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Report on the U.S. DOE Geothermal Technologies Program's 2009 Risk Analysis

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REPORT ON THE U.S. DOE GEOTHERMAL TECHNOLOGIES PROGRAM'S 2009 RISK ANALYSIS

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ABSTRACT

The U.S. Department of Energy (DOE) Geothermal Technologies Program (GTP or “the Program”) conducted a detailed risk analysis of their annual research, development, and demonstration (RD&D) portfolio. The Program worked with the National Renewable Energy Laboratory (NREL) to implement a probabilistic risk analysis of the GTP-sponsored RD&D, primarily enhanced geothermal systems (EGS) in accordance with Program budget authority. EGS technologies are in the early stages of development, and GTP-sponsored, multi-year demonstration projects are now underway to demonstrate technical feasibility, reduce risk for industry, and improve EGS best practices. The risk analysis examined estimates of improvement potential for two metric types: EGS-enabling technologies potential and EGS cost-improvement potential. NREL also evaluated potential improvements in hydrothermal exploration. The analysis employed a spreadsheet add-in that uses Monte Carlo simulation in conjunction with the Geothermal Electric Technology Evaluation Model (GETEM). Four risk groups (exploration, wells/pumps/tools, reservoir engineering, and power conversion) comprised of industry experts, national laboratory researchers, academic researchers and

laboratory subcontractors estimated the RD&D impacts using probability distributions for three budget levels and two future time frames. Risk results were expressed in terms of each metric’s units and input into GETEM to estimate impacts on levelized costs of electricity. The resulting detailed risk analysis summarizes the industry’s current thinking on various metrics and potential for research improvement. Although the well drilling/construction and plant capital costs are key targets for cost reduction, all experts believed (1) that RD&D needs to occur first in enabling technologies for EGS and (2) that Program RD&D funding should not all be spent in only a few areas.

BACKGROUND

DOE has standardized the annual risk process for all programs managed by its Office of Energy Efficiency and Renewable Energy (EERE). The DOE Geothermal Technologies Program tasked NREL with conducting its annual risk analysis, which DOE uses to:

1. Meet the National Academy of Science’s requirement to report uncertainty
2. Improve project, program, and portfolio design, performance, and likelihood of success

3. Clarify issues associated with accepting, managing, or rejecting risks
4. Link science research opportunities with applied energy RD&D
5. Increase decision-maker understanding of potential RD&D results
6. Obtain answers to key RD&D questions.

Additionally, the Program uses the risk information to set technical goals and to provide input for the supply curve used in estimating benefits under the Government Performance and Results Act (GPRA).

The task goal and principal product were a probabilistic risk analysis of GTP-sponsored RD&D primarily for enhanced geothermal systems (EGS). Addressing ubiquitous sources of EGS, beyond the more easily accessible resources, was mandated by Program appropriators when the Program was restarted in Fiscal Year 2008. EGS technologies are in the early stages of development and GTP-sponsored, multi-year demonstration projects are now underway (1) to demonstrate technical feasibility and reduce risk for industry and (2) to better understand and improve EGS best practices.

METHODS

The risk analysis approach taken examines estimates of improvement potential derived from program RD&D work for two types of technology performance metrics (TPMs): EGS-enabling technologies¹ potential and EGS cost-improvement potential. Additionally, potential improvements in hydrothermal exploration were also evaluated. Risk results are expressed in terms of each metric's units, levelized costs of electricity (LCOE)², or both.

Specifically, the analysis used @Risk, a spreadsheet add-in that uses Monte Carlo simulation, to drive the Geothermal Electric Technology Evaluation Model (GETEM), a techno-economic systems analysis tool for evaluating and comparing geothermal project cases. By itself, GETEM is a deterministic model; it computes LCOE values for a set of user-specified input variables that address almost 50 project criteria.

¹ Risk analysts applied the term “enabling technology” to metrics (such as pump temperature capability) that were not used as input to GETEM but for which potential improvement values would interest the Program.

² The LCOE, also known as a “busbar cost,” is a present value of a producer's cost of electricity for commercial and industrial power systems. It covers the exploration, development, construction, and operating phases of a project. LCOE accounts for time-dependent values of equity, borrowed capital, operation and maintenance costs, and discounted values of other cash-flow terms such as taxes, insurance, and escalation.

A particular geothermal project reference scenario was defined by allocating a profile of values to the input variables. GETEM's function is to examine “improved technology” cases compared with the reference scenario by quantifying potential benefits of research in terms of improvements to the baseline input variables defined in the reference scenario. The @Risk/GETEM risk model evaluates multiple ranges of potential impacts of RD&D, coupled with corresponding levels of probability of the occurrence of those impacts. The evaluation computes probability distributions of LCOE for geothermal power projects.

Four risk analysis groups—one each for exploration, wells/pumps/tools, reservoir engineering, and power conversion—provided probability distribution estimates of potential improvement from Program RD&D investments for 21 TPMs. These groups were comprised of 32 experts from industry, federal laboratories and agencies, and academia.

The experts, analysts and GTP personnel worked together to develop a reference scenario plant. The goal was to create a scenario that was reasonable to develop, and could be deployed in a wide range of geographic locations. The resulting scenario parameters are shown in Table 1.

Each expert group provided present-day values for each of their group's metrics based on expert discussion of multiple reports, publications, and data sources. These present-day values were used as baseline input in GETEM against which expert improvement probability distribution estimates were compared.

Experts then independently provided input for each metric in the form of quantitative probability distributions and qualitative comments. The individual expert probability distributions for each metric were aggregated into a single distribution using Monte Carlo sampling in @Risk.

RESULTS

The results of the risk assessment are (1) aggregated expert input distributions and summaries of experts' comments for each metric and (2) for the cost metrics, projected impacts on EGS project LCOE. The mean values of the aggregated expert distributions for each metric are given in Table 2. Full results are provided in the NREL Technical Report.

The results, including both the qualitative comments and the quantitative potential for improvements, were thorough and cohesive in three of the four expert

groups: exploration, wells/pumps/tools, and power conversion. (See the Conclusions section for a discussion of results for the fourth expert group, the reservoir engineering group.) Table 3 summarizes the

effect of Program RD&D investment on individual TPM improvements from these three groups. Table 4 gives the same information for hydrothermal exploration.

Table 1. Reference Scenario Parameters^a

Parameter	Value		Parameter	Value	
Year of the \$	Dec-08		Water Loss/Total Injected	0.02	
Geothermal Type	EGS		Thermal Drawdown (fluid)	0.3%/yr	
Resource Rock Temperature	225° C	437° F	Geofluid Pump Efficiency	0.6	
Fluid Temp at Power Plant Inlet	200° C	392° F	Flashed Wireline Tool Service Time	10 hours	
Ambient Temperature	15° C	59° F	Permanent Tool Lifetime	6 years	
Exploration	few to none O&G wells in area		Pump Lifetime (then replace)	3 years	
Easy Drilling (e.g., Sed overburden)	1,500 m	4,922 ft	Pump Depth Setting	1 km	3,281 ft
Resource Rock Type	igneous		Total Dynamic Head (TDH)	1.2 km	4,000 ft
Drilling Cost Curve (in GETEM)	median cost curve		Injection Pumping	none/low to prevent water losses downhole	
Resource Stress Regime	normal faulting transitional to strike-slip		Number of Fractured Intervals	2	
Well Depth	6 km	19,686 ft	Pump horsepower	1065 HP	
Well Deviation from Vertical	0 degrees		Gross Capacity	30 MWe	
Well Casing ID at TD	17.78 cm	7 in	Net Capacity	20 MWe	
Deviated Ramp Length (at 45°)	500 m	1,641 ft	Capacity Factor	0.95	
Well Separation	650 m	2,133 ft	Energy Conversion	binary	
Producer-Injector Well Ratio	2:1		Cooling Technology	air-cooled	
Producer Flow Rate (per well)	60 kg/s		Plant Lifetime	30 years	
Injection Temperature	80° C	176° F			

^a The risk experts defined a set of EGS parameters to define the reference scenarios. Parameters included GETEM inputs, as well as other qualitative parameters (e.g. resource stress regime) to allow the experts to give risk feedback using common base assumptions.

Table 2: Mean values of aggregated expert input.^a

Varied Metric (TPM)			2009	2015			2025		
#	ANNUAL FUNDING LEVEL:	Units	---	\$0	\$30M	\$60M	\$0	\$30M	\$60M
E1	Non-Well Exploration Costs (EGS)	\$million	1.41	1.14	1.06	0.97	1.10	0.94	0.82
E1	Non-Well Exploration Costs (Hydro)	\$million	1.22	1.18	1.13	1.07	1.16	1.06	0.90
E2	Exploration Well Success Rate (EGS)	%	64	64	66	68	66	69	73
E2	Exploration Well Success Rate (Hydro)	%	35	37	41	43	40	45	49
W1	Well Drilling/Construction Cost	\$million	22.3	21.6	20.3	19.0	20.6	18.3	16.6
W2	Production Pump Cost (per well)	\$million	1.5	1.5	1.3	1.2	1.4	1.2	1.0
W3	Downhole Pump Temperature	°C	167	208	230	245	224	251	269
W4	Pump Horsepower	HP	320	433	671	843	529	865	1,074
W5	Wireline Tool Temperature	°C	175	194	220	237	209	248	272
W6	Permanent Equipment Temperature	°C	125	151	179	199	165	211	237
W7	Zonal Isolation Differential Pressure	Psi	0	134	158	173	148	183	203
W8	Zonal Isolation Temperature	°C	152	171	193	210	194	220	260
R1	Well Stimulation Cost per well triplet ^b	\$million	8.4	7.9	7.5	6.8	7.3	6.4	5.8
R2	Reservoir Creation Probability ^b	%	59	59	55	57	58	56	63
R3	Short-Circuit Mitigation Probability ^b	%	45	44	44	47	44	46	50
R4	Thermal Drawdown Rate ^b	%/yr	13.2	13.3	13.0	12.3	12.6	12.1	11.1
R5	Production Well Flow Rate ^b	kg/s	35	35	37	41	36	42	51
R6	Producer-Injector Ratio ^b	ratio	2.9	2.7	2.7	2.8	2.7	2.9	3.3
P1	Binary System Capital Cost	\$/kW	2,500	2,470	2,380	2,010	2,390	2,250	1,870
P2	Binary System O&M Cost/Yr	¢/kWh	2.2	2.2	2.1	1.9	2.2	2.1	1.8
P3	Brine Effectiveness	W-h/ lbm	9.5	9.5	9.7	10.0	9.6	10.0	10.4

^a Mean values of aggregated expert probability distribution functions for technology performance metrics (TPMs) in risk assessment

^b Expert input for the reservoir engineering group were not thoroughly vetted, and consequently, not cohesive.

Table 3: Summary of 50th Percentile LCOE ^{a,b}

Varied Metric (TPM)	Total Potential LCOE for EGS Reference Scenario					
	2015			2025		
ANNUAL FUNDING LEVEL:	No DOE Funding	DOE Planned	DOE Expanded	No DOE Funding	DOE Planned	DOE Expanded
Well Drilling/Construction Costs	25.3	24.3	23.3	23.9	22.2	21.0
Plant Capital Costs		25.2	24.5		23.6	23.0
Well Stimulation Costs		25.3	25.1		23.7	23.5
Plant O&M Costs		25.3	25.1		23.8	23.6
Pump Costs		25.3	25.3		23.8	23.8
Exploration Success Rate		25.3	25.3		23.9	23.8
Non-Well Exploration Costs		25.3	25.3		23.9	23.9

^a Values for 50th percentile LCOE (in Year 2008 ¢/kWh) for EGS reference scenario for single TPM improvements under no budget, target budget (\$30 million), and over-target budget (\$60 million) levels

^b For comparison: Current estimate of LCOE = 26.4 ¢/kWh. LCOE calculated for reference scenario binary EGS plant. Binary EGS plant reference scenario assumptions: reservoir temperature = 225°C, reservoir depth = 6,000 m, power plant design temperature = 200°C. EGS “enabling technologies” assumed constant: production well flow rate = 60 kg/s, thermal drawdown rate = 0.3%/year, and producer-injector ratio = 2:1. For aggregated expert TPM values, see Table 2.

Table 4: Summary of 50th percentile LCOE—Hydrothermal Reference Case ^c

Varied Metric (TPM)	Total Potential LCOE for EGS Reference Scenario					
	2015			2025		
ANNUAL FUNDING LEVEL:	No DOE Funding	DOE Planned	DOE Expanded	No DOE Funding	DOE Planned	DOE Expanded
Exploration Success Rate	12.5	12.5	12.5	12.2	12.1	12.1
Non-Well Exploration Costs		12.5	12.5		12.2	12.2

^c Values for 50th percentile LCOE (in Year 2008 ¢/kWh) for reference hydrothermal plant for single TPM improvements under no budget, target budget (\$30 million) and over-target budget (\$60 million) levels. Current estimate of LCOE is 12.8 ¢/kWh. LCOE calculated for reference scenario hydrothermal EGS plant (reservoir temperature = 175°C, reservoir depth = 1,524 m, power plant design temperature = 175°C, production well flow rate = 44.2 kg/s, thermal drawdown rate of 0.3%/year, and producer-injector ratio of 3:1).

The calculated results give GTP management a picture of the likelihood of advancing EGS technologies and reducing EGS levelized costs. The results will also help the Program set future target metrics.

Expert input for the reservoir engineering group were not thoroughly vetted, and consequently, not cohesive. Therefore, these input were not used, and instead Program goals were assumed for reservoir engineering enabling technologies such as production well flow rate and thermal drawdown. If these goals are achieved, the results of analysis of the remaining risked metrics indicate that reducing well drilling/construction costs and power plant costs show the greatest potential for reduction in LCOE for EGS.

The recent rise in drilling costs is partly responsible for the large role drilling costs play in overall EGS economics. At the time of the risk elicitation with experts, drilling costs were near historic highs because of high rig rental rents caused by high crude oil and natural gas prices (which led to increased demand for oil and gas drilling) and the scarcity of steel and cement.

The drilling costs used by the experts in this analysis reflect these high costs and represent drilling costs at a point in time based on market conditions. Drilling costs have subsequently decreased significantly from these highs. The decreases in future drilling costs from RD&D and the learning-by-doing projected by the experts indicate cost reductions relative to only the assumed drilling costs and do not consider market volatility. Although the recent decline in drilling costs may lessen the role drilling costs play in overall EGS power costs, the lessons learned from the risk assessment exercise still apply—decreases in drilling costs from expanded RD&D will significantly affect EGS power costs.

Although the well drilling/construction and plant capital costs are key targets for cost reduction, all

experts believed (1) that RD&D needs to occur first in enabling technologies for EGS and (2) that Program RD&D funding should not all be spent in only a few areas. The industry has the potential to benefit by investment in all four areas: exploration, wells/pumps/tools, reservoir engineering, and power conversion technologies. Expert comments on potential improvement in each of these four areas are summarized in the NREL technical report.

While reservoir engineering parameters were considered enabling technologies and their values fixed during the risk assessment, improvements in reservoir engineering have significant potential to decrease EGS LCOE. Overall project well costs can be lowered by decreasing thermal drawdown rates and increasing flow rates, which both decrease the number of wells that are needed. The cost reduction potential shown in Table 5 indicates significant potential for EGS project cost reduction from improvements in reservoir engineering. These improvements may come at a cost (see Conclusions), and trade-off studies should be conducted to better understand the interdependence among TPMs.

Table 5: Effect of thermal drawdown rate and production well flow rate on 50th percentile LCOE (in Year 2008 ¢/kWh) values for reference EGS plant (assuming producer-injector ratio of 2:1).

Prod. Well Flow Rate:	30 kg/s	60 kg/s	90 kg/s
Thermal Drawdown	LCOE (¢/kWh)		
3.0%/yr	75.8	44.5	38.0
1.0%/yr	49.1	30.2	26.6
0.3%/yr	42.4	26.4	23.4

For example, increases in well flow rates can reduce the number of wells needed for a geothermal project, thereby potentially reducing cost. However, these increases in flow rate come at a cost—increased friction loss requiring increased pumping energy needs. Increasing the well diameter can help to

mitigate these issues, but this then increases well costs.

RD&D investment to reduce well costs will lower the LCOE, but more important, RD&D investment in reservoir engineering and plant performance can significantly reduce the number of wells needed. This and other similar relationships need to be better understood and designed for to improve EGS project design and minimize geothermal costs.

DISCUSSION

A distribution of electricity costs based on the input TPM distributions was calculated in GETEM using the @Risk add-in for Microsoft Excel. For each scenario considered, a Monte Carlo simulation consisting of 1,000 iterations was performed.

Preliminary simulations showed that use of all the expert aggregated TPM distributions resulted in EGS LCOE distributions in which the majority of the iterations involved reservoir characteristics that were not economically feasible assuming current costs for the reference EGS plant as shown in Figure 1.

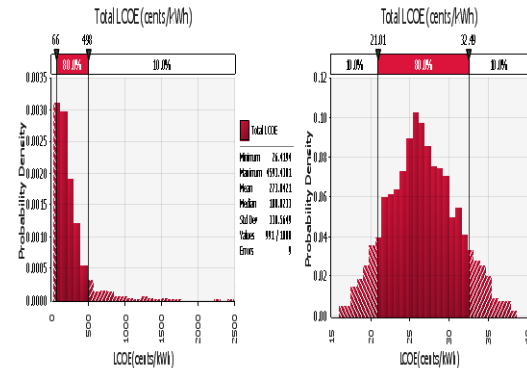


Figure 1: Distribution of LCOEs for reference scenario EGS plant assuming current costs as provided by experts for all TPMs in Table 2.

The wide distribution and large tail are caused by wide probability distributions for two individual metrics: thermal drawdown rates and production well flow rates. The upper portions of these probability distributions (high thermal drawdown rates, low production well flow rates) both causes high number of required wells over the lifetime of the plant. The effect of these TPM distributions for even modest ranges of production well flow rate and thermal drawdown is shown in Table 5. For these reasons, the

Program chose key TPMs as enabling technologies and set them to the Program goal values. Specifically, fixed reference scenario values were assumed for (1) the thermal drawdown rate (0.3 %/year), (2) the production well flow rate (60 kg/s), and (3) the producer-injector ratio (2:1).

Figure 2 shows the LCOE distribution for the EGS reference scenario assuming current costs when these three enabling-technologies TPMs are fixed at the above-stated goal values and the expert aggregated distributions are used for the remaining cost metrics.

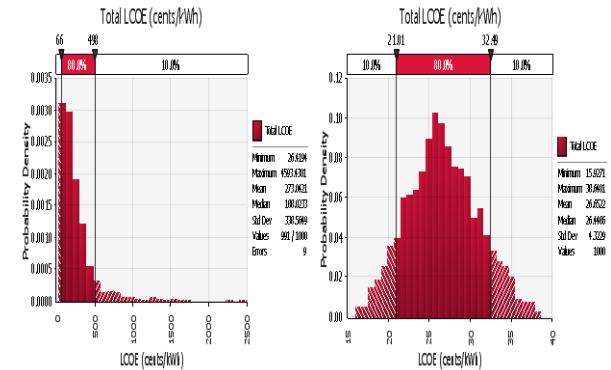


Figure 2: Distribution of LCOEs for reference EGS plant assuming current costs and aggregated expert distributions in Table 2 with EGS enabling-technologies TPMs fixed at constant values of Production Well Flow Rate of 60 kg/s, Thermal Drawdown Rate of 0.3%/year, and Producer-Injector Ratio of 2:1

The importance of the production well flow rate and thermal drawdown rate on LCOE for the EGS reference case can be seen by examining Table 5. A thermal drawdown rate of 3.0%/year requires re-drilling of the EGS reservoir four times over the 30-year lifetime of the power plant, whereas a 1.0%/year drawdown rate requires the reservoir to be re-drilled only once, and a 0.3%/year drawdown rate does not require re-drilling.

A similar trend is seen for increasing the production well flow rate. The reference scenario assumes wells with bottom-hole diameters of 7.0 inches. As the flow rate in the production (and injection) wells increase, friction losses in the wellbores and reservoir rise so that more power is required to run the injection and downhole production pumps, partially

offsetting the decrease in LCOE costs from the lower number of wells required at higher production well flow rates. The same effect was observed for GETEM runs for the conditions shown in Table 5 using a 3:1 producer-injector well ratio. The pressure losses in the injection well for these runs were so large that the LCOE was actually higher for 60-kg/s and 90-kg/s producer well flow rate cases than when a 2:1 producer/injector well ratio was used. Increasing the injection well and production well diameters would eliminate the friction losses in the wellbore at higher flow rates, but these wells would also be more expensive. Input on well costs as a function of bottom-hole diameter was not gathered from the experts, so the reference plant scenario could not be optimized as a function of varying production well flow rates. However, such information would be useful to gather in future trade-off analyses and risk assessments.

According to the experts' experience, fewer large wells are generally less expensive than more small wells for a given total flow rate. If reservoirs can sustain high flow rates, larger wells will be drilled.

The results show that the greatest potential for reduction in levelized cost of EGS power is in reduction in well drilling/construction costs, followed by reduction in power plant costs. Although these two areas would be key targets for cost reduction, all experts believed that (1) RD&D needs to first occur in enabling technologies for EGS and (2) RD&D funding should not all be spent in only a few areas.

Tables 3 and 4 consider only the effect of RD&D improvements from each TPM in isolation, and they report only the median LCOE for each scenario, which more or less corresponds to GETEM results when the median value from the expert distribution is

used. The data in these tables ignore the effect of advances in multiple TPM areas and does not address the LCOE's possible use of TPM values from the full range of the aggregated expert distributions.

Figure 3 shows possible combinations of drilling costs, power plant costs, and stimulation costs that result in an LCOE of 22.5 cents/kWh for the EGS reference case. The figure was made by fixing the drilling and stimulation costs as given percentages of their mean value from the aggregated expert distributions and solving for the power plant cost that resulted in an LCOE of 22.5 cents/kWh. (For example, when the drilling and stimulation costs are 100% of their mean values, the power plant costs must be about 11% of its mean value to result in an LCOE of 22.5 cents/kWh for the EGS reference case). The slope of the curves shows the relative importance of drilling costs to power plant costs to overall project LCOE; the steep slope indicates that drilling costs factor more heavily in determining the LCOE than do power plant costs. The spacing of the lines for the range of stimulation costs considered gives their relative importance; closely spaced lines indicate that stimulation costs do not heavily influence the overall LCOE. The dotted red lines indicate the mean and 10th percentile values of the drilling and power plant costs from the aggregated expert distributions given in Table 2, so that the red box indicates the range of reasonable values for the drilling and power plant costs. A much wider range of possible drilling costs than power plant costs was considered by the experts. The figure indicates that significantly lower LCOE costs are possible for the EGS reference case than indicated in Table 3 if drilling costs, power plant costs, or both can be lowered by amounts considered feasible by at least some of the experts.

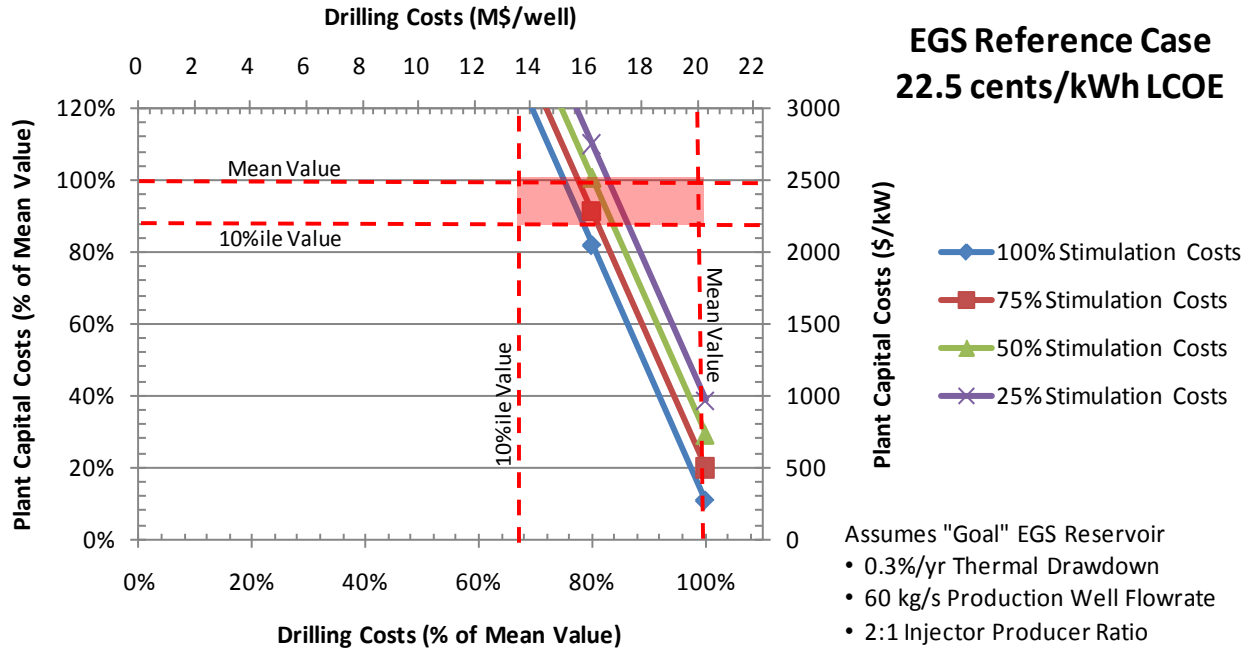


Figure 3. Drilling, power plant and stimulation cost scenarios that give 22.5 cents/kWh EGS reference case LCOE. Axes show plant and capital costs as both actual dollar values and as percentage of mean value from aggregated expert distributions. Dotted red lines indicate 100% of mean value and 10th percentile values from aggregated expert distributions.

CONCLUSIONS

The detailed risk analysis, which summarizes the industry's current thinking on various metrics and potential for research improvement, made considerable strides in establishing a risk analysis protocol to be used by the Geothermal Technologies Program on a regular basis. The following risk tools can be used, with minimal updates, in future risk assessments:

- EGS reference scenario
- Expert briefs
- Risk schedule
- Risk presentations
- Expert input worksheets

The results of the risk analysis indicate that the greatest potential for reduction in levelized cost of EGS power is in reducing well drilling/construction costs and power plant costs. The near-historic high drilling costs (due to high rig rental rents and the scarcity of steel and cement), which was used by experts in this analysis, is partly responsible for the large role it plays in overall EGS economics. Since the risk assessment exercise, drilling costs have decreased significantly. However, the decreases in future drilling costs from RD&D and learning-by-doing projected by the experts in this analysis

indicate cost reductions relative to only the assumed drilling costs and do not consider market volatility. The lessons learned from the risk assessment exercise still apply, and decreases in drilling costs from expanded RD&D will significantly impact EGS power costs.

Although this risk study identified well drilling/construction and power plant costs as key targets for cost reduction, all experts believed that (1) RD&D needs to first occur in enabling technologies for EGS and (2) RD&D funding should not all be spent in only a few areas. The industry has the potential to benefit by investment in all four areas: exploration, wells/pumps/tools, reservoir engineering, and power conversion technologies.

Additionally, improvement in reservoir engineering has significant potential to decrease well costs by decreasing thermal drawdown rates and increasing flow rates, both of which decrease the number of wells that are needed. The cost reduction potential, shown in Table 5 above, indicates that trade-off studies should be conducted to improve on the reference scenario design. For example, increase in well flow rates can reduce the number of wells needed for a geothermal project, thereby potentially reducing cost. But, increases in flow rates come at a cost—increased friction loss and increased pumping needs. Increasing the well diameter can mitigate

these issues, but this increases well costs. This and other similar relationships need to be better understood and designed for to minimize geothermal costs. RD&D investment to reduce well costs will lower the LCOE, but more importantly, RD&D investment in reservoir engineering and plant performance can significantly reduce the number of wells needed.

The results of the risk assessment—both the qualitative comments and the quantitative potential for improvements—will provide the Program with guidance in developing Program targets and focusing RD&D efforts to obtain these targets. These comments and potential improvements were thorough and cohesive in three of the four expert groups: exploration, wells/pumps/tools, and power conversion.

Reservoir engineering expert discussions throughout the risk process, though lengthy, were never concluded. Consequently, the results were inconsistent and conflicting, were deemed invalid, and were not used. Comments from the reservoir engineering experts reveal that further discussion is needed in future risk elicitation activities to validate and better understand the reservoir engineering feedback on potential for metric improvements.

RECOMMENDATIONS

For future analyses, experts should be contacted earlier and more reservoir engineering experts should be targeted to obtain a stronger response from this group. It may also be useful to schedule meetings for risk experts at times that do not coincide with other major geothermal industry events to avoid conflicting meetings.

Not all of the risk information could be covered in the time allotted for risk expert meetings. If the same group of experts is used for future risk elicitation analyses, the same time allotment may be sufficient. Planning for additional time, however, particularly for the reservoir engineering expert group, may be helpful.

In this risk assessment, cost improvements had to be linearly extrapolated from 2025 (the last year for which data were gathered from the experts) to 2050 for purposes of modeling in market penetration models. In future risk analysis, the time frame should be extended to 2050 to reflect the time frames in the market penetration models SEDS (Stochastic Energy Deployment System) and MARKAL (Market Allocation).

Program personnel, NREL's risk analysts, and the risk experts understand that the EGS scenario defined for this study may not be the best design for an EGS system. Because system design and trade-off analyses were beyond the scope of this risk assessment, this scenario was used. As system design is better understood and results from trade-off analyses currently funded by the Program become available, the system design and reference scenario will continue to be updated and improved. Additionally, RD&D projects may help redefine the EGS system in the future. Future risk assessments can rely on these newly developed system design parameters as they are developed.

Future risk assessments should focus on reservoir engineering, since technology understanding will change as current RD&D activities progress.

Future edits of the Program's Multi-Year Research Development and Demonstration Plan (MYRD&D) should reflect recommendations by the experts in all metric areas addressed in this risk assessment, both for the current state of EGS technologies and for potential for improvement. Qualitative comments made by the experts should also be considered in MYRD&D planning efforts.

Finally, as the Program expands, consideration should be given in future risk analyses to expand the scope to include other resources, such as geopressured reservoirs and co-production from oil and gas wells.

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14. ABSTRACT (Maximum 200 Words) NREL conducted an annual program risk analysis on behalf of the U.S. Department of Energy Geothermal Technologies Program (GTP). NREL implemented a probabilistic risk analysis of GTP-sponsored research, development, and demonstration (RD&D) work, primarily for enhanced geothermal systems (EGS). The analysis examined estimates of improvement potential derived from program RD&D work for two types of technology performance metric (TPM): EGS-enabling technologies potential and EGS cost improvement potential. Four risk teams (exploration, wells/pumps/tools, reservoir engineering, and power conversion) comprised of industry experts, DOE laboratory researchers, academic researchers, and laboratory subcontractors estimated the RD&D impacts and TPM-improvement probability distributions. The assessment employed a risk analysis spreadsheet add-in that uses Monte Carlo simulation to drive the Geothermal Electric Technology Evaluation Model (GETEM). The GETEM-based risk analysis used baseline data from the experts' discussion of multiple reports and data sources. Risk results are expressed in terms of each metric's units and/or the program's top-level metric: levelized costs of electricity (LCOE). Results—both qualitative comments and quantitative improvement potential—are thorough and cohesive in three of the four expert groups. This conference paper summarizes the industry's current thinking on various metrics and potential for research improvement in geothermal technologies.								
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