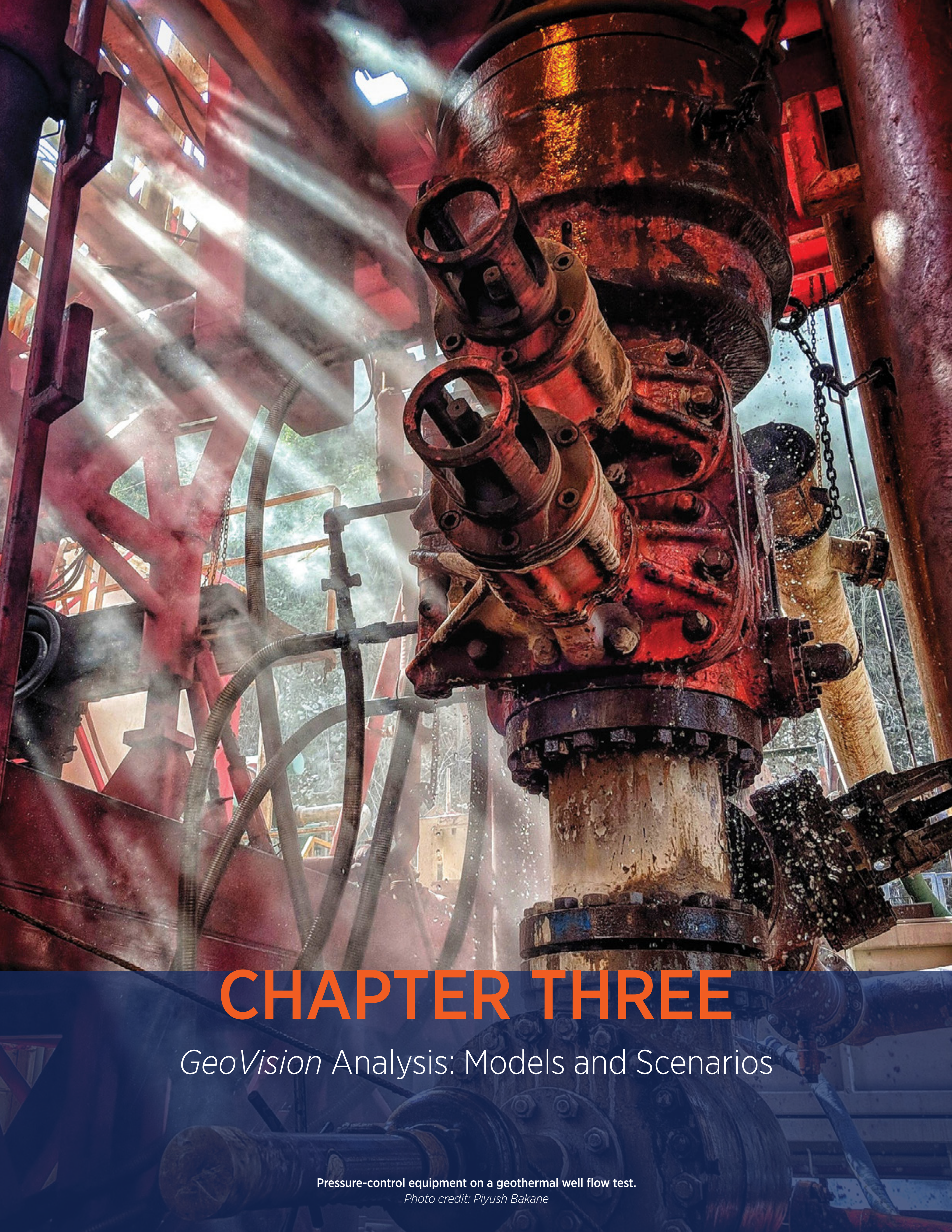

CHAPTER THREE

GeoVision Analysis: Models and Scenarios

Pressure-control equipment on a geothermal well flow test.
Photo credit: Piyush Bakane

3 *GeoVision* Analysis: Models and Scenarios

The *GeoVision* analysis used detailed, quantitative modeling to assess the potential for geothermal deployment under varied scenarios that consider a range of technologies, market conditions, and barriers. Chapter 3 summarizes the modeling analytics and approach used in the analysis. Section 3.1 introduces the modeling platforms and Section 3.2 discusses the various scenarios.

3.1 *GeoVision* Models

The *GeoVision* analysis used comprehensive research, modeling, and data analysis to quantify electric- and non-electric-sector deployment levels within credible and realistic market constraints. A range of impact models was then used to quantify the economic and workforce benefit to the geothermal industry and environmental impacts for the United States under the projected deployment levels (Chapter 4). Modeling platforms and assumptions used in the *GeoVision* analysis are introduced here and described further in Appendix C and Augustine et al. 2019. Not all assumptions and data are included in this chapter or Appendix C; detailed descriptions of the modeling tools, inputs, methodologies, and scenarios that form the quantitative basis for the *GeoVision* analysis are provided in Lowry et al. 2017, Doughty et al. 2018, Augustine et al. 2019, Liu et al. 2019, McCabe et al. 2019, and Young et al. 2019.

3.1.1 Geothermal Electricity Technology Evaluation Model

The *GeoVision* analysis used the U.S. Department of Energy's (DOE's) Geothermal Electricity Technology Evaluation Model (GETEM)[63] to estimate the cost of developing geothermal resources for electric-power generation under various technology scenarios. GETEM is a Microsoft Excel-based model that estimates the overall capital costs, operations and maintenance (O&M) costs, and levelized cost of electricity to develop hydrothermal and enhanced geothermal systems (EGS) projects. GETEM does this using a bottom-up, deterministic model that calculates individual component costs by project phase, such as exploration, wellfield development, and power-plant construction. GETEM is based on user-defined cost inputs, embedded cost and system performance correlations, and cost indices to adjust for the year the project is developed.

GETEM was used to estimate the overnight capital[64] and O&M costs for the hydrothermal and EGS resources described in Section 2.1 on a site-by-site basis. Inputs to GETEM for the *GeoVision* analysis included the resource type—either conventional hydrothermal or EGS—and a power-plant technology configuration based on resource parameters such as temperature,

Steam pipelines at the Bottle Rock geothermal power plant (The Geysers in California). *Photo credit: Betsy Phillips*

63 The GETEM model is available on the DOE website at https://energy.gov/eere/geothermal/geothermal-electricity-technology-evaluation-model.

64 Overnight capital costs are defined as the capital expenditure required to achieve commercial operation of a power plant, excluding the construction period and the financing and interconnection costs.

depth, and project type. The results were used to develop geothermal resource supply curves—a plot of technology resource potential versus the cost to develop the applicable resource. This curve shows how much of a resource is available as well as the cost associated with constructing and using a given power-plant technology to harness the resource for electricity generation. The approach and methodology closely followed the one described in Augustine 2011. Supply curves resulting from GETEM were then entered into the Regional Energy Deployment System (ReEDS) (Section 3.1.2) to support comparisons and capacity-deployment decisions among alternative power-generation technologies.

3.1.2 The Regional Energy Deployment System Model

Developed by DOE's National Renewable Energy Laboratory (NREL), the ReEDS[65] model considers the many electricity generation, storage, and transmission options across the contiguous United States. The model identifies the cost-optimal mix of technologies that meets regional electric-power demand based on grid-reliability requirements, technology-resource constraints, and policy constraints. As a capacity-expansion and dispatch model, ReEDS uses system-wide, least-cost optimization to estimate the type and location of future generation and transmission capacity (Eurek et al. 2016). ReEDS has been used to model capacity expansion for a number of other DOE Vision analyses, including the *Wind Vision*,[66] *Hydropower Vision*,[67] and *SunShot Vision*,[68] as well as the *Renewable Electricity Futures* study.[69]

For the *GeoVision* analysis, the geothermal-resource supply curves calculated in GETEM (Section 3.1.1) were inputs to the ReEDS model. In addition to the resource supply curves, ReEDS used scenario-based metrics identified by the *GeoVision* analysis task forces, such as project financing and construction timelines. The ReEDS and GETEM model interface and workflow are elaborated in Augustine et al. 2019. Outputs from ReEDS included the amount and location of production capacity and annual generation from each potential electricity-generation technology, including geothermal technologies, as well as storage capacity expansion, transmission capacity expansion, total electric-sector costs, electricity price, fuel demand and prices, water withdrawals and consumption, and carbon dioxide emissions.

Springtime at Surprise Valley Hot Spring in California.
Photo credit: Joe LaFleur

Because ReEDS is a system-wide least-cost optimization model, it does not consider revenue impacts for individual project developers, utilities, or other industry participants. The model also does not resolve some other factors that may influence power-system economics, including the following:

- Constraints associated with the supply chain and manufacturing sector are not included internally in ReEDS. All technologies are assumed to be available up to their technical resource potential.

65 The ReEDS model is available on NREL's website at https://www.nrel.gov/analysis/reeds/.

66 https://www.energy.gov/eere/wind/wind-vision

67 https://www.energy.gov/eere/water/new-vision-united-states-hydropower

68 https://www.energy.gov/eere/solar/sunshot-vision-study

69 https://www.nrel.gov/analysis/re-futures.html

- Technology cost reductions from manufacturing economies of scale and "learning by doing" are not calculated in the model internally. These market behaviors are defined as inputs that do not depend on the capacity deployed by the model.
- With the exception of projecting future natural-gas fuel costs, foresight is not considered explicitly in ReEDS. The model makes investment decisions based on the conditions it observes at a given point in time, without considering how those conditions may change in the future.
- ReEDS is deterministic and has limited considerations for risk and uncertainty, so it cannot study variability in energy availability from year to year. As such, the model is restricted to projections of average system behavior.
- As an electric-sector-only model, ReEDS does not directly include fuel infrastructure, challenges of land competition associated with fossil-fuel extraction and delivery, or challenges of water competition associated with agricultural or other use.

Fly Geyser in northern Washoe County, Nevada.
Photo credit: Harmony Ann Warren

3.1.3 Distributed Geothermal Market Demand Model

As noted in Sections 3.1.1 and 3.1.2, the *GeoVision* analysis used GETEM to determine geothermal development costs and resource supply curves in the electric sector and ReEDS to determine geothermal electric-power deployment potential. To evaluate the non-electric heating and cooling sector, DOE developed a dedicated modeling tool called the Distributed Geothermal Market Demand (dGeo) model (Gleason et al. 2017, McCabe et al. 2019).

The dGeo model simulates the potential for deployment of distributed geothermal-energy resources in the residential and commercial sectors of the contiguous United States for two technologies: geothermal heat pumps (GHPs) and geothermal direct-use applications for district heating. To quantify these opportunities, dGeo leverages a high-resolution geospatial database and robust modeling framework whose design is based on and consistent with other Distributed Generation Market Demand models (Sigrin et al. 2016), such as NREL's dSolar model.[70]

dGeo is a long-term scenario-modeling tool. The model has the capability to simulate the technical, economic, and market potential and the technology deployment of GHP and geothermal district-heating applications through 2050 under user-defined input scenarios. Scenarios in dGeo consider changes in costs, performance, and financing; costs of heating and cooling alternatives; and regional heating and cooling energy demand and the potential of geothermal resources to meet that demand. In addition to determining the economic resource potential for geothermal district heating and GHP deployment, the dGeo model also has the capability to identify the extent and speed with which the market can adopt

70 Information about the NREL dSolar module is available on the NRELwebsite: https://www.nrel.gov/analysis/dgen/model-applications.html.

those resources based on consumer behavior.[71] The dGeo market-potential assessment considers regulatory and policy limitations and regional competition with other energy sources.

Figure 3-1 illustrates the various levels of potential that can apply to all types of geothermal resources. *Resource* potential is the total geothermal energy available, based solely on physical characteristics such as volume and heat content. *Technical* potential is the portion of the overall resource that can technically be accessed, considering limitations such as land access, physical access to the reservoir, and equipment efficiency. *Economic* potential is that portion of technical potential that is cost effective to recover based on technology costs and anticipated revenues. *Market* potential indicates how much of and how quickly the resources could actually be adopted and deployed from the economic potential, given market conditions such as regulatory environment, capital availability and investor interest, consumer demand, and energy competition.

The *GeoVision* analysis focused on technology applications with proven track records and sufficient examples from which to develop model parameters. For GHPs, heating and cooling applications were considered. However, only geothermal district heating was considered for direct-use applications; geothermal district-*cooling* systems were omitted from the analysis given the experimental nature of the technology. A literature review indicated that the technology to support district-cooling systems may exist, but few examples (if any) indicate use of a geothermal resource to provide cooling to a network of buildings. The *GeoVision* analysis included assessment of market potential for GHP technologies. Doing the same for geothermal district-heating applications would require determining the consumer adoption behavior of large groups and communities, which was outside the scope of the *GeoVision* analysis. As such, the analysis for geothermal district-heating applications considered only economic potential.

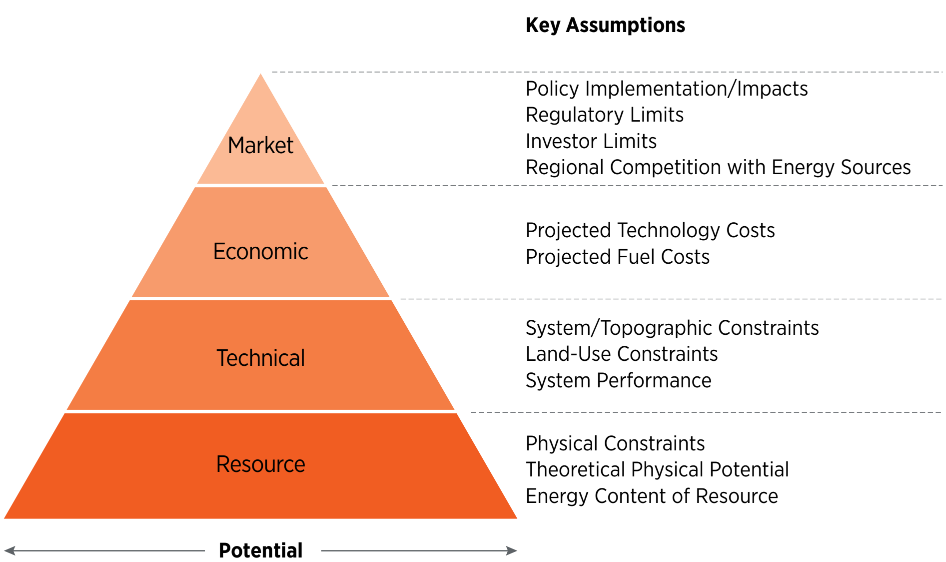

Figure 3-1. Levels of geothermal potential in the dGeo model

*Figure Notes: For geothermal, **resource potential** is the total projected heat resources, limited only by physical/thermodynamic factors. **Technical potential** is the subset of total resources that will be accessible given land-access restrictions, geographical restrictions, and the performance limits of the installed technologies. **Economic potential** is that amount of resources that is cost effective to develop given technology and development cost projections. **Market potential** includes factors such as consumer demand, regulatory and policy restrictions, investment availability, and competition.*

71 Whereas *economic* potential considers the portion of resource that is economically viable, the *market* potential considers the portion that is likely to be deployed, given the reaction of consumers in the market to economic factors. To determine this market and deployment potential, dGeo first relies on a series of empirically derived curves that relate the economic attractiveness of technology adoption and maximum market share for each modeled consumer entity (e.g., an organization or group). Maximum market share is the portion of the market that will eventually adopt the technology given its economic attractiveness. dGeo simulates deployment using the "diffusion of innovations" framework, which establishes how, why, and at what rate technology is spread. Under this framework, technology deployment initially follows slow growth, accelerates as mass-market uptake begins, and then decelerates as the market for the technology reaches saturation.

3.2 *GeoVision* Scenarios

The *GeoVision* analysis included a range of scenarios to evaluate geothermal deployment potential and the impacts that would result from developing and implementing new geothermal technologies under various market conditions. The subsequent sections summarize the scenarios but do not contain the full body of analysis. The inputs and assumptions are detailed in Doughty et al. 2018, Augustine et al. 2019, McCabe et al. 2019, and Liu et al. 2019.

3.2.1 Electricity Sector Scenarios

Three primary scenarios were modeled in the *GeoVision* analysis to explore geothermal deployment potentials within the electric sector: 1) Business-as-Usual (BAU), 2) Improved Regulatory Timeline (IRT), and 3) Technology Improvement (TI). Table 3-1 summarizes the scenarios and their key assumptions with respect to capital and O&M costs, construction times, financing, and undiscovered hydrothermal resource discovery rates. The scenarios are progressive and cumulative.

Scenario	Business-as-Usual	Improved Regulatory Timeline[72]	Technology Improvement
Description	Reflects current industry trends	Streamlined permitting increases the amount of exploration, decreases project timelines, increases resource discovery rate	IRT scenario + access and technology improvements: Advances in drilling, exploration, and EGS reservoir development reduce costs and risks
Capital + O&M Costs	BAU	BAU	Hydrothermal: some reductions EGS: large reductions
Construction Time (years)[73]	Hydrothermal: 8 EGS: 10	Hydrothermal: 4 EGS: 5	Hydrothermal: 4 EGS: 5
Financing[74]	BAU	BAU	ReEDS Standard WACC (8%)
Hydrothermal Discovery Rate[75]	1% of undiscovered resource/year	3% of undiscovered resource/year	3% of undiscovered resource/year

Table 3-1. The *GeoVision* Analysis Electric-Sector Scenarios

Table Notes: The primary scenarios for the electric sector include: (a) the Business-as-Usual scenario, which reflects industry status and projected trends at the time of the GeoVision *analysis; (b) the Improved Regulatory Timeline scenario, which includes assumptions of various regulatory and permitting efficiency improvements that result in reduced development timelines; and (c) the Technology Improvement scenario, which includes the streamlined permitting improvements of the Improved Regulatory Timeline scenario with additional advances in technologies for exploration, drilling, and reservoir stimulation that decrease development costs and risks. WACC refers to "weighted-average cost of capital" and represents the financing rates that projects are able to achieve (see Augustine et al. 2019).*

72 The IRT scenario assumed shortened development timelines aided by streamlined permitting processes; time is the principal variable adjusted in the model. Potential regulatory-related scenarios for these shortened timeframes include centralized permitting offices and a categorical exclusion that would allow drilling and testing of confirmation wells—consistent with the general parameters established for oil and gas in section 390 of the 2005 Energy Policy Act of 2005 (EPAct 2005) and as proposed for the geothermal industry in section 3012 of S. 1460, the Energy and Natural Resources Act of 2017 (115th Congress)—to prove out a reservoir and allow for project financing for the remainder of the project. The details of such streamlined processes were not explored for this scenario, but a study by the Bureau of Land Management was underway at the time of this report to explore this concept in more detail.

73 The construction timeline is the time from pre-exploration to when the project starts providing electricity to the grid. ReEDS implementation starts the clock on costs and time with the pre-drilling exploration phase (see Table 3-2). The basis for construction timelines used in the *GeoVision* analysis is detailed in Augustine et al. 2019 and Young et al. 2019.

74 In the BAU and IRT scenarios, financing (weighted-average cost of capital) for geothermal is about 6% higher than other power-generation technologies (e.g., wind, solar) in ReEDS to reflect high risks and equity financing requirements at the beginning of geothermal projects. Technology improvements in the TI scenario are assumed to increase success rates and decrease development risk such that developers can obtain financing at the same weighted-average cost of capital available to other generation technologies (the ReEDS Standard Weighted Average Cost of Capital, 8%).

75 The increase in discovery rate for undiscovered geothermal resources is based on multiple industry surveys performed as part of the *GeoVision* analysis and considers a decrease in time required to obtain exploration permits. In the IRT scenario, reduced time for permitting greatly increases the amount of exploration that is performed, which ultimately results in more discoveries (Augustine et al. 2019). Discovery rates were conservatively held constant at 3% for the TI scenario because it was not possible to quantify an improvement based on yet-unforeseen technology improvements. Instead, technology improvements in the TI scenario were translated conservatively through to the model in the form of lower technology costs, lowered project risk, and the more competitive weighted-average cost of capital available to other technologies (the ReEDS Standard Weighted Average Cost of Capital, 8%).

The three scenarios were used as inputs for the ReEDS capacity deployment model (Section 3.1.2). Other electricity-generation technologies—including fossil fuel, wind, and solar—were modeled using inputs from the Mid-case scenario of the 2016 Annual Technology Baseline (Cole et al. 2016a).[76] Future electricity demand also comes from the Annual Technology Baseline, which uses the 2016 Annual Energy Outlook projections from the U.S. Energy Information Administration (Energy Information Administration 2016).

Table 3-2 summarizes the total amount of geothermal resources available for development as new electricity generation under each of the three *GeoVision* scenarios (refer to Section 2.1 for a description of resource types). The values of resource potential used in ReEDS are smaller than the total resource values in Section 2.1 for several reasons. Resources in Hawaii and Alaska are not included because ReEDS only models the contiguous United States (see Text Box 2-1). In addition, resource potential in ReEDS excludes areas where geothermal development is legally prohibited, including National Parks and Monuments. The *GeoVision* analysis also identified environmentally sensitive areas such as Wild and Scenic Rivers and National Wildlife Refuges and classified those as areas where geothermal development would be unlikely and/or would face significant barriers. Environmentally sensitive areas were screened and removed from the resource supply curves that provide the basis for the *GeoVision* analysis scenario modeling. The specific barriers included in the available resource assumption vary by scenario, with the TI scenario assuming fewer barriers and, hence, more land areas and accessible resources available for development (Young et al. 2019). Sections 3.2.1.1–3.2.1.3 summarize the available resource potential assumptions and additional barriers. More detail is available in Young et al. 2019 and Augustine et al. 2019.

GeoVision Scenario	Identified Hydrothermal MW_e	Undiscovered Hydrothermal MW_e	Near-Field EGS MW_e	Deep EGS MW_e
BAU and IRT	5,078	18,830	1,382	3,375,275
TI	5,128	23,038	1,443	4,248,879

Table 3-2. Geothermal Resources Available for Development for Electricity Generation (in megawatts-electric, MWe) in the Regional Energy Deployment System Model (ReEDS) under the *GeoVision* Analysis Scenarios

3.2.1.1 Business-as-Usual Scenario

The BAU scenario reflected industry trends and the anticipated future if the industry continues on the same path as 2016 conditions. The *GeoVision* analysis evaluated existing and projected industry capital costs, construction timelines, and project financing. The BAU scenario includes a primary assumption related to the rate of discovery of undiscovered hydrothermal resources. Roughly 75%—about 30,000 megawatts-electric (MW_e)—of the total available conventional hydrothermal resource base is classified as undiscovered (Williams 2008). Because of this, the full resource calculated in the *GeoVision* analysis supply curves is not available for immediate development or deployment. The *GeoVision* analysis included extensive examination and discussion with industry experts to conclude that, under the BAU scenario, 1% (about 200 MW_e) of total undiscovered resources would be found and available for development each year; this is the rate of discovery used in the BAU scenario.

3.2.1.2 Improved Regulatory Timeline Scenario

The IRT scenario was based on the *GeoVision* barriers analysis (Young et al. 2019), which considered a number of pathways and potential combinations of approaches to streamline and reduce project development timelines. Analyzed options are explained in Section 2.4.3.1 and included 1) a geothermal categorical exclusion specific to resource confirmation activities;

76 The Mid-case scenario is a reference scenario that reflects "business-as-usual" conditions applied to the bulk power system model in ReEDS. This scenario is described in detail in the 2016 NREL Standard Scenarios report (Cole et al. 2016b). The Mid-case scenario assumes 1) the 2016 reference cases from the Energy Information Administration's Annual Energy Outlook for electricity demand growth and natural gas prices, 2) mid-case projections for electricity-generation technology costs from the 2016 Annual Technology Baseline, 3) a reference case for existing fleet retirements based on the ABB Velocity Suite database, 4) existing policies as of April 1, 2016 (with the exception of the Clean Power Plan, which is removed), 5) no system feedback due to changes in the Earth's climate, and 6) default resource constraints (Cole et al. 2016a). The Mid-case scenario assumptions were used as inputs in ReEDS for the *GeoVision* analysis for all technologies except geothermal, which used the *GeoVision* analysis inputs for the BAU, IRT, and TI scenarios as described herein.

2) a federal coordinating permit office with dedicated geothermal experts[77]; 3) expanded use of pre-leasing Environmental Assessment to include analysis of a limited amount of surface-disturbing activities; and 4) an updated Programmatic Environmental Impact Statement. Activities assumed as part of the *GeoVision* analysis IRT scenario are limited to the activities elaborated in Young et al. 2019.

The IRT scenario is consistent with the March 21, 2017, Executive Order 13783, which discusses the national interest in terms of, "…promoting clean and safe development of our Nation's vast energy resources, while at the same time avoiding regulatory burdens that unnecessarily encumber energy production, constrain economic growth, and prevent job creation…" The Order further mandates, "…immediate review of all agency actions that potentially burden the safe, efficient development of domestic energy resources." The *GeoVision* analysis IRT scenario included evaluation of the effects of potential reforms in furtherance of Executive Order 13783, as assessed by DOE and the U.S. Department of Agriculture.

In response to this Executive Order, DOE issued its report titled, "Final Report on Regulatory Review Under Executive Order 13783" (DOE 2017). The report includes recommendations for domestic energy development and use, including a review of DOE National Environmental Policy Act policies to determine whether DOE should grant more categorical exclusions, assess whether DOE should adopt categorical exclusions already approved by other federal agencies, and foster interagency collaboration, such as working with the Bureau of Land Management to consider categorical exclusions for geothermal energy on federal lands.

Also in response to Executive Order 13783, the U.S. Department of Agriculture reviewed more than 70 U.S. Forest Service actions, culminating in recommendations for parts of 15 existing agency actions that could be revised or rescinded to alleviate or eliminate burdens on the development or use of domestic energy

The Improved Regulatory Timeline scenario in the *GeoVision* analysis models the impacts of reduced development timelines resulting from regulatory streamlining, but does not assume or create new policies that have not otherwise been introduced.

resources. As part of the review process, the U.S. Department of Agriculture identified three top priorities that would show early and measurable results. Two of the top three priorities concerned reform relevant to geothermal leasing and permitting (U.S. Department of Agriculture 2017):

- **Revise U.S. Department of Agriculture/U.S. Department of the Interior Memorandum of Understanding.**
  The Forest Service has seen increased activity in Expressions of Interest for geothermal development on National Forest System lands. As of 2017, 118,000 acres were leased on National Forest System lands for geothermal energy production. The Forest Service recommended the revision of the U.S. Department of Agriculture and U.S. Department of the Interior's "Memorandum of Understanding Implementing Section 225 of the Energy Policy Act of 2005 Regarding Geothermal Leasing and Permitting." The revision will clarify the roles and responsibilities of the two agencies to allow for increased geothermal development.

- **Require consideration of geothermal leasing and development in national forests with high geothermal resource potential.**
  The Forest Service recommended revision of Forest Service Handbook Section 1909.12 Chapter 20 Section 23.23i to include requirements from Sec. 222.4.d.1 of the 2005 Energy Policy Act (EPAct 2005), which requires forest plans with high

77 Centralized and/or coordinating permit offices exist within the Bureau of Land Management for both oil and gas and renewable energy projects. In 2005, under Section 365 of EPAct 2005, Congress established a Federal Permit Streamlining Pilot Project, which designated seven Bureau of Land Management field offices in Colorado, Montana, New Mexico, Utah, and Wyoming to serve as offices to coordinate and process oil and gas authorizations on federal land. The offices coordinate approvals between agencies within the Department of the Interior, Department of Agriculture, U.S. Army Corps of Engineers, and the U.S. Environmental Protection Agency (Levine et al. 2013). In addition, in 2009, the Bureau of Land Management established the National Renewable Energy Coordination Office, which included program leads for wind, solar, and geothermal. Soon after, regional Renewable Energy Coordination Offices were created in Arizona, California, Nevada, and Wyoming, focused on solar and wind permitting and coordination. At the national level, the Bureau of Land Management geothermal program is a part of the Renewable Energy Coordination Office, whereas at the regional level, these offices are staffed predominately with realty specialists (as opposed to geologists or subsurface specialists), creating a disconnect in skill sets necessary to process geothermal permit and regulatory approvals. As a result, state geothermal programs do not interact with the regional Renewable Energy Coordination Offices at all, whereas other state geothermal programs may only report geothermal project status during scheduled Renewable Energy Coordination Office teleconferences.

geothermal resource potential to be considered for geothermal leasing and development.

The IRT scenario considers the impact that reduced regulatory burdens and streamlined regulations mandated by Executive Order 13783 could have on the geothermal industry. For the *GeoVision* analysis, the variables adjusted within the deployment models were limited to construction time and resource exploration and discovery rates. The analysis determined the extent to which the time and discovery rate variables could plausibly be impacted under different improvement scenarios (Young et al. 2019). The IRT scenario represented one of several permutations of regulatory streamlining and combined improvements that, if successful, could result in up to a 4-year reduction in permitting timelines for hydrothermal projects and a 5-year reduction for EGS projects. Reduced permitting timelines can reduce construction timelines and improve project financing costs as modeled in the *GeoVision* analysis. Results indicate that more and easier exploration under the IRT scenario would increase discovery rates for undiscovered hydrothermal resources from 1% to 3% per year over the BAU scenario (Young et al. 2019).

3.2.1.3 Technology Improvement Scenario

The TI scenario primarily evaluated the impacts of aggressive technology advances and cost reductions on the potential for geothermal deployment. This scenario assumed that the construction of large utility-scale power plants continues to be the predominant goal of project developers and that geothermal providers have advanced technology breakthroughs from a confluence of technology improvements. Many of these technology improvements will require early-stage research and development (R&D) and have been included in the *GeoVision* Roadmap as actions that can help achieve the improved costs and performance assumed in the TI scenario. The TI scenario assumed technology improvements in the areas of resource exploration, drilling, and reservoir creation. The TI scenario technology assumptions are summarized in Table 3-3 and detailed in Augustine et al. 2019.

The TI scenario assumed technology improvements in exploration techniques and technologies that do not directly reduce pre-drilling exploration costs but do increase the ability to successfully identify and target geothermal resources. This results in higher drilling and project success rates for developments that move beyond the pre-drilling phase. Better targeting also translates into increased drilling success rates (fewer dry holes), reduced overall project risk, and decreased financing costs. Advances in drilling technology lead to significant reductions in drilling and well completion costs. The TI scenario also assumed technology improvements in reservoir stimulation that result in EGS reservoirs with performance characteristics—such as flow rate and well productivity[78]—that are similar to conventional hydrothermal resources.

Arrival of condensers at the Blue Mountain Faulkner 1 geothermal power plant in Nevada. *Photo credit: John Casteel*

Improvements described in Table 3-3 are incorporated into the *GeoVision* analysis as reductions in capital and O&M costs. Figure 3-2 shows the reductions in overnight capital costs for a representative hydrothermal flash plant and EGS binary plant that result from the TI scenario technology-improvement assumptions. The charts illustrate the cost reductions from technology improvements in each area independently and combined (full TI scenario), compared to costs under the BAU scenario. For both plants, the sum of cost reductions from individual areas is larger than the total impact from implementing them simultaneously. This is because the geothermal cost-model inputs are highly interrelated. For example, project drilling costs can be decreased by technology improvements that

78 Volumetric well flow rate refers to the volume of fluid produced per unit time, typically reported as gallons/minute or liters/second. Well mass flow rate refers to the mass of fluid produced per unit time, typically reported as 1,000 pounds (mass) per hour (thousands of pounds mass per hour) or kilograms per second. Productivity index refers to ratio of total liquid surface flow rate to the pressure drawdown (differential between the reservoir pressure and wellbore pressure) at the midpoint of a producing interval in a well, typically reported as gallons per minute per pounds per square inch, or gpm/psi, thousands of pounds mass per hour, per pounds per square inch, or kg/s/bar.

directly lower the per-well drilling costs, or through improvements in reservoir creation that increase well productivity and decrease the number of wells required for the project. Improvements in drilling technologies that increase the drilling success rate and/or lower drilling costs have the largest impact on capital costs for conventional hydrothermal plants. For EGS, the increase in well flow rate and productivity leads to the largest reduction in overnight capital costs. Appendix C provides more detailed supply curves and additional information about cost assumptions.

GETEM Input		Business-as-Usual		Technology Improvement	
		Hydrothermal	EGS	Hydrothermal	EGS
RESOURCE EXPLORATION	*Exploration—Pre-Drilling Costs ($/project)*	$600K–$1.2M	$250K	Same as BAU	
	Exploration—Drilling Costs ($/project)	$3.3M–$5.4M	$1.5M–$5M	Two-thirds of BAU	
	Full-Sized Confirmation Well Costs[79]	Base + 20%	Base + 50%	Ideal + 0% (no premium)	
	Full-Sized Confirmation Well Success Rate	50%	50%	75% (with stimulation)	
	Number of Full-Sized Confirmation Wells	3	9	3	
DRILLING	*Drilling Success Rate*[80]	75%		90%	
	Drilling Costs[81]	Base		Ideal	
RESERVOIR CREATION	*Stimulate Wells?*	No	Yes	Yes	
	Well Flow Rate (flow rate per production well)	Flash: 80 kg/s Binary: 110 kg/s	40 kg/s	Flash: 80 kg/s Binary: 110 kg/s	
	Well Productivity	4.6 kg/s/bar (5.8 gpm/psi)	0.46 kg/s/bar (0.58 gpm/psi)	4.6 kg/s/bar (5.8 gpm/psi)	

Table 3-3. Summary of Technology Improvement Scenario Assumptions

Table Notes: (1) Exploration pre-drilling activities typically involve geological, geophysical, and geochemical surveys. These surveys might include, but are not limited to, activities such as geological and structural mapping, remote-sensing data analysis, geophysical assessments of resistivity and temperature data, and geochemical surveys of groundwater and surface water and rock alteration. (2) The TI scenario assumes that the construction of large utility-scale power plants continues to be the predominant goal of project developers and that geothermal providers have advanced technology breakthroughs from a confluence of technology improvements. These improvements include the availability of big data to optimize exploration and drilling, advanced exploration drilling techniques such as micro-hole drilling, reductions in costs and improvements in the success rate of drilling overall, and the development of EGS techniques such as multistage stimulation of deviated wells that increase the productivity and longevity of EGS reservoirs. (3) The TI scenario assumes the BAU values for all other GETEM inputs. The GeoVision analysis used identical GETEM inputs for the geofluid gathering system and pumping, O&M, and power plant for both the BAU and TI scenarios. Values for these inputs can be found in Augustine et al. 2019. (4) kg/s = kilograms per second; kg/s/bar = kilograms per second per bar; gpm/psi = gallons per minute per pounds per square inch.

79 GETEM inputs were structured assuming that the costs of confirmation wells are more expensive than standard production wells drilled during the field-development phase. Costs of standard production wells are based on the drilling cost curves considered as the basis for the *GeoVision* analysis and as elaborated in Lowry et al. 2017. Costs of full-size confirmation wells consider the standard production well cost plus the indicated premium as a percentage of the standard well cost. Lowry et al. 2017 and Augustine et al. 2019 provide a complete description of geothermal well-construction sizes, their cost-benefit relationships, and the manner in which costs are integrated within GETEM and the *GeoVision* analysis.

80 Drilling success rates are for full-size production and injection wells. Success rates are assumed to be the same for brownfield and greenfield sites.

81 Drilling cost curves are taken from Lowry et al. 2017 for ideal and base well cost scenarios.

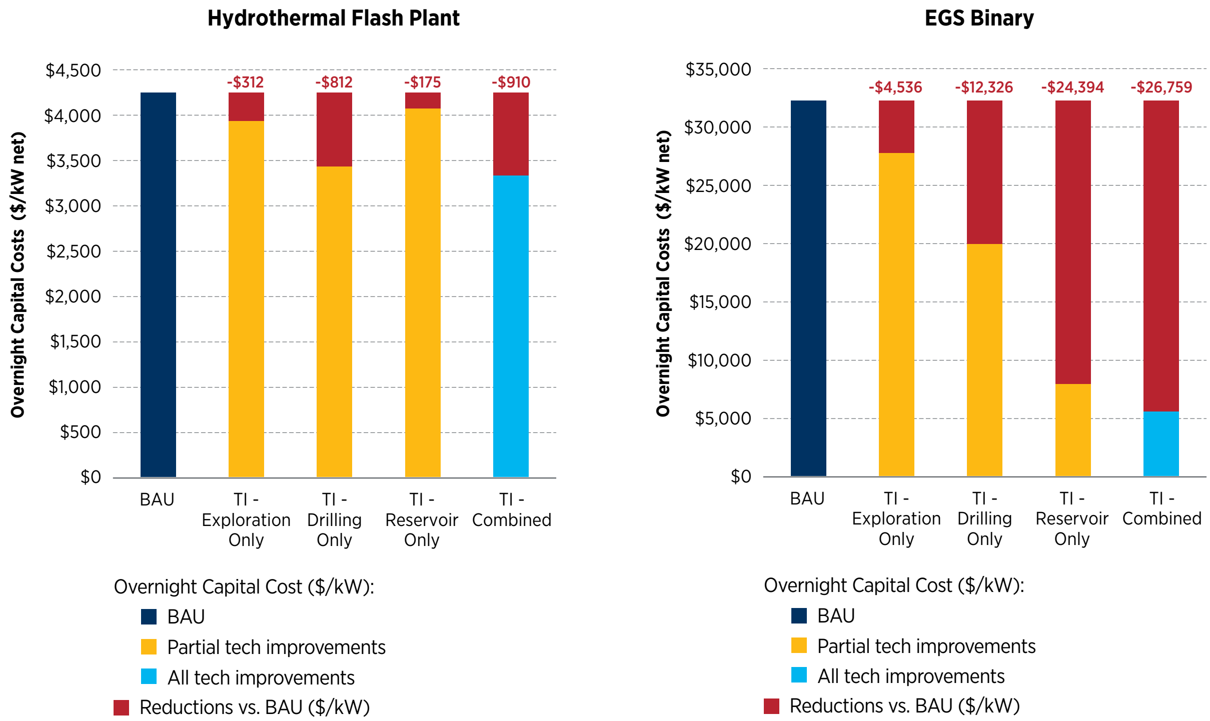

Figure 3-2. Waterfall charts illustrating reductions in overnight capital costs for hydrothermal flash plant (left) and enhanced geothermal system binary plant (right) projects from the Technology Improvement scenario assumptions

Figure Note: Hydrothermal plant cost estimates assume a representative 40-MW_e flash plant with a resource temperature of 225°C at a depth of 2,500 m. EGS plant cost estimates assume a representative 25-MW_e binary plant with a resource temperature of 175°C at a depth of 3,000 m.

The TI scenario also assumed that geothermal projects are able to obtain financing at rates similar to other energy-generation technologies—the ReEDS Standard Weighted-Average Cost of Capital (8%) (Table 3-1). By comparison, financing under the BAU and IRT scenarios was equivalent to the ReEDS Standard Weighted-Average Cost of Capital plus a 6% premium to reflect the higher risk and equity financing at the beginning of a project. As noted previously, the *GeoVision* scenarios are cumulative, so the TI scenario also included the regulatory reforms in the IRT scenario.

Technology improvements benefit both hydrothermal and EGS resource development, reducing EGS costs enough to make the technology commercially competitive. Technology and cost improvements were applied gradually in the *GeoVision* modeling so that costs decrease linearly from BAU values in 2015 to TI values in 2030. As explained in Section 2.1.2, EGS technologies are likely to be developed and deployed in stages—expanding from the low-permeability margins of existing conventional hydrothermal sites (in-field EGS) to previously undeveloped and unexplored deep-EGS sites. To model this transition, the *GeoVision* analysis assumed that EGS reservoir technology improvements were available and first used at near-field EGS sites starting in 2024. Because it will take some time to establish the EGS industry, the growth rate of near-field EGS deployments was artificially limited in the model. This limit started at 50 MW_e per year in 2024 and increased to 200 MW_e per year in 2030 (Augustine et al. 2019). Growth limits were removed starting in 2030, at which time it is assumed that improvements in EGS reservoir technology are available for all EGS resources.

Future Technologies and Resources

DOE has maintained a robust geothermal R&D portfolio since the 1970s. Much of this research has been aimed at developing and deploying improved geothermal exploration techniques that result in better subsurface characterization and reduced risk and costs for exploration. Major areas of focus in the first 30 years of DOE-funded R&D for geothermal exploration included support for industry exploration and drilling activities, cooperative programs with selected states to help assess geothermal resources, studies of selected hydrothermal systems, geological exploration technique development and analysis, and exploration strategies (DOE 2010a, DOE 2010b).[82] In addition to the continuing study of improved and innovative exploration technologies, DOE has initiated several EGS research initiatives. These initiatives are intended to address key R&D questions associated with EGS resource characterization, reservoir creation, production sustainability, and operation.[83]

Accelerated deployment of geothermal resources in the United States could be supported by the development of new technologies and blue-sky concepts that could reduce costs, lower risks, and shorten the time needed to explore and develop all types of geothermal resources.[84] These types of improvements have occurred in the oil and gas industry, where the development of directional drilling and multistage stimulation revolutionized the use of unconventional oil and gas resources (e.g., Warpinski et al. 2009). The expectation is that the geothermal industry could unlock vast resources through innovative technologies and blue-sky concepts.

A key assumption in the TI scenario was that geothermal developers will have access to technology breakthroughs from a range of improvements in existing technology and the development of innovative technologies (Doughty et al. 2018, Augustine et al. 2019). These breakthroughs would have the effect of improving resource discovery and capture through improved exploration, improved drilling, better well-stimulation success rates, and reduced development costs. The *GeoVision* analysis researched an array of exploration and drilling technologies, including those that demonstrate promise as innovative technologies that warrant consideration for targeted R&D. The analysis also included a review of blue-sky concepts, or ideas that are out of the mainstream of existing geothermal R&D, with the potential to provide step-change (as opposed to incremental) advancements in geothermal technologies (Doughty et al. 2018). These concepts include supercritical geothermal systems (Text Box 3-1). Some of these technology improvements and concepts are discussed in the *GeoVision* Roadmap (Chapter 5).

A submersible pump on a geothermal production well in western Oregon. *Photo credit: Alan Ofsoski*

82 DOE initiatives that focus on improved exploration technologies include: 1) The Innovative Exploration Techniques initiative, funded by the American Recovery and Reinvestment and Recovery Act of 2009, 2) The Geothermal Play Fairway Program, and 3) the development of methodologies and techniques that improve the ability to discover and characterize undiscovered hydrothermal resources. The projects comprising these three initiatives are discussed in Doughty et al. 2018.

83 DOE initiatives that focus on EGS R&D include: 1) the Frontier Observatory for Research in Geothermal Energy, or FORGE, 2) the EGS Collab project, 3) EGS field-demonstration projects, and 4) DOE subsurface R&D crosscutting research projects. These projects and initiatives are discussed in detail in Doughty et al. 2018.

84 Blue-sky research considers areas of R&D in which commercial or other practical applications are not immediately apparent. This research domain is generally recognized as having the potential to realize unanticipated scientific breakthroughs and game-changing industry advancements (Bell 2005).

Text Box 3-1. Supercritical Geothermal Systems

Although not included in the modeling assumptions, the *GeoVision* analysis also evaluated supercritical geothermal systems, which exist wherever subsurface conditions exceed the critical point of water (see Note). In areas of high-heat flow around existing geothermal systems or large volcanic provinces where shallow (<16,000 feet, or about 5 km) magma bodies may exist, supercritical resource conditions can be found at depths that may be cost effective to drill; in fact, supercritical resources can be found everywhere on Earth by drilling deep enough. Based on national-scale assessments of temperature with depth (Blackwell et al. 2011), most areas in the United States would require drilling to depths beyond 10 km (about 6.25 miles) to access supercritical conditions. Drilling to this depth is financially prohibitive with existing technology. Economic production of supercritical resources will require the development of entirely new classes of: drilling technologies and methods; innovative stimulation approaches and techniques; and new production materials, processes, and equipment that can accommodate the extreme temperature, pressure, and chemical conditions of supercritical resources.

Supercritical geothermal resources contain geothermal fluids with high energy densities and low viscosities, improving and increasing their reservoir energy- and mass-flow characteristics (Elders et al. 2014). In many ways, supercritical geothermal resources are an extreme variant of the EGS resource spectrum. Because the resource characteristics, metrics, and tools required to model the full potential of supercritical resources are not yet fully developed, these resources could not be quantified as part of the EGS resource supply curves in the *GeoVision* analysis. Therefore, supercritical resources were not explicitly included in GETEM or ReEDS as a deployable resource for the *GeoVision* analysis.

The *GeoVision* analysis did, however, include case-study estimates of the supercritical resource potential of selected sites at a localized scale (Stimac et al. 2017, Doughty et al. 2018). The estimates from these local-scale assessments significantly exceeded that determined through EGS resource estimates for the same geographical site based on a broader, national-scale analysis (Augustine 2016). This finding highlights the potential of supercritical resources, assuming the development of technologies that enable economic production and effective well-targeting for such resources. The finding also suggests that more localized or site-specific resource estimates may identify EGS resource potential at higher levels than those determined through the national-scale estimates used in the *GeoVision* analysis.

Note: In thermodynamics, the "critical point" of a substance is the end point of a phase equilibrium curve separating a liquid and gaseous phase in terms defined by their pressure and temperature conditions. For pure water, the critical point occurs at 374°C and 220.64 bara (3,200 psia). Above the temperatures and pressures defined by the critical point, water exists as a supercritical fluid with unique properties characterized by high energy densities and low viscosities. Most natural systems contain water with salinities that move their critical points to temperatures of 400°C or beyond. Once supercritical conditions are encountered, innovative technologies will be required to develop those resources.

3.2.2 Non-Electric Sector Scenarios: *Geothermal Heat Pumps*

The GHP sector assessment of the *GeoVision* analysis used two primary scenarios—BAU and Breakthrough (BT). Because GHP deployment depends directly on consumer behavior, the GHP sector assessment also integrated two market-adoption rates: Navigant Low and NREL Optimistic (Table 3-4). For the *GeoVision* analysis, both market rates were applied to each scenario. Additional detail on the inputs, assumptions, and characteristics for the GHP scenarios and adoption rates can be found in Liu et al. 2019 and Appendix C.

Geothermal Heat-Pump Sector Scenario	Main Characteristics
Current Installed Capacity (2012 Baseline)	GHP Efficiency: - Residential: 18.2 Energy Efficiency Ratio (EER)[85] 4 Coefficient of Performance (COP)[86] (at 100% load) - Commercial: 20 EER/4.2 COP (at 100% load) Ground Heat Exchanger: $14/foot Installed capacity as of 2012 was used as a baseline for comparison (Navigant 2013). A true BAU projection is difficult to determine for GHP, so for the purpose of impacts calculations (Chapter 4) the analysis of the model results calculated impacts of BT technology, cost reductions, and varying market adoption rates relative to the fixed 2012 baseline value.
Business-as-Usual	GHP Efficiency: - Residential: 21.3 EER/4.7 COP by 2050 - Commercial: 23.4 EER/4.9 COP by 2050 Ground Heat Exchanger: $14/foot Includes all GHP deployment through 2012 as the starting point for the scenario. Projected growth is based on an assumed, moderate (17%) increase in operational efficiency for GHPs relative to conventional heating, ventilation, and air-conditioning systems by 2050 and depends on a chosen GHP market-adoption rate (see Table Note 1).
Breakthrough	GHP Efficiency: - Residential: 27.3 EER/6 COP by 2030 - Commercial: 30 EER/6.3 COP by 2030 Ground Heat Exchanger: $9.80/foot by 2050 Includes aggressive cost reduction and efficiency improvements resulting from technology improvement, with assumptions that the operational efficiency of GHP systems is improved by up to 50% by 2030, with no further improvements through 2050, and that the cost of ground heat exchangers is reduced by up to 30% by 2050.
Geothermal Heat-Pump Market-Adoption Rates	**Main Characteristics**
Navigant Low	dGeo deployment forecast based on consumer technology-adoption rates in Paidipati et al. 2008 as described and used in Navigant 2013 (see Table Note 2)
NREL Optimistic	dGeo deployment forecast based on historical adoption rate of solar photovoltaics developed by NREL (Sigrin and Drury 2013). This rate is higher than the Navigant rate (see Table Note 3).

Table 3-4. Summary of Scenarios and Market Adoption Rates Used to Model Geothermal Heat-Pump Technology Deployment and Impacts

Table Notes: 1) Market-adoption rates are developed from comparative studies of the solar photovoltaics market. For the BAU scenario, the Navigant Low adoption rate is applied; the result is projected growth that is more conservative than historic GHP industry growth rates. 2) The Navigant Low adoption rate is based on a combination of insights from consumer surveys and market data for energy efficiency and heat pumps (Kastovich 1982). 3) After Sigrin and Drury 2014, the NREL Optimistic adoption curves were not influenced by policy incentives to any significant degree.

85 Energy efficiency ratio (EER) is used to indicate the cooling efficiency of heat-pump equipment. EER is often expressed in Btu per hour/watt (i.e., Btu/hour of cooling for each watt of electrical input). The higher the EER, the more efficient the system.

86 Coefficient of performance is the ratio of useful heating or cooling provided to the work required.

3.2.2.1 Business-as-Usual

The BAU scenario for GHPs started from a 2012 Deployment Baseline and assumed existing industry trends for technology advancement. The BAU scenario assumed little or no additional investment in GHP-related R&D and no additional financial incentives or tax credits for GHP installations. The scenario also assumed no cost reductions in ground heat exchangers and only moderate increases in the operational efficiency of GHP systems through 2050. The BAU scenario assumed no significant change in the cost or performance of competing conventional heating, ventilation, and air-conditioning (HVAC) technologies—which are already near their practical efficiency limits—during the same period (i.e., through 2050). The result is a 17% increase in efficiency difference between GHPs and conventional HVAC systems by 2050. The analysis assumed that the incremental cost increase for improving energy efficiency is offset by improvements in manufacturing efficiency and better economies of scale.

The BAU scenario further assumed no change in the costs or service lives of above-ground GHP equipment and baseline HVAC systems. Based on Kavanaugh et al. 2012, the installed cost of ground heat exchangers increased at an average annual growth rate of 2.65% from 1995 through 2012. This rate is slightly higher than the average annual U.S. inflation rate of 2.2% during the same period (Bureau of Labor Statistics, Consumer Pricing Index–All Urban Consumers, data extracted May 7, 2018). As such, the BAU scenario assumed that the real installed cost of ground heat exchangers is effectively constant over time. The dGeo model used an annual inflation rate of 2.5% to adjust costs in future years, through 2050.

3.2.2.2 Breakthrough

Similar to the TI scenario for the electric sector, the BT scenario for GHP incorporated technology improvements to reduce the costs and improve operating efficiencies of GHP systems. Improvements included lower costs of ground heat exchangers, as well as reduced cost and improved operating efficiency of GHP systems. The BT scenario assumed that the installed cost of ground heat exchangers is reduced up to 30% by 2050. This reduction results from technical breakthroughs and better economies of scale from innovative business modes (e.g., utility-owned ground heat exchangers). The BT scenario also assumed that the average operational efficiency of GHP systems approaches the practical limit and improves 50% by 2030, with no further improvements through 2050.

3.2.2.3 Market-Adoption Rates

As noted previously and described in Table 3-4, *GeoVision* analysis modeling for the GHP non-electric sector included two market-adoption rates intended to simulate and account for uncertainties in consumer behavior. The maximum market potential of GHPs in each scenario was determined using two different empirical correlations: one from Navigant (Navigant Low) (Paidipati et al. 2008) and the other from NREL (NREL Optimistic) (Sigrin and Drury 2014). The Navigant Low adoption rate is based on a combination of insights from consumer surveys and market data for energy efficiency and heat pumps (Kastovich 1982), whereas the NREL Optimistic rate is based on market-adoption data for distributed solar photovoltaics.

Helicopter-supported geothermal exploration drilling on Akutan Island, Alaska. *Photo credit: Neil McMahon*

Figure 3-3 illustrates the Navigant Low and NREL Optimistic market-adoption curves that are applied to each of the BAU and BT GHP scenarios. The market-adoption curves reflect correlations between the maximum market-adoption potential (i.e., number of consumers who would eventually adopt the technology) and the investment payback period. Incentives could reduce the costs that a consumer might pay for a given technology, thus reducing the payback period and increasing the maximum market potential. Incentives will not, however, change the adoption curve itself because the relationship between the payback and market potential is static. Market-adoption curves may not be sensitive to technology type because the curves depend on the simple payback of a potential investment, irrespective of the technology in question.

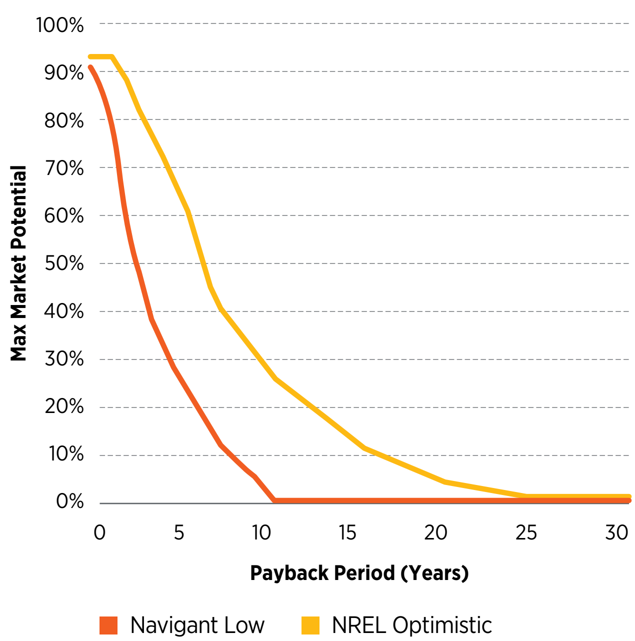

Figure 3-3. Market-adoption curves used in the *GeoVision* analysis and applied to geothermal heat-pump modeling scenarios within dGeo

Source: Liu et al. 2019

Figure Note: In each model year, the maximum market potential—i.e., the fraction of viable GHP systems that would eventually be implemented given the technical and economic conditions—is calculated based on the GHP investment payback period.

3.2.3 Non-Electric Sector Scenarios: *Geothermal Direct Use (Geothermal District Heating)*

The geothermal direct-use assessment for the *GeoVision* analysis used two primary scenarios: Business-as-Usual and Technology Improvement (Table 3-5). Technology cost and performance assumptions for identifying and accessing geothermal direct-use resources are similar to those assumed for electric-sector scenarios of the same name. As discussed in Section 3.1.3 and in McCabe et al. 2019, it was only possible to explore the economic potential—and not the full market-deployment potential—of geothermal direct-use applications for geothermal district heating. Therefore, the *GeoVision* analysis restricted the market-based deployment potential and associated impacts for the non-electric sector to the GHP sector and did not assess this information for geothermal district heating.

For both district-heating scenarios shown in Table 3-5, the resource potential in dGeo is based on a 2016 NREL study (Mullane et al. 2016) investigating the location, temperature, and amount of stored heat of low-temperature (<150°C) and relatively shallow (<3,000 meters) hydrothermal and EGS resources in the United States. Including EGS as a direct-use resource greatly increases the size and geographic reach of district-heating resource potential. Appendix C provides more detail on inputs and assumptions for geothermal district heating.

Geothermal District-Heating Sector Scenario	Main Characteristics
Business-as-Usual	Established as a baseline for comparison purposes. Includes all geothermal direct-use deployment through 2016. Incorporates existing and anticipated values of technical, cost, and financial parameters of geothermal district-heating systems, assuming similar market conditions for the next 30 years or more and no investments to improve technology or financing.
Technology Improvement	Includes cost reductions and technology advances resulting from technology improvements used in the electric-sector TI scenario. Improvements over BAU include: 1) a 50% reduction in drilling costs, 2) an increase in EGS well flow rate from 40 kg/s to 110 kg/s, 3) an average 15% decrease in exploration-related costs, and 4) a 50% improvement in EGS resource-recovery factors (2% to 3%). Also assumes a 32% decrease in discount rate for project financing (weighted-average cost of capital reduced from 2.8% to 1.9%). Improvements are modeled to occur gradually (linearly) from 2016 to 2030 and stay constant through 2050.

Table 3-5. Summary of Scenarios Used to Model Non-Electric-Sector, Geothermal Direct-Use/Geothermal District-Heating Technology Economic Potential

Table Notes: McCabe et al. 2019 provides a full discussion of geothermal direct-use scenarios