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Performance, Cost, and Financial Parameters of Geothermal District Heating Systems for Market Penetration Modeling under Various Scenarios

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ABSTRACT

Geothermal district heating (GDH) systems have limited penetration in the U.S., with an estimated installed capacity of only 100 MW_{th} for a total of 21 sites. We see higher deployment in other regions, for example, in Europe with an installed capacity of more than 4,700 MW_{th} for 257 GDH sites. The U.S. Department of Energy Geothermal Vision (GeoVision) Study is currently looking at the potential to increase the deployment in the U.S. and to understand the impact of this increased deployment. This paper reviews 31 performance, cost, and financial parameters as input for numerical simulations describing GDH system deployment in support of the GeoVision effort. The focus is on GDH systems using hydrothermal and Enhanced Geothermal System resources in the U.S.; ground-source heat pumps and heat-to-electricity conversion technology were excluded. Parameters investigated include 1) capital and operation and maintenance costs for both subsurface and surface equipment; 2) performance factors such as resource recovery factors, well flow rates, and system efficiencies; and 3) financial parameters such as inflation, interest, and tax rates. Current values as well as potential future improved values under various scenarios are presented. Sources of data considered include academic and popular literature, software tools such as GETEM and GEOPHIRES, industry interviews, and analysis conducted by other task forces for the GeoVision Study, e.g., on the drilling costs and reservoir performance.

1. INTRODUCTION

1.1 Market for Geothermal District Heating Systems

A significant amount of primary energy is used in the U.S. and other countries to supply low-temperature heat for residential, commercial, and industrial applications. Fox et al. (2011) calculated that about 25 EJ (7,000 TWh)—or roughly a quarter of the total U.S. primary energy demand—is consumed as heat under 120°C. About half of this heat demand is space and water heating at around 50°C in the residential and commercial sectors. Comparable thermal demand numbers were derived by McCabe et al. (2016), who conducted a geospatial analysis of heat demand in residential, commercial, manufacturing, and agricultural sectors by U.S. county. The vast majority of heating systems supplying this demand are based on natural gas, electricity, and heating oil. Heat from geothermal energy could be an attractive environmentally friendly alternative where supply temperature matches end-use application.

Geothermal resource assessments report massive amounts of geothermal heat available in the U.S. (Tester et al., 2006; Blackwell et al., 2013; Mullane et al., 2016). When considering only resources with temperatures up to 150°C and less than 3 km deep, Mullane et al. (2016) estimate about 8 million TWh of accessible hydrothermal resources are present mainly in the Western U.S., and roughly 800 million TWh of accessible Enhanced Geothermal Systems (EGS)-type resources are distributed throughout the country. Extracting these lower-temperature resources for electricity generation may be uneconomical due to low heat-to-power conversion efficiencies. However, utilizing them instead for a direct-use (DU) application such as space and water heating could result in attractive levelized costs of heat (LCOH) in the range of 8–36 \$/MMBtu for hydrothermal geothermal district heating (GDH) systems (Thorsteinsson & Tester, 2010), 10–30 \$/MMBtu for EGS GDH systems (Reber, 2013), and 4–15 \$/MMBtu for EGS industrial applications (Beckers, 2016).

A district heating (DH) system allows transferring heat efficiently from a central plant through a distribution network to thousands of residential and commercial customers. Various sources of heat can be used, such as geothermal heat, solar thermal heat, waste heat, or heat from burning natural gas or other fossil fuels. Distribution losses can be limited to a few percent when using modern insulated piping and liquid hot water as the heat transfer medium. Based on data reported by the International District Energy Association (IDEA, 2016), it is estimated that 500 to 600 DH systems are in operation in the U.S. supplying on the order of 0.1% of total space and water heating in the country. Only a handful (21) are GDH systems (Snyder et al., 2017), with an estimated total installed capacity of about 100 MW_{th}. The most well-known example is probably the Boise GDH system, consisting of four individual systems for a total installed capacity of 40 MW_{th}, with the first system in operation since 1892 (Snyder et al., 2017). District cooling systems have also been developed, such as the 56 MW_{th} lake-source cooling system at Cornell University. Although district cooling systems could be served with geothermal energy through absorption chillers, they are outside the scope of this paper.

Although GDH—and even DH—systems currently have limited penetration in the U.S., some other countries see much wider deployment. As of 2015, 257 GDH systems are in operation in Europe for a total installed capacity of 4,702 MW_{th} (EGEC, 2016). In Iceland, 90% of residential and commercial space and water heating is supplied using GDH systems (Tester et al., 2015). The GDH system serving the city of Reykjavik provides hot water to 200,000 people from geothermal wells up to 27 km away using a distribution network with 3,000 km of piping. Another successful example is the Paris Basin GDH network, which provides hot water to 150,000 dwellings using 34 geothermal doublets (one injection well for each production well) (Tester et al., 2015). In Germany, the city of Munich is currently developing a 400 MW_{th} GDH system using 25 doublets to provide geothermal hot water to the entire city (Farquharson, 2016).

1.2 GeoVision Study

Investigating the potential for higher GDH penetration rates in the U.S. and understanding its impact and required investment strategies are some of the objectives of the Geothermal Vision (GeoVision) Study, a major undertaking currently ongoing by the U.S. Department of Energy (DOE). The GeoVision Study is assessing geothermal growth scenarios for 2020, 2030, and 2050 across several market segments, with analyses and research conducted by various task forces among several U.S. national laboratories. Other research efforts by the DU thermal applications task force at the National Renewable Energy Laboratory (NREL) include a low-temperature geothermal resource assessment (Mullane et al., 2016) and heat demand assessment (McCabe et al., 2016), as well as a review of the current and historical U.S. GDH installations (Snyder et al., 2017).

1.3 Market Penetration Modeling

To support the GeoVision Study, NREL has developed the Distributed Geothermal Market Demand Model (dGeo) to understand the role that geothermal heat pumps (GHPs) and GDH systems could play in meeting current and future thermal demands in the residential and commercial sectors in the U.S. (Gleason et al., 2016). dGeo estimates the technical, economic, and market potentials, and the technology deployment of GHP and GDH through 2050 under various scenarios. dGeo incorporates the data obtained from the previously conducted resource assessment (Mullane et al., 2016) and heat demand assessment (McCabe et al., 2016), and requires user-specified input for a wide range of performance, cost, and financial parameters. The GeoVision study is conducting similar analyses for the electricity sector using the Regional Energy Deployment System (ReEDS) model. Input data parameters (e.g., drilling costs) for the thermal model (dGeo) and the electric model (ReEDS) were kept consistent between the two models when possible.

1.4 This Paper

This paper discusses the various performance, cost, and financial parameters required as input to dGeo to simulate the techno-economic performance of a GDH system. Current and estimated future values are provided, and their importance, uncertainty, and potential impact are discussed. Although the focus in this report is on GDH systems, several parameters (e.g., drilling costs or well flow rates) are directly applicable to other geothermal DU and electricity applications.

The methodology applied to obtain reliable GDH parameter values is discussed in Section 2. The various GDH parameters, grouped in different categories, are discussed in Section 3. A discussion of the data and its gaps, and how these values are incorporated in scenarios in dGeo is the topic of Section 4. Section 5 provides overall conclusions and suggestions for future work. The actual values for the various parameters are presented in tables in Appendix A.

2. METHODOLOGY

The performance, cost, and financial parameters necessary to simulate GDH system deployment in dGeo were identified in collaboration with the dGeo team, and after review of other NREL distributed generation models, e.g., for wind and photovoltaics (Sigrin et al. 2016); existing geothermal simulation tools, e.g., GETEM (Mines, 2016) and GEOPHIRES (Beckers, 2016); and previous GDH modeling studies, e.g., Reber (2013) and Lund and Lienau (2009). An extensive literature review was then conducted to find current and future values for the identified parameters. Reliability of some parameter values was increased by interviewing the operators of recent installations. Where applicable, data and findings from other GeoVision task forces were used directly to avoid duplicate work and guarantee consistency among the various GeoVision task forces and modeling efforts.

3. RESULTS

The various dGeo GDH input parameters provided and discussed in this section are categorized by type: performance parameters (Section 3.1), cost parameters (Section 3.2), and financial parameters (Section 3.3). For each parameter, we provide a brief description, an overview of values found in literature or reported by an operator, and the selected business-as-usual (BAU) and potential improved values as dGeo input. Tables listing all parameter values for various dGeo scenarios are included in Appendix A.

3.1 Performance Parameters

3.1.1 Plant and End-Use Performance

Peaking Boiler Sizing: Typically, a GDH system is not designed to cover all heat demand, because this would result in underutilization of the (relatively capital-intensive) geothermal system on most days of the year and a corresponding low capacity factor. Geothermal systems are typically designed to cover 50%–60% of the peak demand, with the remaining covered by peaking boilers. Because the peak demand only occurs a few days of the year, the geothermal system would still supply 80%–90% of the annual heat demand (Lund, 2010). Values of peaking boiler size as a percentage of peak load reported in the literature are in the range from 40% (Elíasson and Björnsson, 2003; Lund and Lienau 2009) to 50% (Lund, 2010; CanGEA, 2014). As a dGeo input parameter, an average value of 45% is assumed for peaking boiler size (and the geothermal system supplies 55% of the peak load). For the improved scenarios, dGeo assumes that this value drops to 40% to account for anticipated decreases in drilling costs, and hence, less capital-intensive geothermal systems.

Peaking Boiler Efficiency: dGeo assumes the use of a natural gas as the fuel to operate the boiler. For calculating the required annual amount of natural gas and corresponding costs when running the peaking boiler, the peaking boiler efficiency should be specified. In literature, various natural-gas-fired boiler efficiencies have been reported: 70% (Lund and Lienau, 2009), 75% (Engen, 1978; Rafferty, 2001), 80% (Lienau et al., 1994), 85% (Dagdas, 2007; Reber, 2013), 90% (Beckers, 2016), and 93% (Rafferty, 2001). For dGeo, a peaking boiler efficiency value of 85% was selected, following Reber (2013) from his recent study specifically on GDH systems. It is assumed that the boiler technology is well established; therefore, no efficiency improvements are considered.

Average End-Use Efficiency Factor: The average end-use efficiency factor refers to the ratio of average useful thermal energy consumed by the end users in a DH system to the thermal energy supplied by the geothermal fluid. This factor captures the losses in the transmission and distribution system and heat exchangers and is therefore not a constant but a function of the size, layout, and type of the system. Some values reported in literature for total losses are: 60% (Ozgener, 2012), 72% (Lund, 2009), and 90% (Thorsteinsson, 2008). Reported values for losses in the distribution system (alone) are in the range of 10%–15% (Glassley, 2014). dGeo does assume a constant end-use efficiency factor. A value on the higher end of 80% is selected, assuming the DH systems considered are of the most efficient type (liquid-water based). Because heat exchangers and insulated piping are established, low-tech technology, no future efficiency improvements are anticipated.

3.1.2 Subsurface Performance

Section 3.1.2 only discusses subsurface performance parameters related to EGS reservoirs. The input parameters for hydrothermal systems were selected by Mullane et al. (2016) based on data obtained from U.S. Geological Survey (USGS) circular geothermal resource assessments, e.g., Reed (1983). Further, dGeo does not consider thermal or hydraulic drawdown and sets the well configuration as doublets.

EGS Resource Recovery Factor: The EGS resource recovery factor refers to the percentage of heat that can be recovered from the accessible heat in the geothermal reservoir. Here, the definition by Mullane et al. (2016) is followed, which defines accessible resource base as:

$$\text{(volume of rock layer)} \times \text{(density of rock)} \times \text{(heat capacity of rock)} \times \text{(temperature of rock layer} - \text{reference temperature)}\ , \qquad (1)$$

with the reference temperature set to 15°C. Because GDH reinjection temperatures are typically in the range of 30°C–60°C (IEE, 2016), a reference temperature of 15°C is on the low side and this definition of accessible resource base should be treated as an upper limit. The maximum extractable amount of heat in dGeo is then defined as:

$$\text{(EGS resource recovery factor)} \times \text{(accessible resource base)}\ . \qquad (2)$$

Theoretical models can predict high recovery factors of up to 50%, (e.g., the Gringarten et al. (1975) multiple parallel fractures model), but actual values are much smaller—on the order of 1%–2% (Grant and Garg, 2012; Augustine, 2016). In the Future of Geothermal Energy report (Tester et al, 2006), the conservative value assumed was 2% and the upper limit 40%. Naturally occurring, fractured reservoirs have recovery factors around 5%–15% and are often considered an upper limit for EGS recovery factors (Grant and Garg, 2012). The BAU value selected for the dGeo model is 2%. It is assumed that with improved EGS technology, better EGS reservoirs can be created with more optimal fractures, and hence, higher recovery rates (up to 4%).

EGS Area per Wellset: The EGS area per wellset refers to the planar reservoir area from which heat is extracted from an EGS injection/production well pair. Hence, it is a proxy of the spacing necessary between neighboring well pairs. Augustine (2016) estimated the planar area for a ~250 MW_{th} EGS plant ranging from 27–121 km^2 depending on the calculation method assumed. Using this information—and assuming that a production and injection wellset has a current thermal output on the order of 10 MW_{th}—the resulting area per wellset is on the order of 1 to 5 km^2. An average value of 3 km^2 is assumed as the BAU value for dGeo. The improved scenario assumes the area per wellset can be increased to 5 km^2 due to more effective stimulation methods resulting in larger geothermal reservoirs (and correspondingly larger flow rates and larger MW_{th} production per wellset).

EGS Maximum Sustainable Well Production[1]: The EGS maximum sustainable well production is the flow rate (in l/s) per well-pair for an EGS reservoir. This parameter is known to have a major impact on overall techno-economic feasibility of the geothermal DU project (Reber, 2013; Beckers, 2016). Because EGS-type geothermal reservoirs are still in early stages of research, limited data are available on currently achievable flow rates. The flow rate values selected as input to dGeo were obtained from the GeoVision Reservoir Management and Development Task Force (Augustine, 2017) and fall in the range of 40–110 l/s. This range is in line with values found in literature. For example, the current default value in GETEM is 40 l/s (Mines, 2016), and flow rates under improved scenarios assumed in techno-economic models go up to 70 l/s (Beckers, 2016) and 80 l/s (Tester, 2006; Reber, 2013). Major research and demonstration efforts, e.g., the FORGE initiative (DOE, 2017), are ongoing to create and optimize EGS reservoirs with sufficiently large volume and permeability. Hence, significant improvements are expected for future obtainable flow rates.

3.2 Cost Parameters

3.2.1 Subsurface Plant Costs

Future Drilling Cost Improvements: The drilling costs are the costs for drilling and completion of geothermal wells. Drilling costs are a major component of the overall project cost; any drilling cost improvements would result in significant decreases in LCOH. The current drilling costs and potential future improvements for wells in the range 500–3,000 m are provided by the GeoVision Reservoir Management and Development Task Force (Foris, 2016). Drilling costs for wells shallower than 500 m are estimated using linear

[1] The flow rate for hydrothermal systems has been set internally in dGeo at 31.5 l/s, in accordance with the resource assessment by Mullane et al. (2016).

interpolation between 0 and the cost for a 500 m well. Anticipated future improvements provided by the task force for the breakthrough scenario are up to 50% in cost reduction.

EGS Reservoir Stimulation Costs: To create an EGS reservoir with sufficient volume and permeability, stimulating the reservoir (e.g., by hydraulic, thermal, or chemical means) will be necessary. Reservoir stimulation cost and practice is assumed to be similar for electricity and deep DU (for EGS only) projects. To align with the GeoVision electricity data used in the ReEDS model, stimulation cost ($M/wellset) figures are assumed, as provided by the Reservoir Management and Development Task Force (Augustine, 2017). Note that the ReEDS model does assume stimulation of hydrothermal injection wells in some scenarios; in contrast, dGeo only assumes stimulation of EGS injection wells. It is anticipated that the improvements of a reservoir stimulation job are of a technical nature and not of cost; therefore, the $M/wellset are expected to stay constant in the various scenarios. Rather, for a stimulation job, the obtained volume and permeability are assumed to increase over time due to technical improvements and gained knowledge and experience. These enhancements are reflected by increased flow rates and larger surface area per wellset in the improved scenarios.

Exploration Drilling Costs: The exploration drilling costs include the costs for all temperature gradient wells, slimhole wells, and corehole wells drilled and are expressed as $M/wellset. It is assumed that the exploration drilling costs for DU systems are similar to those for power plants. Hence, the values selected for dGeo are made in agreement with the exploration drilling costs derived by the GeoVision Exploration and Confirmation Task Force (Augustine, 2017) used in the ReEDS modeling, and they are in the range of $1.65M–$3.3M/wellset for hydrothermal resources and $1.67M–$5.0M/wellset for EGS resources, depending on the scenario considered. In dGeo, the hydrothermal resources included have been *identified* by the USGS, and hence, some of the exploration has already occurred. Therefore, the input values assumed correspond to “brownfield” rather than “greenfield” values.

Exploration Non-Drilling Costs: The exploration non-drilling costs include the costs for pre-drilling and other activities not related to drilling exploration wells. Similar to the exploration drilling costs, they are expressed as M$/wellset and made in agreement with the exploration non-drilling costs derived by the GeoVision Exploration and Confirmation Task Force (Augustine, 2017). They fall in the range of $0.24M–$0.83M/wellset for hydrothermal resources and $1.54M–$3.68M/wellset for EGS resources. Again, GETEM brownfield input values are assumed for the hydrothermal systems, because dGeo only considers hydrothermal resources that have been *identified* by the USGS.

3.2.2 Surface Plant Costs

Plant Installation Costs: The plant installation costs include the capital costs for the central plant and substations, consisting of heat exchangers, piping, pumps, and instrumentation and control systems. This cost component is not always specifically provided in literature. For example, Thorsteinsson (2008) reports an average investment cost for U.S. GDH systems on the order of $500/kW$_{th}$, but this number includes the costs for the wellfield and DH system. Rafferty (1996) provides cost figures for only the central plant on the order of $50/kW$_{th}$– $100/kW$_{th}$ (in 2016 dollars), with the lower range for larger systems (5–10 MW$_{th}$). Tester el al. (2010) assumes a cost figure of $150/kW$_{th}$ for the central plant and substations, but this figure also includes the costs for retrofits to an existing DH system. As input for dGeo, a value of $100/kW$_{th}$ has been back-calculated from literature values. Because the components used in the central plant and substations are low-tech and well established, no future cost improvements are assumed.

Operation and Maintenance (O&M) Labor Costs: The O&M labor costs are the annual costs for the workforce operating and maintaining the geothermal plant and DH system. They are assumed to scale with the size of the system and are therefore expressed as $/kW$_{th}$/year. However, over a large range of kW$_{th}$, a constant value for $/kW$_{th}$/year is likely not correct because larger systems tend to be relatively less labor-intensive than smaller systems due to economies of scale. Nevertheless, a constant value is justified here because each community is served by a collection of individual doublet systems, each with a similar size on the order of 10 MW$_{th}$. Based on previous research by Beckers (2016), it is assumed that a 10 MW$_{th}$ system has a labor cost of $250,000/year or $25/kW$_{th}$/year (for 3–5 full-time workers). It is assumed that this value remains constant in the improved scenarios, because GDH systems are considered low-tech and established technology and minimal O&M supervision will likely always be required.

Plant O&M Costs: The annual plant O&M costs are for running the central plant and distribution network (labor costs and distribution pumping costs are excluded from this parameter). The plant O&M costs are expressed as a percentage of the total investment costs of the central plant and distribution network. Values reported in literature for GDH systems are usually around 1% (Lund and Lienau, 2009; Lund, 2010; Lund et al., 2010; Reber, 2013; CanGEA, 2014). A value of 1% is selected as input for dGeo. Because the plant and distribution network are low-tech and well-established technology (heat exchangers and piping), no future cost improvements are assumed.

Wellfield O&M Costs: The annual wellfield O&M costs for the wells include activities such as casing inspection and replacement of a submersible pump. Labor costs and electricity costs for reservoir pumping are excluded. The parameter is expressed as a percentage of the total wellfield investment costs. This parameter is expected to be identical for electricity generation and DU heat utilization. Therefore, the value was provided by the GeoVision P2P Electricity Task Force (Augustine, 2017): 1.5%. This is in agreement with GETEM (Mines, 2016) and slightly higher than the 1% assumed by Tester et al. (2006) and Beckers (2016).

Distribution Network Construction Cost: The distribution network delivers heat from the wellfield to the individual homes and is a major capital cost component. Due to the nature of the dGeo modeling structure, the distribution network piping diameter, a major driver for the piping cost, is not known *a priori* because the demand for DH is unknown upfront. This demand is not known until the cost is specified, which is a function of the pipe diameter. Hence, to circumvent this issue, the diameter is specified upfront for a typical average DH network piping diameter of 7”, based on piping diameters reported by Persson and Werner (2011) and Lund (2015). For a 7” diameter, the average distribution network construction cost is calculated as $750/m using a correlation derived by Reber (2013).

This cost value is a representative value for piping in the suburbs whereas the cost for the inner city can be 20% higher and in rural areas 20% lower (Persson, 2013)—a distinction not implemented in the current version of dGeo. Because distribution piping is low-tech and well established, it is assumed that no future cost improvements are obtained.

Natural Gas Peaking Boiler Cost: As discussed in Section 3.1.1, the geothermal system is typically sized to cover only 50%–60% of the peak demand. The natural-gas-fired peaking boilers supply supplemental heat on cold days to cover the remaining 40%–50% of the peak demand. The capital investment cost reported for natural-gas-fired peaking boilers is around $50/kW$_{th}$ (Reber, 2013; Beckers, 2016); hence, this value is selected as input for the dGeo model. Because boilers are well-established technology, no future cost improvements are assumed.

3.2.3 Residential and Commercial End-User Cost

System Connection Cost: The system connection cost is a flat fee for connecting the building unit to the DH network. This cost covers the piping from the network to the building and is independent of building type (residential vs. commercial) and independent of heating system type inside the building (water vs. air). Reported values in literature are $1,515 per building (OIT, 2011), $1,800 per building (Rafferty, 2011) and $2,000 per building (Reber, 2013). Here, the most recent value of $2,000 is selected as input for dGeo. Because a connecting pipeline is low-tech and has been around for more than a century, no cost improvements are expected for this component for the improved scenarios.

System Installation Cost: The system installation cost covers outside wall cuts, main/tap boxes, building pipes, and potential water-to-air heat exchanger retrofits. This cost component is assumed to scale with building size and has units of \$/ft^2. Various building heating systems exist with hot water-based systems, the easiest to integrate into a DH system (Rafferty, 2011), and defined here as "compatible." Rafferty (2011) states that 85% of small buildings (<10,000 ft^2) have a non-water-based (incompatible) heating system. Values reported in literature for residential buildings are \$1.5/ft^2 (OIT, 2011), \$0.9/ft^2–\$1.7/ft^2 (GBC, 2016), \$1.7/ft^2 assuming a 1,800 ft^2 building (Reber, 2013), and \$1.6/ft^2 (Rafferty, 2011). For commercial buildings, values reported are \$1.1/ft^2–\$1.9/ft^2 (GBC, 2016) and \$1.7/ft^2 assuming a 1,800 ft^2 building (Reber, 2013). As an input for dGeo, an average value of \$1.5/ft^2 is assumed for residential buildings and \$1.7/ft^2 for commercial buildings for new or compatible systems. For incompatible systems, a premium of 33% is assumed (Rafferty, 2011). Because heating systems are well established and are low-tech, no future cost improvements are assumed.

System O&M Cost: Annual O&M costs apply for inspection and maintenance of the heating equipment inside the building. These costs scale with the size of the building; hence, units assumed are ¢/ft^2/year. The O&M costs are often expressed as a percentage of the installation costs. A typical value found in literature is 1% (CEC, 2005; Lund, 2009). Following the same approach, the dGeo input values for O&M costs range from 1.5–1.7 ¢/ft^2/year for compatible systems and 2.0–2.3 ¢/ft^2/year for incompatible systems. Building heating systems are low-tech and well established and no technology or cost improvements are anticipated. Therefore, no O&M costs changes are expected for the improved scenarios up to 2050.

3.3 Financial Parameters

Inflation Rate: The inflation rate refers to the annual price and cost increase over time and links the real interest rate to the nominal interest rate (real interest rate ≈ nominal interest rate - inflation rate). Values for inflation rate reported in literature are: 2% (CEC, 2005; Hochwimmer, 2015; Beckers, 2016), which is also the long-term Federal Reserve target inflation rate; 2.5% in the NREL Technology Baseline and Standard Scenarios (NREL,2016); 3% (Tester, 2006; Thorsteinsson, 2008); and 4% (Sanyal et al., 2007). To be in agreement with the NREL Technology Baseline and Standard Scenarios, a value of 2.5% is selected as input for dGeo, which is close to the average of 2.6% of all values reported. The inflation rate is kept constant in all scenarios.

Debt Fraction: All major utility projects are typically financed using a combination of equity and debt. The debt fraction refers to the percentage of total project financed through debt, with the remaining percentage financed through equity. Few values are reported in literature: 60%–100% (Tester et al, 2006) and 70%–100% (Hochwimmer et al., 2015). For dGeo input, the values of the GeoVision electricity model are used (Augustine, 2017), which fall in the range of 60%–75%.

Interest Rate: The cost of debt is reflected by the interest rate. Values reported in literature for interest rate can be misleading because they can be either nominal or real, and the type is not always specified. In addition, sometimes one refers to the debt-equity weighted-average interest rate (a.k.a., the weighted-average cost of capital, or WACC). dGeo requires a separate value for the interest rate on debt and a value for the rate of return on equity (discussed below), and internally calculates the WACC. Reported values for real interest rate are: 3% (Persson and Werner, 2011), 4% (WACC; assumed by Reber (2013)), 7% (CEC, 2005; Mines, 2016), 8% (Rafferty, 1996), 9% (Engen, 1978), and 10% (Dagdas, 2007; Thorsteinsson, 2008). Hochwimmer et al. (2015) and Sanyal et al. (2007) report a value of 8% and 9%, respectively, but it is unclear whether this is of real or nominal type. The wide range in values is probably explained by the different years (1978 to 2015), different countries (USA, New Zealand, Sweden, Turkey), and different types of projects (geothermal vs. non-geothermal DH) considered. The average of the reported values for real interest rates is about 7%.

In dGeo, the GDH systems considered are of the public utility type, which are characterized by longer time horizons and different funding sources (e.g., funded through low-interest municipal bonds) than systems developed by private entities seeking short-term profit. As a result, the interest rates selected are on the lower end, in the range of 2.9%–3.6%, which, combined with the debt-equity ratio and equity rate of return, results in a weighted-average interest rate internally calculated by dGeo in the range of 4.3%–7.9%. Reber (2013) followed a similar approach and selected an even lower WACC of 4%. For dGeo in the BAU case, the value applicable is 7.9%, significantly lower than the 12% used in GeoVision's ReEDS simulations (Augustine, 2017). However, for the improved scenarios, the WACC drops to 4.3%, which is a value in agreement with the electricity runs.

Rate of Return on Equity: The cost for equity is captured using the rate of return on equity. Few references specifically report values for the rate of return on equity: e.g., 10% (Hochwimmer et al., 2015) and 17% (Tester et al., 2006). As input for dGeo, the value selected is 12.7% for BAU dropping to as low as 7.6% in improved scenarios, following the approach by the GeoVision ReEDS runs (Augustine, 2017) to obtain a WACC of 4.3%–7.9% (see section *Interest Rate*).

Tax Rate: The tax rate refers to the effective tax rate that the operator is charged by the government on the net income. Few values are reported in literature: Hochwimmer et al. (2015) specified 30% (for New Zealand), and Beckers (2016) and (Mines, 2016) selected 39.2% (for the U.S.). For dGeo, a value of 39.2% is assumed. The effective tax rate will likely change over time depending on the administration and the economic climate. Nevertheless, future values are hard to predict; therefore, the value of 39.2% is kept constant for each scenario up to 2050.

Plant Lifetime: The plant lifetime is the economic lifetime assumed for calculating the LCOH or net present value, and it refers both to the lifetime of the geothermal reservoir and DH network. Some values reported in literature are: 20–40 years (Engen, 1978), at least 25 years (GBC 2016), and 30 years (Tester et al., 2006; Persson and Werner, 2011; Reber, 2013; Pirouti et al., 2013; Beckers, 2016). A value of 30 years is assumed as dGeo input. It appears that a lifetime value of about 30 years has been considered in techno-economic analysis already for several decades; hence, this value is kept constant for all scenarios up to 2050. Note that many systems (e.g., Boise) have been around for significantly longer (100 years), and having a longer operation time would decrease LCOH. This would be an interesting area of further investigation.

Construction Period: The construction period refers to the time period between the moment the decision is made to develop a GDH and the moment when heat starts being delivered to the customers. Some values reported in literature for construction period of GDH systems are: 4 years (Reber, 2013) and up to 5 years (OIT, 1991); and for geothermal power plants: 3–5 years, including permitting (Tester et al., 2006), and 6.5 years, including 3 years of exploration (Mines, 2016). In dGeo, a value of 4 years is considered following Reber (2013), and dropping to 3 years in the improved scenarios, along the same lines as potential time improvements considered for the GeoVision ReEDS runs (Augustine, 2017).

Construction Finance Capital Fraction: The construction finance capital fraction refers to the amount of investment that is required during the initial construction period that is subject to the construction interest rate. Typically, most of the construction occurs upfront with geothermal DU systems. We assume, however, that the last well is less risky than the first well, and that some wells could be drilled later after more customers are connected to the DH system. The same holds for the distribution network. This parameter was not specifically encountered in literature review but is assumed to be 50% for each scenario.

4. DISCUSSION

4.1 Parameter Uncertainty and Sensitivity

The values presented in Section 3 and listed in Appendix A should be interpreted with care. Some parameter values are known with confidence such as the cost and efficiency of a natural gas boiler; others, however, are much more uncertain, especially those related to subsurface performance and cost. Because only a handful of EGS demonstration projects are in existence worldwide, the current and potential future values for EGS resource recovery factor and flow rate are highly uncertain. The same is true for future drilling cost improvements and exploration costs—not only because of the inherent uncertainty when dealing with the subsurface, but also, because of the proprietary nature of these costs, as illustrated by the reluctance of operators to share these data when contacted. As a result, the “low” to “breakthrough” values provided in this paper and taken as input for dGeo under various scenarios (Section 4.2) should be treated as “what-if” rather than hard predictions for the future.

A recommended approach to deal with the uncertainty is to conduct a sensitivity analysis to explore the dependence of the output (e.g., LCOH of a GDH system) on the various input parameters. Previous studies by Reber (2013) and Beckers (2016) have identified the parameters with the highest impact on LCOH for EGS GDH and DU systems to be: drilling costs, discount rate, well flow rate, system lifetime, reinjection temperature, geothermal gradient, and surface cost. Hence, these parameters might be the most attractive to investigate further when evaluating a project site, and they have the highest potential—if decreased (e.g., drilling costs) or increased (e.g., well flow rate)—to lead to significant decreases in LCOH. In addition, it highlights the importance of 1) securing low-interest funding to obtain low discount rates, e.g., through municipal bonds for GDH systems as a public infrastructure project, and 2) maximizing the heat extracted per fluid volume rate to minimize the reinjection temperature, e.g., by making use of cascaded systems, by converting steam-based DH to liquid water-based DH, and by implementing smart pricing schemes to incentivize the end user to install energy-efficient heating system.

4.2 dGeo Scenarios

The parameters discussed in Section 3 with corresponding “low” to “breakthrough” values listed in Appendix A are translated into five scenarios provided as input to dGeo to simulate GDH system deployment in the U.S. under various conditions. These scenarios were developed by the GeoVision P2P team (Augustine, 2013) and are consistent between the thermal (dGeo) and electricity (ReEDS) market modeling conducted for the GeoVision study. Additional scenarios will likely be run in future model iterations.

- **Reference scenario**: The reference scenario assumes BAU values for all parameters. This scenario serves as reference for four improved scenarios.
- **High-Tech scenario**: The High-Tech scenario assumes major geothermal technological breakthroughs resulting in significant improvements in subsurface performance and drilling costs, moderate exploration costs improvements, and low financing rates due to significant drops in project risk.

- **Tech-Transfer scenario**: The Tech-Transfer scenario considers major improvements in oil and gas technologies that are transferred to geothermal project development. This translates into significant improvements in subsurface performance and drilling costs. Drops in exploration costs and overall financing interest rate are limited.
- **Exploration De-Risk scenario**: The Exploration De-Risk scenario considers breakthrough improvements in resource exploration resulting in significant drops in exploration costs and financing interest rate. Also, major improvements in subsurface performance and drilling costs are assumed.
- **Nimble-in-Numbers scenario**: The Nimble-in-Numbers scenario assumes significant improvements in subsurface performance, exploration costs, and drilling costs.

The selected values for each parameter for all five scenarios are listed in Table 4 in Appendix A. The results of the dGeo simulations under these scenarios will be published in a forthcoming NREL report.

5. CONCLUSIONS AND FUTURE WORK

As part of the GeoVision Study, we have investigated performance, cost, and financial parameters (31 in total) to model GDH systems in the U.S. Both current and anticipated future improved values have been collected using literature review, phone calls with operators, and in agreement with results from other GeoVision task forces. These values are provided as input under various scenarios to NREL's dGeo geothermal market penetration simulation tool, which models GDH system deployment in the U.S. up to 2050. Significant uncertainty in some parameter values persists, especially those related to subsurface performance and cost.

dGeo simulation runs are currently ongoing and the results will be published in a forthcoming NREL report. The calculated GDH system penetration level and deployment rate will be compared with those in other regions—for example, Europe, which has almost 5 GW_{th} installed capacity of GDH systems as of 2015 with an average of 120 MW_{th} added per year in the last 5 years. In comparison, the U.S. has roughly 100 MW_{th} of total GDH installed capacity, a number that has been staying fairly constant over the last several years. Assessing under which conditions significant GDH systems deployment can be obtained in the U.S. is one of the objectives of the dGeo modeling effort and GeoVision Study. Other future work could include performing sensitivity analyses on individual parameters to explore their impact on the overall results and to pinpoint the parameters that could benefit from additional efforts in finding more reliable values. Other interesting dGeo case studies would be targeting the roughly 500 existing non-geothermal DH systems in the U.S., and modeling geothermal DU applications beyond GDH such as industrial thermal applications (e.g., pasteurization, chemical process heat, or drying of food or biomass).

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APPENDICES:

Appendix A: List of all Performance, Cost, and Financial Input Parameter Values, and dGeo Scenarios

Table 1: Performance Parameter Values

		Low	BAU	High	Breakthrough
Plant and End-Use Performance	**Peaking Boiler Sizing (%)**	45	45	40	40
	Peaking Boiler Efficiency (%)	85	85	85	85
	Average End-Use Efficiency Factor (%)	80	80	80	80
Subsurface Performance	**EGS Resource Recovery Factor (%)**	1.0	2.0	3.0	4.0
	EGS Area per Wellset (km^2/wellset)	2.0	3.0	4.0	5.0
	EGS Maximum Sustainable Well Production (/s)	20	40	70	110

Table 2: Cost Parameter Values

		Low	BAU	Moderate	High	Break-through
Subsurface Plant Costs	Future Drilling Cost Improvements (%)	0	0	15	31	50
	EGS Reservoir Stimulation Costs ($M/wellset)	1.25	1.25	1.25	1.25	1.25
	Hydrothermal Exploration Drilling Costs ($M/wellset)	3.30	3.30	2.19	1.65	1.10
	EGS Exploration Drilling Costs ($M/wellset)	5.00	5.00	3.59	2.50	1.67
	Hydrothermal Exploration Non-Drilling Costs ($M/wellset)	0.83	0.78	0.73	0.42	0.24
	EGS Exploration Non-Drilling Costs ($M/wellset)	3.68	3.38	2.79	2.13	1.54
Surface Plant Costs	Plant Installation Costs ($/kW$_{th}$)	100	100	100	100	100
	O&M Labor Costs ($/kW$_{th}$/year)	25	25	25	25	25
	Plant O&M Costs (%)	1.0	1.0	1.0	1.0	1.0
	Wellfield O&M Costs (%)	1.5	1.5	1.5	1.5	1.5
	Distribution Network Construction Costs ($/m)	750	750	750	750	750
	Natural Gas Peaking Boiler Cost ($/kW$_{th}$)	50	50	50	50	50
Residential & Commercial End-User Cost	System Connection Cost ($)	2,000	2,000	2,000	2,000	2,000
	Compatible System Installation Cost ($/ft^2)*	1.5 / 1.7	1.5 / 1.7	1.5 / 1.7	1.5 / 1.7	1.5 / 1.7
	Incompatible System Installation Cost ($/ft^2)*	2.0 / 2.3	2.0 / 2.3	2.0 / 2.3	2.0 / 2.3	2.0 / 2.3
	Compatible System O&M Cost (¢/ft^2/year)*	1.5 / 1.7	1.5 / 1.7	1.5 / 1.7	1.5 / 1.7	1.5 / 1.7
	Incompatible System O&M Cost (¢/ft^2/year)*	2.0 / 2.3	2.0 / 2.3	2.0 / 2.3	2.0 / 2.3	2.0 / 2.3

*Values are reported as residential systems/commercial systems

Table 3: Financial Parameter Values

		Low	BAU	Moderate	High	Break-through
Project Financing	Inflation Rate (%)	2.5	2.5	2.5	2.5	2.5
	Debt Fraction (%)	60	65	65	70	75
	Interest Rate (%)	3.6	3.6	3.6	3.2	2.9
	Rate of Return on Equity (%)	12.7	11.8	9.4	8.6	7.6
	Tax Rate (%)	39.2	39.2	39.2	39.2	39.2
	Plant Lifetime (years)	30	30	30	30	30
	Construction Period (years)	4	4	4	3	3
	Construction Financial Capital Fraction (%)	50	50	50	50	50

Table 4: dGeo Scenarios

		Scenarios				
		Reference	High-Tech	Tech-Transfer	Exploration De-Risk	Nimble-in-Numbers
Performance Parameters						
Plant & End-Use Performance	Peaking Boiler Sizing	BAU	High	High	High	High
	Peaking Boiler Efficiency	BAU	BAU	BAU	BAU	BAU
	Average End-Use Efficiency Factor	BAU	BAU	BAU	BAU	BAU
Subsurface Performance	EGS Resource Recovery Factor	BAU	High	High	High	High
	EGS Area per Wellset	BAU	High	High	High	High
	EGS Max. Sustainable Well Prod.	BAU	Breakthrough	Breakthrough	Breakthrough	Breakthrough
Cost Parameters						
Subsurface Plant Costs	Future Drilling Cost Improvements	BAU	Breakthrough	Breakthrough	Breakthrough	Breakthrough
	EGS Reservoir Stimulation Costs	BAU	BAU	BAU	BAU	BAU
	Hydrothermal Expl. Drilling Costs	BAU	Moderate	BAU	Breakthrough	High
	EGS Exploration Drilling Costs	BAU	Moderate	BAU	Breakthrough	High
	Hydrothermal Expl. Non-Drilling Costs	Low	BAU	Moderate	High	Breakthrough
	EGS Expl. Non-Drilling Costs	BAU	Moderate	Low	Breakthrough	High
Surface Plant Costs	Plant Installation Costs	BAU	BAU	BAU	BAU	BAU
	O&M Labor Costs	BAU	BAU	BAU	BAU	BAU
	Plant O&M Costs	BAU	BAU	BAU	BAU	BAU
	Wellfield O&M Costs	BAU	BAU	BAU	BAU	BAU
	Distribution Network Constr. Costs	BAU	BAU	BAU	BAU	BAU
	Natural Gas Peaking Boiler Cost	BAU	BAU	BAU	BAU	BAU
Residential & Commercial End-User Cost	System Connection Cost	BAU	BAU	BAU	BAU	BAU
	Compatible System Installation Cost	BAU	BAU	BAU	BAU	BAU
	Incompatible System Installation Cost	BAU	BAU	BAU	BAU	BAU
	Compatible System O&M Cost	BAU	BAU	BAU	BAU	BAU
	Incompatible System O&M Cost	BAU	BAU	BAU	BAU	BAU
Financial Parameters						
Project Financing	Inflation Rate	BAU	BAU	BAU	BAU	BAU
	Debt Fraction	BAU	Breakthrough	Breakthrough	High	BAU
	Interest Rate	BAU	High	BAU	Breakthrough	BAU
	Rate of Return on Equity	Low	Breakthrough	High	Moderate	BAU
	Tax Rate	BAU	BAU	BAU	BAU	BAU
	Plant Lifetime	BAU	BAU	BAU	BAU	BAU
	Construction Period	BAU	High	BAU	High	High
	Constr. Financial Capital Fraction	BAU	BAU	BAU	BAU	BAU