case based on the current status of geothermal technology with $0 assumed for GTP RD&D research funding, and a target case with $50M/year assumed for GTP RD&D research funding and EGS reservoir performance based on Program goals from the MYRD&D. Probability distributions of technology costs and performance estimated by geothermal experts as part of the annual risk assessment were incorporated into the supply curve. These input distributions were used to run Monte Carlo simulations in GETEM with the @Risk risk analysis software. The incorporation of technology component uncertainty results in a distribution of probable project costs rather than a single value. Supply curves based on the median, 10^{th}%ile, and 90^{th}%ile estimates of the LCOE were generated for each of the resource categories. Future cost multipliers for the years 2015 and 2025 were also calculated for each geothermal technology based on expert risk assessment input and GETEM results.

The individual supply curves were combined to create aggregate supply curves for the base and target cases that include all geothermal resources in the supply curve. The aggregate supply curves focused on the most cost effective 50 GW_e of geothermal resource. For the base case, identified and undiscovered hydrothermal resources dominate the lower part of the curve, with some EGS present at higher LCOE values. For the target case, hydrothermal sites still dominate the lower part of the curve, but a significant amount of near-hydrothermal field EGS resource is visible. The cost level at which a large amount of deep EGS resource is found in the supply curve is significantly lower for the target case than for the base case, indicating that meeting GTP goals could have a significant impact on deep EGS deployment.

Capital costs by project phase for the different technologies were also presented. For the hydrothermal and near-hydrothermal field EGS resources, power plant costs tend to make up a significant portion of the capital costs. These resources tend to be shallow, so they have relatively low drilling costs. Exploration/confirmation and plant costs are comparable for hydrothermal and near-hydrothermal field EGS resources, with the major difference in capital costs for the two resources stemming from the need to stimulate the EGS reservoir. For the deep EGS resource, drilling costs are the dominant component of the total capital costs. LCOE and capital costs were generally higher for all geothermal resources in this supply curve than in the last NREL study (Petty and Porro 2007) mainly due to a significant increase in drilling costs over the past several years. The previous study assumed 2004 drilling costs, while this study assumed a 30% discount from 2008 drilling costs based on conversations with geothermal drilling companies. Even at this discounted level, the index value used to adjust drilling costs in GETEM was 64% higher than its 2004 value.

GIS tools were used to perform an analysis of the optimum LCOE for the deep EGS resource by location. It was found that across the country, the deep EGS reservoirs with the minimum LCOE at a given location were located at depths of ≥5 km and had temperatures in the 150^{o}-$250^{o}C$ range. It was concluded that deep EGS RD&D should favor technologies that would lower the cost of developing these types of resources. These conclusions are heavily influenced by the assumptions made for the base and target case, the current drilling cost trend, and the accuracy of the resource estimates. Distributions for the resource characteristics or EGS reservoir technology performance metrics were not included in the risk analysis or subsequent sensitivity analysis.

A sensitivity analysis found that drilling costs and binary power plant costs most significantly affect the LCOE of both hydrothermal and EGS projects. These findings are supported by the results of the capital cost estimates. Future cost multipliers for each of the geothermal technologies were calculated based on funding assumptions in the base and target cases and expert input from the risk assessment.

There is ample room for improvement of the geothermal resource potential estimate as the quantity and quality of geothermal resource data continues to increase over the coming years. Both the undiscovered hydrothermal and near-hydrothermal field EGS resource estimates rely heavily on assumptions. The deep EGS resource is based on data that are sparse in many parts of the country. Additional efforts are needed to better characterize these resources. A co-produced fluid resource assessment is also needed. General recommendations for improvements to the supply curve cost estimates are to improve expert input during the risk assessment process, especially for EGS reservoir TPMs and the application of the expert input to the full range of geothermal resources, the inclusion of resource uncertainty measurements in the supply curve, and the development of drilling cost and reservoir creation models that take into account local lithology and well diameter. Detailed recommendations for future supply curve studies are discussed below.

6.1 Detailed Recommendations for Future Supply Curve Studies

6.1.1 Resource Potential

Below is a list of recommendations for future supply curve studies. Some recommendations can be implemented relatively easily, while others are multi-year projects that would require a considerable amount of time, effort, and resources. Many recommended tasks will be completed as part of planned USGS resource assessments and the establishment of the NGDS, which will assess and classify all geothermal resources and facilitate access to geothermal data sets for developers to lower the risk associated with the development of geothermal projects. Future supply curves should incorporate these data as they become available. Recommendations are grouped by resource category:

1) Identified Hydrothermal Resource: Current potential based on site-specific data from USGS 2008 geothermal resource assessment (Williams, Reed, et al. 2008b).
    - Continue to update database of indentified hydrothermal sites as they are discovered and currently installed capacity as new power plants are constructed and capacity at existing plants is expanded.
    - Update estimates of hydrothermal resource characteristics to include probability distributions for reservoir temperature and volume (from USGS 2008 assessment), and also verify estimated reservoir depth and production well flow rate figures.
2) Undiscovered Hydrothermal Resource: Current potential based on summary data from USGS 2008 geothermal resource assessment (Williams, Reed, et al. 2008b) and assumption that undiscovered resource is similar in nature to identified resource in same state.
    - Learn details of methodology used by USGS to estimate undiscovered resource and apply them to more accurately predict nature and location of undiscovered resource.
3) Near-Hydrothermal Field EGS Resource: Based on difference between 95th%ile and mean estimates of identified hydrothermal resource from USGS 2008 geothermal resource assessment (Williams, Reed, et al. 2008b).
    - Work with industry to better define nature and characteristics of near-hydrothermal field EGS resource.
    - Perform thorough assessment of potential to use EGS techniques to develop marginal areas around identified hydrothermal sites is needed.
4) Deep EGS Resource: Based on SMU temperature vs. depth data (Richards 2009) and methodology described in MIT *Future of Geothermal Energy* report (Tester et al. 2006).
    - Increase quality and quantity of temperature vs. depth data in the United States.
    - Develop more robust methodology for estimating resource potential based on reservoir modeling and EGS demonstration results.

5) Co-Produced Fluids and Geopressured Resources: Not included due to insufficient data.
    - A project to perform an accurate assessment of the co-produced fluid resource is planned and will be included in future updates.

6.1.2 Supply Curve

Recommendations for improving cost estimates for geothermal resources in the supply curve are given below:

1) Resource Characterization
    - Identify sites with characteristics that would significantly affect costs, such as the Salton Sea[2] and Puna, and incorporate these factors in GETEM cost estimates.
2) Drilling Costs
    - Single drilling cost curve used in all geothermal resource cost estimates. Actual drilling costs will vary greatly as a function of location. Long-term goal should be to map lithology with resource and correlate drilling costs with lithology, so that more accurate drilling costs can be used when estimating LCOE for geothermal resources on a spatial basis. Drilling costs should also take well diameter into account.
3) GETEM Input
    - Geofluid pumping parameters greatly affect parasitic power losses. The assumptions and parameter inputs for geofluid pumping need to be better addressed in the risk assessment and GETEM modeling. GETEM should base well diameter on production and injection well flow rate to optimize LCOE.
4) Risk Assessment
    - Credible and consistent expert input on EGS reservoir technologies such as production well flow rate, thermal drawdown rate, and production-to-injection well ratio is needed.
    - Expert inputs on drilling/well completion costs, binary power plant costs, O&M power plant costs, brine effectiveness, and production pump costs were all based on the risk assessment reference plants. These data had to be generalized and applied across the entire range of geothermal resources. Either a better method of gathering expert data that can be applied across a wide range of geothermal resources, or a better method of applying resource-specific expert input is needed. Some parameters, such as brine effectiveness and binary power plant cost, are calculated in GETEM using complex and detailed correlations. Using GETEM solely to calculate these parameters instead of expert input should be considered.

[2] Capital costs for Salton Sea have been updated to $4,000/kW for hydrothermal and $4,800/kW for near-hydrothermal field EGS for FY12 DOE budget planning cycle. Updates based on adjusting material and labor cost multipliers in GETEM to reflect use of exotic materials (titanium and inconel) compared to carbon steel in power plant equipment that come in contact with corrosive brine from reservoir. Drilling costs also adjusted by using "High" drilling cost curve in GETEM (Mines 2009).

5) Risk Analysis

- GETEM modeling should include the uncertainty of the resource; @Risk should also take into account the distributions of the estimated resource temperature, depth, flow rate, etc. when calculating LCOE.
- Distributions for EGS reservoir TPMs are needed. If they cannot be provided by the risk assessment, a reasonable range of values should be considered by the risk analysis.

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Appendix A: Reference Scenario Power Plants

Legend	
Key Reference-Scenario Parameters	
Expert Data Provided from Risk Assessment	*10*th*percentile value*-50thpercentile value-*90*th*percentile value*
Values Calculated by GETEM	

Table A-1. GETEM Input for Hydrothermal Reference Scenario

	GETEM Input for Supply Curve Hydrothermal Reference Scenario					
	Version	Version 2008-A6				
	Case Name	Hydrothemral Reference Scenario				
	Plant Type	Binary, Air-Cooled				
	Reference Year	2008				
	Power Sales	20	MW			
(1)	**ECONOMIC PARAMETERS**					
(1a)	Fixed.Charge.Rate		0.128			
(1b)	Utiliz.Factor		0.95			
(1c)	Contingency		5%			
(1d)	Royalty [b]		10%			
(1e)	Year for Baseline Estimate		2008			
(2)	**RESOURCE DEFINITION**					
(2a)	Is the Resource Type Hydrothermal or EGS?		Hydrothermal			
(2b)	Resource Temperature Used		175	C	(347 ^{o}F)	
(2c)	Resource Depth Used		1,524	m	(5,000 ft)	
(2d)	Plant Design Temperature (used in all model calculations)		175	C	(347 ^{o}F)	
(3)	**POWER SALES**					
(3a)	Are calculations to be based upon Fixed Power Sales or Fixed Number of Production Wells?		Power			
(3b)	Enter either Sales or # of Wells		20	MW or count		
(3c)	Net Plant Output		21.44	MW		
(4)	**EXPLORATION & CONFIRMATION**					
(4a)	Input the # of Exploration Wells or Success Rate?		Rate			TPM 2
(4b)	Enter success rate or # of wells		*20*-34-*50*	% or count		TPM 2
(4c)	Pro-rate Explor & Confirm Costs Based on Resource Potential?		NO			
(4d)	# of Exploration Wells Used		2.87			= 1/(4b)
(4e)	Number of Confirmation wells		2	Count		
(4f)	Confirmation well success		0.80	Ratio		
(4g)	Multiplier for Exploration Well Costs		0.50			
(4h)	Multiplier for Confirmation Well Costs		1.1			
(4i)	Non-Well Exploration Costs Used		*$513*-$1,174-*$2,002*	$k/plant		TPM 1
(4j)	Non-Well Confirmation Costs Used		$250,000			

GETEM Input for Supply Curve Hydrothermal Reference Scenario					
(5)	**WELL FIELD DEVELOPMENT**				
(5a)	# of Spare Production Wells	0			
(5b)	# Production Wells Used (including any confirmation wells used)	8.42			
(5c)	Ratio of Injection Wells to Production Wells	0.33			
(5d)	Number of Injection Wells Used	2.81			= (5b)*(5c)
(5e)	Production Well Depth Used	1,524	m	(5,000 ft)	
(5f)	Calculated Production Well Cost - 2008	$2,004	$k/well		
(5g)	User Adjustment to Production Well Cost	*0.59*-0.86-*1.18*			TPM 3
(5h)	Adjusted Production Well Cost	$1,750	$k/well		
(5i)	Injection Well Depth Used	1,524	m	(5,000 ft)	
(5j)	Calculated Injection Well Cost - 2008	$2,004	$k/well		
(5k)	User Adjustment to Production Well Cost	*0.59*-0.86-*1.18*			TPM 3
(5l)	Adjusted Injection Well Cost	$1,750	$k/well		
(5m)	Surface Equipment Cost	$125	$k/well		
(5n)	Non-Well Costs Incurred (exclusive of drilling)	$2,500	$k		
(6)	**EGS SUBSURFACE FRACTURE SYSTEM**				
(7)	**WELL STIMULATION**				
(7a)	Are wells Stimulated?	No			
(8)	**GF PUMPING**				
(8a)	Are Production Wells Pumped?	Yes			TPM 7
(8b)	Production Well Flow Rate	44.2	kg/s	(350,000 lb/h)	TPM 7
(8c)	Injection Well Flow Rate	135.3	kg/s	(1,052,159 lb/h)	
(8d)	Total GF Flow Rate - Production	372.1	kg/s	(2,953,347 lb/h)	
(8e)	Total GF Flow Rate - Injection	372.1	kg/s	(2,953,347 lb/h)	
(8f)	GF Pump efficiency	60%			
(8g)	Production well diameter (ID) below production pump	7.0	inch	(17.8 cm)	
(8h)	Production pump casing size (ID)	7.0	inch	(17.8 cm)	
(8i)	Injection well diameter (ID)	7.0	inch	(17.8 cm)	
(8j)	Excess Pressure at Pump Suction/Surface	3.5	bar	(50.8 psia)	
(8k)	Is Additional Pressure Required in Injection Well?	Yes			
(8l)	Excess Pressure at Bottom of Injection Well	10.3	bar	(150.0 psi)	
(8m)	Use inputted or calclulated reservoir ΔP?	Calculate			
	Base reservoir dP calculation on k*A or simple fracture flow?	k*A			
	Reservoir permeability	0.15	darcy		
	Reservoir height	125.0	m		
	Reservoir width	750.0	m		
	Distance between production and injection well	1,500.0	m		
(8n)	Input or Calculate Production Pump Depth?	Calculate			
(8o)	Pump Depth Used	65.6	m	(215.1 ft)	
(8p)	Production Pumping Power	47.9	kW/well		
(8q)	Total pumping power required	3.9	kW-s/kg	(0.486 w-hr/lb)	
(8r)	Input or Calculate Production Pump Cost?	Input			TPM 4
	If Pumped, Enter type of Pump used	Submersible			
(8s)	Production Pump Cost	*$1*-$1.5-*$2.0*	$million/well		TPM 4
(8t)	Injection Well Pump Costs	$800,350			

GETEM Input for Supply Curve Hydrothermal Reference Scenario					
(9)	**THERMAL DRAWDOWN**				
(9a)	Input Annual Decline Rate or Calculate Fluid Temperature?	Decline Rate			TPM 8
(9b)	Input Annual Rate of Decline	0.3%	%/yr		TPM 8
(9c)	Discount Rate for Makeup calculations	10.0%			
(9d)	Input Maximum Temperature Decline??	No			= (2b)*(2d)
(9e)	Maximum Temperature Decline	21.8	ΔC	(39.2 ΔF)	
(9f)	First Reservoir Replacement	N/A	year		
(9g)	Number of Reservoirs Used	1.0	count		
(10)	**OPERATING & MAINTENANCE COSTS**				
(10a)	Input Annual O&M Costs or Let GETEM Calculate	Input			TPM 11
(10b)	Input the annual O&M Cost for the Power Plant	2.20	¢/kW-hr		TPM 11
(10c)	Input the annual O&M cost for the Field (including production pumps)	0.44 (Value Calculated by GETEM)	¢/kW-hr		
(11)	**ENERGY CONVERSION SYSTEM**				
(11a)	Number of independent power units	1			
(11b)	Apply performance improvement to reducing flow requirement or increasing power output?	Power			
(11c)	Design Ambient Temperature	15	°C	(not changeable)	
(11d)	Is the Conversion System Flash or Binary?	Binary			
(11e)	GF Pumping	0.49	w-h/lb		
(11f)	Sales per well	2,375	kW/well		
(11g)	Binary System Performance	7.26	w-h/lb		TPM 12
(11h)	Binary Conversion System Cost	*$2.72*-$3.09-*$3.46*	$k/kW.plant output		TPM 10

Table A-2. GETEM Input for Near-hydrothermal Field EGS Reference Scenario

GETEM Input for Supply Curve Near-Hydrothermal Field EGS Reference Scenario						
	Version	Version 2008-A6				
	Case Name	Near-Hydrothemral Field EGS Reference Scenario				
	Plant Type	Binary, Air-Cooled				
	Reference Year	2008				
	Power Sales	20	MW			
(1)	**ECONOMIC PARAMETERS**					
(1a)	Fixed.Charge.Rate		0.128			
(1b)	Utiliz.Factor		0.95			
(1c)	Contingency		5%			
(1d)	Royalty [b]		10%			
(1e)	Year for Baseline Estimate		2008			
(2)	**RESOURCE DEFINITION**					
(2a)	Is the Resource Type Hydrothermal or EGS?		EGS			
(2b)	Resource Temperature Used		175	C	(347 °F)	
(2c)	Resource Depth Used		1,524	m	(5,000 ft)	
(2d)	Plant Design Temperature (used in all model calculations)		175	C	(347 °F)	
(3)	**POWER SALES**					
(3a)	Are calculations to be based upon Fixed Power Sales or Fixed Number of Production Wells?		Power			
(3b)	Enter either Sales or # of Wells		20	MW or count		
(3c)	Net Plant Output		21.47	MW		
(4)	**EXPLORATION & CONFIRMATION**					
(4a)	Input the # of Exploration Wells or Success Rate?		Rate			TPM 2
(4b)	Enter success rate or # of wells		*50*-63-*80*	% or count		TPM 2
(4c)	Pro-rate Explor & Confirm Costs Based on Resource Potential?		NO			
(4d)	# of Exploration Wells Used		1.58			= 1/(4b)
(4e)	Number of Confirmation wells		2	Count		
(4f)	Confirmation well success		0.80	Ratio		
(4g)	Multiplier for Exploration Well Costs		0.50			
(4h)	Multiplier for Confirmation Well Costs		1.1			
(4i)	Non-Well Exploration Costs Used		*$417*-$1,314-*$2,534*	$k/plant		TPM 1
(4j)	Non-Well Confirmation Costs Used		$250,000			
(5)	**WELL FIELD DEVELOPMENT**					
(5a)	# of Spare Production Wells		0			
(5b)	# Production Wells Used (including any confirmation wells used)		6.21			
(5c)	Ratio of Injection Wells to Production Wells		0.50			
(5d)	Number of Injection Wells Used		3.11			= (5b)*(5c)
(5e)	Production Well Depth Used		1,524	m	(5,000 ft)	
(5f)	Calculated Production Well Cost - 2008		$2,004	$k/well		
(5g)	User Adjustment to Production Well Cost		*0.59*-0.86-*1.18*			TPM 3
(5h)	Adjusted Production Well Cost		$1,750	$k/well		
(5i)	Injection Well Depth Used		1,524	m	(5,000 ft)	
(5j)	Calculated Injection Well Cost - 2008		$2,004	$k/well		
(5k)	User Adjustment to Production Well Cost		*0.59*-0.86-*1.18*			TPM 3
(5l)	Adjusted Injection Well Cost		$1,750	$k/well		
(5m)	Surface Equipment Cost		$125	$k/well		
(5n)	Non-Well Costs Incurred (exclusive of drilling)		$2,500	$k		

GETEM Input for Supply Curve Near-Hydrothermal Field EGS Reference Scenario					
(6)	**EGS SUBSURFACE FRACTURE SYSTEM**				
(6a)	Is the EGS evaluation to be based on calculations of simplified subsurface model?	No			
(7)	**WELL STIMULATION**				
(7a)	Are wells Stimulated?	Yes			
(7b)	Use Fixed Well Stimulation Cost or Base on Fracture Surface Area?	Fixed Cost			
(7c)	Well Stimulation Cost Used	\$0.9-\$2.6-\$5.0	\$million/Well		TPM 6
(8)	**GF PUMPING**				
(8a)	Are Production Wells Pumped?	Yes			TPM 7
(8b)	Production Well Flow Rate	60.0	kg/s	(476,198 lb/h)	TPM 7
(8c)	Injection Well Flow Rate	122.4	kg/s	(971,444 lb/h)	
(8d)	Total GF Flow Rate - Production	372.7	kg/s	(2,957,725 lb/h)	
(8e)	Total GF Flow Rate - Injection	380.1	kg/s	(3,016,879 lb/h)	
(8f)	GF Pump efficiency	60%			
(8g)	Production well diameter (ID) below production pump	7.0	inch	(17.8 cm)	
(8h)	Production pump casing size (ID)	7.0	inch	(17.8 cm)	
(8i)	Injection well diameter (ID)	7.0	inch	(17.8 cm)	
(8j)	Excess Pressure at Pump Suction/Surface	3.5	bar	(50.8 psia)	
(8k)	Is Additional Pressure Required in Injection Well?	Yes			
(8l)	Excess Pressure at Bottom of Injection Well	10.3	bar	(150.0 psi)	
(8m)	Use inputted or calclulated reservoir ΔP?	Calculate			
	Base reservoir dP calculation on k*A or simple fracture flow?	k*A			
	Reservoir permeability	0.15	darcy		
	Reservoir height	125.0	m		
	Reservoir width	750.0	m		
	Distance between production and injection well	1,500.0	m		
(8n)	Input or Calculate Production Pump Depth?	Calculate			
(8o)	Pump Depth Used	177.0	m	(580.7 ft)	
(8p)	Production Pumping Power	177.2	kW/well		
(8q)	Total pumping power required	3.9	kW-s/kg	(0.496 w-hr/lb)	
(8r)	Input or Calculate Production Pump Cost?	Input			TPM 4
	If Pumped, Enter type of Pump used	Submersible			
(8s)	Production Pump Cost	*\$1-\$1.5-\$2.0*	\$million/well		TPM 4
(8t)	Injection Well Pump Costs	\$477,513			
(9)	**THERMAL DRAWDOWN**				
(9a)	Input Annual Decline Rate or Calculate Fluid Temperature?	Decline Rate			TPM 8
(9b)	Input Annual Rate of Decline	0.3%	%/yr		TPM 8
(9c)	Discount Rate for Makeup calculations	10.0%			
(9d)	Input Maximum Temperature Decline??	No			= (2b)*(2d)
(9e)	Maximum Temperature Decline	21.8	ΔC	(39.2 ΔF)	
(9f)	First Reservoir Replacement	N/A	year		
(9g)	Number of Reservoirs Used	1.0	count		
(10)	**OPERATING & MAINTENANCE COSTS**				
(10a)	Input Annual O&M Costs or Let GETEM Calculate	Input			TPM 11
(10b)	Input the annual O&M Cost for the Power Plant	2.20	¢/kW-hr		TPM 11
(10c)	Input the annual O&M cost for the Field (including production pumps)	0.52 (Value Calculated by GETEM)	¢/kW-hr		

GETEM Input for Supply Curve Near-Hydrothermal Field EGS Reference Scenario					
(11)	**ENERGY CONVERSION SYSTEM**				
(11a)	Number of independent power units	1			
(11b)	Apply performance improvement to reducing flow requirement or increasing power output?	Power			
(11c)	Design Ambient Temperature	15	^{o}C	(not changeable)	
(11d)	Is the Conversion System Flash or Binary?	Binary			
(11e)	GF Pumping	0.50	w-h/lb		
(11f)	Sales per well	3,220	kW/well		
(11g)	Binary System Performance	7.26	w-h/lb		TPM 12
(11h)	Binary Conversion System Cost	*$2.72*-$3.09-*$3.46*	$k/kW.plant output		TPM 10

Table A-3. GETEM Input for Deep EGS Reference Scenario

GETEM Input for Supply Curve Deep EGS Reference Scenario						
	Version	Version 2008-A6				
	Case Name	Deep EGS Reference Scenario				
	Plant Type	Binary, Air-Cooled				
	Reference Year	2008				
	Power Sales	20	MW			
(1)	**ECONOMIC PARAMETERS**					
(1a)	Fixed.Charge.Rate		0.128			
(1b)	Utiliz.Factor		0.95			
(1c)	Contingency		5%			
(1d)	Royalty [b]		10%			
(1e)	Year for Baseline Estimate		2008			
(2)	**RESOURCE DEFINITION**					
(2a)	Is the Resource Type Hydrothermal or EGS?		EGS			
(2b)	Resource Temperature Used		225	C	(347 °F)	
(2c)	Resource Depth Used		6,000	m	(19,685 ft)	
(2d)	Plant Design Temperature (used in all model calculations)		200	C	(347 °F)	
(3)	**POWER SALES**					
(3a)	Are calculations to be based upon Fixed Power Sales or Fixed Number of Production Wells?		Power			
(3b)	Enter either Sales or # of Wells		20	MW or count		
(3c)	Net Plant Output		26.34	MW		
(4)	**EXPLORATION & CONFIRMATION**					
(4a)	Input the # of Exploration Wells or Success Rate?		Rate			TPM 2
(4b)	Enter success rate or # of wells		*50*-63-*80*	% or count		TPM 2
(4c)	Pro-rate Explor & Confirm Costs Based on Resource Potential?		NO			
(4d)	# of Exploration Wells Used		1.58			= 1/(4b)
(4e)	Number of Confirmation wells		2	Count		
(4f)	Confirmation well success		0.80	Ratio		
(4g)	Multiplier for Exploration Well Costs		0.50			
(4h)	Multiplier for Confirmation Well Costs		1.1			
(4i)	Non-Well Exploration Costs Used		*$417*-$1,314-*$2,534*	$k/plant		TPM 1
(4j)	Non-Well Confirmation Costs Used		$250,000			
(5)	**WELL FIELD DEVELOPMENT**					
(5a)	# of Spare Production Wells		0			
(5b)	# Production Wells Used (including any confirmation wells used)		5.68			
(5c)	Ratio of Injection Wells to Production Wells		0.50			
(5d)	Number of Injection Wells Used		2.84			= (5b)*(5c)
(5e)	Production Well Depth Used		6,000	m	(19,685ft)	
(5f)	Calculated Production Well Cost - 2008		$17,871	$k/well		
(5g)	User Adjustment to Production Well Cost		*0.59*-0.86-*1.18*			TPM 3
(5h)	Adjusted Production Well Cost		$15,607	$k/well		
(5i)	Injection Well Depth Used		6,000	m	(19,685ft)	
(5j)	Calculated Injection Well Cost - 2008		$17,871	$k/well		
(5k)	User Adjustment to Production Well Cost		*0.59*-0.86-*1.18*			TPM 3
(5l)	Adjusted Injection Well Cost		$15,607	$k/well		
(5m)	Surface Equipment Cost		$125	$k/well		
(5n)	Non-Well Costs Incurred (exclusive of drilling)		$2,500	$k		

GETEM Input for Supply Curve Deep EGS Reference Scenario					
(6)	**EGS SUBSURFACE FRACTURE SYSTEM**				
(6a)	Is the EGS evaluation to be based on calculations of simplified subsurface model?	No			
(7)	**WELL STIMULATION**				
(7a)	Are wells Stimulated?	Yes			
(7b)	Use Fixed Well Stimulation Cost or Base on Fracture Surface Area?	Fixed Cost			
(7c)	Well Stimulation Cost Used	$0.9-$2.6-$5.0	$million/Well		TPM 6
(8)	**GF PUMPING**				
(8a)	Are Production Wells Pumped?	Yes			TPM 7
(8b)	Production Well Flow Rate	60.0	kg/s	(476,198 lb/h)	TPM 7
(8c)	Injection Well Flow Rate	122.4	kg/s	(971,444 lb/h)	
(8d)	Total GF Flow Rate - Production	340.7	kg/s	(2,703,830 lb/h)	
(8e)	Total GF Flow Rate - Injection	347.5	kg/s	(2,797,907 lb/h)	
(8f)	GF Pump efficiency	60%			
(8g)	Production well diameter (ID) below production pump	7.0	inch	(17.8 cm)	
(8h)	Production pump casing size (ID)	7.0	inch	(17.8 cm)	
(8i)	Injection well diameter (ID)	7.0	inch	(17.8 cm)	
(8j)	Excess Pressure at Pump Suction/Surface	3.5	bar	(50.8 psia)	
(8k)	Is Additional Pressure Required in Injection Well?	Yes			
(8l)	Excess Pressure at Bottom of Injection Well	10.3	bar	(150.0 psi)	
(8m)	Use inputted or calclulated reservoir ΔP?	Calculate			
	Base reservoir dP calculation on k*A or simple fracture flow?	k*A			
	Reservoir permeability	0.15	darcy		
	Reservoir height	125.0	m		
	Reservoir width	750.0	m		
	Distance between production and injection well	1,500.0	m		
(8n)	Input or Calculate Production Pump Depth?	Calculate			
(8o)	Pump Depth Used	134.5	m	(441.3 ft)	
(8p)	Production Pumping Power	980.7	kW/well		
(8q)	Total pumping power required	18.2	kW-s/kg	(0.496 w-hr/lb)	
(8r)	Input or Calculate Production Pump Cost?	Input			TPM 4
	If Pumped, Enter type of Pump used	Submersible			
(8s)	Production Pump Cost	*$1-$1.5-$2.0*	$million/well		TPM 4
(8t)	Injection Well Pump Costs	$561,189			
(9)	**THERMAL DRAWDOWN**				
(9a)	Input Annual Decline Rate or Calculate Fluid Temperature?	Decline Rate			TPM 8
(9b)	Input Annual Rate of Decline	0.3%	%/yr		TPM 8
(9c)	Discount Rate for Makeup calculations	10.0%			
(9d)	Input Maximum Temperature Decline??	No			= (2b)*(2d)
(9e)	Maximum Temperature Decline	32.3	ΔC	(58.1 ΔF)	
(9f)	First Reservoir Replacement	N/A	year		
(9g)	Number of Reservoirs Used	1.0	count		
(10)	**OPERATING & MAINTENANCE COSTS**				
(10a)	Input Annual O&M Costs or Let GETEM Calculate	Input			TPM 11
(10b)	Input the annual O&M Cost for the Power Plant	2.45	¢/kW-hr		TPM 11
(10c)	Input the annual O&M cost for the Field (including production pumps)	1.10 (Value Calculated by GETEM)	¢/kW-hr		

GETEM Input for Supply Curve Deep EGS Reference Scenario					
(11)	**ENERGY CONVERSION SYSTEM**				
(11a)	Number of independent power units	1			
(11b)	Apply performance improvement to reducing flow requirement or increasing power output?	Power			
(11c)	Design Ambient Temperature	15	^{o}C	(not changeable)	
(11d)	Is the Conversion System Flash or Binary?	Binary			
(11e)	GF Pumping	2.29	w-h/lb		
(11f)	Sales per well	3,435	kW/well		
(11g)	Binary System Performance	9.50	w-h/lb		TPM 12
(11h)	Binary Conversion System Cost	*$2.22*-$2.53-*$2.83*	$k/kW.plant output		TPM 10
(11i)	Binary Conversion System Cost	Calculate	$k/kW.sales		
(11j)	Binary Conversion System Cost	Calculate	total $		

Appendix B: Geothermal Supply Curve Data

Table B-1. Identified hydrothermal sites

Site Name	Location Data					GETEM Input - Reserevoir Characteristics						GETEM Output	
	State	NEMS Region	MARKAL Region	Latitude[a]	Longitude[a]	Reservoir Temp[a]	Reservoir Depth[b]	Production Well Flow Rate[b]	Plant Type[c]	Potential Capacity[a]	Remaining Potential Capacity[d]	Capital Cost	O&M Cost
						°C	km	(kg/s)	Binary/ Flash	MW	MW	2008 US$/kW	2008 US$/kW/yr
Adak	AK	N/A	9	51.98	-176.62	155	1.52	44.2	Binary	13.3	13.3	$7,632	$280
Akutan Fumaroles	AK	N/A	9	54.15	-165.91	250	1.52	44.2	Flash	49.2	49.2	$2,899	$139
Alvord HS	OR	11	9	42.54	-118.53	135	1.22	63.1	Binary	19.5	19.5	$9,264	$352
Amedee	CA	13	10	40.30	-120.18	115	0.46	101.0	Binary	7.8	5.6	$17,269	$770
Arrowhead HS	CA	13	10	34.19	-117.27	115	1.37	50.5	Binary	7.1	7.1	$16,646	$590
Bailey Bay Hot Springs	AK	N/A	9	55.98	-131.66	125	1.52	44.2	Binary	16.9	16.9	$12,147	$389
Baker Hot Spring	WA	11	9	48.76	-121.67	115	1.52	63.1	Binary	22.7	22.7	$18,339	$618
Baltazor Hot Springs	NV	11	8	41.92	-118.71	140	1.07	94.7	Binary	20.5	20.5	$9,232	$386
Bell Island HS	AK	N/A	9	55.93	-131.57	120	1.52	44.2	Binary	10.6	10.6	$14,185	$464
Beowawe HS	NV	11	8	40.57	-116.58	215	2.44	69.4	Binary	54.1	41.3	$4,164	$155
Big Creek Hot Springs	ID	11	8	45.31	-114.34	135	1.52	63.1	Binary	21.1	21.1	$9,796	$356
Black Rock Point area	NV	11	8	40.96	-119.11	120	1.52	44.2	Binary	8.5	8.5	$14,380	$480
Black Warrior	NV	11	8	39.90	-119.22	135	1.52	44.2	Binary	17.0	17.0	$9,837	$328
Blue Mountain	NV	11	8	41.00	-118.13	205	0.91	88.4	Binary	62.4	62.4	$3,707	$168
Boyes HS	CA	13	10	38.31	-122.49	110	1.52	44.2	Binary	8.4	8.4	$19,948	$636
Bradfield Canal Hot Spring	AK	N/A	9	56.24	-131.26	110	1.52	44.2	Binary	7.3	7.3	$20,083	$649
Brady HS	NV	11	8	39.79	-119.02	185	0.30	94.7	Binary	44.1	18.1	$4,495	$203
Breitenbush Hot Springs	OR	11	9	44.78	-121.98	150	2.13	65.7	Binary	7.9	7.9	$9,408	$361
Butte Springs (Trego)	NV	11	8	40.77	-119.11	115	1.52	63.1	Binary	7.3	7.3	$19,371	$712
Calistoga HS	CA	13	10	38.58	-122.57	140	1.52	82.1	Binary	16.9	16.9	$9,829	$391

Site Name	Location Data					GETEM Input - Reserovoir Characteristics						GETEM Output	
	State	NEMS Region	MARKAL Region	Latitude[a]	Longitude[a]	Reservoir Temp[a]	Reservoir Depth[b]	Production Well Flow Rate[b]	Plant Type[c]	Potential Capacity[a]	Remaining Potential Capacity[d]	Capital Cost	O&M Cost
						°C	km	(kg/s)	Binary/ Flash	MW	MW	2008 US$/kW	2008 US$/kW/yr
Canby (I'SOT)	CA	13	10	41.44	-120.87	120	1.52	44.2	Binary	9.4	9.4	$14,289	$473
Carson Lake Corral	NV	11	8	39.36	-118.66	125	1.52	44.2	Binary	11.4	11.4	$12,420	$412
Carson River	CA	13	10	38.77	-119.72	145	1.52	44.2	Binary	15.7	15.7	$8,433	$294
Clark Ranch	OR	11	9	43.86	-118.55	110	1.52	44.2	Binary	7.1	7.1	$20,112	$652
Clear Lake (Sulphur Bank mine)	CA	13	10	39.02	-122.65	300	3.66	37.9	Flash	29.2	29.2	$3,763	$135
Clifton Hot Springs	AZ	12	8	33.08	-109.30	110	1.52	63.1	Binary	14.5	14.5	$24,274	$830
Colado area	NV	11	8	40.23	-118.37	110	1.07	63.1	Binary	10.8	10.8	$20,028	$743
Coso area	CA	13	10	36.05	-117.77	285	1.52	69.4	Flash	518.5	289.2	$1,838	$94
Cove Fort - Sulphurdale - Liquid	UT	11	8	38.60	-112.55	150	0.76	94.7	Binary	25.7	9.7	$7,228	$304
Cove Fort - Sulphurdale - Vapor	UT	11	8	38.60	-112.55	155	0.76	94.7	Binary	1.7	1.7	$11,728	$573
Crane Creek-Cove Creek area	ID	11	8	44.31	-116.74	150	3.05	63.1	Binary	54.8	54.8	$9,487	$260
Crump's HS	OR	11	9	42.23	-119.88	150	1.52	44.2	Binary	44.0	44.0	$7,586	$244
Dann Ranch Hot Spring	NV	11	8	40.32	-116.43	140	1.52	44.2	Binary	22.3	22.3	$8,891	$294
Darrough Hot Springs	NV	11	8	38.82	-117.18	120	0.61	63.1	Binary	11.3	11.3	$11,970	$484
Deer Creek Hot Spring (old 97)	ID	11	8	44.09	-116.05	125	1.83	63.1	Binary	15.7	15.7	$13,911	$481
Desert Peak	NV	11	8	39.75	-118.95	215	1.68	50.5	Binary	33.0	15.5	$4,071	$170
Dixie Hot Springs	NV	11	8	39.80	-118.07	130	2.90	94.7	Binary	9.6	9.6	$61,150	$2,062
Dixie Valley Geothermal Field	NV	11	8	39.99	-117.85	225	1.52	44.2	Flash	149.3	93.3	$3,416	$116
Dixie Valley Power Partners	NV	11	8	39.95	-117.92	280	1.52	44.2	Flash	102.9	77.9	$2,178	$99

Site Name	Location Data					GETEM Input - Reservoir Characteristics							GETEM Output	
	State	NEMS Region	MARKAL Region	Latitude[a]	Longitude[a]	Reservoir Temp[a]	Reservoir Depth[b]	Production Well Flow Rate[b]	Plant Type[c]	Potential Capacity[a]	Remaining Potential Capacity[d]	Capital Cost	O&M Cost
						°C	km	(kg/s)	Binary/ Flash	MW	MW	2008 US$/kW	2008 US$/kW/yr
Double Hot Springs area	NV	11	8	41.05	-119.03	120	1.52	44.2	Binary	9.4	9.4	$14,294	$473
Dulbi	AK	N/A	9	65.27	-155.27	110	1.52	44.2	Binary	9.1	9.1	$19,844	$628
Dunes	CA	13	10	32.80	-115.01	145	1.07	50.5	Binary	18.5	18.5	$7,716	$294
Dyke Hot Springs area	NV	11	8	41.57	-118.57	110	1.52	63.1	Binary	5.4	5.4	$25,548	$941
East Brawley	CA	13	10	32.99	-115.35	285	3.05	63.1	Flash	358.5	358.5	$2,289	$80
East Mesa (Deep)	CA	13	10	32.78	-115.25	190	1.52	44.2	Binary	60.3	60.3	$4,943	$173
East Mesa (Shallow)	CA	13	10	32.78	-115.25	165	1.07	94.7	Binary	142.4	41.4	$5,833	$224
Emigrant	NV	11	8	37.86	-117.87	165	2.44	15.8	Binary	40.1	40.1	$11,416	$202
Ennis (Thexton) Hot Springs	MT	11	8	45.37	-111.73	115	1.52	63.1	Binary	12.9	12.9	$18,729	$658
Fallon Naval Air Station	NV	11	8	39.38	-118.65	195	2.13	31.6	Binary	53.4	53.4	$5,573	$151
Fernley area (Patua HS/Hazen)	NV	11	8	39.60	-119.11	155	1.68	50.5	Binary	22.2	22.2	$7,357	$261
Fish Lake Valley	NV	11	8	37.86	-118.05	205	1.52	44.2	Binary	57.1	57.1	$4,217	$158
Fort Bidwell	CA	13	10	41.86	-120.16	110	0.76	75.8	Binary	9.1	9.1	$20,428	$825
Geyser Bight	AK	N/A	9	53.22	-168.47	182	1.52	44.2	Binary	97.9	97.9	$5,339	$173
Geysers	CA	13	10	38.80	-122.80	242	1.83	94.7	Flash	519.7	0.0	$2,604	$112
Geysers Hi T Reservoir	CA	13	10	38.80	-122.80	315	1.83	18.9	Flash	517.2	0.0	$2,882	$114
Gillard (Morenci) Hot Springs	AZ	12	8	32.97	-109.35	110	1.52	63.1	Binary	11.8	11.8	$24,486	$848
Goddard Hot Springs	AK	N/A	9	56.84	-135.37	135	1.52	44.2	Binary	14.8	14.8	$9,922	$335
Great Boiling Springs (Gerlach)	NV	11	8	40.66	-119.36	175	0.61	50.5	Binary	49.3	49.3	$5,063	$203
Great Sitkin Island	AK	N/A	9	52.07	-176.08	130	1.52	44.2	Binary	14.5	14.5	$10,948	$363

Site Name	Location Data					GETEM Input - Reserovoir Characteristics						GETEM Output	
	State	NEMS Region	MARKAL Region	Latitude[a]	Longitude[a]	Reservoir Temp[a]	Reservoir Depth[b]	Production Well Flow Rate[b]	Plant Type[c]	Potential Capacity[a]	Remaining Potential Capacity[d]	Capital Cost	O&M Cost
						°C	km	(kg/s)	Binary/ Flash	MW	MW	2008 US$/kW	2008 US$/kW/yr
Gregson (Fairmont) Hot Springs	MT	11	8	46.04	-112.81	110	1.52	63.1	Binary	7.1	7.1	$25,102	$905
Heber Deep	CA	13	10	32.72	-115.53	205	1.22	63.1	Binary	34.5	34.5	$3,983	$179
Heber Shallow	CA	13	10	32.72	-115.53	170	1.22	63.1	Binary	125.1	5.9	$5,378	$193
Hot (Borax) Lake	OR	11	9	42.33	-118.60	150	1.52	44.2	Binary	42.9	42.9	$7,594	$245
Hot Springs Bay (Akutan Island)	AK	N/A	9	54.17	-165.82	130	1.52	44.2	Binary	15.0	15.0	$10,930	$361
Hot Springs Cove	AK	N/A	9	53.23	-168.35	110	1.52	44.2	Binary	5.0	5.0	$20,900	$698
Hot Springs Ranch (Pumpernickel Valley)	NV	11	8	40.76	-117.49	125	1.52	63.1	Binary	11.4	11.4	$13,068	$483
Hot Sulphur Springs - Tuscarora	NV	11	8	41.47	-116.15	155	0.76	107.3	Binary	35.9	35.9	$6,812	$286
Huckleberry Hot Springs	WY	11	8	44.11	-110.69	120	1.52	63.1	Binary	38.7	38.7	$14,626	$485
Humboldt House - Rye Patch	NV	11	8	40.54	-118.27	205	0.91	82.1	Binary	90.4	90.4	$3,648	$158
Jemez Springs (Ojos Calientes)	NM	12	8	35.77	-106.69	110	1.52	44.2	Binary	8.6	8.6	$19,906	$633
Kahneetah Hot Springs	OR	11	9	44.86	-121.20	115	1.07	65.7	Binary	6.1	6.1	$17,079	$682
Kellog HS	CA	13	10	41.13	-121.02	110	1.52	44.2	Binary	5.4	5.4	$20,703	$688
Kelly HS	CA	13	10	41.45	-120.83	120	1.83	63.1	Binary	9.5	9.5	$17,168	$605
Kluichef - Atka Island	AK	N/A	9	52.32	-174.19	230	1.52	44.2	Flash	43.4	43.4	$3,446	$154
Korovin - Atka Island	AK	N/A	9	52.35	-174.25	170	1.52	44.2	Binary	26.0	26.0	$6,146	$221
Lake City Hot Springs	CA	13	10	41.67	-120.21	160	1.52	44.2	Binary	100.7	100.7	$6,496	$199
Lakeview area (Hunters and Barry Ranch Hot Springs)	OR	11	9	42.20	-120.36	135	1.07	65.7	Binary	20.1	20.1	$9,022	$351

Site Name	Location Data					GETEM Input - Reserovoir Characteristics						GETEM Output	
	State	NEMS Region	MARKAL Region	Latitude[a]	Longitude[a]	Reservoir Temp[a]	Reservoir Depth[b]	Production Well Flow Rate[b]	Plant Type[c]	Potential Capacity[a]	Remaining Potential Capacity[d]	Capital Cost	O&M Cost
						°C	km	(kg/s)	Binary/ Flash	MW	MW	2008 US$/kW	2008 US$/kW/yr
Latty Hot Springs	ID	11	8	43.12	-115.31	110	1.52	18.9	Binary	6.4	6.4	$24,975	$568
Leach HS	NV	11	8	40.60	-117.65	120	1.52	31.6	Binary	7.5	7.5	$15,386	$457
Lee Hot Springs	NV	11	8	39.21	-118.72	150	1.52	31.6	Binary	26.4	26.4	$8,383	$253
Leonards Hot Sps./Seyferth HS	CA	13	10	41.60	-120.09	125	1.52	44.2	Binary	10.0	10.0	$12,536	$422
Lightning Dock	NM	12	8	32.15	-108.83	130	2.74	63.1	Binary	14.6	4.6	$15,507	$473
Little Valley area	OR	11	9	43.89	-117.50	125	1.07	65.7	Binary	14.6	14.6	$11,600	$449
Long Valley caldera - deep	CA	13	10	37.64	-118.91	205	3.05	31.6	Binary	47.5	47.5	$6,077	$151
Long Valley shallow	CA	13	10	37.64	-118.91	175	3.05	31.6	Binary	15.0	0.0	$8,826	$226
Maazama Well (Crater Lake)	OR	11	9	42.90	-121.99	140	3.05	31.6	Binary	32.3	32.3	$12,963	$251
Magic Reservoir area	ID	11	8	43.33	-114.40	110	1.22	63.1	Binary	9.1	9.1	$21,563	$794
Makushin	AK	N/A	9	53.89	-166.92	205	1.52	82.1	Binary	107.3	107.3	$3,877	$157
McLeod 88 (Big Smokey Valley)	NV	11	8	39.03	-117.14	120	1.52	44.2	Binary	9.9	9.9	$14,251	$469
Medicine Lake (Glass Mt.)	CA	13	10	41.57	-121.57	255	2.74	37.9	Flash	365.6	265.7	$3,411	$78
Mickey HS	OR	11	9	42.35	-118.35	170	1.07	63.1	Binary	41.0	41.0	$5,475	$218
Milky River - Atka Island	AK	N/A	9	52.32	-174.15	245	1.52	44.2	Flash	54.2	54.2	$2,982	$135
Mitchell Butte	OR	11	9	43.76	-117.16	120	1.07	65.7	Binary	10.1	10.1	$13,754	$539
Mt. Signal	CA	13	10	32.65	-115.71	135	1.52	44.2	Binary	14.7	14.7	$9,925	$335
Neal HS	OR	11	9	44.02	-117.46	150	1.07	65.7	Binary	29.6	29.6	$7,151	$276
Newberry Caldera	OR	11	9	43.72	-121.23	275	2.13	56.8	Flash	124.2	124.2	$2,222	$92
Newcastle area	UT	11	8	37.66	-113.56	110	0.76	63.1	Binary	12.3	12.3	$17,659	$673
North Brawley	CA	13	10	33.02	-115.52	250	1.52	44.2	Flash	138.0	74.0	$2,749	$107

Site Name	Location Data					GETEM Input - Reserevoir Characteristics						GETEM Output	
	State	NEMS Region	MARKAL Region	Latitude[a]	Longitude[a]	Reservoir Temp[a]	Reservoir Depth[b]	Production Well Flow Rate[b]	Plant Type[c]	Potential Capacity[a]	Remaining Potential Capacity[d]	Capital Cost	O&M Cost
						°C	km	(kg/s)	Binary/ Flash	MW	MW	2008 US$/kW	2008 US$/kW/yr
Olene Hot Springs	OR	11	9	42.17	-121.62	110	1.52	63.1	Binary	8.3	8.3	$24,910	$886
Owl Creek Hot Springs	ID	11	8	45.34	-114.46	110	1.83	63.1	Binary	7.8	7.8	$29,166	$997
Pilgrim Hot Springs	AK	N/A	9	65.09	-164.92	140	1.22	63.1	Binary	15.0	15.0	$8,588	$340
Pinto Hot Springs	NV	11	8	41.35	-118.78	145	1.52	31.6	Binary	26.0	26.0	$8,886	$260
Puna Geothermal Venture	HI	N/A	9	19.48	-154.89	350	1.07	151.5	Flash	181.3	150.3	$1,354	$89
Raft River	ID	11	8	42.10	-113.38	145	1.83	63.1	Binary	46.6	27.0	$8,261	$278
Railroad Valley	NV	11	8	38.43	-115.53	135	1.52	44.2	Binary	17.1	17.1	$9,836	$327
Reese River	NV	11	8	39.89	-117.14	135	0.76	63.1	Binary	17.1	17.1	$8,589	$348
Roosevelt HS	UT	11	8	38.50	-112.85	250	1.22	107.3	Flash	119.5	51.5	$2,247	$111
Routt	CO	12	8	40.56	-106.85	110	1.52	63.1	Binary	8.3	8.3	$24,907	$886
Rowland Hot Springs	NV	11	8	41.88	-115.63	110	1.52	44.2	Binary	5.8	5.8	$20,483	$676
Salton Sea area	CA	13	10	33.20	-115.60	310	2.29	69.4	Flash	2,209.9	1,911.9	$1,781	$87
San Emidio Desert area	NV	11	8	40.38	-119.40	190	1.07	75.8	Binary	65.2	61.7	$4,483	$184
Serpentine (Arctic) Springs	AK	N/A	9	65.86	-164.71	145	1.52	44.2	Binary	17.3	17.3	$8,370	$289
Sespe HS	CA	13	10	34.59	-119.00	120	1.52	44.2	Binary	10.7	10.7	$14,174	$463
Sharkey Hot Springs	ID	11	8	45.01	-113.61	115	1.83	63.1	Binary	10.0	10.0	$21,391	$734
Silver Star (Barkel's) Hot Springs	MT	11	8	45.69	-112.30	115	1.52	63.1	Binary	9.1	9.1	$19,067	$689
Sitka Hot Spring	AK	N/A	9	56.85	-135.37	125	1.52	44.2	Binary	13.1	13.1	$12,329	$404
Smith Creek Valley area	NV	11	8	39.31	-117.55	125	1.83	63.1	Binary	12.5	12.5	$14,102	$496
Soda Lake area	NV	11	8	39.57	-118.85	205	1.37	94.7	Binary	48.1	37.2	$4,001	$181
Sonoma Mission Inn	CA	13	10	38.31	-122.48	110	1.52	44.2	Binary	6.3	6.3	$20,315	$666

Site Name	Location Data					GETEM Input - Reserevoir Characteristics						GETEM Output	
	State	NEMS Region	MARKAL Region	Latitude[a]	Longitude[a]	Reservoir Temp[a]	Reservoir Depth[b]	Production Well Flow Rate[b]	Plant Type[c]	Potential Capacity[a]	Remaining Potential Capacity[d]	Capital Cost	O&M Cost
						°C	km	(kg/s)	Binary/ Flash	MW	MW	2008 US$/kW	2008 US$/kW/yr
South Brawley (Mesquite)	CA	13	10	32.91	-115.54	250	3.05	63.1	Flash	42.3	42.3	$3,381	$123
Squaw Hot Springs area	ID	11	8	42.12	-111.93	130	1.52	18.9	Binary	13.9	13.9	$14,675	$332
Steamboat Hills	NV	11	8	39.37	-119.77	210	1.52	44.2	Binary	44.4	0.0	$4,137	$163
Steamboat Springs	NV	11	8	39.39	-119.74	165	1.52	44.2	Binary	18.5	0.0	$6,635	$244
Stillwater area	NV	11	8	39.52	-118.55	160	1.01	50.5	Binary	57.1	48.6	$6,136	$220
Sulphur Hot Springs (Ruby Valley)	NV	11	8	40.59	-115.29	165	1.83	63.1	Binary	34.0	34.0	$6,427	$234
Summer Lake Hot Springs	OR	11	9	42.73	-120.65	110	1.01	63.1	Binary	8.3	8.3	$19,799	$755
Surprise Valley HS	CA	13	10	41.53	-120.08	115	1.52	44.2	Binary	7.8	7.8	$16,798	$552
Tecopa HS	CA	13	10	35.87	-116.23	120	1.52	63.1	Binary	9.0	9.0	$15,622	$577
The Needles (Needle Rocks, Pyramid Lake)	NV	11	8	40.15	-119.68	120	1.07	63.1	Binary	17.4	17.4	$13,158	$490
Thermo Hot Springs	UT	11	8	38.18	-113.20	125	0.76	63.1	Binary	15.5	5.5	$10,674	$422
Tolvana	AK	N/A	9	65.27	-148.85	110	1.52	44.2	Binary	14.5	14.5	$19,452	$592
Trout Creek	OR	11	9	42.19	-118.38	115	0.91	63.1	Binary	9.1	9.1	$15,455	$604
Tungsten Mountain	NV	11	8	39.68	-117.69	125	1.52	44.2	Binary	12.5	12.5	$12,357	$407
Upper Division Hot Spring	AK	N/A	9	66.36	-156.77	110	1.52	44.2	Binary	7.0	7.0	$20,119	$652
Vale HS	OR	11	9	43.99	-117.23	145	1.07	65.7	Binary	45.2	45.2	$7,331	$273
Valles Caldera - Redondo	NM	12	8	35.89	-106.58	275	3.35	37.9	Flash	101.8	101.8	$3,312	$73
Valles Caldera - Sulphur Springs	NM	12	8	35.91	-106.62	225	3.35	37.9	Flash	27.5	27.5	$5,980	$163
Vulcan Hot Springs	ID	11	8	44.57	-115.70	115	1.52	18.9	Binary	10.1	10.1	$21,007	$461
Wabuska Hot Springs	NV	11	8	39.16	-119.18	115	1.52	63.1	Binary	8.5	7.6	$19,152	$696
Waunita Hot Springs	CO	12	8	38.51	-106.51	120	1.52	75.8	Binary	12.2	12.2	$18,021	$677

Site Name	Location Data					GETEM Input - Reservoir Characteristics						GETEM Output	
	State	NEMS Region	MARKAL Region	Latitude[a]	Longitude[a]	Reservoir Temp[a]	Reservoir Depth[b]	Production Well Flow Rate[b]	Plant Type[c]	Potential Capacity[a]	Remaining Potential Capacity[d]	Capital Cost	O&M Cost
						°C	km	(kg/s)	Binary/ Flash	MW	MW	2008 US$/kW	2008 US$/kW/yr
Wayland (Battle Creek) Hot Springs	ID	11	8	42.13	-111.93	130	1.83	63.1	Binary	14.0	14.0	$12,098	$430
Wedell Hot Spring (Gabbs)	NV	11	8	38.92	-118.20	140	1.52	44.2	Binary	17.7	17.7	$8,998	$305
Wendel	CA	13	10	40.36	-120.25	125	1.52	44.2	Binary	11.4	11.4	$12,423	$413
West Ukinrek Maar	AK	N/A	9	57.80	-156.50	200	1.52	44.2	Binary	22.7	22.7	$4,668	$192
West Valley Reservoir	CA	13	10	41.19	-120.39	130	1.83	63.1	Binary	12.6	12.6	$12,184	$437
White Licks Hot Springs	ID	11	8	44.68	-116.23	110	1.22	63.1	Binary	9.0	9.0	$21,564	$794
Wilbur Springs	CA	13	10	39.04	-122.42	160	1.07	82.1	Binary	29.3	29.3	$6,373	$264

[a]Data provided by USGS from USGS 2008 Geothermal Resource Assessment. Median values for estimated reservoir temperature and potential capacity used.
[b]When available, estimated values from Petty and Porro 2007 used. Otherwise, default values of 1.52 km (5,000 feet) and 44.2 kg/s (350,000 lb/hr) used for reservoir depth and production well flow rate, respectively.
[c]Assumed that sites with estimated reservoir temperature ≥ 225°C were flash plants, otherwise assumed to be binary power plants. Dry steam plants not considered.
[d]Remaining potential capacity is difference between median potential capacity estimated from USGS and currently installed capacity in Table 4. In some cases, such as the Geysers, installed capacity exceeded estimated reservoir potential capacity, so remaining capacity was assumed to be zero.

Table B-2. Undiscovered Hydrothermal Resource

Site ID	Location Data			GETEM Input - Reservoir Characteristics					GETEM Output	
	State	NEMS Region	MARKAL Region	Reservoir Temp[a]	Reservoir Depth[a]	Production Well Flow Rate[a]	Plant Type[b]	Potential Capacity[c]	Capital Cost	O&M Cost
				°C	km	(kg/s)	Binary/ Flash	MW_e	2008 US$/kW	2008 US$/kW/yr
Undiscovered < 150 C - AK	AK	N/A	9	113	1.50	44.8	Binary	695	$17,027	$517
Undiscovered > 150 C - AK	AK	N/A	9	209	1.52	54.0	Binary	1,092	$4,292	$193
Undiscovered < 150 C - AZ	AZ	12	8	110	1.52	63.1	Binary	1,042	$24,093	$803
Undiscovered < 150 C - CA	CA	13	10	121	1.40	55.3	Binary	492	$13,447	$456
Undiscovered > 150 C - CA	CA	13	10	279	2.11	62.8	Flash	10,848	$3,043	$200
Undiscovered < 150 C - CO	CO	12	8	110	1.52	64.9	Binary	1,105	$25,027	$840
Undiscovered > 150 C - HI	HI	N/A	9	200	1.52	44.2	Binary	2,436	$4,743	$197
Undiscovered < 150 C - ID	ID	11	8	115	1.67	51.9	Binary	1,563	$17,016	$535
Undiscovered > 150 C - ID	ID	11	8	150	3.05	63.1	Binary	308	$10,071	$302
Undiscovered < 150 C - MT	MT	11	8	107	1.52	62.1	Binary	772	$28,739	$1,040
Undiscovered < 150 C - NM	NM	12	8	110	2.19	54.5	Binary	358	$26,309	$757
Undiscovered > 150 C - NM	NM	12	8	264	3.35	37.9	Flash	1,126	$4,741	$185
Undiscovered < 150 C - NV	NV	11	8	124	1.41	53.5	Binary	1,071	$12,128	$412
Undiscovered > 150 C - NV	NV	11	8	203	1.39	58.9	Binary	3,293	$4,377	$200
Undiscovered < 150 C - OR	OR	11	9	123	1.39	58.3	Binary	878	$12,531	$437
Undiscovered > 150 C - OR	OR	11	9	206	1.69	55.1	Binary	1,014	$4,416	$193
Undiscovered < 150 C - UT	UT	11	8	111	0.95	58.4	Binary	295	$17,073	$601
Undiscovered > 150 C - UT	UT	11	8	231	1.13	105.0	Flash	1,168	$3,340	$227
Undiscovered < 150 C - WA	WA	11	9	115	1.52	63.1	Binary	300	$18,445	$626
Undiscovered < 150 C - WY	WY	11	8	120	1.52	63.1	Binary	174	$15,021	$519

[a]Reservoir characteristic calculated from capacity-weighted mean of values from identified sites in same state and temperature group.
[b]Assumed that sites with estimated reservoir temperature ≥ 225°C were flash plants, otherwise assumed to be binary power plants. Dry steam plants not considered.
[c]Potential capacity based on median values by state in USGS 2008 Geothermal Resource Assessment. Capacity divided among temperature groups based on proportion of identified hydrothermal sites in state in each temperature group.

Table B-3. Near-Hydrothermal Field EGS Resource

Site Name	Location Data			GETEM Input - Reservoir Characteristics				GETEM Output			
								Base Case[d]		Target Case[e]	
	State	NEMS Region	MARKAL Region	Reservoir Temp[a]	Reservoir Depth[a]	Plant Type[b]	Potential Capacity[c]	Capital Cost	O&M Cost	Capital Cost	O&M Cost
				°C	km	Binary/ Flash	MW_e	2008 US$/kW	2008 US$/kW/yr	2008 US$/kW	2008 US$/kW/yr
Adak	AK	N/A	9	155	1.52	Binary	12.6	$12,377	$889	$8,805	$291
Akutan Fumaroles	AK	N/A	9	250	1.52	Flash	48.7	$5,957	$377	$3,561	$144
Alvord HS	OR	11	9	135	1.22	Binary	21.2	$15,790	$1,291	$11,145	$317
Amedee	CA	13	10	115	0.46	Binary	8.7	$23,092	$2,167	$16,757	$479
Arrowhead HS	CA	13	10	115	1.37	Binary	7.7	$25,506	$2,692	$19,537	$538
Bailey Bay Hot Springs	AK	N/A	9	125	1.52	Binary	21.4	$19,863	$1,840	$14,476	$378
Baker Hot Spring	WA	11	9	115	1.52	Binary	24.5	$25,143	$2,656	$19,334	$466
Baltazor Hot Springs	NV	11	8	140	1.07	Binary	21.6	$14,429	$1,074	$10,065	$296
Bell Island HS	AK	N/A	9	120	1.52	Binary	13.0	$22,402	$2,273	$16,869	$448
Beowawe HS	NV	11	8	215	2.44	Binary	44.7	$8,072	$486	$5,026	$159
Big Creek Hot Springs	ID	11	8	135	1.52	Binary	25.9	$16,204	$1,364	$11,487	$313
Black Rock Point area	NV	11	8	120	1.52	Binary	11.0	$22,517	$2,292	$16,979	$460
Black Warrior	NV	11	8	135	1.52	Binary	19.7	$16,324	$1,382	$11,600	$325
Blue Mountain	NV	11	8	205	0.91	Binary	70.1	$7,108	$396	$4,692	$155
Boyes HS	CA	13	10	110	1.52	Binary	10.3	$29,272	$3,502	$23,729	$602
Bradfield Canal Hot Spring	AK	N/A	9	110	1.52	Binary	9.1	$29,355	$3,523	$23,829	$613
Brady HS	NV	11	8	185	0.30	Binary	31.6	$8,484	$475	$5,780	$205
Breitenbush Hot Springs	OR	11	9	150	2.13	Binary	4.6	$15,636	$1,240	$11,645	$400
Butte Springs (Trego)	NV	11	8	115	1.52	Binary	9.2	$25,701	$2,762	$19,916	$532
Calistoga HS	CA	13	10	140	1.52	Binary	18.5	$15,120	$1,187	$10,616	$309
Canby (I'SOT)	CA	13	10	120	1.52	Binary	10.5	$22,550	$2,297	$17,009	$463
Carson Lake Corral	NV	11	8	125	1.52	Binary	13.8	$20,088	$1,876	$14,695	$402
Carson River	CA	13	10	145	1.52	Binary	19.2	$13,964	$1,052	$9,787	$291

Site Name	Location Data			GETEM Input - Reservoir Characteristics				GETEM Output			
								Base Case[d]		Target Case[e]	
	State	NEMS Region	MARKAL Region	Reservoir Temp[a]	Reservoir Depth[a]	Plant Type[b]	Potential Capacity[c]	Capital Cost	O&M Cost	Capital Cost	O&M Cost
				°C	km	Binary/ Flash	MW_e	2008 US$/kW	2008 US$/kW/yr	2008 US$/kW	2008 US$/kW/yr
Clark Ranch	OR	11	9	110	1.52	Binary	8.6	$29,408	$3,534	$23,884	$619
Clear Lake (Sulphur Bank mine)	CA	13	10	300	3.66	Flash	15.9	$6,745	$456	$4,228	$185
Clifton Hot Springs	AZ	12	8	110	1.52	Binary	28.1	$28,732	$3,392	$23,142	$533
Colado area	NV	11	8	110	1.07	Binary	12.8	$27,614	$3,090	$21,494	$547
Coso area	CA	13	10	285	1.52	Flash	273.7	$4,446	$270	$2,588	$100
Cove Fort - Sulphurdale - Liquid	UT	11	8	150	0.76	Binary	20.9	$12,116	$806	$8,568	$274
Cove Fort - Sulphurdale - Vapor	UT	11	8	155	0.76	Binary	1.1	$17,944	$1,335	$14,117	$625
Crane Creek-Cove Creek area	ID	11	8	150	3.05	Binary	76.3	$15,006	$1,254	$10,490	$246
Crump's HS	OR	11	9	150	1.52	Binary	51.8	$12,515	$876	$8,864	$245
Dann Ranch Hot Spring	NV	11	8	140	1.52	Binary	34.6	$14,864	$1,150	$10,382	$282
Darrough Hot Springs	NV	11	8	120	0.61	Binary	13.5	$20,475	$1,842	$14,753	$412
Deer Creek Hot Spring (old 97)	ID	11	8	125	1.83	Binary	20.2	$20,704	$1,995	$15,221	$390
Desert Peak	NV	11	8	215	1.68	Binary	18.9	$7,645	$452	$4,953	$189
Dixie Hot Springs	NV	11	8	130	2.90	Binary	9.8	$22,384	$2,405	$16,822	$431
Dixie Valley Geothermal Field	NV	11	8	225	1.52	Flash	95.2	$7,303	$424	$4,327	$126
Dixie Valley Power Partners	NV	11	8	280	1.52	Flash	66.0	$4,739	$299	$2,818	$119
Double Hot Springs area	NV	11	8	120	1.52	Binary	11.4	$22,489	$2,287	$16,952	$457
Dulbi	AK	N/A	9	110	1.52	Binary	11.7	$29,172	$3,483	$23,640	$591
Dunes	CA	13	10	145	1.07	Binary	22.8	$13,343	$953	$9,286	$279
Dyke Hot Springs area	NV	11	8	110	1.52	Binary	6.1	$29,991	$3,610	$24,319	$657

Site Name	Location Data			GETEM Input - Reservoir Characteristics				GETEM Output			
								Base Case[d]		Target Case[e]	
	State	NEMS Region	MARKAL Region	Reservoir Temp[a]	Reservoir Depth[a]	Plant Type[b]	Potential Capacity[c]	Capital Cost	O&M Cost	Capital Cost	O&M Cost
				°C	km	Binary/ Flash	MW_e	2008 US$/kW	2008 US$/kW/yr	2008 US$/kW	2008 US$/kW/yr
East Brawley	CA	13	10	285	3.05	Flash	273.1	$5,246	$336	$3,014	$94
East Mesa (Deep)	CA	13	10	190	1.52	Binary	46.6	$8,522	$495	$5,774	$187
East Mesa (Shallow)	CA	13	10	165	1.07	Binary	127.6	$10,316	$627	$6,989	$196
Emigrant	NV	11	8	165	2.44	Binary	50.3	$11,844	$849	$8,066	$218
Ennis (Thexton) Hot Springs	MT	11	8	115	1.52	Binary	18.0	$25,296	$2,681	$19,471	$483
Fallon Naval Air Station	NV	11	8	195	2.13	Binary	60.5	$8,627	$530	$5,662	$172
Fernley area (Patua HS/Hazen)	NV	11	8	155	1.68	Binary	23.3	$12,257	$873	$8,653	$263
Fish Lake Valley	NV	11	8	205	1.52	Binary	62.6	$7,469	$429	$4,897	$158
Fort Bidwell	CA	13	10	110	0.76	Binary	8.7	$26,948	$2,912	$20,547	$556
Geyser Bight	AK	N/A	9	182	1.52	Binary	79.7	$9,094	$536	$6,233	$185
Geysers	CA	13	10	242	1.83	Flash	240.1	$6,392	$378	$3,763	$114
Geysers Hi T Reservoir	CA	13	10	315	1.83	Flash	273.4	$3,964	$236	$2,271	$96
Gillard (Morenci) Hot Springs	AZ	12	8	110	1.52	Binary	15.8	$28,984	$3,444	$23,428	$568
Goddard Hot Springs	AK	N/A	9	135	1.52	Binary	18.2	$16,361	$1,388	$11,632	$329
Great Boiling Springs (Gerlach)	NV	11	8	175	0.61	Binary	50.0	$9,277	$542	$6,212	$198
Great Sitkin Island	AK	N/A	9	130	1.52	Binary	17.4	$17,987	$1,597	$12,929	$357
Gregson (Fairmont) Hot Springs	MT	11	8	110	1.52	Binary	8.6	$29,407	$3,533	$23,883	$619
Heber Deep	CA	13	10	205	1.22	Binary	26.5	$7,455	$437	$4,965	$184
Heber Shallow	CA	13	10	170	1.22	Binary	83.8	$9,944	$611	$6,731	$192
Hot (Borax) Lake	OR	11	9	150	1.52	Binary	40.5	$12,588	$887	$8,925	$253
Hot Springs Bay (Akutan Island)	AK	N/A	9	130	1.52	Binary	16.4	$18,018	$1,602	$12,959	$360

Site Name	Location Data			GETEM Input - Reservoir Characteristics				GETEM Output			
								Base Case[d]		Target Case[e]	
	State	NEMS Region	MARKAL Region	Reservoir Temp[a]	Reservoir Depth[a]	Plant Type[b]	Potential Capacity[c]	Capital Cost	O&M Cost	Capital Cost	O&M Cost
				°C	km	Binary/ Flash	MW_e	2008 US$/kW	2008 US$/kW/yr	2008 US$/kW	2008 US$/kW/yr
Hot Springs Cove	AK	N/A	9	110	1.52	Binary	4.8	$30,552	$3,673	$24,896	$693
Hot Springs Ranch (Pumpernickel Valley)	NV	11	8	125	1.52	Binary	13.8	$20,087	$1,876	$14,694	$402
Hot Sulphur Springs - Tuscarora	NV	11	8	155	0.76	Binary	21.8	$11,466	$749	$8,034	$260
Huckleberry Hot Springs	WY	11	8	120	1.52	Binary	60.0	$21,805	$2,170	$16,235	$375
Humboldt House - Rye Patch	NV	11	8	205	0.91	Binary	54.8	$7,144	$404	$4,727	$161
Jemez Springs (Ojos Calientes)	NM	12	8	110	1.52	Binary	10.7	$29,239	$3,495	$23,698	$598
Kahneetah Hot Springs	OR	11	9	115	1.07	Binary	7.0	$24,849	$2,519	$18,671	$531
Kellog HS	CA	13	10	110	1.52	Binary	5.9	$30,066	$3,619	$24,396	$662
Kelly HS	CA	13	10	120	1.83	Binary	10.4	$23,472	$2,494	$17,956	$477
Kluichef - Atka Island	AK	N/A	9	230	1.52	Flash	42.9	$7,132	$449	$4,275	$162
Korovin - Atka Island	AK	N/A	9	170	1.52	Binary	25.6	$10,481	$691	$7,186	$229
Lake City Hot Springs	CA	13	10	160	1.52	Binary	81.3	$11,246	$724	$7,714	$211
Lakeview area (Hunters and Barry Ranch Hot Springs)	OR	11	9	135	1.07	Binary	20.9	$15,621	$1,253	$10,977	$315
Latty Hot Springs	ID	11	8	110	1.52	Binary	8.1	$29,498	$3,545	$23,941	$625
Leach HS	NV	11	8	120	1.52	Binary	5.7	$23,516	$2,405	$17,835	$525
Lee Hot Springs	NV	11	8	150	1.52	Binary	31.7	$12,679	$897	$9,005	$262
Leonards Hot Sps./Seyferth HS	CA	13	10	125	1.52	Binary	9.8	$20,342	$1,913	$14,932	$426
Lightning Dock	NM	12	8	130	2.74	Binary	18.6	$21,331	$2,219	$15,791	$384
Little Valley area	OR	11	9	125	1.07	Binary	17.3	$19,137	$1,678	$13,682	$376

Site Name	Location Data			GETEM Input - Reservoir Characteristics				GETEM Output			
								Base Case[d]		Target Case[e]	
	State	NEMS Region	MARKAL Region	Reservoir Temp[a]	Reservoir Depth[a]	Plant Type[b]	Potential Capacity[c]	Capital Cost	O&M Cost	Capital Cost	O&M Cost
				^{o}C	km	Binary/ Flash	MW_e	2008 US$/kW	2008 US$/kW/yr	2008 US$/kW	2008 US$/kW/yr
Long Valley caldera - deep	CA	13	10	205	3.05	Binary	25.0	$9,392	$665	$5,932	$188
Long Valley shallow	CA	13	10	175	3.05	Binary	10.3	$12,772	$985	$8,674	$272
Maazama Well (Crater Lake)	OR	11	9	140	3.05	Binary	41.6	$18,281	$1,695	$12,926	$297
Magic Reservoir area	ID	11	8	110	1.22	Binary	11.1	$28,220	$3,227	$22,243	$570
Makushin	AK	N/A	9	205	1.52	Binary	68.8	$7,451	$427	$4,881	$155
McLeod 88 (Big Smokey Valley)	NV	11	8	120	1.52	Binary	11.8	$22,471	$2,284	$16,933	$455
Medicine Lake (Glass Mt.)	CA	13	10	255	2.74	Flash	264.3	$6,321	$398	$3,690	$105
Mickey HS	OR	11	9	170	1.07	Binary	37.3	$10,007	$625	$6,811	$215
Milky River - Atka Island	AK	N/A	9	245	1.52	Flash	52.8	$6,169	$386	$3,684	$141
Mitchell Butte	OR	11	9	120	1.07	Binary	13.2	$21,366	$2,043	$15,696	$429
Mt. Signal	CA	13	10	135	1.52	Binary	10.2	$16,702	$1,440	$11,987	$363
Neal HS	OR	11	9	150	1.07	Binary	36.5	$12,178	$818	$8,595	$254
Newberry Caldera	OR	11	9	275	2.13	Flash	112.5	$5,014	$308	$2,914	$100
Newcastle area	UT	11	8	110	0.76	Binary	14.5	$26,601	$2,848	$20,204	$517
North Brawley	CA	13	10	250	1.52	Flash	92.9	$5,810	$341	$3,433	$114
Olene Hot Springs	OR	11	9	110	1.52	Binary	9.9	$29,297	$3,509	$23,759	$605
Owl Creek Hot Springs	ID	11	8	110	1.83	Binary	9.6	$30,695	$3,834	$25,481	$636
Pilgrim Hot Springs	AK	N/A	9	140	1.22	Binary	18.9	$14,661	$1,113	$10,262	$304
Pinto Hot Springs	NV	11	8	145	1.52	Binary	26.0	$13,826	$1,034	$9,663	$278
Puna Geothermal Venture	HI	N/A	9	350	1.07	Flash	139.2	$3,327	$212	$1,899	$100
Raft River	ID	11	8	145	1.83	Binary	47.9	$14,071	$1,076	$9,794	$259
Railroad Valley	NV	11	8	135	1.52	Binary	19.9	$16,320	$1,381	$11,597	$325

Site Name	Location Data			GETEM Input - Reservoir Characteristics				GETEM Output			
								Base Case[d]		Target Case[e]	
	State	NEMS Region	MARKAL Region	Reservoir Temp[a]	Reservoir Depth[a]	Plant Type[b]	Potential Capacity[c]	Capital Cost	O&M Cost	Capital Cost	O&M Cost
				°C	km	Binary/ Flash	MW_e	2008 US$/kW	2008 US$/kW/yr	2008 US$/kW	2008 US$/kW/yr
Reese River	NV	11	8	135	0.76	Binary	19.9	$15,267	$1,182	$10,690	$313
Roosevelt HS	UT	11	8	250	1.22	Flash	74.5	$5,720	$339	$3,389	$123
Routt	CO	12	8	110	1.52	Binary	10.0	$29,292	$3,508	$23,752	$605
Rowland Hot Springs	NV	11	8	110	1.52	Binary	6.8	$29,802	$3,583	$24,117	$642
Salton Sea area	CA	13	10	310	2.29	Flash	1,773.8	$4,225	$253	$2,408	$95
San Emidio Desert area	NV	11	8	190	1.07	Binary	51.3	$8,250	$472	$5,585	$184
Serpentine (Arctic) Springs	AK	N/A	9	145	1.52	Binary	22.9	$13,885	$1,041	$9,716	$283
Sespe HS	CA	13	10	120	1.52	Binary	12.7	$22,415	$2,275	$16,881	$450
Sharkey Hot Springs	ID	11	8	115	1.83	Binary	12.8	$26,629	$2,956	$20,887	$525
Silver Star (Barkel's) Hot Springs	MT	11	8	115	1.52	Binary	11.4	$25,543	$2,732	$19,737	$514
Sitka Hot Spring	AK	N/A	9	125	1.52	Binary	15.7	$20,006	$1,864	$14,615	$394
Smith Creek Valley area	NV	11	8	125	1.83	Binary	14.6	$20,873	$2,023	$15,410	$408
Soda Lake area	NV	11	8	205	1.37	Binary	33.5	$7,503	$439	$4,963	$176
Sonoma Mission Inn	CA	13	10	110	1.52	Binary	7.0	$29,746	$3,576	$24,087	$639
South Brawley (Mesquite)	CA	13	10	250	3.05	Flash	37.1	$7,305	$494	$4,376	$161
Squaw Hot Springs area	ID	11	8	130	1.52	Binary	20.2	$17,909	$1,586	$12,854	$349
Steamboat Hills	NV	11	8	210	1.52	Binary	20.9	$7,634	$446	$4,969	$189
Steamboat Springs	NV	11	8	165	1.52	Binary	9.8	$11,475	$796	$8,035	$285
Stillwater area	NV	11	8	160	1.01	Binary	43.8	$10,970	$681	$7,517	$226
Sulphur Hot Springs (Ruby Valley)	NV	11	8	165	1.83	Binary	39.7	$11,151	$752	$7,641	$223
Summer Lake Hot Springs	OR	11	9	110	1.01	Binary	9.9	$27,577	$3,074	$21,434	$563
Surprise Valley HS	CA	13	10	115	1.52	Binary	8.7	$25,767	$2,771	$19,967	$537

Site Name	Location Data			GETEM Input - Reservoir Characteristics				GETEM Output			
								Base Case[d]		Target Case[e]	
	State	NEMS Region	MARKAL Region	Reservoir Temp[a]	Reservoir Depth[a]	Plant Type[b]	Potential Capacity[c]	Capital Cost	O&M Cost	Capital Cost	O&M Cost
				°C	km	Binary/ Flash	MW_e	2008 US$/kW	2008 US$/kW/yr	2008 US$/kW	2008 US$/kW/yr
Tecopa HS	CA	13	10	120	1.52	Binary	10.1	$22,576	$2,302	$17,039	$467
The Needles (Needle Rocks, Pyramid Lake)	NV	11	8	120	1.07	Binary	19.0	$21,164	$2,012	$15,527	$408
Thermo Hot Springs	UT	11	8	125	0.76	Binary	16.8	$18,597	$1,570	$13,206	$370
Tolvana	AK	N/A	9	110	1.52	Binary	22.4	$28,819	$3,410	$23,241	$546
Trout Creek	OR	11	9	115	0.91	Binary	11.4	$23,903	$2,357	$17,797	$481
Tungsten Mountain	NV	11	8	125	1.52	Binary	14.6	$20,050	$1,871	$14,658	$399
Upper Division Hot Spring	AK	N/A	9	110	1.52	Binary	8.5	$29,419	$3,535	$23,891	$619
Vale HS	OR	11	9	145	1.07	Binary	40.4	$13,156	$925	$9,104	$257
Valles Caldera - Redondo	NM	12	8	275	3.35	Flash	84.2	$5,937	$391	$3,423	$102
Valles Caldera - Sulphur Springs	NM	12	8	225	3.35	Flash	33.8	$9,608	$676	$5,757	$167
Vulcan Hot Springs	ID	11	8	115	1.52	Binary	12.1	$25,505	$2,724	$19,693	$510
Wabuska Hot Springs	NV	11	8	115	1.52	Binary	10.1	$25,637	$2,748	$19,834	$524
Waunita Hot Springs	CO	12	8	120	1.52	Binary	14.5	$22,332	$2,262	$16,793	$441
Wayland (Battle Creek) Hot Springs	ID	11	8	130	1.83	Binary	19.9	$18,602	$1,713	$13,470	$356
Wedell Hot Spring (Gabbs)	NV	11	8	140	1.52	Binary	21.9	$15,040	$1,175	$10,545	$301
Wendel	CA	13	10	125	1.52	Binary	12.7	$20,140	$1,884	$14,746	$407
West Ukinrek Maar	AK	N/A	9	200	1.52	Binary	21.5	$7,997	$491	$5,353	$198
West Valley Reservoir	CA	13	10	130	1.83	Binary	13.6	$18,825	$1,746	$13,668	$378
White Licks Hot Springs	ID	11	8	110	1.22	Binary	11.2	$28,217	$3,226	$22,237	$569
Wilbur Springs	CA	13	10	160	1.07	Binary	32.1	$11,090	$701	$7,636	$236

[a]Reservoir temperature and depth for near-hydrothermal field resource were assumed to be same as for identified resource at same site.
[b]Assumed that sites with estimated reservoir temperature ≥ 225°C were flash plants, otherwise assumed to be binary power plants. Dry steam plants not considered.

[c]Potential capacity assumed to be difference between USGS 2008 Geothermal Resource Assessment 90%ile value and median value for identified hydrothermal resource at site.
[d]Base case assumes production well flow rate of 30 kg/s, 3.0%/year thermal drawdown rate, and 2:1 producer/injector ratio for all sites.
[e]Target case assumes production well flow rate of 60 kg/s, 0.3%/year thermal drawdown rate, and 2:1 producer/injector ratio for all sites.

Table B-4. Deep EGS Resource – Capital and O&M Costs

Site ID	Deep EGS Resource			GETEM Input -Reservoir Characteristics			GETEM Output			
							Base Case[c]		Target Case[d]	
	Reservoir Temp Range	Reservoir Depth Range	Potential Capacity	Reservoir Temp[a]	Reservoir Depth[a]	Plant Type[b]	Capital Cost	O&M Cost	Capital Cost	O&M Cost
	°C	km	MW_e	°C	km	Binary/ Flash	2008 US$/kW	2008 US$/kW/yr	2008 US$/kW	2008 US$/kW/yr
4k-150C	150-200	3-4	91,516	162.5	4.0	Binary	$15,684	$1,615	$10,756	$317
5k-150C	150-200	4-5	589,759	162.5	5.0	Binary	$20,295	$2,352	$13,410	$334
6k-150C	150-200	5-6	1,135,509	162.5	6.0	Binary	$27,566	$3,551	$17,812	$358
7k-150C	150-200	6-7	1,332,595	162.5	7.0	Binary	$39,720	$5,526	$24,867	$396
8k-150C	150-200	7-8	1,534,312	162.5	8.0	Binary	$59,604	$8,773	$36,427	$460
9k-150C	150-200	8-9	1,870,329	162.5	9.0	Binary	$92,413	$14,156	$55,756	$554
10k-150C	150-200	9-10	1,892,385	162.5	10.0	Binary	$146,512	$23,017	$88,610	$749
4k-200C	200-250	3-4	117	212.5	4.0	Binary	$10,221	$908	$6,438	$223
5k-200C	200-250	4-5	26,526	212.5	5.0	Binary	$13,206	$1,284	$7,942	$228
6k-200C	200-250	5-6	227,962	212.5	6.0	Binary	$17,873	$1,895	$10,383	$236
7k-200C	200-250	6-7	721,864	212.5	7.0	Binary	$25,651	$2,894	$14,372	$248
8k-200C	200-250	7-8	1,124,638	212.5	8.0	Binary	$38,185	$4,521	$21,012	$285
9k-200C	200-250	8-9	1,155,241	212.5	9.0	Binary	$58,574	$7,176	$31,965	$347
10k-200C	200-250	9-10	1,247,675	212.5	10.0	Binary	$91,896	$11,500	$50,046	$447
4k-250C	250-300	3-4	0	272.5	4.0	Flash	$8,367	$752	$4,997	$220
5k-250C	250-300	4-5	134	272.5	5.0	Flash	$11,133	$1,044	$6,304	$222
6k-250C	250-300	5-6	7,680	272.5	6.0	Flash	$15,322	$1,519	$8,427	$225
7k-250C	250-300	6-7	86,056	272.5	7.0	Flash	$22,370	$2,290	$11,950	$236
8k-250C	250-300	7-8	345,193	272.5	8.0	Flash	$33,750	$3,551	$17,799	$268
9k-250C	250-300	8-9	760,475	272.5	9.0	Flash	$52,194	$5,608	$27,262	$319
10k-250C	250-300	9-10	1,012,359	272.5	10.0	Flash	$82,542	$8,959	$42,887	$402

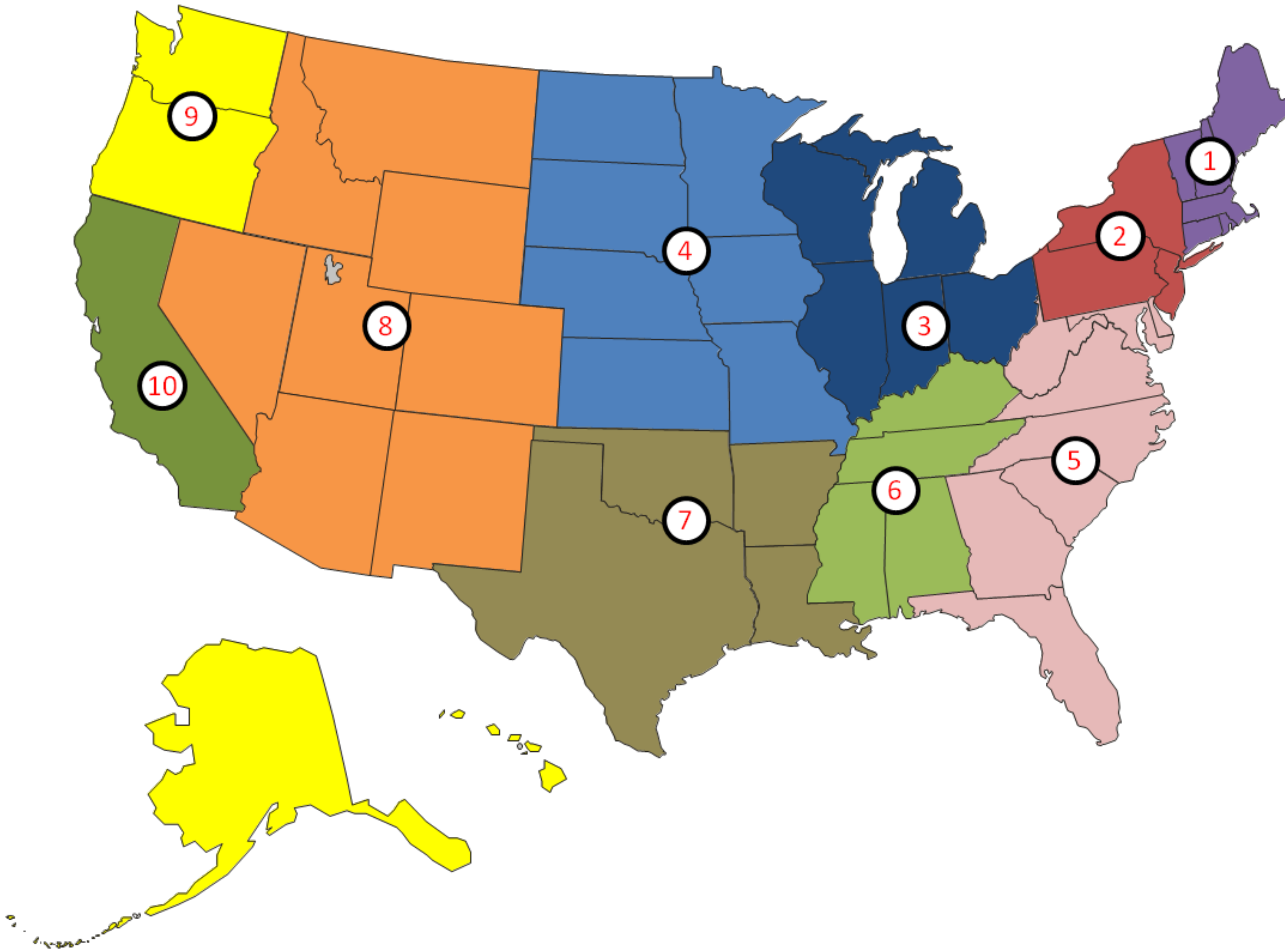
Site ID	Deep EGS Resource			GETEM Input -Reservoir Characteristics			GETEM Output			
							Base Case[c]		Target Case[d]	
	Reservoir Temp Range	Reservoir Depth Range	Potential Capacity	Reservoir Temp[a]	Reservoir Depth[a]	Plant Type[b]	Capital Cost	O&M Cost	Capital Cost	O&M Cost
	°C	km	MW_e	°C	km	Binary/ Flash	2008 US$/kW	2008 US$/kW/yr	2008 US$/kW	2008 US$/kW/yr
4k-300C	300-350	3-4	0	312.5	4.0	Flash	$6,218	$541	$3,730	$202
5k-300C	300-350	4-5	0	312.5	5.0	Flash	$8,132	$711	$4,637	$203
6k-300C	300-350	5-6	50	312.5	6.0	Flash	$11,177	$1,003	$6,123	$205
7k-300C	300-350	6-7	630	312.5	7.0	Flash	$16,195	$1,477	$8,516	$207
8k-300C	300-350	7-8	32,964	312.5	8.0	Flash	$24,306	$2,250	$12,579	$228
9k-300C	300-350	8-9	138,203	312.5	9.0	Flash	$37,524	$3,513	$19,185	$261
10k-300C	300-350	9-10	433,329	312.5	10.0	Flash	$59,140	$5,571	$29,944	$317
4k-350C	350+	3-4	0	362.5	4.0	Flash	$4,923	$452	$2,947	$189
5k-350C	350+	4-5	0	362.5	5.0	Flash	$6,190	$548	$3,612	$187
6k-350C	350+	5-6	0	362.5	6.0	Flash	$8,449	$751	$4,715	$186
7k-350C	350+	6-7	0	362.5	7.0	Flash	$12,151	$1,081	$6,531	$187
8k-350C	350+	7-8	321	362.5	8.0	Flash	$18,154	$1,618	$9,579	$202
9k-350C	350+	8-9	9,922	362.5	9.0	Flash	$27,944	$2,497	$14,508	$226
10k-350C	350+	9-10	69,299	362.5	10.0	Flash	$43,985	$3,928	$22,560	$266

[a]Deep EGS reservoir assumed to have temperature 12.5°C above low end of temperature range and that reservoir extended to total depth of depth range.
[b]Assumed that sites with estimated reservoir temperature ≥225°C were flash plants, otherwise assumed to be binary power plants. Dry steam plants not considered.
[c]Base case assumes production well flow rate of 30 kg/s, 3.0%/year thermal drawdown rate, and 2:1 producer/injector ratio for all sites.
[d]Target case assumes production well flow rate of 60 kg/s, 0.3%/year thermal drawdown rate, and 2:1 producer/injector ratio for all sites.

Table B-5. Deep EGS Resource – Potential Capacity by MARKAL Region (see Figure B-1)

Potential Deep EGS Capacity (MW_e)											
Site ID	MARKAL Region										Total
	1	2	3	4	5	6	7	8	9	10	
4k-150C	0	0	0	0	0	0	0	65,854	15,207	10,454	91,516
5k-150C	0	0	0	15,194	0	2,459	67,122	378,969	81,749	44,266	589,759
6k-150C	0	535	0	70,584	1,046	26,408	166,077	670,108	119,380	81,371	1,135,509
7k-150C	1,923	6,458	6,444	276,637	17,319	58,832	253,740	569,521	77,735	63,985	1,332,595
8k-150C	52,513	26,654	143,677	393,478	90,545	86,818	306,251	363,357	29,107	41,912	1,534,312
9k-150C	78,562	58,357	247,530	518,104	167,156	168,782	350,729	228,807	10,197	42,107	1,870,329
10k-150C	82,955	83,918	337,181	396,268	251,569	194,338	341,707	150,833	14,130	39,486	1,892,385
4k-200C	0	0	0	0	0	0	0	117	0	0	117
5k-200C	0	0	0	0	0	0	0	17,327	5,126	4,073	26,526
6k-200C	0	0	0	0	0	0	0	177,456	32,378	18,129	227,962
7k-200C	0	0	0	14,772	0	1,280	49,792	497,801	97,907	60,312	721,864
8k-200C	0	243	0	61,202	2,554	14,590	162,451	665,738	130,397	87,462	1,124,638
9k-200C	176	2,674	575	124,954	7,874	46,318	240,455	569,892	97,110	65,213	1,155,241
10k-200C	4,191	12,478	9,461	349,548	26,555	71,146	250,251	443,399	40,006	40,640	1,247,675
4k-250C	0	0	0	0	0	0	0	0	0	0	0
5k-250C	0	0	0	0	0	0	0	134	0	0	134
6k-250C	0	0	0	0	0	0	0	4,683	0	2,997	7,680
7k-250C	0	0	0	0	0	0	0	64,258	13,821	7,977	86,056
8k-250C	0	0	0	0	0	0	318	271,389	46,116	27,370	345,193
9k-250C	0	0	0	3,993	0	141	24,227	561,951	105,176	64,987	760,475
10k-250C	0	0	0	37,429	1,911	6,318	124,685	622,328	134,025	85,661	1,012,359
4k-300C	0	0	0	0	0	0	0	0	0	0	0
5k-300C	0	0	0	0	0	0	0	0	0	0	0

Potential Deep EGS Capacity (MW_e)											
Site ID	MARKAL Region										Total
	1	2	3	4	5	6	7	8	9	10	
6k-300C	0	0	0	0	0	0	0	50	0	0	50
7k-300C	0	0	0	0	0	0	0	630	0	0	630
8k-300C	0	0	0	0	0	0	0	21,398	7,094	4,471	32,964
9k-300C	0	0	0	0	0	0	0	104,947	21,904	11,352	138,203
10k-300C	0	0	0	0	0	0	719	342,102	56,220	34,289	433,329
4k-350C	0	0	0	0	0	0	0	0	0	0	0
5k-350C	0	0	0	0	0	0	0	0	0	0	0
6k-350C	0	0	0	0	0	0	0	0	0	0	0
7k-350C	0	0	0	0	0	0	0	0	0	0	0
8k-350C	0	0	0	0	0	0	0	321	0	0	321
9k-350C	0	0	0	0	0	0	0	5,887	0	4,035	9,922
10k-350C	0	0	0	0	0	0	0	47,772	13,767	7,760	69,299



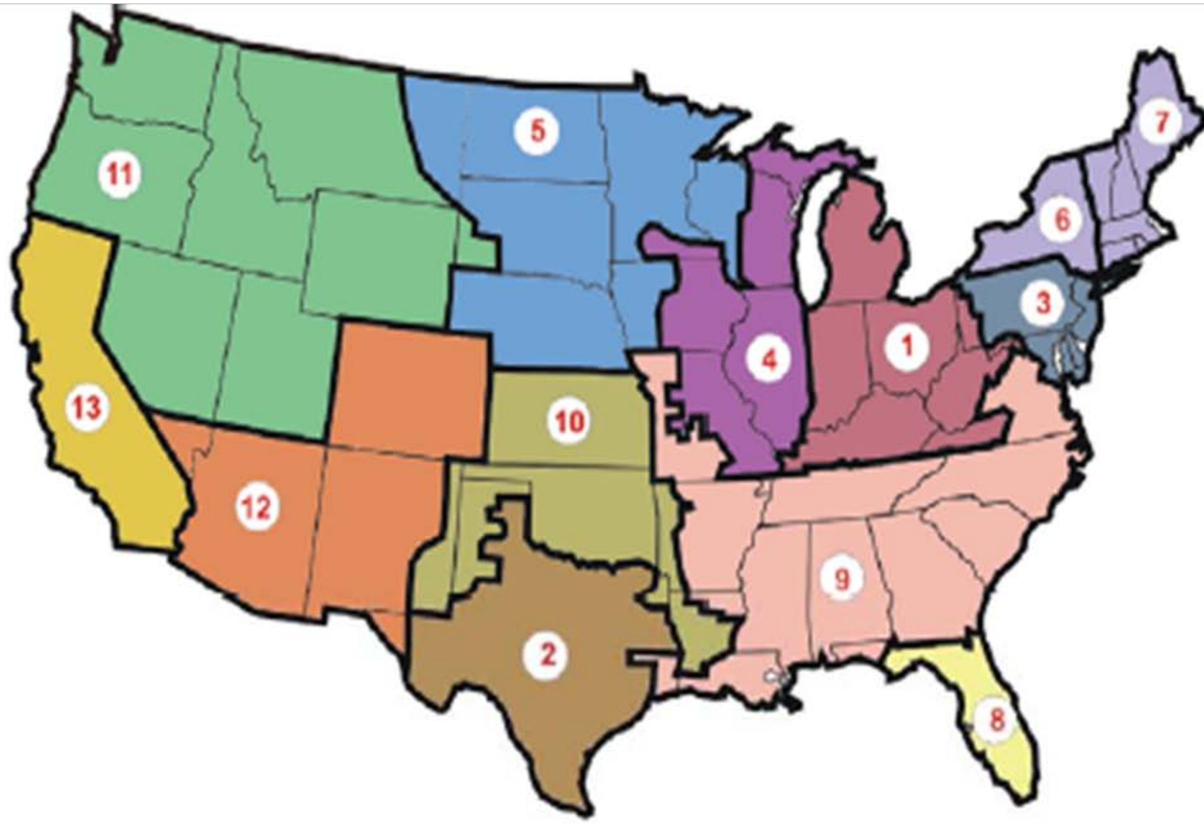
Region	States
1	ME-VT-NH MA-RI-CT
2	NY-NJ-PA
3	OH-MI-IN-IL-WI
4	MN-IA-MO-ND SD-NE-KS
5	MD-DC-DE-WV VA-NC-SC-GA-FL
6	KY-TN-MS-AL
7	AR-LA-TX-OK
8	ID-MT-WY-NV AZ-UT-CO-NM
9	AK-HI-OR-WA
10	CA

Figure B-1. Map of MARKAL regions.

Table B-6. Deep EGS Resource – Resource Potential by NEMS Region (see Figure B-2)

Potential Deep EGS Capacity (MW_e)														
Site ID	NEMS Region													Total
	1	2	3	4	5	6	7	8	9	10	11	12	13	
4k-150C	0	0	0	0	0	0	0	0	0	0	58,329	22,732	10,455	91,515
5k-150C	0	30,262	0	0	19,933	0	0	0	26,845	12,225	281,671	174,554	44,268	589,758
6k-150C	0	94,493	535	0	98,005	0	0	567	78,802	19,218	502,163	260,622	80,921	1,135,326
7k-150C	4,980	144,637	4,390	5,370	226,096	2,185	1,924	2,222	121,441	135,712	436,783	183,908	62,808	1,332,455
8k-150C	67,877	143,271	14,116	121,429	254,053	10,640	52,581	3,221	227,008	218,081	256,540	124,632	40,663	1,534,111
9k-150C	211,615	161,434	26,549	145,232	310,955	26,539	78,722	6,625	341,194	284,284	143,299	92,858	41,291	1,870,598
10k-150C	258,551	158,907	38,188	173,771	274,768	44,208	83,142	36,944	412,370	224,182	89,451	59,532	39,050	1,893,064
4k-200C	0	0	0	0	0	0	0	0	0	0	117	0	0	117
5k-200C	0	0	0	0	0	0	0	0	0	0	13,152	9,301	4,073	26,526
6k-200C	0	0	0	0	0	0	0	0	0	0	142,214	67,618	18,127	227,960
7k-200C	0	12,705	0	0	18,299	0	0	0	24,495	12,982	359,777	233,288	60,310	721,855
8k-200C	2,332	86,735	466	0	83,256	0	0	0	71,264	17,832	515,324	260,311	86,972	1,124,492
9k-200C	5,607	129,386	3,116	575	151,520	0	176	911	115,192	54,998	456,637	172,743	64,089	1,154,948
10k-200C	11,365	135,438	7,168	7,910	276,010	4,448	4,193	2,574	130,833	173,014	310,525	144,707	39,317	1,247,501
4k-250C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5k-250C	0	0	0	0	0	0	0	0	0	0	134	0	0	134
6k-250C	0	0	0	0	0	0	0	0	0	0	498	4,185	2,997	7,680
7k-250C	0	0	0	0	0	0	0	0	0	0	48,919	29,156	7,981	86,056
8k-250C	0	318	0	0	0	0	0	0	0	0	199,295	118,215	27,364	345,193
9k-250C	0	8,002	0	0	5,627	0	0	0	8,743	6,333	406,726	260,129	64,948	760,508
10k-250C	1,827	55,361	84	0	48,339	0	0	0	55,253	18,917	505,150	242,048	85,296	1,012,276
4k-300C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5k-300C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6k-300C	0	0	0	0	0	0	0	0	0	0	50	0	0	50

Potential Deep EGS Capacity (MW_e)														
Site ID	NEMS Region													Total
	1	2	3	4	5	6	7	8	9	10	11	12	13	
7k-300C	0	0	0	0	0	0	0	0	0	0	431	199	0	630
8k-300C	0	0	0	0	0	0	0	0	0	0	17,428	11,064	4,471	32,964
9k-300C	0	0	0	0	0	0	0	0	0	0	83,644	43,205	11,354	138,203
10k-300C	0	717	0	0	0	0	0	0	0	0	240,487	157,849	34,287	433,339
4k-350C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5k-350C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6k-350C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7k-350C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8k-350C	0	0	0	0	0	0	0	0	0	0	321	0	0	321
9k-350C	0	0	0	0	0	0	0	0	0	0	956	4,931	4,035	9,922
10k-350C	0	0	0	0	0	0	0	0	0	0	37,988	23,550	7,760	69,299



Region	Name
1	ECAR
2	ERCOT
3	MAAC
4	MAIN
5	MAPP
6	NY
7	NE
8	FL
9	SERC
10	SPP
11	NPP
12	RMPA
13	CA

Figure B-2. Map of NEMS regions.

Table B-7. Tabulated GETEM Input and Output for Hypothetical Hydrothermal Sites in Figure 15

Site ID	GETEM Input - Reservoir Characteristics					GETEM Output	
	Reservoir Temp	Reservoir Depth	Production Well Flow Rate	Plant Type[a]	Net Plant Output	Capital Cost	O&M Cost
	^{o}C	km	(kg/s)	Binary/ Flash	MW_e	2008 US$/kW	2008 US$/kW/yr
1k-150C	150	1.0	44.2	Binary	20.0	$7,461	$278
2k-150C	150	2.0	44.2	Binary	20.0	$8,410	$268
3k-150C	150	3.0	44.2	Binary	20.0	$10,096	$261
1k-200C	200	1.0	44.2	Binary	20.0	$4,481	$203
2k-200C	200	2.0	44.2	Binary	20.0	$4,997	$187
3k-200C	200	3.0	44.2	Binary	20.0	$5,983	$186
1k-250C	250	1.0	44.2	Flash	20.0	$3,323	$219
2k-250C	250	2.0	44.2	Flash	20.0	$3,718	$206
3k-250C	250	3.0	44.2	Flash	20.0	$4,441	$187
1k-300C	300	1.0	44.2	Flash	20.0	$2,697	$212
2k-300C	300	2.0	44.2	Flash	20.0	$2,968	$202
3k-300C	300	3.0	44.2	Flash	20.0	$3,416	$190

[a]Assumed that sites with estimated reservoir temperature ≥225^{o}C were flash plants, otherwise assumed to be binary power plants. Dry steam plants not considered.

Table B-8. Tabulated GETEM Input and Output for Hypothetical Near-Hydrothermal Field EGS Sites in Figure 16 and Figure 17

Site ID	GETEM Input - Reservoir Characteristics				GETEM Output			
					Base Case[a]		Target Case[b]	
	Reservoir Temp	Reservoir Depth	Plant Type	Net Plant Ouput	Capital Cost	O&M Cost	Capital Cost	O&M Cost
	^oC	km	Binary/ Flash	MW_e	2008 US$/kW	2008 US$/kW/yr	2008 US$/kW	2008 US$/kW/yr
1k-150C	150	1.0	Binary	20.0	$12,243	$844	$8,749	$277
2k-150C	150	2.0	Binary	20.0	$13,416	$1,030	$9,584	$284
3k-150C	150	3.0	Binary	20.0	$15,430	$1,314	$10,915	$294
1k-200C	200	1.0	Binary	20.0	$7,639	$470	$5,188	$200
2k-200C	200	2.0	Binary	20.0	$8,446	$550	$5,580	$201
3k-200C	200	3.0	Binary	20.0	$9,785	$702	$6,247	$202
1k-250C	250	1.0	Flash	20.0	$6,315	$445	$3,975	$219
2k-250C	250	2.0	Flash	20.0	$6,794	$493	$4,293	$216
3k-250C	250	3.0	Flash	20.0	$7,717	$570	$4,814	$213
1k-300C	300	1.0	Flash	20.0	$4,929	$370	$3,109	$210
2k-300C	300	2.0	Flash	20.0	$5,224	$389	$3,295	$205
3k-300C	300	3.0	Flash	20.0	$5,833	$428	$3,629	$202

[a]Base case assumes production well flow rate of 30 kg/s, 3.0%/year thermal drawdown rate, and 2:1 producer/injector ratio for all sites.
[b]Target case assumes production well flow rate of 60 kg/s, 0.3%/year thermal drawdown rate, and 2:1 producer/injector ratio for all sites.