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Constructing Deep Closed-Loop Geothermal Wells for Globally Scalable Energy Production by Leveraging Oil and Gas ERD and HPHT Well Construction Expertise

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Abstract

Deep closed-loop geothermal systems (DCLGS) are introduced as an alternative to traditional enhanced geothermal systems (EGS) for green energy production that is globally scalable and dispatchable. Recent modeling work shows that DCLGS can generate an amount of power that is similar to that of EGS, while overcoming many of the downsides of EGS (such as induced seismicity, emissions to air, mineral scaling etc.). DCLGS wells can be constructed by leveraging oil and gas extended reach drilling (ERD) and high-pressure high-temperature (HPHT) drilling expertise in particular.

The objectives of this paper are two-fold. First, we demonstrate that DCLGS wells can generate significant geothermal power, i.e. on the order of 25-30 MWt per borehole initially. To this extent, we have developed a coupled hydraulic-thermal model, validated using oil and gas well cases, that can simulate various DCLGS well configurations. Secondly, we highlight the technology gaps and needs that still exist for economically drilling DCLGS wells, showing that it is possible to extend oil and gas technology, expertise and experience in ERD and HPHT drilling to construct complex DCLGS wells.

Our coupled hydraulic-thermal sensitivity analyses show that there are key well drilling and design parameters that will ultimately affect DCLGS operating efficiency, including strategic deployment of managed pressure drilling / operation (MPD/MPO) technology, the use of vacuum-insulated tubing (VIT), and the selection of the completion in the high-temperature rock formations. Results show that optimum design and execution can boost initial geothermal power generation to 25 MWt and beyond. In addition, historical ERD and HPHT well experience is reviewed to establish the current state-of-the-art in complex well construction and highlight what specific technology developments require attention and investment to make DCLGS a reality in the near-future (with a time horizon of ~10 years). A main conclusion is that DCLGS is a realistic and viable alternative to EGS, with effective mitigation of many of the (potentially show-stopping) downsides of EGS.

Oil and gas companies are currently highly interested in green, sustainable energy to meet their environmental goals. DCLGS well construction allows them to actively develop a sustainable energy field in which they already have extensive domain expertise. DCLGS offers oil and gas companies a new direction

for profitable business development while meeting environmental goals, and at the same time enables workforce retention, retraining and re-deployment using the highly transferable skills of oil and gas workers.

Introduction

Oil and gas exploration and production (E&P) companies currently find themselves caught up in an energy transition, which involves the reduction of greenhouse gas (GHG) emissions, partial divestments out of E&P, and entry into alternative energy sources such as onshore and offshore wind, solar, biomass, and geothermal (GT) energy (IEA, 2020a). GT energy, i.e. "*harnessing the heat beneath our feet*" (US-DOE 2019), plays an important - but often overlooked - part in the global energy mix, because it can provide baseload dispatchable green energy. It should at first glance make an interesting target for involvement of - and investment by - the E&P industry, given evident overlap and synergies with the GT industry on drilling, completion / stimulation and overall well construction. As opposed to the other alternative energy sources, the E&P industry actually has considerable domain expertise in complex well construction, including the construction of very deep high-pressure, high–temperature (HPHT) wells, which are in many ways comparable to challenging GT wells (but also with some key differences, as outlined in the following). In fact, exactly this very logical argument for increased E&P involvement in GT was presented in a 2009 paper by Petty et al. (2009). This paper highlights how the industry could help the growth of high-enthalpy Engineered (or Enhanced) Geothermal Systems (EGS) in particular, indicating that recovery of just 2% of the thermal energy available between 3 and 10 km depth in the United States would generate enough energy to cover about 2,800 times the domestic US energy demand, a truly staggering figure.

More than a decade has passed since the paper by Petty et al. (2009), which unfortunately seems to have been largely ignored. Forays into GT by E&P companies have until now been tentative at best, with only sporadic investments by companies and industry venture funds in select GT start-ups. Although the reasons for this are not entirely clear, it is likely that the industry at the time (i.e. 2009) got wrapped up entirely in the "shale revolution" and/or found the GT value proposition and associated technical and economical / cost risks not attractive at the time. However, the most recent downturn in the industry, the aforementioned energy transition, and high-profile events such as the PIVOT 2020 roundtable discussion organized by the Geothermal Entrepreneurship Organization (GEO) at the University of Texas at Austin have brought new momentum to E&P consideration of GT opportunities. This paper aims to contribute to this renewed GT interest by E&P by showing the possibilities and opportunities in deep GT energy though the exploitation of closed loop GT systems (CLGS).

In this paper, we are concerned with high enthalpy GT systems with temperatures above 150°C (note that GT systems below 100°C are considered low enthalpy resources, while those ranging from 100°C - 150°C are classified as mid-enthalpy systems, see Brommer and O'Sullivan 2020). Global GT gradients, being the variation of temperature with depth, range from 20°C/km in subduction zones and stable continental areas to 40-80°C/km in volcanic areas and areas with a thin continental crust, with 30°C/km being the average global gradient (Arndt 2011). Assuming an average global surface temperature of 15°C, it follows that such high-enthalpy GT systems are encountered at a depth beyond 5 km, and more typically in the depth range of 7 to 10 km. Note that we are not (yet) considering "supercritical" (SC) systems where subsurface conditions exceed the critical point of freshwater, which is at 374°C and 220.64 bar (3,200 psi). Instead, we are interested here in applications with bottom-hole static temperatures in the range of 200°C – 350°C. Fig. 1 shows that the E&P industry already has considerable experience in drilling wells in this temperature range, which is typically classified as ultra-HPHT (UHPHT) and extreme HPHT (XHPHT) (note that the HPHT, UHPHT and XHPHT domains as defined by major service companies differ in terms of their particular temperature and pressure cut-offs, see Shadravan and Amani 2012). A key difference is that E&P companies pursue sedimentary systems for hydrocarbon extraction, whereas deep GT applications may involve heat extraction e.g. from "hot dry rock" (HDR) with largely impermeable matrices (granites, basalts, etc.) The

GT industry refers to wells drilled in this temperature range as EGS petrothermal (see Fig. 2), suitable for producing commercial electricity in flash and dry steam GT power plants (Brommer and Sullivan 2020).

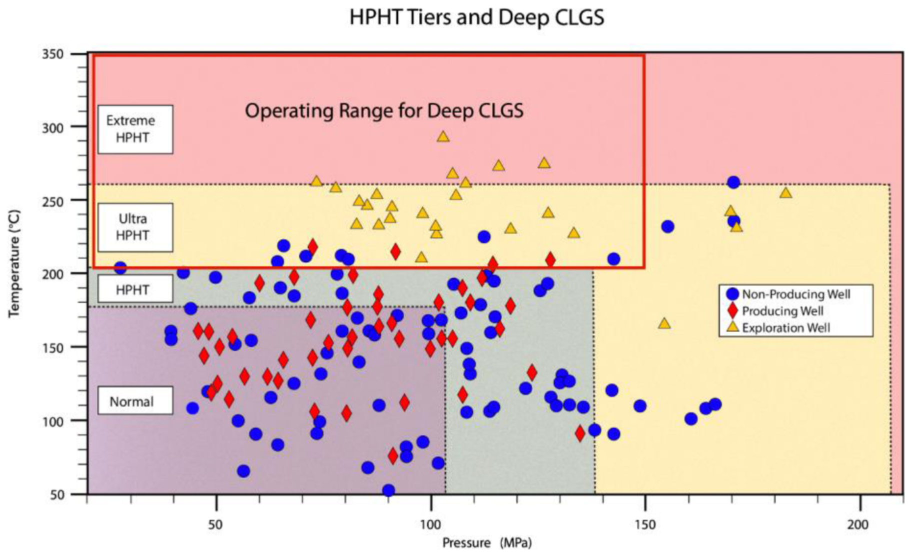

Figure 1—Experience with HPHT, UHPHT and XHPHT drilling in the E&P industry. Modified from Shadravan and Amani (2012).

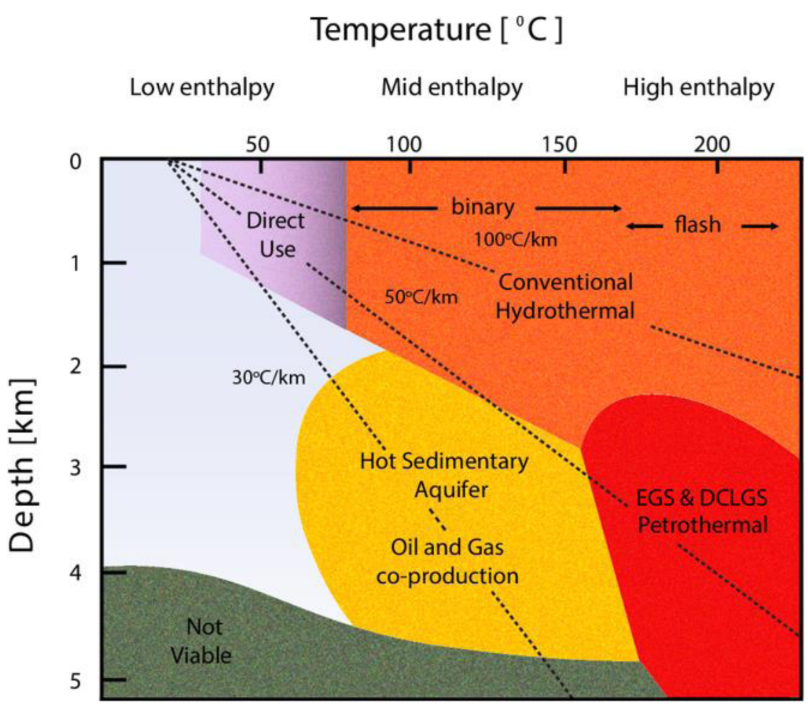

Figure 2—Temperature vs. depth diagram showing GT categories. Modified from Brommer and O'Sullivan (2020), with the original source being the International Geothermal Association.

The US Department of Energy (DOE) in its recent GeoVision report (US-DOE 2019) highlighted the potential of EGS systems as follows (GeoVision Report, Chapter 2):

With technology improvements, EGS could be engineered cost effectively wherever there is hot rock at accessible depths, enabling economic capture of EGS potential nationwide. The total EGS resource potential used in the GeoVision analysis was based on an assumed depth cut-off of 7 km and minimum temperature of 150°C (...) and estimated on that basis to be at least 5,157 gigawatts-

electric (GWe) (...) for power generation purposes—nearly five times the total installed utility-scale electricity generation capacity in the United States in 2016 (1,074 GWe) (...). As innovative drilling and stimulation technologies enable access to greater depths and reduce drilling and engineering costs, larger volumes of high-temperature EGS resources than those considered in the GeoVision analysis could be harnessed (Augustine 2011).

There are some important takeaways from the GeoVision report, including:

- EGS may provide scalable baseload energy, which is low in environmental impact, low carbon footprint, locally derived, and fuel-less, not only nationwide in the US but anywhere on Earth irrespective of geographical location, provided one can drill deep enough to the desired temperature range.
- Innovative new drilling and completion technology will be essential for the construction of EGS wells
- Reduction in drilling and engineering costs is a must in order to make EGS resources economical. Metrics typically used are cost per unit of power ($/kW) for capital expenditure (CAPEX) and cost per unit of energy ($/kWh) for levelized cost of energy (LCOE). In order for GT to effectively compete with other forms of alternative energy there is a target CAPEX cost on the order of $2,000 - $2,500/kW and an LCOE of less than $150/MWh and preferably below $100/MWh (IEA, 2020b).

At this point, a clarification is in order. CLGS is currently considered a subset of EGS (Petty 2020), but it is really a distinctly different entity. EGS mostly involves well designs that rely on natural or induced fractures for heat extraction. These include directionally drilled wells with an open-hole completion relying on hydro-shearing of natural fractures (example: Newberry in the US), high-angle parallel directional wells connected through hydraulic fractures (example: Soultz in France), near-horizontal wells connected through multi-zone hydrofracs perpendicular to the wellbores (McClure and Horne 2014), and parallel horizontal wells at different depths connected through large explosive-generated vertical fractures (example: Geysers in the USA). Such open systems are quite different from CLGS wells in that the latter use closed conduits for thermal fluid circulation and heating and do not rely on fractures for heating (example: the Eavor Loop in Canada (Eavor, 2021)). CLGS relies on fluids pumped through a closed loop, with typical configurations (see Fig. 3) being an open U-shaped or a J-shaped design with fluid pumped down the annulus and returned to surface through an inner conduit, in both cases with thermal isolation of the returning fluid to prevent heat loss using e.g. vacuum insulated tubing (VIT). For the remainder of this paper, we shall treat CLGS systems as different from EGS systems, with the understanding that the benefits and potential assigned by the GeoVision report to EGS wells also extend to CLGS wells, and that the drilling technologies discussed here as enablers for CLGS wells apply equally to EGS wells as well.

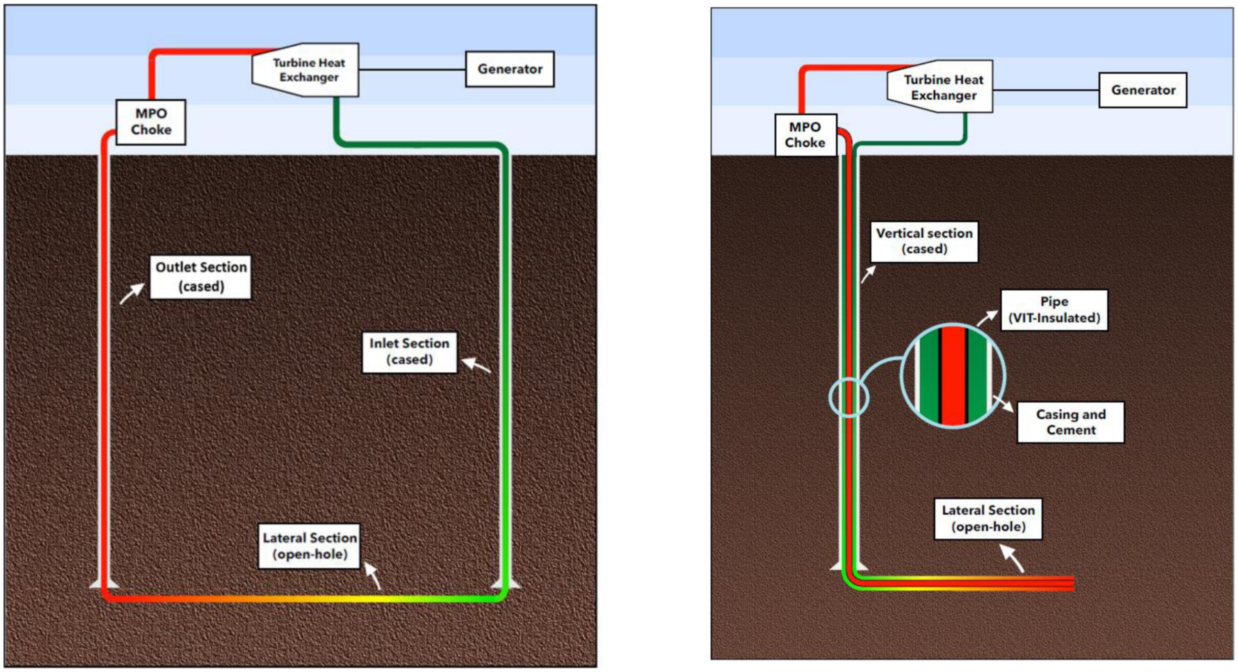

Figure 3—Schematic overview of (left) U-shaped, and (right) J-shaped closed loop well designs.

In the GT domain, the vast majority of attention and funding is currently assigned to EGS projects, such as the Forge project in Utah (Moore et al. 2018) sponsored by the US-DOE. A case is made here to continue to invest in – and further develop – CLGS technology (and deep-CLGS (DCLGS) technology, which in this paper we define as going deeper than 5 km TVD, and more typically in the depth range of 7 to 10 km TVD) due to its more favorable risk profile compared to EGS. Table 1 gives a high-level overview of the different risks associated with EGS and (D)CLGS wells. It can be seen that (D)CLGS can side-step some of the technical and environmental risks associated with EGS, such as emissions to air, the problem of scaling, fracture permeability maintenance, and the risk of induced seismicity. The latter has led to high-profile earthquake events in Basel, Switzerland (Valley and Evans 2009, Catalli et al. 2016) and more recently in Pohang, South Korea (Grigoli et al. 2018, Kim et al. 2018, Ellsworth et al. 2019). Events such as these, which led to the cancellation of the projects involved and a complicated legal aftermath, may become showstoppers for EGS technology in the future. Moreover, despite the general acceptance of fracking in North America, there is still significant resistance and opposition to it globally (e.g. Steger and Milicevic 2014 and references therein). This is undoubtedly a hurdle for the global acceptance of EGS using natural and stimulated fractures. These remarks are not meant to discourage further support, investigation and development of EGS technologies, but serve to show that it makes sense to develop (D)CLGS alongside EGS as an alternative, lower-risk option.

Table 1—Comparison of risk profiles of EGS vs. CLGS (modified from original information courtesy Malcolm Ross).

Risk Element	EGS	CLGS / DCLGS
Induced seismicity	Reported at some sites (e.g. Basel, Switzerland and Pohang, South Korea)	None expected
Natural seismicity (energy plants can be fragile, e.g. Fukushima, Japan)	Plants are simple and robust (e.g. geothermal plant in Fukushima survived earthquake and tsunami)	Robust
Surface subsidence	Reported at some sites	None expected
Fluid use / losses	Potentially high losses if open system leaks into fracture system (potentially sequester CO_2 if used as heat exchanger)	Small for H_2O-based systems, none for sCO_2

Risk Element	EGS	CLGS / DCLGS
Water pollution	Reported at some sites	None/small (depending on completion)
Surface gas emissions (H_2S, CO_2)	Significant with flash tanks and measurable in binary cycles	None/minor potential of H_2S, CO_2 leaks (depending on cased hole or open hole completion)
Mineral scaling in pipes	Well integrity and flow assurance often compromised	None/small (depending on cased hole or open hole completion)
Permeability maintenance, fracture network plugging / thermal breakthrough	Rendering energy extraction less efficient	Not applicable
Prediction of energy production over time	High uncertainty due to fracture plugging, breakthrough, geomechanical changes	Highly calculable operation, reliable over long time periods

The structure of the paper is as follows. In part I, we introduce the modeling results of a new hydraulic model coupled with a thermal model that is suitable for calculating the power generation of DCLGS wells. Modeling results demonstrate a case for action to consider the construction of such deep wells based on their power output, which rivals that of EGS designs. In Part II, we highlight main technology gaps and needs of DCLGS drilling and well construction, and identify opportunities where E&P know-how and technology can either be directly applied and leveraged, or can be further developed.

Part I – Case for Action – DCLGS Power Generation

Closed loop heat exchanging wells have been discussed previously by Schulz (2008), Oldenburg et al. (2016), Amaya et al. (2020) and Hu et al. (2020), to name a few. These authors have developed hydraulic models with temperature coupling (e.g. based on approaches such as outlined by Kabir et al. 1996) to calculate circulation temperatures and power generation from their CLGS designs. What they have in common is that they all consider relatively shallow well designs, with true vertical depth (TVD) typically not exceeding 3 km (~10,000 ft) in depth. Although such wells will be relatively easy to drill, their shallow depth limits their energy production to only a few megawatts if they are drilled in areas with average heat flow. This will not be sufficient to generate electricity on a large utility scale and achieve the economic targets mentioned previously. For this, we need to drill deeper, longer wells. For example, well-known work by the Geothermal Laboratory at SMU (Blackwell et al. 2011) shows that rock formations with temperatures above 200°C at the depth of 7.5 km are available in most regions within the US, most prominently in the Western states and in East Texas.

UHPHT and XHPHT conditions make drilling deeper CLGS wells technically difficult but certainly not impossible. Deep vertical wells were drilled in Russia at the Kola Peninsula (12+ km) (Kozlovsky 1984) and the KTB site in Germany (9+ km) (Emmermann and Lauterjung 1997). These wells were drilled with 50-year and 30-year old drilling technology respectively, and this technology has advanced significantly since that time. Moreover, breakthroughs in directional drilling technology have enabled the construction of world record ERD wells up to 13+ km (~42,000 ft) in measured depth drilled in the Sakhalin development in Russia (Denney 2006, Walker 2012, Gupta et al. 2014). As discussed in the following, additional drilling and well construction technology will be needed to drill DCLGS ERD wells. However, given sufficient interest and investment in combination with historical GT and E&P HPHT experience (see Fig. 1) and ERD drilling experience (see Alemi et al. 2018 for recent combined ERD and HPHT experience in the North Sea) there do not appear to be any insurmountable challenges that would prevent the drilling of such wells like the ones discussed below within a time horizon of ~10 years.

To evaluate the feasibility and economic viability of DCLGS wells for power generation, it is essential to first develop a thorough understanding of the hydraulic and thermal behavior of the fluid under the pertaining HPHT conditions of a DCLGS well. As stated, there are a few thermal models for the estimation of temperature profiles in U-shaped CLGSs in the published literature. Sun et al. (2020) provides a general literature review of the U-shaped systems, with numerical models given by Sun et al. (2018) and Sun et al. (2019) to estimate the steady-state temperature profile in U-shaped wells using supercritical CO_2 as the heat exchanging fluid. Schulz (2008), Oldenburg et al. (2016), and Song et al. (2018) have developed models for simulating shallow U-shaped GT wells using water as the working fluid, providing estimates of the temperature profiles over the lifetime of low-temperature CLGS wells. However, fast transients and short-term effects, such as those caused by changing the circulation pump rate, are not considered in these models. We are particularly interested in transient hydraulic and thermal behavior in order to be able to use MPD/MPO techniques (Rehm et al. 2008) to control the well during drilling and well operations. MPD/MPO using surface backpressure (SBP) will allow us to control e.g. well influxes, wellbore instability and lost circulation during drilling, and enable us to dynamically control well pressures during well operation and heat extraction. MPD/MPO can be used to control the phase dynamics of the circulating fluid in the well, and is particularly important if the well is not cased off but completed with an open-hole, "bare-foot" completion in the thermal reservoir. Active management of SBP can then be used to control and guarantee borehole stability in the exposed open-hole formation(s).

Details of our new integrated thermal and hydraulic model are given in Appendix A, with a more complete description given in Fallah et al. (2020). Note that consideration of the lifetime performance of the GT system is beyond the scope of this paper. The long-time thermal depletion around the wellbore and the consequent power reduction can be estimated using external formation heat transfer models (Ramey 1962, Cheng et al. 2011).

To show the capabilities of the developed model, two illustrative cases are provided here: (1) a U-shaped closed loop well with a 31.12 cm (12.25 in.) hole, and (2) a J-shaped well where the fluid is pumped into a 31.12 cm (12.25 in.) annulus and back to surface through a 17.78 (7 in.) VIT-insulate pipe. In both cases, water is used as the working fluid and is pumped at a rate of 350 m^3/hr (1,541 gpm). Both wells are 7 km (22,966 ft) deep with a 7 km (22,966 ft) lateral section and a barefoot completion in the reservoir. The formation temperature gradient is 0.03 °C/m (0.016 °F/ft) with a downhole temperature of 250 °C (482 °F). The surrounding rock has a density of 2,700 kg/m^3 (22.53 ppg), a specific heat capacity of 1,000 J/kg. K (0.239 BTU/lb.°F), and a thermal conductivity of 2.5 W/m.K (1.45 BTU/hr.ft.°F).

Fig.4 and Fig.5 show the temperature profile at different times within the circulation for the U-shaped and J-shaped wells, respectively. In the U-shaped well, the water temperature increases along the inlet vertical section and the open-hole lateral section. The maximum temperature gradient is observed at the beginning of the open hole lateral section, where the temperature difference between the water and surrounding rock is maximum. In the return section, hot water is continuously heated by the surrounding rock until the temperature of the hot water is in equilibrium to that of the surrounding rock. From this location to the surface, to avoid heat loss, the well wall could potentially be insulated using VIT. Similar temperature profiles are observed in the J-shaped well. The only difference is that the return section in this case is through a VIT-insulated pipe inside the annulus. The increased velocity through the VIT-insulated pipe (with an inside diameter of 13.97 cm (5.5 in.)) results in a temperature increase along the return section. This temperature increase, however, comes at the price of increased pump pressure to overcome frictional pressure losses.

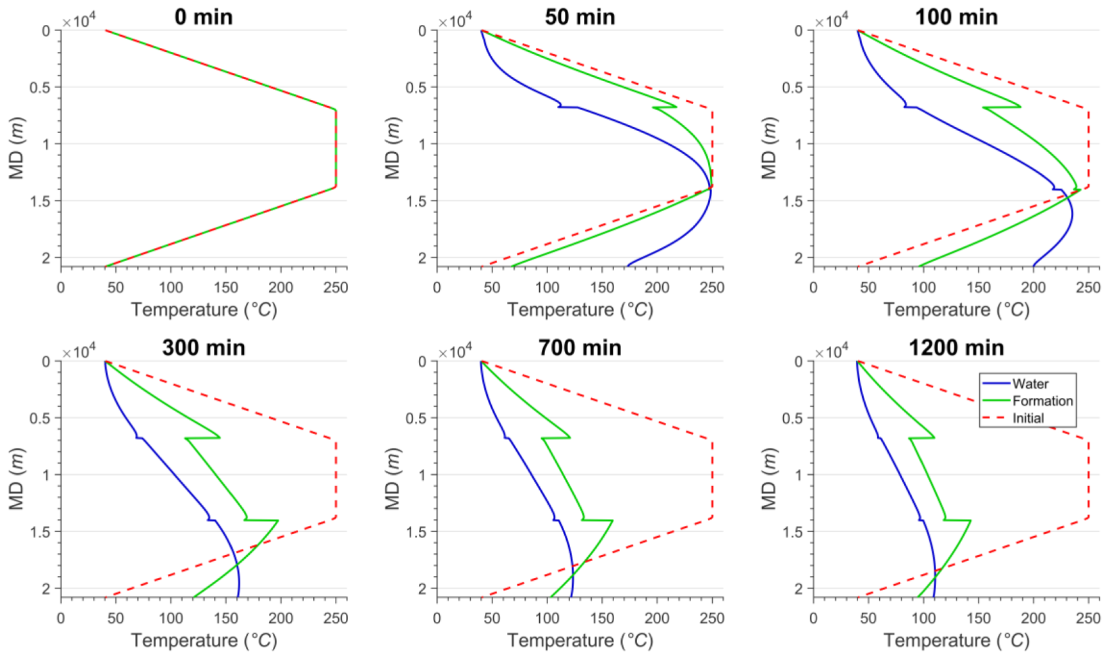

Figure 4—Temperature profile at different times into the simulation for the U-shaped well.

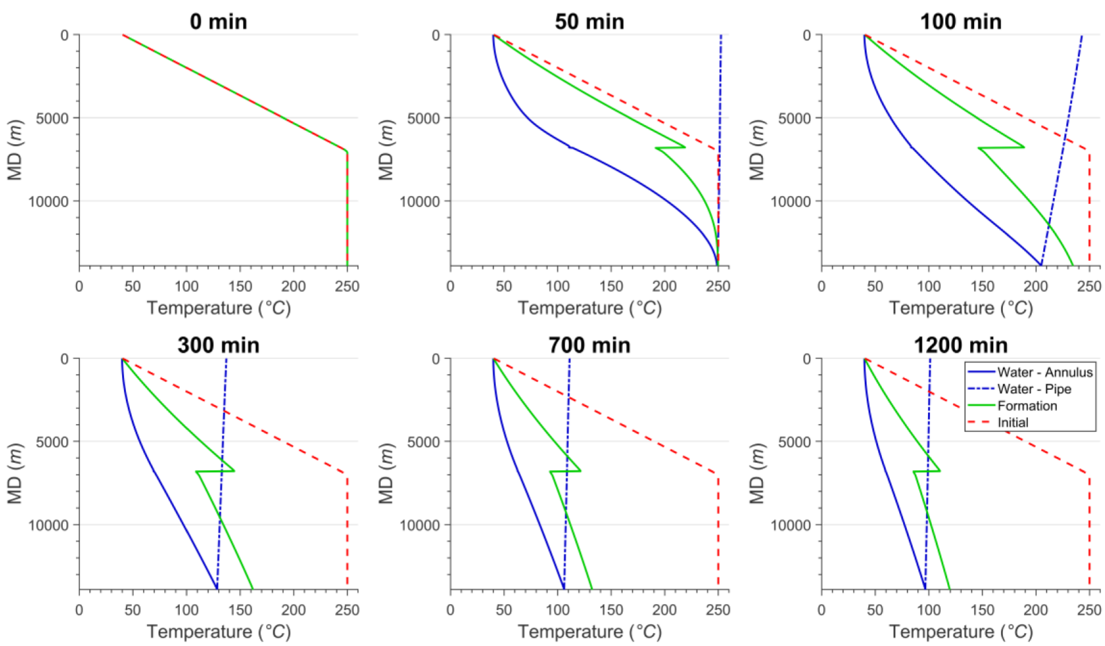

Figure 5—Temperature profile at different times into the simulation for the J-shaped well.

Fig. 6 shows the outlet temperature, net thermal power, choke opening, and the surface backpressure for both wells. At early stages, the high temperature water that was initially in the well is circulated to surface, which results in an increase in the outlet temperature and net thermal power for both cases. The maximum observed outlet temperatures are 203°C (397°F) and 253°C (487°F) for the U-shaped well and the J-shaped well, respectively. The resulting thermal power is 56 MWt and 78 MWt. After that, the outlet temperature drops as the initial hot water is removed from the well and the temperature reaches steady-state. After 20 hours of circulation, the outlet temperature is 109°C (228°F) and 101°C (214°F) for the U-shaped well and the J-shaped well, respectively, representing a thermal power generation in the 25-30 MWt range. Note that the return section of the U-shaped well enables more heat transfer to the returning fluid, increasing the outlet temperature and generated power. In both cases, the boiling pressure of water varies with the transient outlet temperature. The automatic proportional–integral (PI) controller of the MPO control system is able to adjust the choke opening in both cases to apply sufficient backpressure to avoid boiling. Note that we have not added significant additional surface pressure for borehole stability in these cases, assuming that the open hole formations will be stable at the applied circulating pressure of water and the applied SBP to control the phase dynamics (with an added safety margin of 1 MPa). This is not in any way a limitation, and the controller can be programmed to take borehole stability requirements into account.

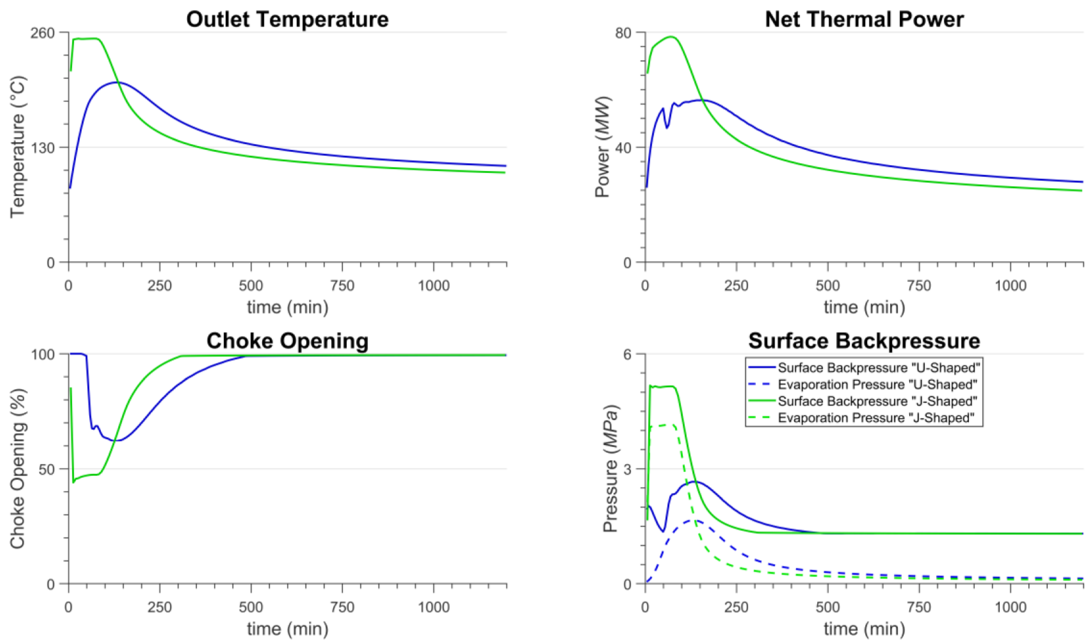

Figure 6—Outlet temperature, thermal power, choke opening, and surface backpressure versus time for both cases.

It is important to note that our power estimates are given for short time-periods only (due to the nature of our modeling, which is concerned with real-time MPD control), and that modeling for longer time periods still needs to be performed. Long-term power generation will depend on how much heat transfer (and depletion) will occur due to conduction and convection, which in turn will depend on geology (sedimentary, igneous, metamorphic rocks), presence of natural and drilling-induced fractures, the number of closed-loop laterals that are combined in a multi-lateral design to generate commercial power, etc. This very interesting topic is beyond the scope of this paper. Instead, we will focus on how deep, long-lateral wells can be drilled cost-effectively, thereby attracting more attention and investment from E&P companies. This is the topic of Part II of this paper.

Part II – DCLGS Drilling and Well Construction

Introduction

Current State-of-the-Art. The current state of GT drilling and well construction has been well-summarized in the "Handbook of Best Practices for Geothermal Drilling" by Finger and Blankenship (2010), in a subsequent presentation by Blankenship (2016) and a recent Geothermal Resources Council (GRC) workshop by Capuano and Capuano (2020). What follows are some pertinent highlights of GT drilling to date.

- Drilling to >450°C has been accomplished (Seji and Sakuma 2000), with GT well depth typically not exceeding 5 km in TVD (Friðleifsson et al. 2017).

- Various bit types have been used (roller cone, polycrystalline diamond compact (PDC), natural diamond bits etc.) with tungsten carbide insert (TCI) roller cone bits used predominantly in hard rock. PDC have been shown to yield superior ROP when they can be kept from being prematurely damaged (Raymond et al. 2012). Mud hammers have shown great promise in drilling hard formations (Gerbaud et al. 2018, Li et al. 2019). There are claims that ROP is improving after drilling through the brittle-ductile transition (Petty 2020).
- Directional drilling is typically accomplished with simple pendulum, fulcrum and packed assemblies (drop, build, hold), without azimuthal control. Surveying for deviation/azimuth is done while tripping. Limited use has been made of directional drilling with motors and concurrent MWD/LWD due to temperature limitations (Capuano and Capuano 2020).
- Cementing solutions are available up to 350°C (660°F). Fluid formulations are available with temperature stability up to 315°C (600°F). Casing and connections need to be de-rated for temperature and require corrosion resistance from sour and sweet gas attack (Finger and Blankenship, 2010).
- Major technical problem areas, discussed in the following, include low ROP drilling hard rocks, lost circulation, casing and cementing, as well as MWD/LWD and directional drilling in high temperature environments.

Similarities and Differences between Deep GT and E&P HPHT Wells. There are many similarities between HPHT E&P wells and Deep GT wells, but also some key differences:

- GT wells generally use larger production hole sizes than typical land wells (and are in this regard more comparable to Deepwater wells with high-rate / high-ultimate completions) to support high flow rates required for energy production. Our examples in this paper use a 31.12 cm (12.25 in) production hole size, and this appears to be a suitable requirement in order to attain sufficiently high flow rates.
- GT reservoirs in igneous, metamorphic or deep sedimentary formations (e.g., granite, basalt, gabbro, granodiorite, quartzite, greywacke, rhyolite and volcanic tuff) may be very challenging to drill, with strengths exceeding 240 MPa (35,000 psi), abrasive components (quartz > 50%), with fractures present and being under-pressured (Finger and Blankenship 2010).
- Casing-cement annuli are typically cemented back to surface to avoid trapped annular pressures (TAP), associated casing failure risks and wellhead growth from the upper parts of the well heating up during the production phase. Any fluid left in void space behind casing will expand during heating, creating casing collapse risks (Blankenship 2016).
- GT wells may be drilled in more forgiving pore pressure fracture gradient (PPFG) environments (for the parts of the wells where pore pressure is still a relevant quantity) with wider drilling margins than geopressured HPHT wells in hydrocarbon systems. Tight drilling margins encountered in the latter wells are a main source of non-productive time NPT (spent on well control, lost circulation and borehole instability) and associated well cost inflation. The topic is discussed in detail in Section II.2.2.
- Severe lost circulation appears to be a universal problem in deep GT wells, which invariably encounter fracture systems. The situation is comparable to drilling fractured oil or gas reservoirs. Deep EGS wells need to be careful with blocking off fractures in producing intervals because this might lead to reduced heat extraction in the production phase. We will see that we can be more aggressive in dealing with losses in DCLGS wells because they do not rely on fractures for heat extraction.
- Cost comparisons have been made between GT and E&P (Blankenship et al. 2005, Blankenship and Mansure 2013, Lukawski et al. 2014) showing significant cost differences for wells with deeper

depths. Drilling costs can account for 50% or more of the total capital costs for a GT energy project, which makes reducing drilling costs one of the most important factors for GT energy production to become economically viable across a range of subsurface environments (Lowry et al. 2017). The topic is discussed in more detail in Section II.2.4.

- The number of GT wells drilled annually is dwarfed by the number of E&P wells drilled each year (Finger and Blankenship 2010). An important implication is that the datasets on GT wells are much smaller than those for E&P wells, and that GT wells can rely less on an organic, "trial and error" learning curve than E&P wells. This is particularly relevant for higher cost GT wells such as our proposed DCLGS designs, which will require a high focus on operational excellence for cost control.

Technology Solutions, Leveraging Oil and Gas Know-How

When developing a GT project, there are generally five areas to cover, with the first three in the well design / construction / operation realm: resource characterization, well construction and reservoir creation, well operation, plant design and operations, and electrical grid integration. The remainder of this paper is dedicated exclusively to DCLGS drilling and well construction, i.e. reservoir creation. We have subdivided the technical focus areas into the following five categories:

1. Deep Hole Making and Directional Drilling
2. Wellbore Geomechanics and Completion Design
3. High Temperature Materials and Systems
4. Flow Dynamics and Control, Energy Production and Economic Analysis
5. GTAIML (Geothermal Artificial Intelligence and Machine Learning)

In the following discussion of these categories, we by no means aim to be complete, which would be far beyond the scope of a conference paper. Rather, we highlight what some of the remaining technical gaps and needs are, how they can be addressed, and how E&P expertise can be leveraged to capitalize on "low-hanging fruit".

Deep Hole Making and Directional Drilling. Efficient hole-making in hard rock is a key challenge (Finger and Blankenship 2010, Baujard et al. 2017, Diaz et al. 2018), and many sources, including the GeoVision report (US-DOE, 2019) have conclude that development and application of new hole-making techniques is imperative to cost-effective exploitation of deep EGS and CLGS systems. New drilling techniques in development include:

- Electrical impulse drilling (Lehr et al. 2016, Voigt et al. 2016);
- Hydrothermal spallation drilling (e.g. Potter et al. 2010, Naganawa 2017, Naganawa et al. 2017a, Rossi et al. 2020a, 2020b);
- Impact drilling, using particles (Tibbets et al. 2011, 2013) or hypersonic projectiles (Ackermann 2015, Urselmann et al. 2020);
- Millimeter wave drilling (e.g. Oglesby et al. 2014, Wostov 2017);
- Laser drilling (e.g. Parker et al. 2003, Zediker 2014, Jamali et al. 2019);
- Plasma drilling (Kocis et al. 2013, Kocis et al. 2017).

Technology developments in these areas have been supported by government organizations (e.g. DOE / ARPA-E in the US), investment by industry partners (including E&P), and/or private equity. These new drilling technology developments are certainly very exciting and may pay off at some point in the future. However, there are still some long-standing issues and technical hurdles to address. For instance, how to transmit sufficient power through a suitable conduit across many kilometers to the downhole energy source failing the rock (electrical pulses, lasers, millimeter waves, plasma, etc.) or deliver it with a sufficiently powerful downhole battery that can survive the challenging downhole environment (high temperature, high pressure, potential shock loads, etc.)? How to make hole in the presence of potentially dense, opaque drilling fluid necessary for cooling, borehole stability and debris evacuation from the borehole (or otherwise, how should the borehole be stabilized and cleaned in the absence of any drilling fluid? Note that metamorphosis / vitrification of the near-wellbore through high energy impact radiation is unlikely to provide sufficient stability for boreholes that require active support from mud hydrostatic overbalance)? Moreover, what impact will these techniques have on near-wellbore geomechanics with consequences for borehole stability and lost circulation tendencies? An interesting observation is furthermore that several of the new drilling techniques revolve around triggering rock failure by heating (by electrical pulses, lasers, millimeter waves, plasma), which appears counterintuitive when deployed in a downhole environment that is already at very high temperature. Cooling / freezing and associated thermal fracturing, which is effective in failing hard-brittle rock (Enayatpour et al. 2018, 2019), on the other hand seems to have been largely overlooked.

A 1960's overview of novel drilling techniques by Maurer (1968) already mentioned laser drills, plasma drills, electric arc/spark drills (i.e. electrical impulse drills), microwave and ultrasonic drills (similar to millimeter wave drills), pellet drills (i.e. particle impact drills), jet-piercing drills (i.e. thermal spallation drills) and even nuclear drills. Notwithstanding new innovations and developments, the fact that these ideas and technologies have apparently been around for more than half a century indicates a high likelihood that they may not be ready for primetime and widely deployable in the very near-future (i.e. on the timescale of the next decade or so - note that the authors are more than willing to be proven wrong on this particular point).

Yet perhaps we do not have to look too far for more short-term solutions. In the past decade or so, a wealth of information on drilling efficiency optimization has been uncovered, primarily associated with drilling unconventional shale wells. A general conclusion is that harmful drillstring dynamics / vibrations and improper bit management are prime causes of premature bit failure and limited bit runs (Raymond et al. 2012, Curry et al. 2017). PDC bits, for instance, have been demonstrated to be able to drill very hard formations (~ 35,000 psi UCS and above) for certain bit and cutter designs (Rahmani et al. 2020). Elimination of drilling dysfunction greatly benefits from real-time ML and AI routines that can diagnose adverse drilling conditions, and smart auto-drillers that can automatically sense and correct for non-optimum drilling parameters. Better bit management will result from the emerging field of automated bit dull grading and bit forensics (Pastusek et al. 2018, Ashok et al. 2020). For instance, it is now known that when drilling hard rocks one should not allow PDC bits to ring out before being pulled, as point-loading on the limited number of exposed cutters of the next bit will likely lead to a premature bit failure (see Fig. 7). The key point here is that effective real-time drilling efficiency optimization (including active vibration mitigation, optimized hydraulics, better bit management including knowing the depth of cut that can be sustained in hard rock formations, Pastusek et al. 2018) will greatly extend the operating and efficiency envelope for the use of conventional bit technology in deep GT drilling.

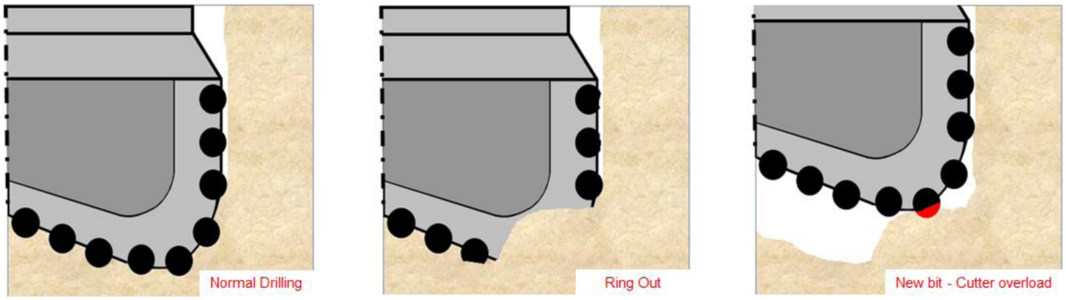

Figure 7—Example of poor bit management, where allowing a PDC to ring out in hard formations will lead to cutter overload and rapid bit failure for the next bit run into the hole – image courtesy Ysabel Witt-Doerring and Paul Pastusek.

As indicated, PDC's have been shown to deliver ROP benefits in GT drilling compared to TCI roller cones (Raymond et al. 2012). They, however, can get damaged when drilling heterogeneous interbedded and/or fractured formations due to interfacial severity (Pastusek et al. 2018). This, then, presents a good opportunity for the use of hybrid bits, which have been previously considered for GT drilling operations (Chatterjee et al. 2014, 2016), have actually been used successfully for GT projects (Rickard et al. 2014), and have been shown able to successfully drill volcanic basement rock (Wan et al. 2015). The real question is why they have not been used more. Note that hybrid bit can be built to withstand 300°C (MacPherson 2020). Use of mud hammers and rotary percussion drilling (Gerlero et al. 2014, Souchal et al. 2017, Gerbaud et al. 2018, Li et al. 2019) also presents an excellent opportunity to improve ROP in deep directional GT wells, given that they can operate at lower WOB, torque and RPM levels. Impreg bits can drill very high strength rock when spun on turbines, but it is questionable if they can deliver the enhanced ROP desired to make deep GT economical. It does make very good sense to consider combinations of technologies that do not require a lot of RD to mature, such as combination of PDC/hybrid bits with abrasive jetting (Lu et al. 2013, Stoxreiter et al. 2018), or the use of mud hammers together with active cooling to more effectively fail hard brittle rock.

For deep hot directional drilling, a main limiting factor has been the thermal stability of elastomers. This has led to the development of metal-to-metal motors that eliminate them. Note that directional motors have already been developed for applications up to 300°C bottom-hole temperatures (Dick et al. 2012, Chatterjee et al. 2014, 2016, Stefánsson et al. 2018). This would already be sufficient to cover the majority of DCLGS applications discussed here, particularly when the use of such motors is coupled with continuous circulation (CC) (Rehm et al. 2008) that would provide continuous motor and bit cooling. With CC, the downhole motor would always experience the lower bottom-hole circulating temperature (BHCT) and never be exposed to the higher bottom-hole static temperature (BHST). This, then would allow formations at 350+°C in-situ temperature to be directionally drilled.

Deep hot directional drilling is a field that might see accelerated technology development in the near-term. It was recently discovered that azimuthal bending (Rohlfs de Macedo et al. 2020) may be used for high-temperature directional drilling. A simple practical approach may be useful here as well. Directional drilling has been practiced for many years in GT plays using simple directional assemblies. If all we care about is exposure to hot rock, there may not be a need for very precise directional control and highly accurate well placement: just getting enough exposure length to hot rock with a wellbore of sufficient quality to run production tubing in a J-shaped design may be sufficient.

An entire paper could be dedicated to the discussion of drilling systems for deep GT drilling alone, so only a few pertinent points are mentioned here. Similar to Sakhalin and other deep drilling projects such as KTB project in Germany, the rigs used for DCLGS and deep EGS wells will need to be custom-designed with a high-level of automation (e.g. on pipe handling) and systems integration (e.g. integrated MPD pressure management). In terms of their pump rates, hoisting capability, torque/rotation ability etc. they will reflect more the systems currently used in offshore deepwater environments than current land rigs. This, of course, will negatively affect the drilling economics and place even more emphasis on drilling efficiency.

The past two decades have seen major learning and improvements in ERD drilling, with systems for automated wellbore friction management to guarantee WOB and torque on bit (TOB) transmission to the bit, advancements in cuttings transport modeling and hole cleaning management, etc. Improper hole cleaning is a major cause of NPT in ERD drilling, and will need special attention in DCLGS wells. It is desirable to equip the driller with an advisory system that can provide the hole cleaning status in real-time. Significant efforts have been put into developing advisory systems in E&P which can be readily adapted to the GT drilling practice. To estimate the hole cleaning status, existing methods are mainly based on experience, rule of thumb, and simple calculations. For instance, Shah et al. (2007) and Kelessidis and Mpandelis (2004) developed experimental models to predict the settling velocity of solid particles in non-Newtonian fluids. Others proposed experimental models to estimate critical transport velocities and bed height in deviated wells (Larsen et al. 1997, Luo et al. 1992, Ozbayoglu et al. 2008, Rubiandini 1999, Xiaofeng et al. 2013). These experimental models provide fundamental understanding of how the cuttings are transported or settling during drilling and hole cleaning operations. However, due to their steady-state nature, these models fail to provide real-time information on transient bed formation and cuttings flow, which is crucial for effective hole cleaning in field practice. Multi-phase flow models, such as Computational fluid dynamics (CFD) models (Akhshik et al. 2015), have been proposed to simulate the cuttings transport considering the collision dynamics. Another example is the approach by Erge and van Oort (2020) where the annular velocity profile is used to determine the cuttings bed height. These models provide 3D estimations of the cuttings bed and are practical for analyzing specific sections of the well, as well as determining the optimal parameters for efficient hole cleaning. However, these models are highly complex and computationally expensive due to the 3D discretization of the well, intricate forces between the phases, particle settling, collision between the particles, pipe eccentricity and hole size effects, etc. This renders these models unsuitable for real-time and fully-transient estimation of the dynamic solid concentration and pressure profiles along the entire wellbore, which is necessary to execute timely control actions during actual drilling and hole cleaning operations.

In order to reduce the complexity and computational cost, one-dimensional models that integrate numerical modeling with experimental results have been proposed, as summarized by Nazari et al. (2010). However, the proposed models in the literature do not consider the automated choke control, which makes the model not suitable for MPD operations. In addition, assumptions used by many of these models, such as incompressible mud (Naganawa et al. 2017b), limited range of fluid rheology, neglecting the effect of pipe rotation, etc. make the estimation less accurate. A model developed by Cayeux et al. (2014) considers the effect of mud compressibility and expansion. However, the numerical solution procedure is not provided in the published work, making it difficult to verify the fully transient behavior of the model and the capability to be integrated with automatic controllers.

A transient cuttings transport model has been developed by Fallah et al. (2020) to estimate the cuttings concentration and the dynamic bed height during drilling and hole cleaning operations. The model integrates a drift-flux modeling (DFM) approach with a robust semi-implicit numerical scheme for fast real-time simulations. The semi-implicit algorithm enables using small time-steps (on the order of 10^{-2} s) to capture the fast transients and the pressure waves in the well. This is necessary for simulating MPD operations, where the automatic choke controller adjusts the bottom-hole pressure (BHP) rapidly to maintain it within the drilling margin. The cuttings concentration and blockage effects are considered in the model, allowing the automated controllers to maintain the BHP during dynamic drilling and hole cleaning operations. The developed model considers the pressure-dependent mud density, non-Newtonian viscosity (including the effect of suspended cuttings), cuttings slip velocity, pipe rotation and eccentricity effects, complex 3D well path and geometry, etc. Moreover, the model can be integrated with wired-pipe data to detect cuttings bed build-up at early stages to take proactive actions. Using steady-state temperature models, the effect of temperature on cuttings transport can also be included through the thermal expansion of the mud. This modeling framework for the hole cleaning operation can be readily transferred to GT applications.

Clearly, there is sophisticated advisory software for deep ERD currently available. Moreover, there are various advisory firms that specialize in extended reach well construction in particular. Their knowledge and capabilities appear to be straightforwardly transferable to deep GT drilling.

Summarizing, while new drilling techniques and tools are being developed and validated, it is advised to explore how much further conventional drilling technologies (use of PDCs, hybrid, mud hammers, high-temperature directional drilling systems, etc.) can be pushed together with drilling efficiency optimization to enable deep GT drilling.

Wellbore Geomechanics (Borehole Stability, Lost Circulation, Well Control) and Completion Design. One of the most significant challenges in the construction of E&P HPHT wells is the often very challenging PPFG environment, where high geopressures in sedimentary rock lead to a closure of the drilling margin. Such an environment can operationally give rise to a combination of well control, borehole instability and lost circulation problems that in turn can lead to significant well cost escalation and budget overruns, even when enabling technologies (such as MPD, casing drilling, expandables, artificial wellbore strengthening, etc.) are used. Such challenges have made many deep E&P HPHT plays uneconomical, with very reputable and experienced operators either incurring heavy cost penalties and/or having given up on them altogether (e.g. deep tertiary HPHT wells drilled on the GOM Shelf, Shadravan and Amani 2012). This is where deep GT wells may be significantly less problematic, because they can be drilled in much more forgiving PPFG environments with wide margins and/or in under-pressured hot dry rock. As noted, this is one of the factors that make cost comparisons between deep HPHT wells and deep GT wells as proposed here difficult at present.

The standard GT well design favors an open-hole completion, with the optional use of a slotted liner in case of formation instability, and the use of VIT for production of heated fluids to prevent heat loss. This is the type of open-hole completion that we favor for DCLGS wells as well, provided they are feasible. An open-hole completion would offer the benefit of avoiding many problems related to casing and cementing at high temperatures, would lower well construction costs and improve heat exchange with the formation (with casing and cement sheets acting as thermal insulators – preliminary work shows casing and cement reduce heat transfer in our DCLGS designs to reduce energy production by ~15%). An open hole completion on the other hand raises the issue of wellbore stability, which has to be guaranteed not only during drilling but also during long-term well operation and heat extraction. An investment into pro-active wellbore stability modeling, applying learnings from E&P is therefore essential, including:

- Thorough understanding of the 3D in-situ stress environment (i.e. characterization of the stress tensor, understanding of anisotropic in-situ stress etc.), see Brudy et al. 1997.
- Characterization of formation strength of exposed open hole formation (including e.g. anisotropy / planes of weakness), with rock mechanics test done on downhole materials at realistic in-situ conditions.
- Understanding the requirements for mechanical wellbore stability. Do the exposed formations require hydrostatic overbalance for wellbore stability (which can be supplied by fluid density augmented by surface back-pressure delivered through SBP-MPD, see below) or can they be exposed to underbalance conditions and still remain stable? This is an important issue not only during drilling but also when using open-hole heat production.
- Understanding of temperature changes, such as those associated with repeated heating and cooling of the heat-exchanging part of the well resulting from dispatching energy according to demand, and associated stress/load cycling at the wellbore, with the possibility of triggering wellbore fatigue over time. Note that cooling has a positive effect on wellbore stability by reducing near-wellbore

stresses, but a negative effect on lost circulation by lowering near-wellbore tangential stress and fracture initiation pressure (Gonzalez et al. 2004, Hettema et al. 2004, Algu et al. 2007).

- Prevention of formation hydration and pressure transmission due to exposure to the drilling mud and circulating fluid while operating the well, that could weaken near-wellbore formations and reduce near-wellbore effective stresses over time, resulting in instability. Note that this was observed and became an operational problem while drilling the KTB well beyond a depth of 7.5 km TVD in gneiss and amphibolite rock (see Borm et al. 1997, Azzola et al. 2019). Wellbore instability worsened over time despite the very low rock permeability (on the order of 0.1-0.2 nD, see van Oort 1994), a typical sign of time-delayed hydration and pressure transmission. Such effect can be eliminated by applying suitable plugging/coating agents in the drilling mud and heat-exchanging fluid during production, such as silicates and aluminates used in water-based fluids, see van Oort (2018).

As already mentioned, lost circulation is one of the most important trouble areas in GT well construction, with historical well data indicating that lost circulation NPT and associated cost can take up as much as 15% of well cost (Finger and Blankenship 2010, Nugroho et al. 2017). Deep GT wells invariably encounter fractures with large apertures and under-pressurized rock, with the risk of massive-to-total losses. Lost circulation mitigation in current GT wells relies primarily on drilling with the lightest fluid that the wellbore will permit (e.g. air, foam, mist, aerated fluids), and on conventional treatments with the deployment of suitable (cement) squeezes (generally not ideal, because cement is difficult to place and is easily contaminated) and use of LCM pills (e.g. cotton-seed hulls). There is a complication here for EGS wells when losses are encountered in producing zones, because production relies heavily on open fractures/ conduits that may get damaged/impaired when using comprehensive lost circulation treatments. There is an important difference here with DCLGS wells: since the latter do not rely on fractures for heat production, one can deploy more aggressive means with materials that can withstand GT temperatures to control heavy losses in them. The following are a few ideas on how DCLGS wells (and to a certain extent EGS wells as well) can benefit from E&P lost circulation control expertise:

- E&P employs a wider array of LC pills and squeeze methods than GT, ranging all the way from traditional gunk squeezes to sophisticated settable spots, resin squeezes, and the solidification of water-based and oil-/synthetic-based muds. All of these can be considered for DCLGS application with the formation damage concern removed. The use of circulating subs, common in deepwater applications, may be useful to deliver pills with high LCM concentrations without the need to run bits with large or no jets. Lost circulation control may also benefit from the deployment of various MPD techniques, discussed below.
- Complex well construction (including deepwater, HPHT and ERD wells) has benefited greatly in recent years from deployment of artificial wellbore strengthening (WBS) technology to e.g. avoid from induced fracture losses in narrow PPFG environments (van Oort and Razavi 2014, and references therein). WBS does not appear to have found adoption in GT well construction yet, and there may be significant opportunities here. The "casing smear" effect that comes with casing-while-drilling (CWD) / drilling-with-casing (DWC) under certain circumstances (factors including casing-to-hole size ratio, particle size distribution in the mud, presence of larger bridging particles, Watts et al. (2010)) needs to be mentioned here for consideration also. Note that a complicating factor is presented by the fact that WBS treatments to date do not work well for rocks with low-permeability matrices (there are various schools of thought on how WBS is accomplished, but they all agree that leak-off of fluid to the formation in fractures is essential for the WBS phenomenon to be effective). This provides an incentive for developing WBS treatments that work well in rock formation encountered in deep GT wells (granites, basalts, etc.).

- As already indicated, cooling reduces near-wellbore thermal and tangential stress, lowering fracture initiation pressure. This can result in more pronounced induced lost circulation problems when mud circulation is actively cooled during drilling (as observed e.g. in deepwater wells with narrow margins, Gonzalez et al. 2004, Hettema et al. 2004, Algu et al. 2007). Mud cooling in deep GT and HPHT wells therefore exacerbates the already significant lost circulation challenge, a "self-inflicted injury" that comes as a trade-off from the need to lower temperatures to get muds, directional drilling equipment and MWD/LWD tools to work in deep hot wells. Although there appears to be little that can be done at the present time to alleviate the need for cooling, it is important to remember the downsides of cooling and to avoid excessive cooling. Moreover, the need for cooling may be alleviated in future as more temperature-stable materials and systems become available.
- Besides presenting a lost circulation risk, the occurrence of open fractures and under-pressured formations also raises the risk of differential sticking (i.e. getting differentially stuck on a fracture due to the differential pressure between the wellbore and the fracture), which is best addressed by eliminating/minimizing the loss problem through good formation bridging and plugging of fractures.

GT well control practices have been summarized by Finger and Blankenship (2010) and Capuano and Capuano (2020). A main difference with E&P is that the latter often has to deal with well control risk from abnormal/geopressurized formations, whereas GT environments are rarely over-pressured and more often under-pressured. Kicks usually occur either through heavy losses reducing hydrostatic head in the well, or fluids in the wellbore flashing to steam. Gas kicks can be hazardous if they contain undiagnosed hydrocarbons and/or if H_2S is present (note that sudden flashing to steam is expected to be less of a problem with DCLGS wells that are not drilled in traditional hotspots such as volcanic areas, where there can be unexpected sudden increases in formation temperature). The GT industry has developed practical solutions to deal with fluids flashing to steam (e.g. "drilling a controlled blowout" when drilling with air and producing dry steam), with some risks involved. Rotating control devices (RCDs) are used, but generally not with active MPD control. MPD has been mentioned a number of times in this paper already, and it appears GT drilling in general can benefit from MPD techniques, including:

- SBP practiced with the use of an RCD, choke and mass flow meter allows for more control, including control over the phase dynamics of the fluid in the wellbore (preventing fluids from flashing to steam) and delta flow measurements for early kick detection (much more sensitive than traditional flow rate measurements with paddle meters and pit volume totalizers). SBP can also be used to control ECD's during drilling and cementing (i.e. managed pressure cementing, MPC), to alleviate losses and deal with differential sticking incidents.
- CC through the use of continuous circulation valves appears to be a good option for drillstring and wellbore temperature management, as well as hole cleaning and stuck pipe/differential sticking prevention (Pinkstone et al. 2018). CC would create a very stable temperature environment inside and outside of the drillstring, preventing downhole tools and the wellbore itself from being exposed to large temperature swings that could lead to fatigue failures.
- Mud cap drilling (MCD) could be used for lost circulation control. Many GT wells are drilled with either very heavy losses or without returns, drilling blind. Pressurized and floating mud cap drilling are possible options here to gain more control, especially when there is a risk of kicks associated with the losses. Note that an SBP-MPD operation can be easily transformed into an MCD operation, as the use of equipment is the same. Availability of sacrificial fluid for drilling (SAC) and light annular mud (LAM) for annular control will need to be addressed, but it often found in MCD operations that the incurred losses are lower than when attempting to drill conventionally (Ladron de Guevara et al. 2012).

- As mentioned previously, in order to build DCLGS wells for large-scale power generation, it is necessary to develop a MPO system to maintain wellbore integrity, avoid reservoir influx and fluid contamination, control the pressure-volume-temperature (PVT) behavior of the working fluid, and enable open-hole completion of the lateral portion of the DCLGS well. Like E&P MPD, MPO also requires a transient thermal and hydraulic model to describe the fluid in the GT well. The model detailed in Appendix A was developed for the MPO control in DCLGS wells, allowing conventional feed-forward and classical feedback control methodologies to be employed.

Summarizing, GT wellbore geomechanics is a very important focus area for further study and additional technology development, but also for consideration of techniques, tools and learnings from E&P (such as use of MPD techniques, artificial wellbore strengthening, insights into borehole stabilization) that may find ready deployment in deep GT well construction.

High Temperature Materials and Systems. When it comes to high-temperature materials and systems, the main concerns involve downhole logging/monitoring and associated telemetry, drilling fluid, casing and cement, which are briefly discussed here. On the logging side, GT employs very similar open-hole logs as E&P (Finger and Blankenship 2010, Blankenship 2016), e.g. resistivity, gamma ray (GR), neutron porosity and density, nuclear magnetic resonance (NMR) logging, borehole imaging (through ultrasonic caliper). On the monitoring side, measurements of temperature, pressure and flow (by spinner survey), and directional survey data (inclination and azimuth) are important. Particularly important for DCLGS drilling optimization will be vibration frequency and magnitude / shock load monitoring (axial, lateral and torsional), and near-bit monitoring of RPM, TOB and WOB. Other logs of interest include multi-arm calipers, casing inspection and cement bond/variable density logs (CBL/VDL), vertical seismic profile (VSP), and distributed temperature sensing (DTS) using fiber optics. The latter involves temperature monitoring in completed wells through fiber optic sensors (FOS) using (combinations of) Rayleigh, Brillouin and Raman scattering. A challenge that needs to be addressed is the hydrogen darkening challenge for long-term operation (Weiss 2005). This challenge is actively being addressed for geothermal wells using newly developed technology and E&P DTS and DAS experience from e.g. steam assisted gravity drainage (SAGD) wells (see Haberer et al. 2020 for a recent report).

Wireline and slickline logging tools used in GT are generally protected by thermal flasks/Dewars (Finger and Blankenship 2010). The traditional cut-off temperature for MWD/LWD tools use in GT and HPHT drilling has been 175°C (~350°F) (Shadravan and Amani 2012), but this has been recently expanded for HPHT drilling to 200°C (~390°F) (Lunney et al. 2017) and up to 250°C (~480°F) (Hall et al. 2017) for density measurements. Moreover, there are important MWD/LWD sensor aspects associated with Sandia's effort to develop monitoring systems for EGS wells (Normann et al. 2017).

Pushing MWD/LWD systems beyond this range will require additional R&D as well as novel ideas and non-traditional methods, with very encouraging developments in recent years. Piezo-electric sensors for high-temperature (500°C) flow and pressure measurements have already been developed (Normann et al. 2017). Novel transistors based on silicon-on-insulator (SOI) and silicon carbide (SiC), with temperature ranges on the order of 300°C and >450°C respectively are becoming available for logging purposes (Hugue et al. 2010, Grella et al. 2013, Vedum et al. 2019). It is to be expected that there will be novel and unexpected developments in micro- and nano-sensors in particular (such as revisiting the idea of "smart dust" for downhole fracture sensing, e.g. Pyrak-Nolte et al. 2020) that will be of considerable use to deep GT well construction in the not-too-distant future.

On the telemetry side, the same options are available as in E&P, including mud pulse (not possible/ ineffective with air/mist/foam drilling), EM, acoustic, and wired pipe, all with their own current temperature limitations. A practical approach must be considered here as well: if obtaining MWD/LWD measurements concurrently with drilling runs into limitations, causes significant/insurmountable technical problems (such as induced lost circulation through active cooling to make the tools work, see Section II.2.2), consideration should be given to getting the information after drilling in short, dedicated logging runs on wireline or slickline.

Overviews of GT drilling fluids are offered by Chemwotei (2011) and Finger and Blankenship (2010) and the reader is referred to these papers for more details, with only essentials covered here. Simple, lightweight fluids are typically used for GT drilling: air, mist, foam, aerated mud, or clean water. Muds when used are typically simple dispersed systems viscosified with bentonite. Biopolymers have limited thermal stability, such that one generally needs temperature-stable synthetic polymers for polymer-based fluids. Active cooling is generally necessary when using mud.

Oil-based/synthetic-based muds are not used in traditional GT drilling, but have of course been extensively used in X/U/HPHT wells and ERD wells, for their lubricity/friction reduction characteristics, temperature stability, ability to stabilize wellbores in reactive formations, etc. These highly lubricious systems may have to be considered for use in deep, directional GT wells as friction and force transmission to the bit (TOB, WOB) become very important. Invert emulsion systems have been formulated with excellent pressure and temperature stability up to 315°C (600°F) (see Shadravan and Amani 2012, and references therein). It is possible to formulate these at relatively low densities (with the density of base oil being lower than that of water). Use of "oily fluids", however, will place even more emphasis on lost circulation, because such fluids are expensive and lost circulation tends to be a more pronounced problem in OBM/SBM systems than WBMs (due to lower fracture propagation pressures in the former systems, van Oort and Razavi 2014). It is therefore important to deploy good lost circulation control systems in OBM/SBM, such as OBM/SBM solidification methods. Water-based muds have been formulated with temperature stability up to 260°C (500°F) (Shadravan and Amani 2012), but these fluids typically yield higher friction coefficients than OBM/SBMs. Interesting candidates are formate fluids, which can stabilize biopolymers at high temperatures (Howard and Downs, 2011).

GT casing issues have been discussed in detail by Finger and Blankenship (2010) and Phi et al. (2019). The two key issues are de-rating yield strength for elevated temperatures, using appropriate API and ISO criteria (e.g. API TR 5C3, ISO 10400, API 17TR8, API 1PER15K-1, ISO 15156), and taking into account casing corrosion from exposure to H_2S (sour gas corrosion, sulfide stress cracking/hydrogen embrittlement), CO_2, corrosive brines, etc. Solutions range from avoiding high-strength casing grades that are particularly sensitive to hydrogen embrittlement, to using corrosion resistant alloys (CRA doped with e.g. chromium, nickel, molybdenum), and all the way to using titanium casing. As indicated in Table 1, we expect DCLGS wells to suffer to a much lesser extent from corrosion than their EGS counterparts, because heat-exchanging fluids are circulated in a closed conduit with less exposure to formation chemistry (gases, brine) than when they are circulated through open fractures.

There are special challenges for casing connections in deep GT wells that are not met by using premium connections, such as being able to handle highly variable loads due to thermal cycling. Cyclic loads range from full tension loads when the well is cool, such as during cementing and heat exchanging fluid circulation, to compression loads when the well heats up during shut-ins. This has caused notable casing collapse failures in the past (Ingason et al. 2014). This challenge is being addressed in recent years by a European Horizon 2020 initiative into the development of a flexible coupling (Thorbjornsson et al. 2017, Kaldal et al. 2019) that can expand with temperature to avoid compression and associated casing collapse (note that the issue of cement bonding to such a flexible coupling will need to be addressed).

As indicated, GT well cementing requirements differ from E&P well cementing in the need to cement annuli back to surface to avoid TAP when the upper portions of the well heat up during production, and to shield casing from chemical attack (acid gas, brine) leading to corrosion. A key concern during displacement is therefore the lifting of the cement column to cement the entire annular space, and a key hurdle is lost circulation which should be addressed during drilling. Again, an advantage of DCLGS over EGS is that it can deal more decisively with losses. Cement displacements can be performed either through conventionally circulating "the long way around" or by reverse circulation, with the latter often preferable as it avoids the need to over-retard the cement and obtaining a long transition time in the process (with associated gas migration risks). As indicated previously, MPC is expected to be useful for ECD reduction when cementing long casing strings in DCLGS and EGS wells.

Standard cement for HPHT and GT wells is Class G Portland with silica flour addition to avoid strength retrogression, but this creates a cement sensitive to CO_2 attack. Solutions to this problem were developed by Brookhaven National Labs (BNL) with support from industry partners, resulting in sodium silicate-activated slag (SSAS) cement, able to resist hot, strong acid environments with low levels of CO_2, and calcium aluminate phosphate cement (CaP) for use in mildly acidic CO_2 rich environments. Finger and Blankenship (2010) report that the latter have received more attention than the former in GT practice.

Another prominent problem in GT cementing is the relatively low bond strength (typically < 200 psi, Nelson and Guillot, 2006) between casing and cement, making the cement prone to debonding with intermittent cooling (casing shrinkage) and heating (casing expansion) during thermal cycling of the well. This allows the formation of a micro-annulus behind casing, which can become a pathway for gas and fluid migration, thereby jeopardizing long-term well integrity.

Future GT cement solutions may be found in the diverse "geopolymer" family of alkali-activated materials (AAM). For instance, Bernal et al. (2011) have reported on a silicate-activated geopolymer of metakaolin and granulated blast furnace slag exhibiting enhanced (thermal) stability at temperatures exceeding 800°C, with no variation in the compressive strength and no additional shrinkage identified. Not only do such materials exhibit excellent thermal stability, they also exhibit highly desirable self-healing/self-repairing behavior after damage that is typically absent in Portland cements (Liu et al. 2017). It was also recently found that silicate-activated geopolymers have much higher casing-to-cement bond strengths than Portland cements (van Oort et al. 2019), and are therefore expected to be much better equipped to deal with thermal cycling while still maintaining well integrity.

Summarizing, there are evident gaps and needs in the area of high temperature materials and systems that should be addressed with appropriate R&D efforts, but also very promising new developments. The latter, however, are dispersed among a great many parties, such that there will be a need for good integration to develop fully integrated systems.

Flow Dynamics and Control, Energy Production and Economic Analysis. Modeling the transient dynamics inside a GT well is crucial for evaluating the well's economic viability and developing real-time controllers. As introduced in Part I, there are thermal models developed to describe the well temperature behavior. Sun et al. (2018, 2019) have developed steady-state thermal models by using mass, energy, and momentum conservation equations to describe the temperature along a U-shaped CLGS. The assumption that the system is under steady-state conditions renders the method to be only usable for rough estimation of the CLGS long-term yearly performance and not suitable for developing real-time controllers for transient CLGS operation. Schulz (2008) developed a 3D model to predict the energy generation of U-shaped CLGS wells and evaluate their economic viability. This 3D model iteratively solves the equations and estimates the temperature profile along the wellbore, as well as temperature changes within the rock formation based on a 3D mesh of the wellbore and the surrounding rock. Even though the model can predict the effect of surrounding formation temperature variation on the well fluid temperature, the well hydraulics themselves are considered quasi-steady. Therefore, the model can neither predict the temperature cycling associated with power demand cycling and varying pump rates nor describe the pressure wave propagation inside a well, which are required by real-time controllers. Oldenburg et al. (2016) established a simulation framework to integrate the well model with the surrounding formation model. Darcy's law is used to describe the fluid passing through porous formation. The transient momentum equation based on the drift-flux modeling approach is used to describe the multi-phase fluid dynamics within the well. Again, this model uses simplified equations to describe the wellbore hydraulics and is only suitable for quasi-steady long-term estimations. Song et al. (2018) have also developed models to describe U-shaped GT wells. A linear finite difference approach is used to discretize the wellbore, which significantly reduces the computational burden. However, in order to generate accurate predictions, a fine mesh needs to be used when discretizing the well geometry. Therefore, the multiple iterative steps of the finite difference approach make the model unfit for controller design. In general, these models can only predict the well temperature over a long-term steady-state condition and simulate cases where casing and heat conducting cement are used to seal off the horizontal section and wellbore stability is already ensured. To understand the transient short-term behavior and control DCLGS in real-time, it is necessary to develop a modeling methodology that can describe the well transient dynamic behavior under various pump rate and wellbore conditions, both during drilling and production phases. The pressure wave dynamics, which is required by dynamic well control, needs to be considered as well.

Thermal models have been developed and used by the E&P industry to describe the well hydraulics. In addition to the modeling approach by Kabir et al. (1996), Bendiksen et al. (1991) have developed a multi-phase model based on the two-fluid modeling approach to capture complex well hydraulics. The model's implicit numerical scheme, individual momentum equations for each phase, and interconnected boundary conditions lead to a high computational expense. Similarly, Sun et al. (2017) and Yin et al. (2017) developed fully implicit models, which are also computationally expensive, making their approach unsuitable for controller design. The stability issue of the implicit numerical schemes could also be problematic in the case of simulating a fluid mixture with high gas volume fractions. In order to reduce the computational burden and still achieve high accuracy, integrating drift-flux models (DFMs) with energy equation was proposed to describe the well temperature behavior. Petersen et al. (2008) have proposed a de-coupled energy equation that considers the temperature profile in the axial and radial directions. Again, linearization is performed to simplify the 2D temperature calculations. However, their temperature prediction is not verified or validated. Moreover, the impact of temperature changes on predicting the pressure dynamics is not studied. Xu et al. (2019) have developed a similar model to describe the well dynamic thermal behavior. In their paper, the assumption of having constant density and using simplified fluid viscosity neglects the interaction between the temperature and pressure, thus reducing the modeling accuracy. Fallah et al. (2020) developed a transient model to describe the temperature profile along the wellbore by integrating a DFM with the energy equation. Temperature dynamics within the surrounding rock formation are also considered using an integrated 2D heat transfer network. However, their model is developed based on drilling fluids for the E&P industry and the sub-models used to calculate fluid properties are unsuitable for GT fluids. To obtain accurate and reliable temperature estimations, new polynomial models should be used to consider the effect of temperature on fluid properties (e.g. density, viscosity, thermal conductivity, and specific heat capacities). More details of the dynamic thermal model are given in the Appendix.

A thorough analysis on deep geothermal well construction economics still remains to be done and is beyond the scope of this paper. Here, we present a ballpark estimate based on benchmarked GT and E&P cost data provided by Lukawski et al. (2014). Based on data obtained in the 1976-2009 timeframe with costs adjusted to money-of-the-day (MOD) 2009 using the Cornell Energy Institute (CEI) index, they derived the following two equations for well cost as a function of measured depth (MD):

$$\text{Oil and Gas Well Cost} = 1.65 \times 10^{-5} \times (\text{MD})^{1.607} \tag{1}$$

$$Geothermal\ Well\ Cost = 1.72 \times 10^{-7} \times (MD)^2 + 2.32 \times 10^{-3} \times MD - 0.62 \tag{2}$$

The results are shown graphically in Fig. 8. Assuming a well of 14,000 m MD in accordance with our J-shaped design shown in Part I, we obtain a completed GT well cost of ~$65.5 million (and a E&P well cost of ~$76 million). However, we hasten to say that this is a very rough estimate done as a first approach, with the following limitations:

- The GT offset well dataset (see Lukawski et al. 2014) did not include any wells over 10,000 m MD, with the majority of wells in the dataset only a few 1000 m long and mostly vertical. It is probably not appropriate to extrapolate to a much higher (directional) complexity well with a much longer MD.
- As indicated, the costs are MOD 2009, and do not account for cost escalation in the 2009-2020 timeframe, including cost de-escalations as a result of the 2008 economic crisis, the 2015 downturn in E&P, and the most recent 2020 economic/Covid-19 downturn.
- The cost estimates do not include cost reductions due to drilling efficiency optimization learnings and techniques. Some of them described in this paper, for instance, dramatically reduced unconventional well cost in US and Canadian land drilling in the past decade (van Oort et al. 2011).

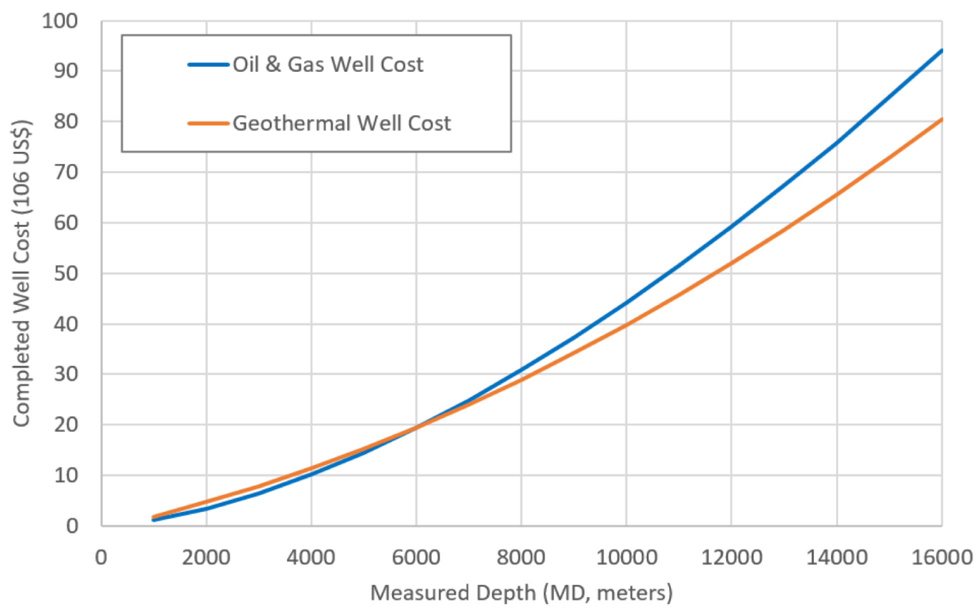

Figure 8—Well cost vs. measured depth according to Lukawski et al. (2014).

As indicated, more quantitative work will be necessary here, which will be complicated by the lack of good offset well comparisons. However, it is reasonable to expect that first demo DCLGS well may cost on the order of $50 million per well, with the goal to reduce costs significantly below $50 million using the drilling efficiency optimization and the application of new drilling technology.

GTAIML (Geothermal Artificial Intelligence and Machine Learning). When it comes to data and data-analysis, E&P appear to be at a clear advantage to the GT industry. The GeoVision report in Chapter 5 (US-DOE 2019) stresses the importance of developing a GT drilling database because:

> "*The global oil and gas and mining industries drill tens of thousands of wells per year, in environments with relatively distinct and consistent classes of geological conditions. Collecting and analyzing large sets of drilling data has allowed these industries to optimize drilling approaches for specific conditions and subsurface environments, which has resulted in faster, lower-cost, and lower-risk drilling*."

A similar effort is clearly needed in the GT industry to significantly bring down costs and the associated risks. A couple of examples of the value that data collection and analysis can deliver are given in the following. Huang et al. (2020) recently presented their work on identifying areas within the western Canadian sedimentary basin in Alberta that had a temperature gradient high enough to reach 120° C at depths of less than 14,700 feet, using E&P temperature data. The various issues associated with these datasets include measurement errors, single temperature point at a certain depth, not knowing the depth of the measurements, not knowing when during the drilling process the temperature measurement was taken, etc. ML techniques can be developed to deal with this type of uncertainty. Faulds et al. (2020) and Vesselinov et al. (2020) demonstrated the use of Artificial Neural Networks (ANN) and unsupervised machine learning techniques to identify GT prospects as well as features that are relevant to identifying such prospects. Techniques such as these must be adopted in the search for DCLGS prospects as well. Even though DCLGS is technically an "anywhere in the world" system, the shallower wells in areas with higher geothermal gradients would be targeted first in a phased approach.

In addition to creating a GT drilling database, the GT industry in general can also benefit from the numerous AI and ML techniques developed in E&P over the past decades, to analyze large historical datasets quickly as well as to process drilling data streams for real-time advisory and automation. In fact, for DCLGS, the adoption of these techniques can be considered to be a necessity for economic viability. Data analysis (both historical and real-time) needs to be automated to lower the cost of drilling. There is no longer the luxury of relying on an organic "trial-and-error" learning curve (van Oort et al. 2011). In the following, we give an overview of Ml and AI methodologies that have been developed by us at UT Austin, recognizing that this is a quickly expanding area in E&P.

There are three technologies that are recommended for adoption and deployment to enable rapid and accurate data analysis for DCLGS: automated data validation (Ashok et al. 2013) (Baumgartner et al. 2019), story boarding (Saini et al. 2018a) and spider bots (Saini et al. 2018b).

- Automated data validation: Data collected from sensors on the drilling rig, and through human input (which should in fact be minimized) are very error-prone. Automated data cleansing techniques such as those developed for lower frequency surface sensor data (Ashok et al. 2013) and downhole high frequency data (Baumgartner et al. 2019) are essential before any type of ML or AI techniques can be applied on the data. In its absence, we will end up in a "garbage in, garbage out" scenario.
- Storyboarding: AI and ML algorithms that provide recommendations are generally black boxes, and there is often a struggle to get the end user to understand and accept the AI/ML results and recommendations. Saini et al. (2018a) have developed a storyboarding process whereby the results are displayed as a series of relevant charts, thereby providing the end user support information to verify the computer-generated results. This is an essential component of getting the industry to adopt AI/ML.
- Spider bots: Finally, even with the creation of a massive GT database, insights cannot be generated quickly (seconds / minutes as opposed to weeks / months) without a framework that allows various scripts to be run automatically and repeatedly whenever new data arrives, or whenever the ML model changes. These scripts get their name "spider bots" from the bots used by search engine providers to crawl the web and index them so as to provide the user valuable information in milliseconds. Here, three categories of scripts are recommended: cleansing scripts, processing scripts and indexing scripts (Saini et al. 2018b) to automate the process of analyzing and indexing data, so that insights can be drawn in seconds.

As mentioned earlier in the paper, the cost of drilling a GT well is a major proportion of any GT project. The total well delivery cost itself can be considered to be made up of two parts: the cost to drill the well at its technical limit (i.e., best well possible, if everything went according to plan), and the cost of inefficiencies that creep into the process (Fig. 9). It has been proven in E&P drilling that AI and ML techniques can greatly improve the detection and reduction (and sometimes, even elimination) of Invisible Lost Time (ILT) and NPT. We briefly provide some references to such techniques in the following sections.

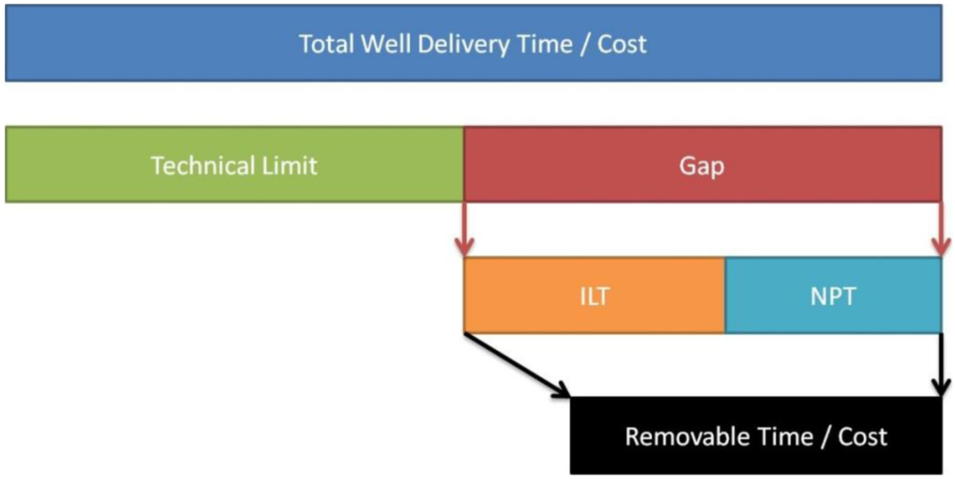

Figure 9—Cutting removable drilling time and cost through AI/ML.

ILT refers to time lost during the construction of the well that is often very difficult to track without proper and appropriate data analysis (hence the name: invisible lost time). ILT analysis provides us with answers to questions such as: Could the rig have drilled faster? Could the rig have tripped faster? Could the rig have made the connections faster? Did the rig spend too much time circulating? The key algorithm that helps with this is an automated rig state analysis algorithm that calculates the times spent on various drilling activities (van Oort et al. 2008). This is generally calculated using drilling surface data, and will help identify inefficiencies that exists in the drilling process and help eliminate them. This will be very critical for DCLGS, especially since the well will be deeper and longer than normal. During well construction, there are activities that occur outside of the actual drilling process such as rigging up/down, cementing, casing run, etc. during which time data collection is not reliable. For these tasks, it is necessary to analyze manually entered activity memos and code to determine the source of inefficiency. Here ML techniques are very helpful in cleaning this error-prone human entered data, so that the automated analysis can provide accurate insights (Ucherek et al. 2020). ML models are also available to automatically detect drilling dysfunctions and enable higher ROP (Ambrus et al. 2017) (Saini et al. 2020a). Their use can drastically reduce drilling inefficiencies. Self-learning auto drillers have also been developed that automatically find the drilling parameters sweet spot through reinforcement learning (Pournazari 2018). Kaneko et al. (2018) shows how a combined physics and data based model can be used to predict downhole WOB for ultra-deep wells (~26,000 ft).

Many AI/ML techniques already exists for unplanned NPT events such kicks and lost circulation (Pournazari et al. 2015), washouts, pump failures (Ambrus et al. 2018), etc. Such early detection systems can identify unwanted events before (or as soon as) they happen, thereby helping reduce NPT. Stuck pipe incidents are another major source of NPT, heavily influenced by hole cleaning and the tortuosity of the well. Given the nature of DCLGS, this would be a major source of concern and the deployment of a digital twin can help avoid this problem. In this context, a digital twin refers to a combined physics and data-based model able to simulate multiple action-able future scenarios, and evaluate these in real-time. This, in turn, allows taking proper actions before an NPT event occurs. Such twins have already been developed to provide hole cleaning advice (Saini et al. 2020b). To further improve hole cleaning, sensors that use 3D laser and 2D vision cameras have been developed to continuously monitor the cutting and cavings that come out of the shale shaker. These sensors use ML to process the 3D/2D data streams for real-time hole condition determination (Han et al. 2017, 2018). Longer wells also tend to put more stress on the drilling tools such as top drives, mud pumps, mud motors, etc. A top drive failure can cause significant NPT, and this can be avoided through condition-based maintenance (CBM) techniques such as described in Pournazari et al. (2016). In the absence of downhole sensors, a forensic analysis of the drill bit provides the best indication of downhole conditions and such information can be used for improving future drilling performance. Automated routines built on deep learning and image processing techniques (Ashok et al. 2020) are now available to streamline this process.

To summarize, there are many AI and ML techniques in the E&P drilling industry that are appropriate for adoption in the GT industry. DCLGS would need to leverage all of these, to be economically competitive. An initiative known as "GOOML" (Siratovich et al. 2020) already exists for the application of ML techniques to optimize operational efficiency of existing GT plants. A similar initiative on the drilling and well construction side needs to be established also. There is large value in data, and extraction of that value must be maximized.

Additional Oil and Gas Industry Opportunities

The previous sections have made the case that E&P companies have domain expertise and technologies that can be enablers for deep GT well construction, and for DCLGS in particular. Here, we briefly highlight some other E&P opportunities.

It has been suggested by several authors (including Davis and Michaelides 2009, Bu et al. 2012, Templeton et al. 2014, Wight and Bennet 2015, Caulk et al. 2017, Yu et al. 2019) that it may be possible to retro-fit and repurpose abandoned - or to be abandoned - wells as GT wells, extending their productive life. If this is possible, it would be a significant opportunity for E&P operators. Well abandonment and decommissioning is one of the biggest technical and economic challenge areas in current E&P practice, with many millions of wells to be abandoned in the coming decades, delivering no return on what will require many billions of dollars of investment. To turn such wells into profitable GT wells (possibly without significant added drilling cost) would truly be "killing two birds with one stone". However, we may have temper expectations here, for the following reasons:

- The majority of literature publications are modeling studies calculating efficiency of heat extraction in abandoned wells, with little-to-no regard of the practical implications of actually turning old wells into high-integrity GT producers;
- As already indicated, GT wells require excellent well integrity, including fully cemented casing string to prevent TAP, and casing programs and cement sheaths that can stand up to cyclical thermal loads. On the other hand, many (to be) abandoned wells either do not have complete annular cementations or have other cement integrity issues and were not designed with high absolute temperatures and thermal load cycling in mind;
- As mentioned previously, GT wells generally need larger production hole sizes than typically used in E&P. Abandoned E&P wells may therefore not offer the hole size and drift necessary to economically exploit thermal energy, especially when wells need to be deepened to access higher temperature zones. Sidetracking abandoned wells shallow to achieve a large production hole size may not offer significant cost savings compared to drilling entirely new wells, and may inherit the aforementioned well integrity issues of the parent wells.

In all, it appears that re-using abandoned wells as GT wells will turn out to be an opportunity only for a select group of wells, especially those drilled in areas with very high heat flows (Caulk and Tomas 2017) that have good well integrity and can be repurposed with minimum modifications.

More tangible E&P opportunities are presented by the industry's ability to leverage a workforce of trained and skilled workers that can be easily re-deployed and retrained to construct GT wells. Finding a synergy and establishing a technology transfer between the E&P and GT will strengthen the competitiveness and adaptability of the workforce in the job market, which in turn will unify the energy sector and propel the entire GT sector to advance more rapidly. GT involvement will also help raise the profile of an E&P industry habitually plagued by bad PR, while at the same time offering an ability to make good on the considerable energy transition promises made, as mentioned at the very start of this paper.

Main Conclusions

This paper introduces deep closed-loop geothermal systems (DCLGS), currently still defined as a subset of engineered/enhanced geothermal systems (EGS) but distinctly different from it by extracting subsurface heat with a closed conduit rather than through a natural and/or induced fracture system. Both systems offer the promise of globally scalable, fully dispatchable baseload energy, with the potential to transform energy provision throughout the world through an inexhaustible green energy supply.

Although most of the current funding and attention is directed towards EGS, this paper makes the case to develop DCLGS alongside it as a potential alternative option. DCLGS addresses many of the downsides associated with the EGS concept, while still being able to deliver the same amount of energy as deep EGS wells. Our new hydraulic model coupled with a thermal model shows that large-scale DCLGS wellbores can deliver on the order of 25-30 MWt of power per well initially.

Making DCLGS a reality, however, is a non-trivial challenge, because it will require world-record, deep ERD drilling in an ultra- or extreme-HPHT environment, with bottom-hole static temperatures in the 200°C – 350°C range, true vertical depths deeper than 5 km (and more typically in the 7 to 10 km range) and measured depths on the order of 14 km and larger. Some of the technical gaps and needs are assessed here, and an overview is given in this paper of technology solutions, both in terms of what is currently available or what could be developed with appropriate investment in the short-to-medium term (with a time horizon of ~10 years). Technical areas discussed include deep hole making and directional drilling, wellbore geomechanics and completion design, high temperature materials and systems, flow dynamics and control, energy production and economic analysis, and GTAIML (geothermal artificial intelligence and machine learning). In all of these areas, we see considerable opportunities for cross-fertilization between the E&P industry and the geothermal industry, particularly when it comes to leveraging E&P ERD and HPHT well construction expertise. Capitalizing on latest technology and understanding will be crucial, with no room for an organic, "trial-and-error" learning curve, due to the relatively low volume of geothermal wells being drilled and the high initial well cost associated with first demonstration DCLGS wells. Operational excellence will need to be delivered from the very start.

Deep geothermal is currently where wind and solar were 20 years ago. It could follow the same trajectory, possibly significantly accelerated given enough interest and investment. It offers a particularly compelling case for oil and gas involvement (a case we have tried to further support in this paper), given the well construction domain expertise, technology application experience and transferable skills that can immediately be leveraged in GT domain. Moreover, it allows oil and gas companies in their ability to deliver on the goals for their ongoing sustainable energy transitions.

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Greek Letters

μ : viscosity, Pa.s

ρ : density, Kg/m^3

Subscripts

g : gravitational

i : inner

o : Outer
w : Wall

Nomenclature

A: cross sectional area, m^2
c_p : specific heat, constant pressure, J/Kg.K
c_v : specific heat, constant volume, J/Kg.K
D : diameter, m
e : internal energy, J/kg
f_D : Darcy-Weisbach friction factor
f_g : gravitational force, $Kg/m^2.s^2$
f_w : wall friction, $Kg/m^2.s^2$
g : gravitational acceleration, m/s^2
h : convection coefficient $W/m^2.K$
H : enthalpy, J/Kg
$\dot{H}_{source}$: rate of enthalpy inlet, W/m^3
k : thermal conductivity, W/m.K
$\dot{m}_{source}$: rate of mass inlet, $Kg/m^3.s$
$\dot{M}_{source}$: rate of momentum inlet, $Kg/m^3.s^2$
Nu : Nusselt number
p : pressure, Pa
Pr : Prandtl number
$\sqrt{\dot{q}}$: heat transfer rate, W/m^3
r : radius, m
R : thermal resistance, $m^3.K/W$
Re : Reynolds number
t : time, s
T : temperature, K
v : velocity, m/s
x : measured depth, m
z : true vertical depth, m

Acronyms

ANN : artificial neural networks
BHCT : bottom-hole circulating temperature
BHP : bottom-hole pressure
BHST : bottom-hole static temperature
CaP : calcium aluminate phosphate
CAPEX : capital expenditure
CBL : cement bond log
CBM : condition based maintenance
CC : continuous circulation
CFD : computational fluid dynamics
CTFV : critical transport fluid velocity
CWD : casing while drilling
DCLGS : deep closed-loop geothermal system

DFM : drift-flux modeling
DTS : distributed temperature sensing
DWC : drilling with casing
E&P : oil / gas exploration and production
EGS : enhanced geothermal system
ERD : extended reach drilling
FOS : fiber optic sensors
GHG : greenhouse gas
GR : gamma ray
GT : geothermal
GTAIML : geothermal artificial intelligence and machine learning
HPHT : high-pressure high-temperature
ILT : invisible lost time
LAM : light annular mud
LCOE : levelized cost of energy
LWD : logging while drilling
MCD : mud cap drilling
MD : measured depth
MPC : managed pressure cementing
MPD : managed pressure drilling
MPO : managed pressure operation
MWD : measurement while drilling
NPT : non-productive time
OBM : oil-based mud
PDC : polycrystalline diamond compact
PI : proportional integral
PPFG : pore pressure fracture gradient
PVT : pressure-volume-temperature
RCD : rotating control device
ROP : rate of penetration
R&D : research and development
SAC : sacrificial fluid for mud cap drilling
SAGD : steam assisted gravity drainage
SBM : synthetic-based mud
SBP : surface backpressure
SC : supercritical
SiC : silicon carbide
SOI : silicon-on-insulator
SSAS : sodium silicate-activated slag
TAP : trapped annular pressure
TCI : tungsten carbide insert
TOB : torque on bit
TVD : true vertical depth
UCS : unconfined compressive strength
UHPHT : ultra high-pressure high-temperature
VDL : variable density log
VIT : vacuum-insulated tubing
VSP : vertical seismic profile

WBM : water-based mud
WBS : wellbore strengthening
WOB : weight on bit
XHPHT : extreme high-pressure high-temperature

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Appendix A

In this section, an overview of the integrated thermal and hydraulic modeling approach. Details of the solution procedure can be found in Fallah et al. (2020). The solution algorithm is based on solving the mass, momentum, and energy conservation equations for the working fluid within the DCLGS well:

$$\frac{\partial \rho}{\partial t}+\frac{\partial \rho v}{\partial x}=\dot{m}_{source} \quad \text{(A-1)}$$

$$\frac{\partial \rho v}{\partial t}+\frac{\partial \rho v^2}{\partial x}=-\frac{\partial p}{\partial x}+f_g+f_w+\dot{M}_{source} \quad \text{(A-2)}$$

$$\frac{\partial \rho\left(e+\frac{1}{2}v^2+gz\right)}{\partial t}+\frac{\partial \rho v\left(h+\frac{1}{2}v^2+gz\right)}{\partial x}=\frac{\partial}{\partial x}\left(k\frac{\partial T}{\partial x}\right)+\dot{q}_{wall}+\dot{H}_{source} \quad \text{(A-3)}$$

where t is time, x is the length along the direction of the well (MD), ρ is density, v is velocity, $\dot{m}_{source}$ is the rate of mass generation per unit volume from sources, p is pressure, f_g is gravitational force per unit volume, f_w is wall friction per unit volume, $\dot{M}_{source}$ is the rate of momentum generation per unit volume from sources, e is the internal energy, g is the gravitational acceleration, z is the vertical depth, h is enthalpy, k is thermal conductivity, T is temperature, $\dot{q}_{wall}$ is the rate of external heat transfer per unit volume through the walls, and $\dot{H}_{source}$ is the rate of enthalpy generation per unit volume from sources, defined as follows:

$$e=\int_{T_0}^{T} c_v\left(T\right)dT+e_0 \quad \text{(A-4)}$$

$$h=e+p/\rho \quad \text{(A-5)}$$

where c_v is the specific heat capacity at constant volume, and T_0 and e_0 are reference temperature and internal energy. The gravitational force and wall friction terms in the momentum equation are calculated as (Ma et al., 2016):

$$f_g=\rho g\cos(\theta) \quad \text{(A-6)}$$

$$f_w=-\frac{1}{2}\frac{f_D\rho v^2}{D} \quad \text{(A-7)}$$

where θ is the hole deviation from the vertical direction, f_D is the Darcy-Weisbach friction factor, and D is the hole diameter. The external heat transfer in the energy equation was calculated in the heat transfer network.

A semi-implicit numerical scheme was used to discretize and solve the conservation equations (Evje and Fjelde, 2002). Density, viscosity, thermal conductivity, and specific heat capacities were modeled as functions of temperature and pressure depending on the working fluid, which was assumed to be water. Its density was modeled by a first-order polynomial function of pressure combined with a second-order polynomial function of temperature as:

$$\rho=\frac{p}{1490.9}-0.0026*T^2-0.1594*T+1001.5515 \quad \text{(A-8)}$$

where pressure is measured in Pa, temperature in °C, and density in kg/m^3.

Neglecting the effect of pressure, the viscosity, specific heat capacities, and thermal conductivity are assumed to be functions of temperature and are modeled as:

$$\mu=\begin{cases}3.27*10^{-11}*T^4-9.14*10^{-9}*T^3+9.93*10^{-7}*T^2-5.56*10^{-5}*T+1.79*10^{-3}, & T<100^{\circ}\mathrm{C}\\ -2.025*10^{-11}*T^3+1.72*10^{-8}*T^2-5.18*10^{-6}*T+6.44*10^{-4}, & T\geq 100^{\circ}\mathrm{C}\end{cases} \quad \text{(A-9)}$$

$$c_p=1.16*10^{-4}*T^3-2.35*10^{-2}*T^2+1.61*T+4.17*10^3 \quad \text{(A-10)}$$

$$c_v=3.40*10^{-5}*T^3-1.01*10^{-2}*T^2-3.95*T+4.24*10^3 \quad \text{(A-11)}$$

$$k=-5.71*10^{-6}*T^2+1.64*10^{-3}*T+5.69*10^{-1} \quad \text{(A-12)}$$

where temperature is measured in *°C*, viscosity in *Pa.s*, specific heat capacities in *J/Kg.K*, and thermal conductivity in *W/m.K*.

A 2-D heat transfer network was developed to calculate the conduction heat transfer within the rock formation and to estimate rock temperature dynamics. The rock temperature affects the wellbore flow through the wall heat transfer term in equation (A-3). Heat transfer between the wellbore flow and the formation rock, which are separated by casing and cement for cased-hole sections and are in direct contact for open-hole sections, as well as inside the formation rock is calculated using the heat transfer network shown in Fig. A-1. The formation rock is discretized radially to account for the formation temperature dynamics in close vicinity of the well. Due to the negligible temperature gradients in the axial direction, only the radial heat conduction inside the formation rock is taken into account (Fallah et al., 2019). Continuous heat transfer to the working fluid reduces the surrounding rock temperature (i.e. thermal depletion), which needs to be considered for accurate estimation of the generated power.

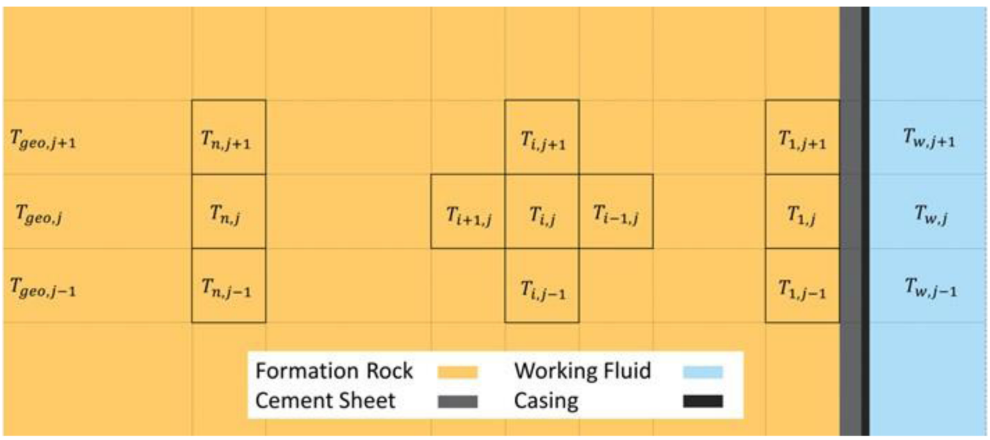

Figure A-1—Discretization of formation rock for heat transfer calculations for a cased section of the well (with bi-lateral symmetry). The casing and cement sheet are omitted when simulating open-hole well sections.

The heat transfer between the wellbore and the first formation node was calculated using:

$$\dot{q}_{wall} = \frac{T_1 - T_w}{R} \tag{A-13}$$

where T_1 is the temperature of the first formation cell, T_w is the temperature of the water in the well, and R is the thermal resistance. Total thermal resistance is calculated by summing the individual resistances between the water and the first cell i.e. convection in the water, conduction through the casing and cement (which is zero in open-hole), and conduction in the formation rock. The heat transfer between the adjacent formation cells is calculated similarly, where the resistance is only the conduction resistance through the rock. Each individual conduction or convection resistance is calculated as:

$$R_{conduction} = \frac{A ln\left(\frac{r_o}{r_i}\right)}{2\pi k_s} \tag{A-14}$$

$$R_{convection} = \frac{A}{h\pi D} \tag{A-15}$$

where A is the cross-sectional area of the well, r_o and r_i are the outer and inner radius of the solid across which heat is being conducted, k_s is the conductivity of the solid, D is the diameter of the wall at which heat is being convected, and h is the convection coefficient. The convection coefficient is defined as:

$$h = \frac{Nuk}{D} \tag{A-16}$$

where k is the conductivity of water, D is the diameter of the hole, and Nu is the Nusselt number calculated from Equation (12) (Nellis and Klein, 2009):

$$Nu = \begin{cases} 4, & laminar\ flow \\ \dfrac{\left(\frac{f}{8}\right)(\mathrm{Re}-1000)Pr}{1+12.7\left(\mathrm{Pr}^{\frac{2}{3}}-1\right)\sqrt{\frac{f}{8}}}, & turbulent\ flow \end{cases} \tag{A-17}$$

where Re and Pr are the Reynolds number and Prandtl number, respectively.

A Proportional Integral (PI) controller was also developed to simulate the automated choke for controlling the PVT behavior of the working fluid, as well as well control over the open-hole sections. Due to the high temperatures in the well, water will boil as it is being circulated back to surface. Large differences between the densities of liquid water and water vapor lead to a large drop in hydrostatic pressure, known as the thermosiphon effect. This makes control over the BHP and maintaining well integrity (in the case of an open-hole completion) challenging. Reservoir fluids could also enter the well (through any exposed permeable formations and fractures) and pollute the water that is circulated out of the well. Moreover, evaporation could lead to excessive pressures on surface due to the expansion. To address these issues, return flow is controlled using an automatic choke such that the entire operation is under MPO control at any time. A polynomial fit of the pressure as a function of temperature is presented in Equation (A-18). The boiling pressure monotonically increases with the temperature (Moran et al., 2010). At any given temperature, water starts boiling if the pressure is below the boiling pressure threshold.

$$p_{boil} 1.57*10^{-3}*T^4 - 2.44*10^{-1}*T^3 + 3.30*10^1*T^2 - 1.77*10^3*T + 3.46*10^4 \tag{A-18}$$

where temperature is measured in $°C$ and pressure in Pa. Deep in the wellbore itself, the hydrostatic pressure of the water column applies sufficient pressure to avoid boiling downhole, even for extreme temperature gradients and high absolute downhole temperatures. The well location where boiling is most likely to occur is on surface at the exit due to the reduced hydrostatic pressure. Therefore, a proportional integral (PI) controller that enables MPO is designed to maintain SBP above the boiling pressure by adjusting the choke opening automatically. Note that the MPO system plays a crucial role in the proposed DCLGS concept. The MPO system controls the fluid PVT behavior, maintains pressure control across the open lateral, ensures well integrity, and avoids reservoir influxes and fluid contamination. Simulating the automated choke control behavior relies on capturing the pressure wave dynamics and the fast transients associated with rapid choke adjustments. In this paper, we simulate choke opening manipulation such that:

$$p_{surface} = p_{boil}(T) + SM \tag{A-19}$$

where $p_{surface}$ is the SBP that is maintained by the choke, p_{boil} is the boiling pressure on surface (which is a function of the outlet temperature), and SM is an additional safety margin that may also account for excess pressure needed for maintaining wellbore stability in exposed open-hole sections in the well (note that this term can be further delineated if real-time estimation of pore pressure and the pressure requirements for wellbore stability is possible (Zoback, 2010). Temperature data collected at a one-minute-or-higher frequency are used in the model to calculate the boiling pressure and maintain the required SBP. For the simulations presented here, the safety margin is set to 1 MPa.