THE IMPACTS OF DRILLING AND RESERVOIR TECHNOLOGY ADVANCES ON EGS EXPLOITATION

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ABSTRACT

The publication of "The Future of Geothermal Energy" in the fall of 2006 brought renewed interest and focus to work on Engineered Geothermal Systems (EGS) in the U.S. The magnitude of the resource, coupled with its ability to provide baseload electric power and recent technical advances achieved in field experiments internationally, have increased awareness of the potential of geothermal energy in the U.S. The U.S. Congress authorized legislation to support an ambitious national geothermal energy program as part of the recent omnibus energy bill (HR 6). An important cost component of an EGS project is drilling costs. As the quality of an EGS resource declines, drilling costs dominate the total capital investment. In this paper we explore the effects of resource quality, reservoir performance, and drilling costs on EGS economics to identify areas that could benefit from intensified R&D. The parameter space examined includes— drilling costs as a function of depth, average temperature gradient, production well flow rate, and the impacts of drilling technology innovation.

CONTEXT

In 2005-2006, a panel assembled by the Massachusetts Institute of Technology (MIT) conducted a 15 month assessment of the potential of geothermal energy in the U.S. The study report (Tester et al., 2006) documented their analysis of the EGS resource, established requirements for extracting and utilizing energy from EGS resources and estimated the costs for EGS supplied electricity. The report concluded that EGS has the potential to provide the United States with 100,000 MW of geothermal electricity by 2050 at competitive prices with an investment of about one billion dollar in research and demonstration projects and deployment assistance spread over the next ten to fifteen years (Tester et al., 2006). The Energy Independence and Security Act of 2007 (HR 6, 2007) acknowledges critical needs in resource assessment, reservoir testing and development, and deployment assistance, and provides for sufficient, sustained support that would reduce technical and economic risks and thus increase the impact of geothermal energy as a major energy supply in the U.S.

POTENTIAL

The accessible geothermal resource base in the United States is enormous with the majority of it contained in the thermal energy stored in sedimentary and basement rock formations to a depth of 10 km. The quality of a geothermal resource varies as a function of temperature with depth along with the natural porosity, permeability and/or connectivity of the rock that comprises it. Overall, the geothermal resource can be viewed as a continuum of grades or regions, as depicted in Figure 1. The continuum ranges from high grade hydrothermal resources, which have high average temperature gradients and the presence of naturally occurring high reservoir connectivity and high fluid content, to low grade EGS resources, which have lower temperature gradients, little or no natural connectivity, and no significant fluid content.
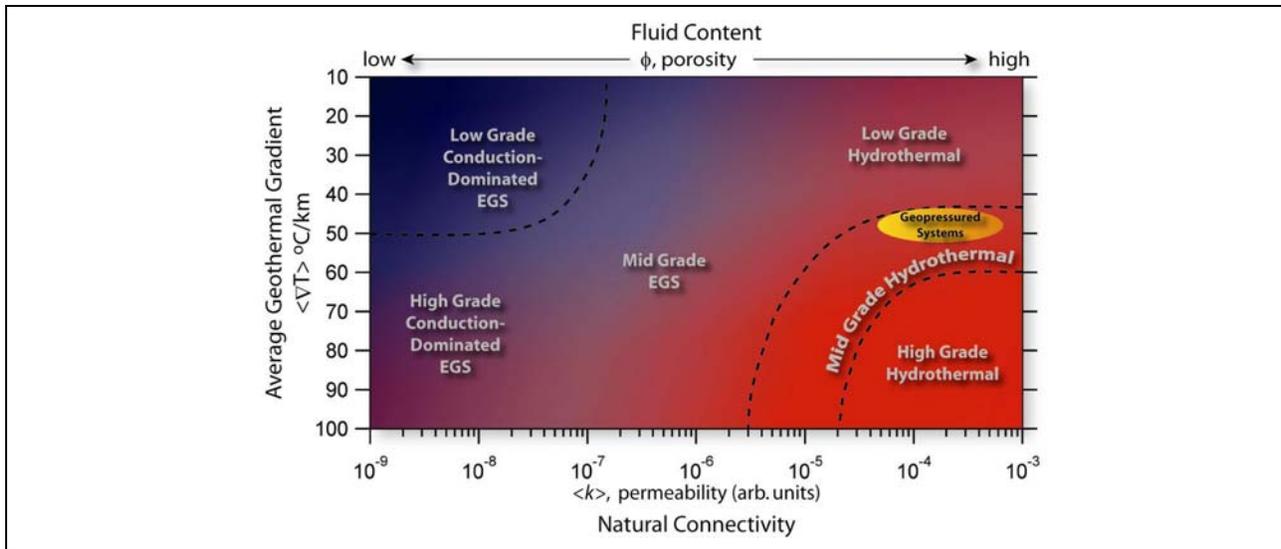
Figure 1 The continuum of geothermal resources as a function of average temperature gradient, natural connectivity and fluid content

As is often the case for mineral resources, the amount of a particular grade of resource varies inversely with its quality. Figure 2 shows the estimated amount of stored thermal energy for different categories of resources. These estimates are derived from Table 1.1 and Figure 1.6 of "The Future of Geothermal Energy" report (a complete description is found in Chapter 2 of (Tester et al., 2006)). Note that in all cases the total amount of accessible energy far exceeds the annual U.S. demand, which is currently 100 EJ.

In order for a geothermal resource to be utilized, its location is important. Sites too distant from load centers or transmission grids will be less attractive for development because they will have to pay the economic penalty of necessary transmission line construction. Low- and mid-grade EGS resources, which are conveniently more evenly distributed nationally, make up the vast majority of the overall geothermal resource base. Therefore, a means of developing EGS economically for all resource grades will eventually be needed to harness the full potential of the U.S. geothermal resource.
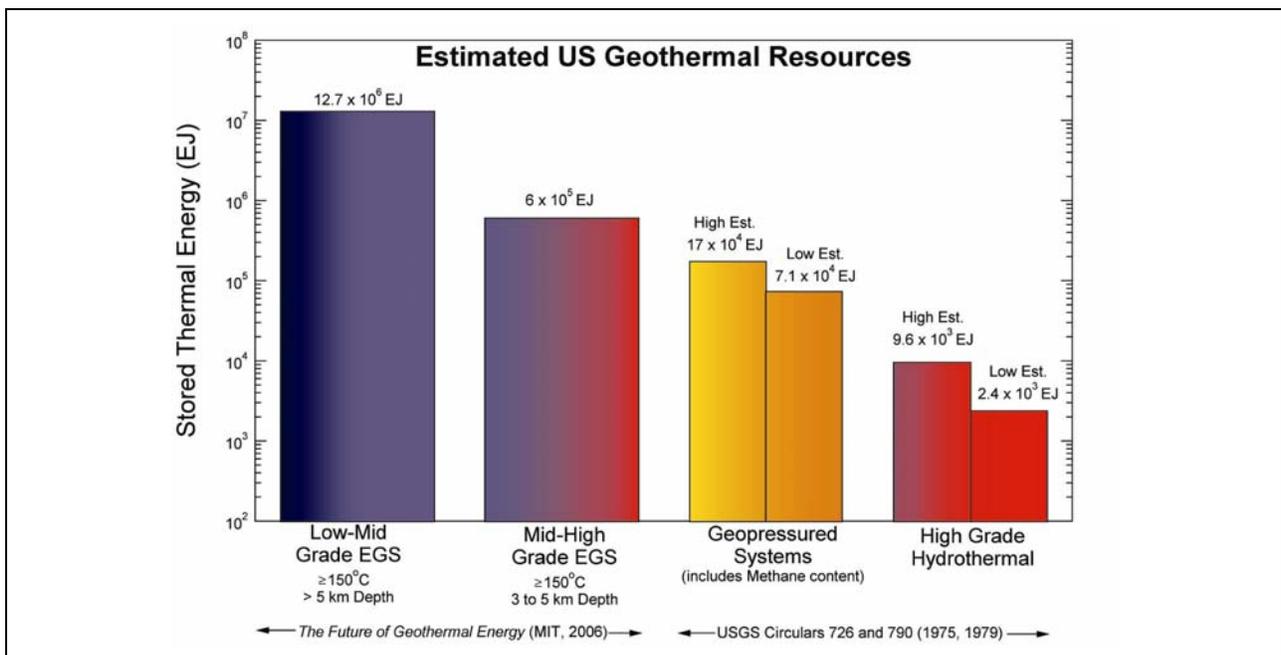

Figure 2 Stored thermal energy resource base for different types of geothermal resources (data from (Tester et al., 2006), (Muffler & Guffanti, 1979) and (Papadopulos et al., 1975)

CO$_2$ MITIGATION

A significant displacement of fossil fuel use and subsequent CO$_2$ mitigation could be realized with large scale deployment of EGS technology. The amount of CO$_2$ reduction possible by EGS electric power generation was calculated using 2006 data from the Energy Information Administration (EIA).

According to EIA data, 2006 U.S. electricity generation was 4092 TWh and U.S. electric generating capacity was 1.0 TWe. In 2030, EIA projects that generation will have reached 5,800 TWh and U.S. generation capacity will grow to 1.2 TWe (Energy Information Association, 2007a).

For our study, we assumed EIA's electricity production prediction up to 2030 and, as a "worst case" scenario, extrapolated to 2100 using the same energy mix predicted for 2030 and growth rate predicted between 2029 and 2030. Under these conditions, U.S. generation and electric capacity in 2100 would be 10,200 TWh and 2.3 TWe, respectively.

Further, we assumed that EGS would only replace coal and natural gas for electric power generation and that the replacement of coal and natural gas was non-preferential. Also, for simplification, EGS power plants were specified as non-CO$_2$-emitting binary plants with a capacity factor of 95%.

Figure *3* shows the effects of displacing coal and gas fired plants with EGS electricity generation. The chart shows that CO$_2$ emissions would be 30% lower than current energy sector emissions if 100 GW of EGS capacity were online today. In 2030, 100 GW of EGS capacity online would decrease CO$_2$ emissions by 21%, and the same capacity of EGS in 2100 would reduce CO$_2$ emissions by 11%. 300 GW of EGS capacity today would lower CO$_2$ emissions by 77% and the same EGS capacity in 2030 and 2100 would lower CO$_2$ emissions by 35% and 13% respectively. The reason such a large reduction in emissions is achieved with only 300 GW of EGS capacity is due to the large capacity factor of EGS plants compared to coal and natural gas plants, which have an average capacity rating of 72.6% and 38.3% respectively (Energy Information Association, 2007b)
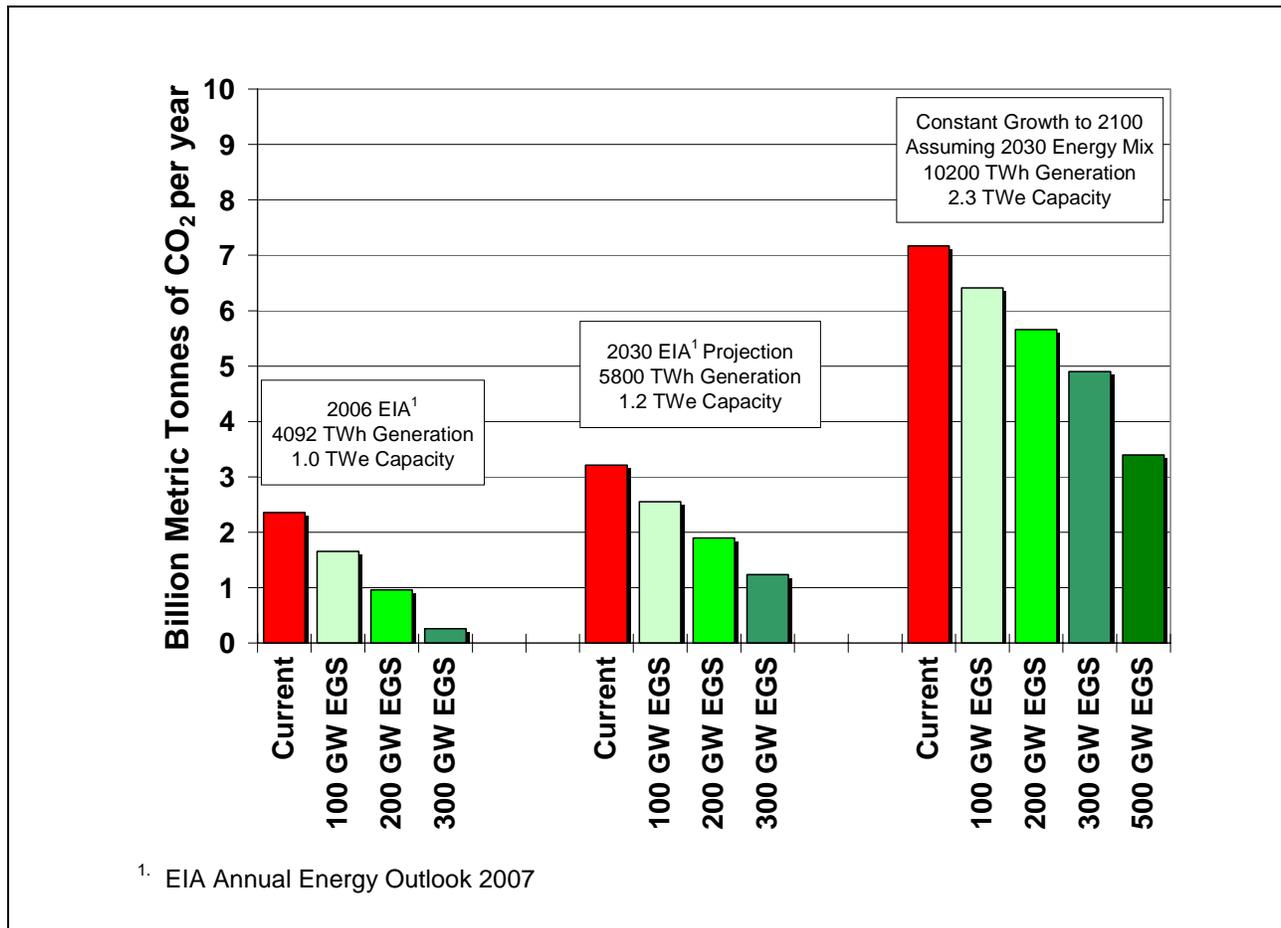

Figure 3 Effect of geothermal deployment (EGS) on CO$_2$ emissions from U.S. electricity generation

EGS ECONOMIC MODEL

An updated version of the MIT EGS model was used to predict Levelized Electricity Costs (LEC), surface plant costs and well costs. "EGS Modeling for Windows" was developed based on work done by Tester and Herzog (Tester & Herzog, 1990) and further enhanced by subsequent work at the MIT Energy Laboratory by Tester, Herzog and co-workers. The model was updated for "The Future of Geothermal Energy" assessment by Anderson and slightly modified in this study to facilitate the analysis given in our paper.

Description

A range of depths, average temperature gradients and flow rates were explored to analyze their effects on levelized costs of electricity. In order to explore the space, drilling depths from 3 km to 10 km were analyzed along with average temperature gradients from 10°C per km to 100°C per km and production well flow rates of 20, 40, 60, 80 and 100 kg per second. Feasible fluid temperatures for electricity production were assumed to lie between 100°C and 400°C. The same base case technical and financial parameters as used in the MIT study (see chapter 9 in Tester, et al, 2006) were used with two changes. First, the production to injection well ratio was changed from being a quartet with three production wells and one injection well to being five production wells for every four injection wells. Second, the debt to equity ratio was changed from 60/40 to 70/30 to reflect industry practice. All financial and cost figures cited in this paper are in 2004$ unless designated otherwise.

SURFACE PLANT COSTS

Surface plant costs were predicted using the same assumptions as were used for "The Future of Geothermal Energy" (Tester et al., 2006). As a conservative estimate, it was assumed that binary type power plants would be used to convert EGS resources to electricity regardless of the resource temperature. Surface plant costs were calculated using the following empirical correlation:

$$C = 2642.025 - 3.5 * T \qquad (1)$$

Where:

C = surface plant costs ($/kW in 2004$)
T = geothermal fluid temperature ($^{\circ}$C)

DRILLING COSTS

Two scenarios were used to represent drilling costs for EGS plants: one based on current technology and the other on projected advanced technology improvements. The current technology scenario uses drilling costs generated by the Wellcost Lite model, as presented in "The Future of Geothermal Energy" report (Tester et al., 2006). The advanced technology scenario does not assume or endorse any technology in particular, but instead estimates costs for advanced wells with certain characteristics that lead to lower increases in costs as a function of well depth. Both the current and advanced drilling cost scenarios assume 2004 drilling cost numbers.

Wellcost Lite

The Wellcost Lite model (Mansure et al., 2005) estimates the cost of drilling a well by sequentially accounting for the events and materials that occur during the course of drilling. The model calculates the time needed to drill each interval, including drilling time, tripping time, logging and maintenance time, etc., as well as the costs of mobilization and demobilization, daily rig rental, and/or purchasing items for each of these events. These costs are then summed and reported on a per-casing interval basis, and the cost of each interval is summed to obtain a total well cost.

The drilling costs used in this study assume the same wells and assumptions presented in Chapter 6 in (Tester et al., 2006). Well costs were estimated for depths from 1,500 m (4,900 ft) to 10,000 m (32,800 ft). The drilling costs estimated by the Wellcost Lite model are given in Table 1. A second-order polynomial was fit to these drilling costs, and this was used to calculate drilling costs for the economic model. Drilling costs of ±25% were also assumed and used in the economic model to determine how variations in these estimated costs, such as those that might be expected when drilling in different lithologies, affected overall EGS costs.

Table 1   Wellcost Lite base case costs (from Table A.6.3b in Future of Geothermal Energy Report)

Well Depth (m)	Well Depth (ft)	Estimated Cost (2004 M$)
1500	4921	2.303
2500	8202	3.372
3000	9842	4.022
4000	13123	5.223
5000	16404	6.740
6000	19685	9.172
7500	24606	14.645
10000	32808	19.731

Advanced Drilling Technologies

Well costs for advanced drilling technologies were also estimated. These estimates were used to determine how substantially lower drilling costs could affect EGS development costs in the future.

Previous studies have identified the need for an increasing number of casing intervals with depth as a reason that drilling costs increase significantly with depth (Augustine et al., 2006). Conventional wells are drilled in intervals that are cased and cemented in segments that telescope down to the final well diameter. These cased intervals are needed to control and stabilize the well and prevent collapse of the well as the depth increases. As the number of intervals increases, the amount of casing and cementing needed - as well as the size and expense of drilling equipment needed to complete the hole - increases. Additionally, extra time is needed to complete the intervals. Another major factor affecting drilling costs is the rate of penetration of the drill bit itself. Lower rates of penetration mean longer drilling time and increased rig rental costs. This could be a significant problem for EGS if wells are drilled in hard, granitic rock. As well depth increases, tripping time also becomes an issue.

Advanced drilling technologies that mitigate or eliminate some of the factors that lead well costs to increase non-linearly with depth were explored. Three cases of progressively advanced technologies to eliminate these factors were assumed. The particular technologies used to achieve these advances were not specified. We only assumed that the technology existed and was technically mature when it was deployed. The attributes of each advanced well case used to estimate costs is explained in greater detail below:

Case #1: Single-Diameter Wells

Technologies that eliminate the need for intermediate casing intervals that telescope down to the final well diameter were considered as examples that could enable lowering the cost of drilling substantially. Such technologies would create a "monobore" or "single-diameter" well that eliminates the need for much of the tangible costs and time associated with creating casing intervals. These wells could be envisioned by using an advanced expandable tubular system, a polymer or composite resin that coats the well wall and creates a temporary "casing" that adequately stabilizes the well for several weeks or months while the well is completed, or by simply assuming that deep EGS wells will typically be in competent, crystalline hard rock that can be drilled as an open hole over very long intervals, as for example in deep holes at Fenton Hill. As stated above, the particular technology is not important, only the resulting well attributes.

In this case, the following assumptions were made:

1. The well was drilled in three segments:
   a. A 36" (91 cm) conductor pipe to a depth of ~100 ft (30.5 m) at the surface (pre-spud).
   b. A 14-¾" (37.5 cm) diameter hole with 11-¾" (30 cm) casing to the top of the production zone.
   c. A 10-5/8" (27 cm) diameter hole drilled 4,000 feet (1,200 m) into the production zone with 8-5/8" (22 cm) perforated production liner.
2. All other intermediate intervals were excluded.
3. Trouble costs were kept to a minimum.

Case #2: Continuous Drilling

In addition to the assumptions made in Case #1, a technology that allowed continuous drilling in rock was envisioned for Case #2. Such a technology would assume a different, revolutionary mechanism of rock penetration, such as thermal spallation or fusion (Potter & Tester, 1998), chemical dissolution (Polizzotti et al., 2003), particle impact (Geddes & Curlett., 2006), or some other form of drilling where the "drill bit" does not wear out and need to be replaced. This type of drilling would eliminate the need for tripping and reduce rig rental times, especially for deep wells. Such a technology would also complement a "single-diameter" well system nicely.

In this case, the following assumptions were made:

1. Assumptions from Case #1 still apply.
2. Drilling system does not require bit replacement, so tripping time can be eliminated.
3. Rate of penetration does not change with depth, and was assumed to be 25 feet (7.62 m) per hour, which is slightly higher than rates assumed for conventional drilling in Wellcost Lite model.

Case #3: Reduced Casing Costs

In addition to the assumptions made in Case #1 and Case #2, a technology that reduced the capital costs for the casing used in the "single-diameter" 14-3/4" (37.5 cm) interval was envisioned for Case #3. This technology might utilize conventional casing designs that can be made with some newly developed, significantly cheaper material, an advanced polymer or resin that coats the well wall while drilling and is strong and stable enough to act as permanent casing, or some sort of reinforced cement with advanced strength and stability properties.

In this case, the following assumptions were made:

1. Assumptions from Case #1 and Case #2 still apply.
2. The cost of casing for the 11-3/4" (30 cm) casing interval is half what it would be for conventional steel casing.

3. Cementing costs are still assumed to apply, whether or not actual cement would be used to affix whatever form the casing may take.
4. Smaller rigs are needed to implement these new drilling and casing technologies due to their smaller size, weight, or the manner in which they are installed. Pre-spud costs and rig rental rates needed for a 10,000 ft (~3 km) conventional hole are assumed for all well depths.

Model Description

For each of the advanced drilling cases, costs for wells ranging in depth from 10,000 ft (3,050m) to 30,000 ft (9,150 m) were estimated using a system similar to that employed by the Wellcost Lite model. Costs for the pre-spud, conductor pipe interval, intermediate interval, and production interval were calculated and summed. It was assumed that most of the equipment and tools, or similar versions of them, would be used in the advanced technologies wells, so that costs for these individual items and services would be similar in both cases. Therefore, costs in the intervals were based on the costs associated with conventional drilling technology, with appropriate adjustments made depending on the case considered. For example, the costs estimated for Case #1 are very similar to those used in Wellcost Lite, except only one intermediate interval is used and it is extended over the entire length between the surface and the production interval. As the depth increased, adjustments were made for increased rig sizes, different rates of penetration and bit life, and more expensive casing.

The resulting well cost estimates for the different cases are shown in Table 2 through Table 4. It was found that estimated well costs as a function of depth could be described using a linear fit of the data. The results of this fit are also included in the table. These correlations were used in the EGS economic model to estimate drilling costs for the three cases.

An updated version of completed well costs as a function of drilling depth is shown in Figure 4, including the estimated well costs from Wellcost Lite, with the ±25% cases shown as dashed red lines above and below the base case, and the estimated linear well costs from the advanced technology cases shown as dashed black lines. The figure shows how the different drilling scenarios will be used to explore the sensitivity of LEC to variable drilling costs for EGS plants.

STIMULATION COSTS

Following the methodology used earlier in the EGS assessment (Tester et al., 2006), stimulation costs were assumed to be $500,000 for each well regardless of depth, temperature gradient or production well flow rate.

Table 2 Estimated well costs and linear fit of well cost estimates versus depth for Advanced Drilling Technology Case #1

	Well Depth (ft)						Linear Well Cost Fit (with 95% Confidence Interval)	
	10000	12000	16000	20000	25000	30000		
PreSpud	$188,000	$313,000	$346,000	$346,000	$346,000	$346,000	Slope ($/ft)	304 ± 23
Interval 1	$1,460,000	$1,985,000	$2,872,000	$4,282,000	$5,600,000	$6,876,000	Intercept ($)	-191955 ± 457710
Interval 2	$995,000	$1,177,000	$1,483,000	$1,463,000	$1,520,000	$1,576,000	R^2 Value	0.997
Total	**$2,715,000**	**$3,474,000**	**$4,701,000**	**$6,091,000**	**$7,466,000**	**$8,798,000**		

Table 3 Estimated well costs and linear fit of well cost estimates versus depth for Advanced Drilling Technology Case #2

	Well Depth (ft)						Linear Well Cost Fit (with 95% Confidence Interval)	
	10000	12000	16000	20000	25000	30000		
PreSpud	$188,000	$313,000	$346,000	$346,000	$346,000	$346,000	Slope ($/ft)	204 ± 37
Interval 1	$1,230,000	$1,595,000	$2,253,000	$3,498,000	$4,138,000	$5,008,000	Intercept ($)	332366 ± 746979
Interval 2	$774,000	$822,000	$955,000	$985,000	$939,000	$945,000	R^2 Value	0.983
Total	**$2,264,000**	**$2,730,000**	**$3,554,000**	**$4,829,000**	**$5,424,000**	**$6,298,000**		

Table 4 Estimated well costs and linear fit of well cost estimates versus depth for Advanced Drilling Technology Case #3

|	Well Depth (ft)						Linear Well Cost Fit (with 95% Confidence Interval)	
	10000	12000	16000	20000	25000	30000		
PreSpud	$188,000	$260,000	$260,000	$260,000	$260,000	$260,000	Slope ($/ft)	132 ± 6
Interval 1	$1,086,000	$1,323,000	$1,745,000	$2,373,000	$3,005,000	$3,612,000	Intercept ($)	788897 ± 112607
Interval 2	$774,000	$771,000	$862,000	$840,000	$844,000	$848,000	R^2 Value	0.999
Total	**$2,120,000**	**$2,353,000**	**$2,867,000**	**$3,473,000**	**$4,108,000**	**$4,720,000**		
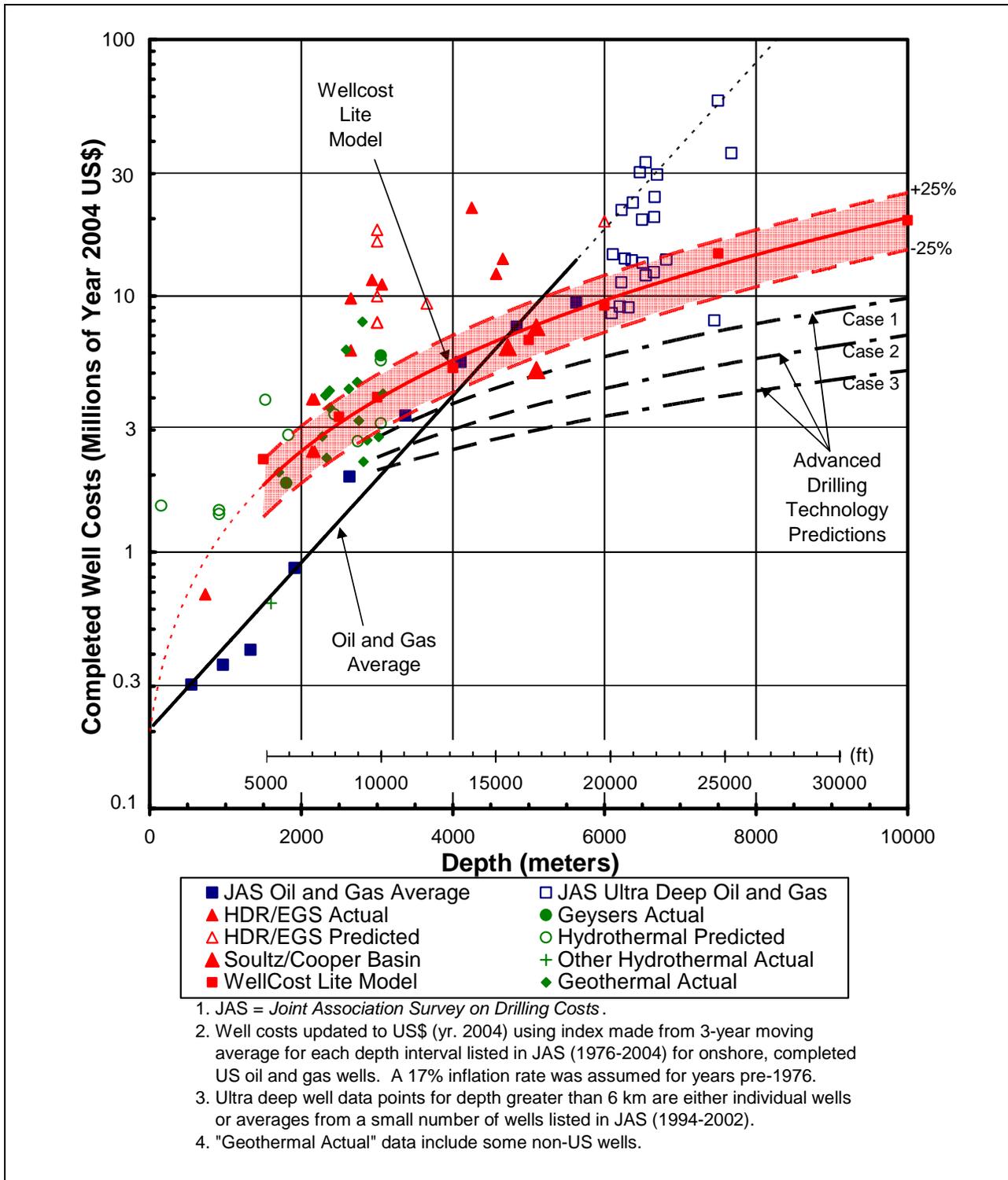
Figure 4 Predicted and actual drilling costs as a function of depth (adapted from Figure 1.8 in (Tester et al., 2006))

ELECTRICIY PRICES

To analyze the feasibility of drilling scenarios, a market electricity price forecast for baseload energy was made. The price of baseload energy is a reflection of the lowest price energy available for dispatch in the system. The system operator will dispatch from the bottom of the bid stack in order to satisfy load at the lowest price. Today, baseload operators will typically bid zero, and the system operator will pay for electrical energy based on the estimated marginal cost for generating electricity

from the last units accepted for dispatch. This will vary depending on the area served, but presuming that both coal and nuclear were available, nuclear would be dispatched first and coal second given their operating price schedule. Higher priced coal would be dispatched for load following. Firming would typically be done first with hydroelectric supplies followed by the next most expensive bid.

Baseload energy demands are not specifically forecast by most energy agencies such as the EIA (Energy Information Administration) or the NEB (National Energy Board). In these cases the forecast will typically address the composite energy price that includes fuel prices by source such as coal, natural gas, or oil, (but not renewable sources). In addition, contracts for power delivery from these sources will reflect long term and relatively stable (i.e. less volatile) pricing.

Available forecasts are limited in their time horizon. For instance, the EIA forecast goes to 2030 (and is projected to increase linearly at the same rate of 1.4% per year) and the NYMEX only projects prices until 2016.

In our base case forecast, the energy price is assumed to increase at 2% per year in excess of the rate of inflation. Primarily, it reflects U.S. population and associated demand increases plus some small margin for energy intensity. An average of the estimated price of coal and nuclear energy is used as a base price estimate. Projected natural gas prices were not included in our base case forecast.

Additionally, a high price case prediction was made. The following assumptions were made for the high price case:

- 10% of the existing coal fleet is replaced in 2015 and 40% in 2020.
- 60% of the existing nuclear fleet is relicensed in 2010 for an additional 20 years and 100% of the fleet is retired in 2030.
- Limited new nuclear plant construction begins in 2015 and prices increase by 25% over the previous year, and then inflate at 3% per year, while coal inflates at 2% per year.
- Nuclear price increases occur again in 2020 (25%) and 2030 (50%) and then inflate at 3% per year to 2050.
- New coal construction in 2015 causes 25% rise in delivered price from previous year.
- Coal price increases occur again in 2020 (25%) and 2030 (50%) and then inflate at 2% per year to 2050.

Figure 5 shows the base case and high case baseload electricity price projections. In 2050 the base case price forecast projects the price of electricity to be 7 cents/kWh, while the high price case forecast projects the 2050 price to be just below 29 cents/kWh.
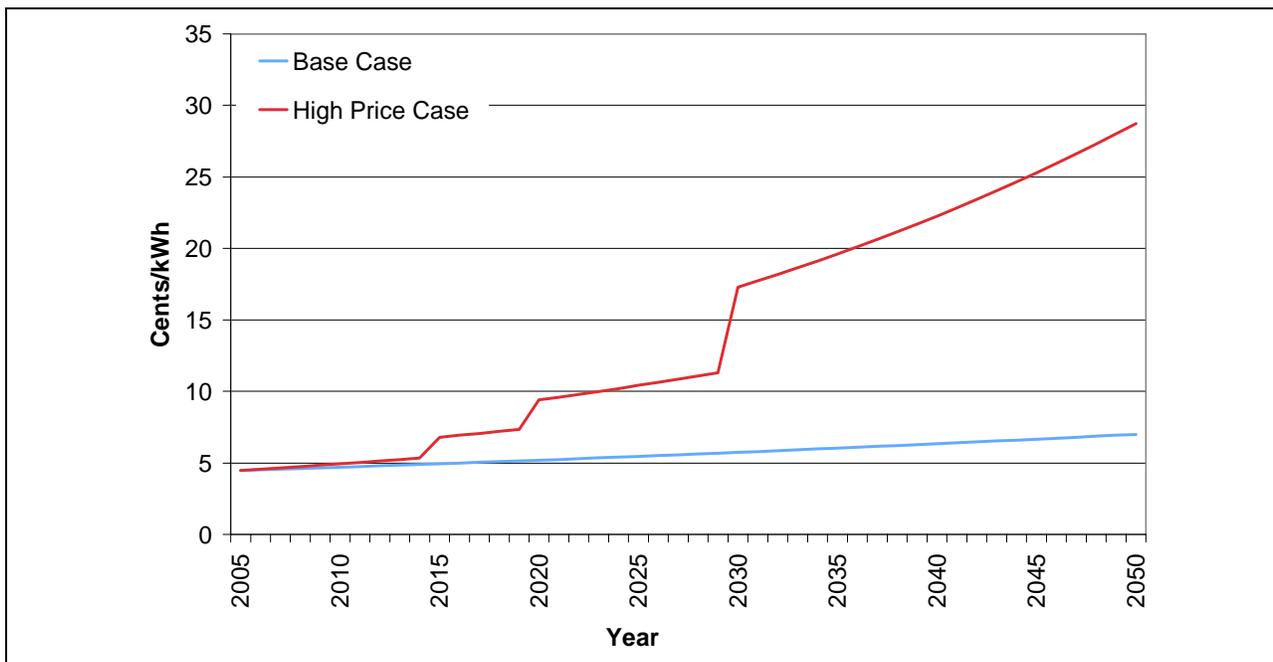

Figure 5 U.S. electricity price forecast in 2007$

RESULTS

The model produces estimates of the levelized cost of electricity (LEC) along with total well costs and surface plant capital costs for each set of parameters considered. The model run results were analyzed with respect to both base and high price electricity price forecasts. Base case price feasibility was defined as those scenarios with an LEC less than 7 cents/kWh. Feasibility for the high market electricity price case was defined as those scenarios where the LEC is less than 29 cents/kWh.

Effect of reservoir quality - well production rates

Figure 7 – Figure 9 show the feasibility of various parameter combinations. The lower half of each square indicates the feasibility of the respective parameter combination for the high price case

scenario while the top half of each square shows the feasibility for the base price case scenario. The colors show the lowest flow rate that will allow for economically feasible EGS electricity production.
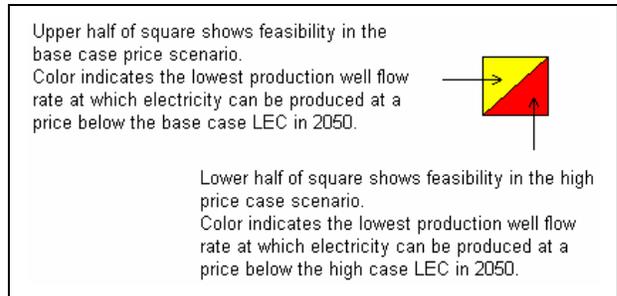
Figure 6 Figure key for figures 7-9
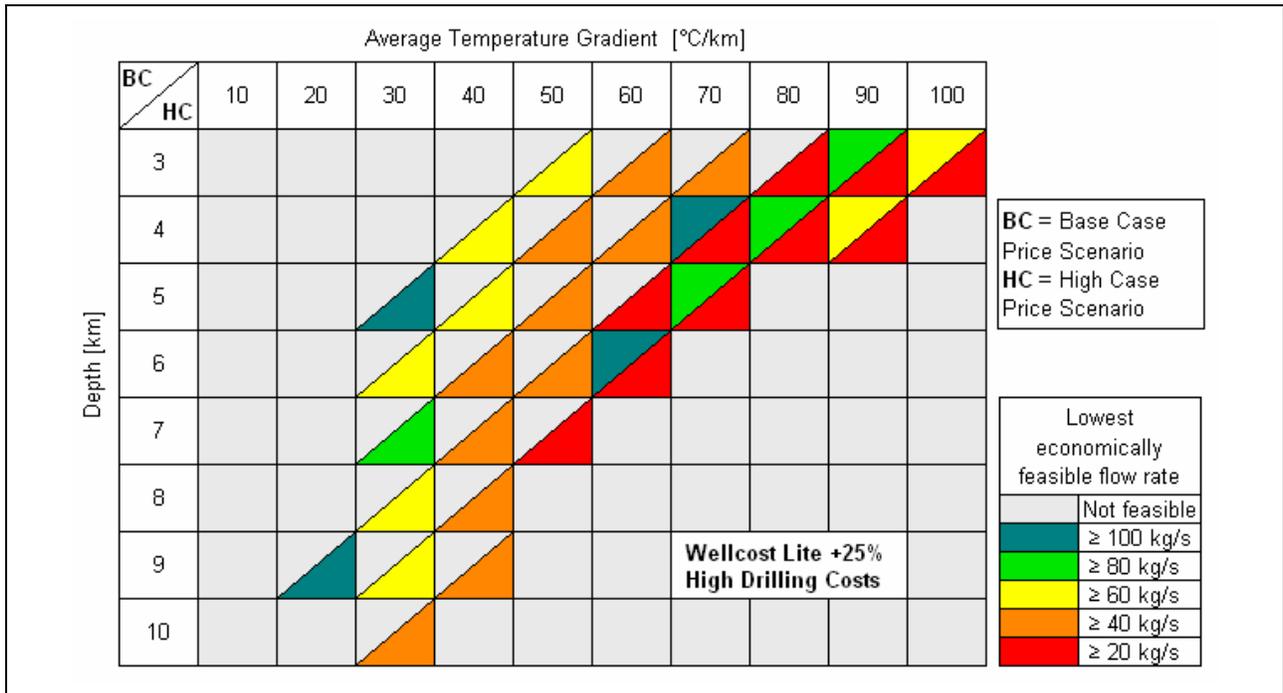
Figure 7 Base case and high case price scenario economic feasibility for drilling cost case Wellcost Lite +25%
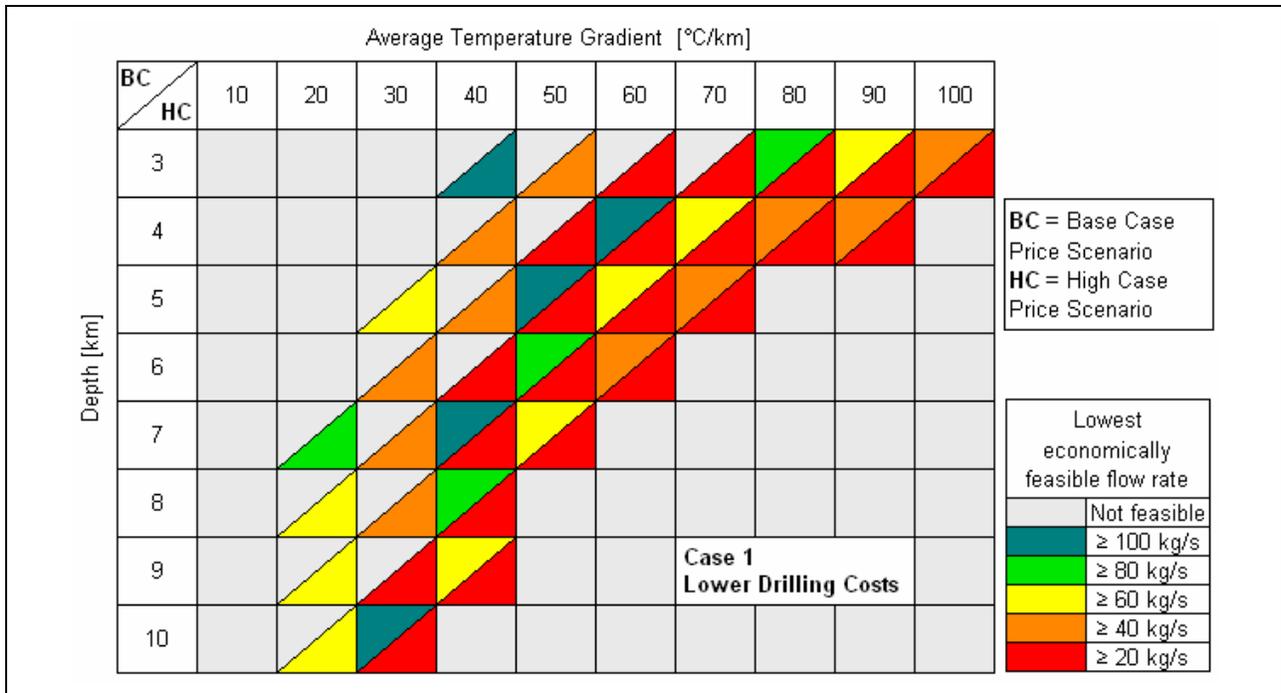
Figure 8 Base case and high case price scenario economic feasibility for drilling cost Case 1
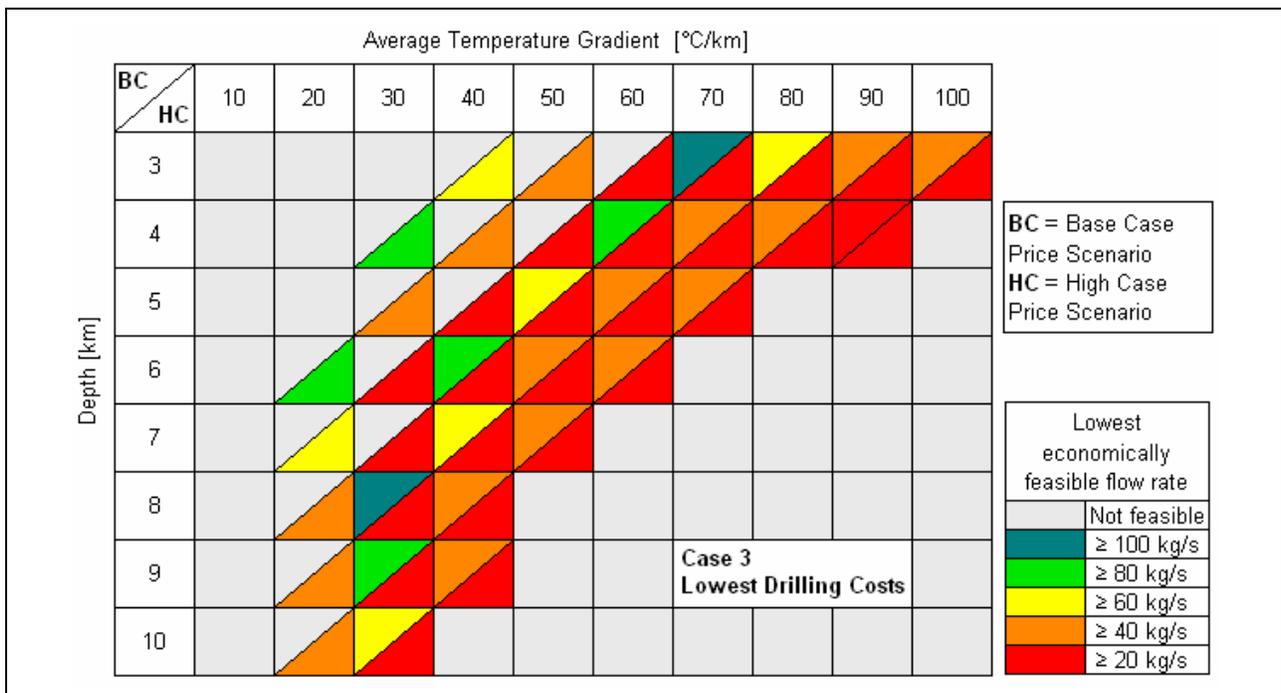

Figure 9 Base case and high case price scenario economic feasibility for drilling cost Case 3

Figures 7-9 show that economic feasibility increases considerably with drilling cost reductions. For example, for advanced technology Case 3, a 40-60 kg/s flow rate is sufficient for base price case feasibility for a wide range of depths and average temperature gradients. However, EGS electricity production at 40-60 kg/s at Wellcost Lite +25% conditions is only feasible under the base price case scenario at average temperature gradients above 80°C/km and depths less than 5 km. Also, as drilling costs decrease, higher flow rates are no longer as crucial for economic feasibility in mid- to low- grade resource areas shown in Figure 1.

Well and Surface Plant Costs

Economic feasibility results were correlated with the well and surface plant costs. Conditions were chosen for analysis that would represent different feasibility conditions. Figure 10 and Figure 11 show the base case price feasibility of the six drilling cases for different flow rates at depths of 5 and 4 km respectively and average temperature gradients of 60°C/km and 80°C/km respectively. Figure 12 shows the high price case feasibility at 10 km depth and an average temperature gradient of 20°C/km. By comparing the three figures it can be seen that well costs become increasingly dominant as reservoir productivity declines. As well costs are lowered, economic feasibility is achieved in both the base price case and the high price case. Additionally, Figure 11 shows that the first EGS deployment projects should be focused on areas with high average temperature gradients where shallow wells suffice to reach feasible production temperatures.
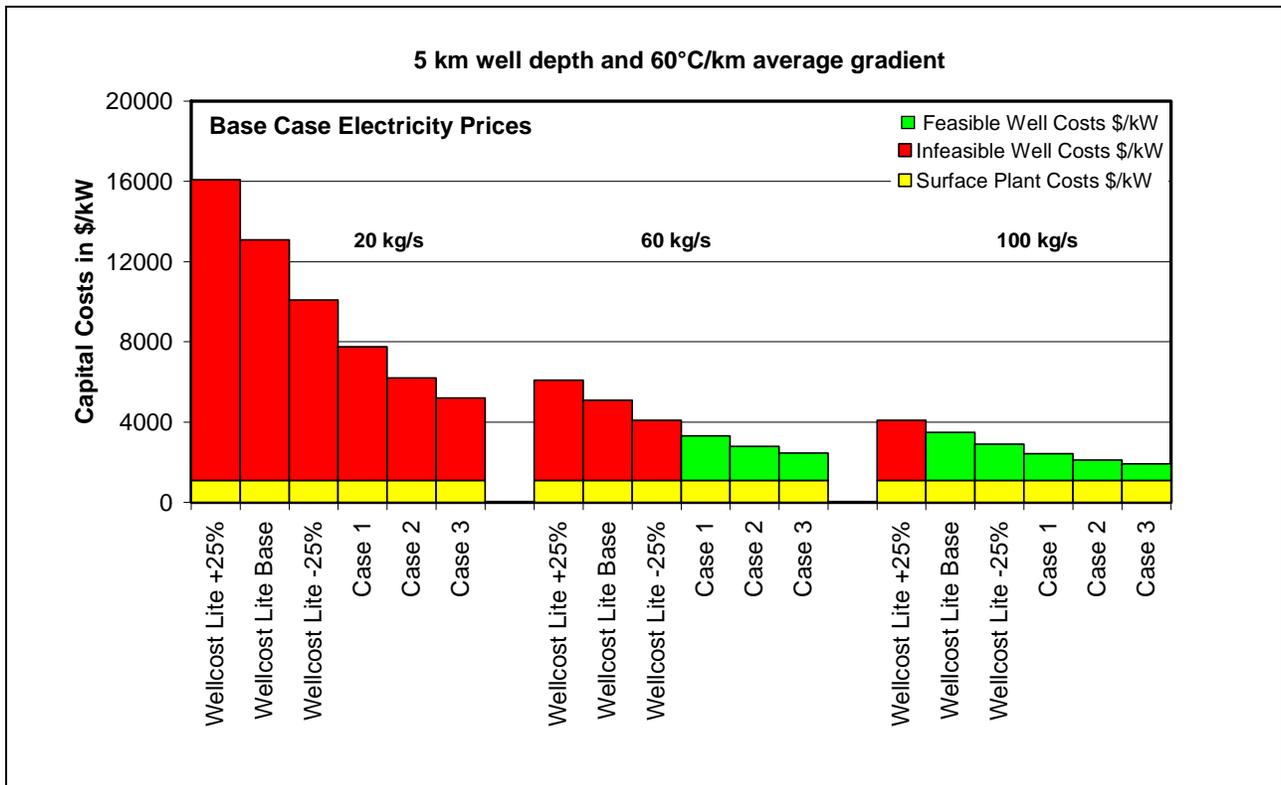

Figure 10 Well costs and surface plant costs for different drilling technology cases. Economic feasibility at base case electricity prices for 2050 indicated by color of bars representing drilling costs
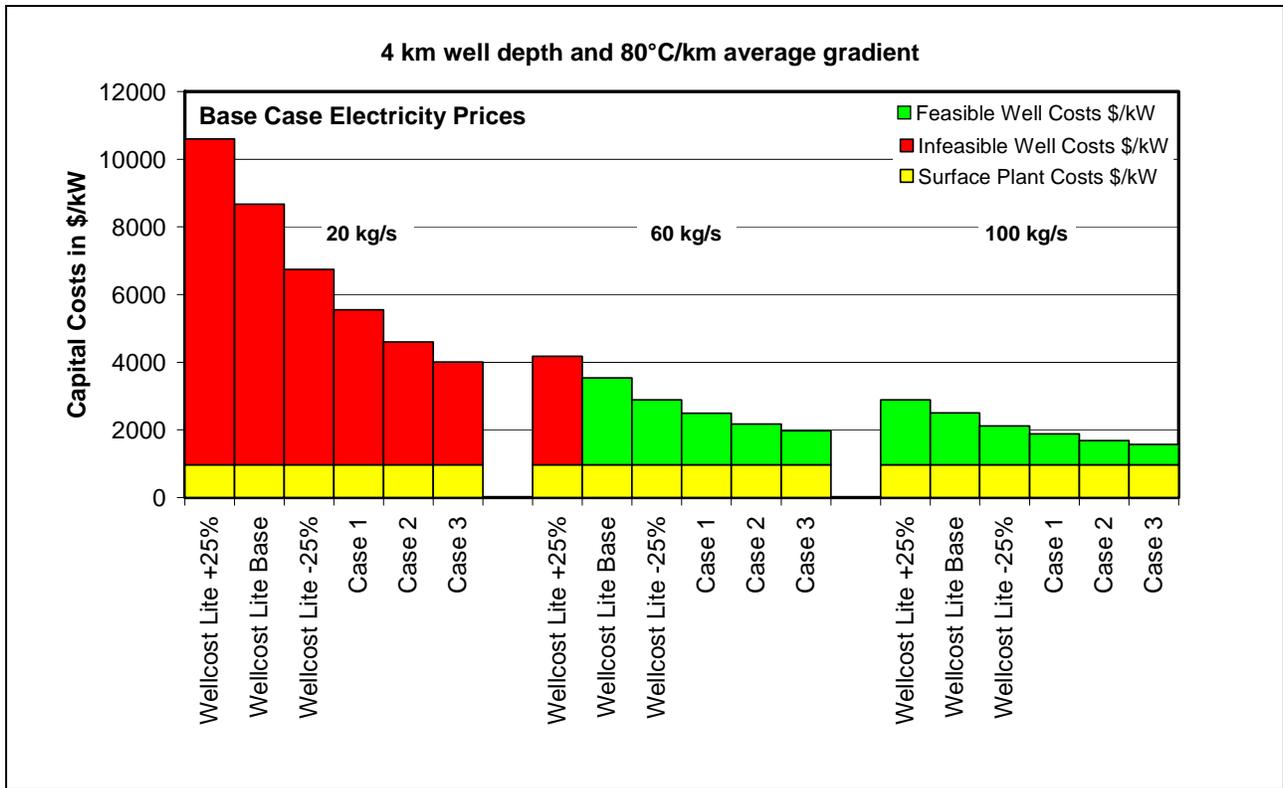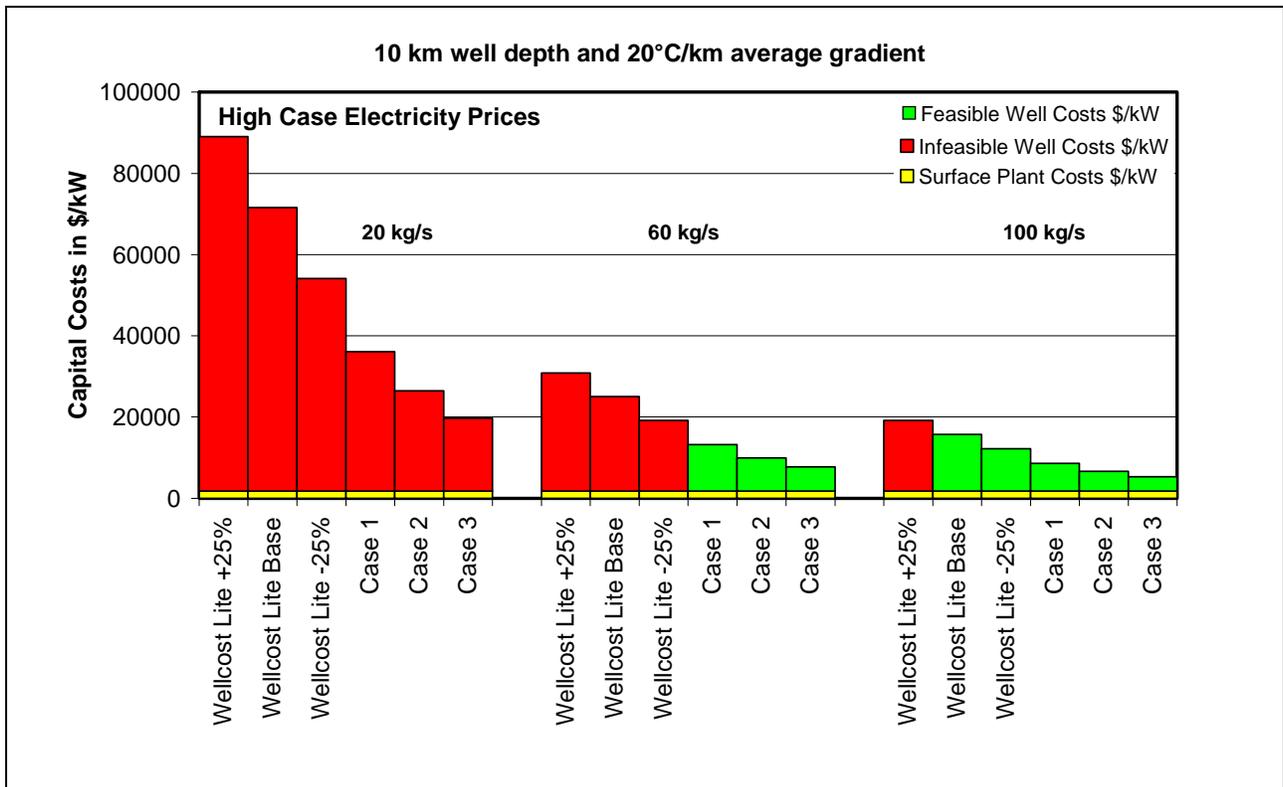
Figure 11 Well costs and surface plant costs for different drilling technology cases. Economic feasibility at base case electricity prices for 2050 indicated by color of bars representing drilling costs

Figure 12 Well costs and surface plant costs for different drilling technology cases. Economic feasibility at high case electricity prices for 2050 indicated by color of bars representing drilling costs

CONCLUSIONS

Drilling costs are a significant component in any EGS development. The drilling component becomes increasingly important as required depths for drilling increase for lower gradient resources. By laying out six drilling cost cases and pairing them with different parameters for flow and resource quality in an updated version of the MIT EGS model, the cost space for EGS was explored. The advanced technology drilling cases were developed without a specific technology in mind but rather with the intention of covering a wide range of cost scenarios and of mitigating or eliminating some of the factors that lead well costs to increase non-linearly with depth. In the advanced drilling technologies cases, the main cost reducing factors used were single diameter wells, an increased rate of penetration and reduced casing costs.

To analyze the feasibility of the six drilling cases, two electricity price forecasts to 2050 were developed: a base case scenario and a high price scenario. The base case price scenario predicts 7 cents/kWh in 2050 while the high price scenario predicts 29 cents/kWh, both in year 2007$. The model runs show that economic feasibility increases considerably with drilling cost reductions. Figure 10 to Figure 12 show clearly that drilling costs represent a significant portion of EGS capital costs. As drilling costs are lowered, the ratio between well costs/kW and plant costs/kW decreases, and economic feasibility is achieved.

Well production flow rates are another important performance factor for any EGS project as they are a measure of how well engineered the subsurface is. Field experiments in Soultz, France have achieved flow rates of 20 kg/s (Tester et al., 2006) with a clear path to increase them by two to three fold. At a flow of 20 kg/s, economic feasibility is only achieved under high electricity price forecast conditions based on our model. If the flow rate is doubled, base case price feasibility will still not be achieved in today's energy markets unless innovation occurs in drilling technology. However, if a three fold increase in production flow rates is achieved, Figure 11 shows that economic feasibility is attainable under base case price conditions in areas with high average temperature gradients. Accordingly, the first EGS development projects should be focused on those areas. Furthermore, if the high price scenario proves to be right, then 40 kg/s will prove sufficient for economic feasibility for a wide range of depths and average temperature gradients.

CO_2 mitigation calculations show that utilizing only a portion of the massive EGS resource base would significantly lower U.S. greenhouse gas emissions. For instance, 100 GW of EGS replacement capacity online in 2030 would decrease U.S. CO_2 emissions by 21%. As technology innovations occur and energy and financial markets evolve, it is important to identify and quantify what EGS resource and engineering conditions are likely to produce economic feasibility. Consequently, EGS economic analysis needs to be continually updated with respect to technical advances and project costs.

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