Enhanced Geothermal Systems
Reservoir Management and Operations Workshop

San Francisco, CA
September 17, 2007

Summary Report

Executive Summary

A workshop on Reservoir Management and Operations for Enhanced Geothermal Systems (EGS) was held in San Francisco, California on September 17, 2007. Participants were asked to evaluate the present state of reservoir management technologies and identify areas of improvement needed to move EGS into the market place.

The goals of reservoir management are to maintain production temperature, optimize the mining of heat with respect to the temperature drop, maintain the rate of production, prevent fluid loss, and minimize induced seismicity. As heat mining proceeds, temperatures in the reservoir decline. Successful EGS management will require monitoring and mitigation of the impact of reservoir evolution on heat recovery and power plant efficiency. Post-stimulation characterization and real-time monitoring, preferably down-hole, will be essential.

Several technological advances will be needed to insure success and maximize economic feasibility. High-temperature packers and other zonal isolation tools are needed to reduce or eliminate fluid loss, identify and mitigate short-circuiting of flow from injectors to producers, and target individual fractures or fracture networks for testing and validating reservoir models. Electric submersible pumps with 1,000-3,000 horsepower motors that can survive for at least three years at temperatures in excess of 200^{o}C will be needed to minimize parasitic losses associated with high injection pressures. Temperature-hardened tools for real-time down-hole monitoring of temperature, pressure, and flow would significantly enhance the ability to track reservoir evolution, monitor rock-fluid interactions, and provide appropriate field data for validating and updating reservoir models and simulators. Development of new "smart" tracers (for example, tracers that can measure the surface area responsible for heat exchange) is warranted. Tracers are a multi-use technology that has value outside the EGS domain. Fully coupled Hydrologic-Thermal-Mechanical-Chemical (H-T-M-C) models and simulators will be necessary to predict fluid flow, heat extraction and temperature drawdown, rock-mechanical processes, and chemical processes that affecting reservoir operation and sustainability.

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Issues and Research Needs in Reservoir Characterization Summary

The distinction between reservoir creation and management is somewhat artificial; the reservoir evolves over time. The rock and site properties before and after enhancement are assumed to have already been addressed by the Reservoir Creation workshop.

A workshop on Reservoir Management and Operations for Enhanced Geothermal Systems (EGS) was held in San Francisco, California on September 17, 2007. This was the third of a series of four workshops, the first of which evaluated the assumptions set forth in the report by the Massachusetts Institute of Technology (MIT) entitled *The Future of Geothermal Energy* (MIT 2006), and three (in the areas of Reservoir Creation, Reservoir Management and Operations, and Wellfield Construction) which focused on identifying technology gaps associated with EGS development. The intent of the workshops was to motivate facilitated discussion on technology gaps related to reservoir management and operations.

The question is whether some locations are better for EGS than others. If characterization work is being done, this question has already been answered.

The reservoir features that must be characterized after enhancement are the fractures, flow, and drawdown. Stress should be characterized both before and after enhancement. Valuable improvements would include depth-dependent detection and release for tracers; the ability to detect temperature within fractures; and robust long-term logging tools to detect drawdown.

A. Systems Analysis

Reservoir characterization requires a systems approach. The steps in the development of an EGS are identification of a target; drilling and stimulation (hydraulic and/or chemical); characterization; design of reservoir operations; and management of fluid flow and heat extraction (location of injection and production, well rates and pressures, and injection chemistry.) The potential roadblocks to development are ability to stimulate a large enough volume; ability to prevent short circuits; ability to avoid dissolution-precipitation cycles that cause a loss of reservoir permeability; and ability to manage the reservoir through realistic modeling of coupled H-T-M issues and research needs in reservoir characterization and development. Needs include:

- Modeling of reservoir behavior and sustainability
- Development and improvement of EGS management and operation techniques and tools
- Technological development for using induced seismicity as a monitoring tool and the potential societal impact of induced seismicity
- Site development and site characterization

Workshop participants were encouraged to speak freely and discussions were allowed some latitude to encourage dialog. While notes were taken, the proceedings of the workshop were not transcribed, again to encourage discussion. Participants were also encouraged to provide written comments to the workshop organizers following the day's discussion. The key discussions and written comments from the workshop are covered here.

Techniques for reservoir characterization are a high priority only if they produce something useful (e.g. fracture network visualization). Characterization and modeling are closely related, and should not be treated as separate processes. At the same time, characterization without modeling may be useful, but modeling without characterization is not. Modeling can be used to determine the required reservoir characteristics for EGS.

II. Modeling

A. Reservoir modeling approaches
B. Geochemical modeling
C. Rock mechanics and stress modeling
D. Role of modeling in planning and risk reduction
E. Experience from the mining industry

Effective reservoir management and operations depends on determination of general reservoir properties, and models used for reservoir management must be calibrated against these bulk properties. Determination of how the reservoir behaves is the ultimate goal. Other technical questions are means to achieving this end.

III. Development/Improvement of Techniques and Tools Required for EGS Management and Operations

A. Logging tools
B. Microseismicity
C. Tracers
D. Packers and remediation tools
E. Pumps

The system as a whole, including the entire 3-d permeability field, must be understood to enable prevention of channeling and short circuits. This requires higher-level analysis than individual fracture behavior. Determination of permeability requires well-to-well testing. This implies a project with multiple closely-spaced wells. Wide-scale tests may provide more useful information than identification of specific properties of parts of the reservoir.

IV. Induced Seismicity

It was suggested that in EGS, thermodynamics is working against the economics of the system because the low-energy path is favored. However, the low-energy flow path is not necessarily the path where the lowest amount of energy is extracted from the rock.

V. Need for Site Development/Experimentation

I. Issues and Research Needs in Reservoir Characterization

Characterization should address whether some locations are better for EGS than others. If there are only one or two wells in an experiment, there are very few alternative ways to manage the resource. It is not known whether a field experiment should be more than two or three wells, or whether a large system is required or it is possible to learn from small ones.

The characteristics of the EGS reservoir determine how the reservoir is managed. Some of the necessary rock and site characterization before and after stimulation was addressed by the Reservoir Creation workshop. There are overlaps between reservoir creation and management, but the evolution and control of the reservoir is the unique concern of reservoir operations and management.

Optimization studies could be undertaken on well spacing and configurations (three-spot, five-spot, etc.) based on whatever observations are available. The optimization studies should be specific to the type of fracture system. While these paper studies can be performed, real data from field sites will be required to advance EGS. By itself, performing these studies will not accelerate commercialization; they cannot substitute for field data. Advancing the state of the art requires constraining the models with data.

There is a fundamental difference between oil and gas and geothermal economics. Because oil and gas are so much more highly valued than oil, there is an economic barrier to adoption of oil and gas technology because profitability requires 50,000 barrels/day of production for geothermal energy, and only 100 barrels/day for oil. The difference in the value of the product is dramatic: a barrel of hot water is worth 25 cents, while a barrel of oil is worth $70.

For a commercial technology application, the big oil companies want to see rapid payback at relatively low risk, and they would prefer to own the technology.

A. Systems Analysis

Reservoir characterization and management requires a systems approach to enable prevention of channeling and short circuits. Extrapolation of laboratory-determined rock properties and individual fracture behavior to reservoir scale is problematic. Potential roadblocks to development include the ability to stimulate a large enough volume; ability to prevent short circuits; ability to avoid dissolution-precipitation cycles that cause a loss of reservoir permeability; and ability to manage the reservoir through realistic modeling of coupled H-T-M-C processes with realistic input data on appropriate scales.

The Australians (at Cooper Basin) were able to access private capital because they were able to show that they had a large system with the potential of being economic. If a large system is found with economic potential, it is possible to raise private sector funds.

B. Fractures

It is possible to drill new legs or wells to add fractured area and maintain production without cooling. This should work, but it is expensive. Developing more fractures in a single borehole would be more economic.

If the location and orientation of the natural fracture network is known, well placement and the site development strategy is greatly simplified. This would require detailed characterization of both the pre-existing fracture system and the post-stimulation system.

In oil and gas fields, the wells are moved around and the fractures are left alone. Using a highway as an analogy, the O&G industry has onramps (multiple input and production wells to manage the field), while geothermal systems only have the highway – a single channel or set of channels from the injection well to the production well.

Researchers should try to determine what can be measured to identify which fractures carry fluid. While seismic events can potentially show fracture location and orientation, they cannot identify fluid-carrying fractures or fracture properties relevant to fluid flow, such as aperture and permeability. Current technology cannot measure aperture well enough for reservoir management.

In geothermal reservoirs, all rock appears to have either natural fractures or thermal fractures.

A larger number of fractures in the borehole will provide more heat exchange area, allowing higher flow rates without rapid cooling. The oil and gas industry isolates zones and stimulates them separately. In geothermal systems, the entire open interval of the well is stimulated due to higher temperature environments. Tools capable of isolating selected zones of the open hole for stimulation must be developed. Chemical agents that can be used as stimulants or diverters for EGS environments are also needed.

One way of manipulating fractures is to increase or decrease the density of the fracturing fluid. At Soultz, increasing the density of the fluid caused the fractures to travel downward.

It is possible to drill new legs or wells to add fractured area and maintain production without cooling. This works in oil and gas stimulations, but may be prohibitively expensive. Increasing control over fracture stimulation in a single borehole is likely to be more economic.

In order to improve production, it may be necessary to prop fractures in production wells. High-temperature high-strength proppants that won't dissolve over time are not available. Bauxite, used extensively in oil and gas fields, dissolves rapidly under geothermal conditions. Ceramics or epoxy-coated sands may work, but haven't been adequately tested under geothermal conditions.

C. Flow and Short Circuits

Reservoir management and operation requires determination of which fractures are flowing, and what the flow rate is. Spinners are routinely used in the oil and gas industry to log flow, fluid entry points, and fluid flux into the well. In geothermal wells, spinner data are difficult to interpret because of hole size effects and inconsistent well diameters and flow turbulence. Industry would benefit from improved methods for visualizing fractures, flow, and possibly temperatures and enthalpy. Geothermal wells are open hole, so unlike the oil and gas industry (which uses cased wells) the spinner can only be used to measure velocity, because the aperture is not well known.

Injection and production can cause either a net loss or gain from the water already in the system. Depending on the system, the water injected may not be the same as the water produced, but there should be a balance between the two. In many situations, there is actually a gain as water flows in from the far field. Natural recharge sometimes saves hydrothermal systems that would otherwise not produce at economic rates. At any given non-hydrothermal site there is actually a natural system present and filled with water, and it is in equilibrium with the rock, but it is extremely low in permeability. Once the permeability is enhanced, the flow rate is accelerated.

Flow channeling or short circuiting results in inadequate heat exchange along the flow path. Pre-stimulation flow mapping can help prevent creation of a dominant fracture during stimulation. In some cases, a temperature survey can be used to identify the zones that take most of the fluid.

One element of resource management is identification of flow paths to prevent channeling. One reason for flow mapping is to prevent creation of a dominant fracture during stimulation. The goal is to be able to predict the location of channeling. A temperature survey can be used to see which zones take most of the fluid. It is not clear whether it is possible to mitigate short circuits and optimize production at the same time, or whether the reservoir reaches equilibrium.

A “good” reservoir may deteriorate as a consequence of fluid circulation, because cooling from injected waters may self-enhance short-circuiting pathways and because the solvent properties of water at geothermal temperatures will induce mineral dissolution and precipitation.

If geochemistry is understood well enough, it may be possible to devise lasting solutions to short circuits. The chemical strategy is to inject something that precipitates in the preferred path and closes it off. Short circuiting is an issue that will have to be dealt with; it is clear that short circuiting will occur. In chemical grouting of fractured limestone, when a fix is made a short circuit occurs because dissolution produces a new route. In this case, industry is trying to plug the aquifer rather than enhance it, but the analogy still holds. If the geochemistry is understood it is possible to identify solutions to the problem. An attempt to mitigate a short circuit has the advantage that all the chemicals introduced into the system will go directly to the problem site. If the repair method is correct, it makes fixing the short circuit easy. The strategy is to inject something that precipitates in the preferred path and closes it off.

However, chemical strategies are not problem-free; chemicals for stopping short circuits can be washed out due to high flow rates commonly found in geothermal wells. In hydrothermal systems, the classic method of dealing with a short circuit is to move the injector. This is not as easy in EGS.

The success rate of mitigating short circuits is high if the problem can be isolated, but sometimes it is not possible to know exactly where the problem is. It is not clear whether it is possible to mitigate short circuits and optimize production at the same time.

The oil and gas industry works within the limits of the natural environment to plan wellfield operations in order to mitigate short circuits. At the same time, individual wells are not pre-planned to deal with short circuiting, and there are not enough resources to identify where fluid is coming from. The success rate of mitigating short circuits is high if the problem can be isolated, but sometimes it is not even possible to know exactly where the problem is. In an open-hole completion, trying to treat a thousand feet of wellbore would destroy the economics of the treatment; isolation of the problem area is required. Also, chemicals for stopping short circuits can be washed out due to high flow rates commonly found in geothermal wells.

Chemical disequilibrium between the injected water and the reservoir lithology may be a major issue. To maintain production rates, rock/fluid interactions must be monitored for scale production in the reservoir that reduces permeability or for the creation of preferred pathways that reduce heat mining efficiency. The industry will need techniques for manipulating the geochemistry to prevent short circuiting or plugging flow channels. Models suggest different indications of what should be done, so the required treatment will be uncertain and likely to be site specific. With the large volumes of water involved, it will not be economic to provide extensive treatment.

There are some cases where current technology is inadequate to seal off a short circuited area. At a field in the Philippines, an effort to close off a short circuit using calcium chloride failed because there was so much pressure drop that although all the $CaCl2$ went to the problem zone, it was not possible to plug it due to inflow from an aquifer above the steam field.

If a fracture becomes plugged options include creating another fracture, redrilling the well, or using mechanical flow diverters to isolate the plug for chemical treatment. Water chemistry can be manipulated to dissolve the plugging material. In conventional hydrothermal systems, chemical treatments that have controlled scale build-up in wellbores may be applicable to plugging within the reservoir.

In water flooding, geochemistry can seal the wells. Different water chemistry may be a major issue in EGS. The question is how to use the natural system to advantage, and how to fix it if the natural system is not working as desired. The industry will need techniques for manipulating the geochemistry to prevent short circuiting and avoid plugging the channels. Chemical additives to makeup water that can deal with oxygen or reducing environments can tweak the system to avoid problems and make improvements. With the large volumes of water going through a large system, it will not be economical to provide extensive treatment because margins will be relatively low. The assumption is that the produced water will have to be treated, but models show different indications of what should be done, so the actual treatment that will be required is uncertain. Control of pH will probably be required, and possibly removal of silica will also be required. Makeup water and recirculated water may have to be kept separate in some systems.

D. Thermal Drawdown

If a fracture is plugged, options include creating another fracture, redrilling the well, or using flow diverters for treatment. It is possible to change pH and alter the water chemistry in other ways, and manipulate the system that way. In hydrothermal systems, it is possible to control scale in the wellbore, and this carries over into the reservoir and changes the interaction between the water and the reservoir.

Thermal drawdown is an unavoidable consequence of EGS resource exploitation. Methods of ensuring that the temperature is maintained include improving modeling to be able to better predict the results of production; creating more heat exchange area; and better monitoring and measurement to observe changes in the system. Tracking drawdown requires pressure and temperature monitoring as a function of depth in the well, ideally at the level of individual fractures and in real time. Drawdown may be a more important issue in EGS than in hydrothermal systems because the number of fractures in an EGS reservoir may be smaller than in the typical hydrothermal reservoir (though this is not certain).

The problem with small, simple field experiments is that their results cannot necessarily be extrapolated to the very large fields required for commercial projects. If the starting point is a large deep permeable zone, there is little difference from a hydrothermal system. If a short circuit occurs, it can be cased off, as in hydrothermal systems.

Ideally, new technologies should be developed to monitor the temperature down-hole to isolate problematic fractures or areas of the borehole. In this way zones could be individually targeted for mitigation or isolation. It is currently not possible to continuously monitor down-hole temperature.

In oil and gas fields, the wells are moved around and the fractures are left alone. Using a highway as an analogy, the O&G industry has onramps (multiple input and production wells to manage the field), while geothermal systems only have the highway – a single channel or set of channels from the injection well to the production well.

Preventing short circuiting may be receiving too high a priority. The first priority should be creation of the primary fracture system. It must be possible to create a sufficiently large system with enough surface area, and it must be possible to manage fracture size. Remediation over a large surface area is extremely difficult, but to some degree it will be required. Flow management and fluid loss is an issue that will have to be considered.

D. Drawdown

Drawdown is an effect of exploitation of the resource. Tracking drawdown requires pressure and temperature monitoring as a function of depth in the well (ideally at the level of individual fractures). Drawdown may be a more important issue in EGS than in hydrothermal systems because the number of fractures in an EGS reservoir may be smaller than in the typical hydrothermal reservoir (though this is not certain.) Potential methods of tracking drawdown may include fiber optics and DTS. Two-phase flow may occur, complicating measurements. It would be useful to measure enthalpy downhole, but this cannot be done currently.

Improving fracture detection will require higher resolution than provided by current instruments. Flow mapping will also benefit from new and/or better instruments.

The goals of reservoir production are to maintain production temperature; optimize the mining of heat with respect to the temperature drop; maintain the rate of production; prevent fluid loss; and reduce seismicity.

No temperature drop means that heat is not being mined efficiently, but the temperature has to be kept within the range where the power generator operates effectively. Methods of ensuring that the temperature is maintained include improving modeling to be able to better predict the results of production; creating more heat exchange area; and better monitoring and measurement to observe changes in the system.

High flow rates improve system economics, but they may lead to early breakthrough of cool water and reduce total heat recovery. Short circuits that develop during stimulation or that develop during operation may reduce the temperature rapidly. High flow rates may also create stress changes and short circuits that will affect system operation.

Optimizing heat mining vs. temperature drop will require improved reservoir modeling and predictive tools. It is not possible to model changes in fractures effectively due to changing stresses and temperatures during operation, and the models are not tied to economics to allow economic optimization. Modeling software available for prediction of reservoir behavior doesn't model thermal stress, while software that predicts thermal stress doesn't model overall long-term reservoir behavior.

E. Stress

A large heat exchange area without preferred pathways allows high production rates while maintaining heat mining efficiency and reducing the risk of a premature temperature drop. To maintain production rates, rock/fluid interactions cannot create scale in the reservoir that reduces permeability, or create preferred pathways that reduce heat mining efficiency.

For a homogeneous body, stress profile prediction is acceptable, but for others (shales) a large amount of extrapolation is required. It would be valuable to find other ways of getting stress data. Injecting at high pressure may increase fluid loss, even though it increases production rate. Preventing fluid loss is an issue because in many areas in the United States, getting makeup water will be a problem; water is expensive. It is preferable to pump the production well, rather than pressurizing the injection well. High injection pressure may also increase the risk of significant seismicity. The influence of thermal stress is not well understood.

Optimizing heat mining vs. temperature drop will require improved reservoir modeling and predictive tools. Existing dual porosity reservoir models work well and have a good user interface, but it is not possible to effectively model changes in fractures due to changing stresses and temperatures during operation, and the models are not tied to economics to allow economic optimization.

Whether it is possible to economically increase heat exchange area, and how it could be done, in the case of a drop in temperature is not known. The ability to increase heat exchange area by drilling new wells, stimulation, deepening wells, or kicking off new legs has not been tested because no systems have operated for long enough to require this.

Improved modeling tools to predict reservoir behavior are required. Modeling software available for prediction of reservoir behavior doesn't model thermal stress, while software that predicts thermal stress doesn't model overall long-term reservoir behavior.

A large stress drop is located around the stimulated area. The Acoustic Emission (AE) reflection method (surface reflection of seismic activity) can be used to find fractures. It allows detection of sub-vertical structures and is sensitive to the fractured zone (through the S-wave). However, locating fractures by itself does not define the stress field since mapped fractures may or may not be active features reflecting the present state of stress in the system.

II. Modeling

Effective reservoir management requires reservoir models that are based on a conceptual model of the geologic system for which physical and chemical behavior has been translated into mathematical expressions. Maintaining temperature will require good monitoring. Temperature can be monitored at the surface to find out whether any given well is having problems, but ideally it would be possible to monitor the temperature downhole to see whether there is a particular area of the borehole that is dropping in temperature faster than other areas. It is currently not possible to continuously monitor downhole temperature. Fiber optic instruments have been tried, but hydrogen degrades the fiber. This may be fixable, but it has not been determined that this is a priority.

Modeling is commonly used for planning expansion in conventional hydrothermal systems. Modeling helps to interpret changes in system behavior (identify what could be causing the changes, and find ways to amplify favorable changes and decrease unfavorable changes). Prediction of reservoir behavior is the ultimate goal. Although first-principle process models would be ideal, some processes may have to be dealt with empirically.

E. Stress

Hydraulic stimulation will preferentially open fractures oriented parallel to the maximum effective stress.

Modeling tools and predictions must be validated with field data. Much more data is needed for calibration of available models. Models that combine heat flow, temperature, mechanical, and chemical processes are not available. Hydrologic-thermal-mechanical (HTM) models should be coupled with rock/fluid interaction models. Improved input data for all models is required.

When cores are taken, laminations are often within inches. To extrapolate a stress profile from such data is probably not realistic. For a homogeneous body, stress profile prediction is acceptable, but for others (shales) a large amount of extrapolation is required.

Further definition of technology gaps will be possible once more wells have been drilled in a variety of natural settings, bigger systems have been created, and more data from field work is available. Not enough operating data on working EGS systems is available to clearly define these gaps.

The effect of stress state is not well defined. Borehole breakouts don't always occur or don't provide good data. Sometimes it is not practical to make mini-frac measurements to get stress data. It would be valuable to find other ways of getting stress data.

A. Reservoir modeling approaches

Stress measurement capability is a critical technology gap, but it is more important for stimulation than for reservoir management and characterization. The stress should already be known when the reservoir is being created. However, there are some development strategies where the initial stress field may not need to be known, e.g. if a single well is drilled and stimulated and the fractures are mapped before drilling the second well. In this case, the stress field is much less important than if the plan is to drill two wells and stimulate (one or both) to connect them. There are several potential modeling approaches. It is possible to start with basic a priori models and add features to try to match the data, or start with the data and build the model to match it.

Models in O&G can be very complex, and often are not completed until after the operations are well underway and sufficient data is available to calibrate them. Fenton Hill is a counterexample where the stress field tended to force fractures closed. This suggests that an early development strategy is to identify places where development should not be considered due to unfavorable stress, so that these sites can be avoided. The highest heat flow is generally found in stressed regimes, but the subsurface stress is usually not well known. Stress is a complicated parameter that can be correlated with MEQs, but direct detection requires well drilling. While it is not possible to identify the stress state without drilling, some sites (for example, the margins of calderas) may not be good candidates *a priori*. Inhomogeneity in stress fields is a problem at all scales. At a San Juan basin site where stress was critical, the model (by Pollard) was inadequate for the site.

A large stress drop is located around the stimulated area. The AE reflection method (surface reflection of seismic activity) can be used to find fractures. Better reflecting fractures are thought to be more open/bigger fractures. In reflection seismology, stiffness (not thickness) affects reflectivity. AE is high-energy, robust, resistant to surface conditions, simple, low cost, and is available for inside basement rock or highly attenuated media in geothermal fields. It allows detection of sub-vertical structures and is sensitive to the fractured zone (through the S-wave).

Expectations for short-term results should be low, because a tremendous amount of data is required is required to enable refinement of the models, and work will have to be performed in a variety of lithologic environments.

It is possible to get a huge injectivity increase by simply running cold water through the system over a long period (months); the injectivity continues to increase as long as the water keeps running. What is driving the injectivity increase is not clear; modeling suggests that the changing stress regime causes shear.

II. Modeling

It is hard to plan reservoir management without a conceptual model of the system. Models can define the reservoir requirements, aid in design of the stimulation and characterization of the reservoir, help plan reservoir operation, calibrate injection water chemistry, and explore the potential of alternative approaches (e.g., EGS with CO_2 as a working fluid).

The empirical approach is required because the first-principles approach shows a huge range of potential effects. The problem with an entirely empirical approach is that the system must be produced to obtain the data used to constrain the model, yet investors will not pay for the initial development without a reservoir model to reduce uncertainty. Private industry is not going to provide the level of investment required. Ultimately, the goal is to build a bridge between empirical and deterministic modeling.

It may not be possible to specifically identify technology gaps at this stage because not enough data is available. There isn't a good picture of the role of modeling in the development of the resource. It is not possible to perform modeling before field work. Much more data is needed for calibration of available models; each field test has produced vastly different results.

Given the state of the art, modeling can be used to understand the system and eliminate reservoir management options from consideration. Actions are taken based on the best estimates of what the system response will be, and then the results are fed back into the model to improve it. It will be possible to identify technology gaps once many wells have been drilled and bigger systems have been created. The problems with small systems will be disproportionate; a failure in one out of three wells is 1/3 of the project.

In hydrothermal systems, modeling is used for planning expansion. The future role of modeling is likely to be in providing more specific insight into reservoir requirements, and in assisting with management and operation of the system. Modeling helps to gain insight to better interpret changes in system behavior (identify what could be causing the changes, and find ways to amplify favorable changes and decrease unfavorable changes). Modeling for a conventional system is most useful after the system has been running for some time, in order to enable calibration of the model. This is expected to remain the case. Some first-principles issues may have to be dealt with empirically.

Modeling tools have not been validated. Field data are required to calibrate the models. Prediction through models has to be matched to real world data. Differences in the results of different simulation codes may be significant, depending on the models. Even O&G models don't work very well, but models have to be used as part of due diligence. Even with modeling, investment risk is still relatively high.

There are several modeling approaches. It is possible to start with basic a priori models and add features to try to match the data, or start with the data and build the model to match it. Models in

O&G get very complex, and often aren't completed until after the operations have already been performed. Coal bed methane is an example of a case where the projects came before modeling, allowing collection of enough data to enable successful modeling.

Most modelers start with simplified heat exchange thermal modeling with simplified pressure drop through fractures for a conceptual model, and then begin applying a large-scale dual-porosity difference model once the system is well enough understood.

A fundamental geoscience approach is to have multiple hypotheses about the situation, and start using the data to form opinions and reach conclusions about which hypothesis or model best matches the real world case. This yields continuous improvement with time. Expectations for short-term results should be low, because a tremendous amount of data is required is required to enable refinement of the models, and work will have to be performed in a variety of lithologic environments. Even in the Barnett shale (which is relatively well-characterized), there are complications; across different lithologies, the situation will be even more complex, and it will take a long time to develop a database.

B. Geochemical modeling

In the best EGS reservoirs, the created reservoir may be similar to a hydrothermal reservoir. If this is the case, hydrothermal data will be valuable for these sites because there is a lot of history matching data available for hydrothermal systems. Hydrothermal reservoirs can be compared to the predicted EGS reservoir, and the data could be scaled and compared to match the actual reservoir. This would be a valuable starting place because there is no operating history with EGS.

Geochemical modeling capabilities are fairly advanced, but applications to field problems remain challenging due to limited availability of field data and the scale dependence of parameters. While hydrothermal systems provide a basis for history matching, it may not be possible to extrapolate that to EGS. In a hydrothermal system, natural processes have created a reservoir with significant volume. These are dynamic systems, but they do not change rapidly. EGS are expected to change rapidly, which means that researchers will be trying to calibrate the models to a moving target. Also, the magnitude of the changes may be larger in an EGS than in a hydrothermal system, and some of the changes may affect the system negatively. The only way to develop credible models in this situation is to base the models on field data and test them against field experience. The work that has been done up to now does not approach the commercial scale, and it has only begun to explore the properties of diverse lithologic environments. Once a few projects have been developed, it will be possible to develop models that can be extrapolated across sites and begin to attract investors. Public sector research will have to provide sufficient risk reduction for private sector investors to begin providing funding. Collecting data on a large enough scale would require private sector investment, and there is a chicken-and-egg problem – private industry won't invest due to risk, and the risk is high due to the lack of investment.

The empirical approach is required because the first-principles approach shows a huge range of potential effects. The problem with the empirical effect is that the perturbations in the system that are used to constrain the model do not appear until the system is producing, and system production can't start because there is too much uncertainty, and investors are not prepared to pay to develop the project up to that point. Private industry is not going to provide the level of investment required.

The accuracy of model predictions depends on the appropriate choice of process model and model parameters (see e.g. Figure X), which include fundamental thermodynamic and kinetic data as well as data about reservoir fluids and minerals. Thermodynamic data is limited for high-ionic strength fluids and CO_2/water mixtures, and reaction kinetics and the dependence of reaction parameters on scale are not fully understood. Little data is available for systems with dry anhydrous CO_2, and there has been no chemical modeling of this type of system.

In systems with hundreds of wells, first-principles models fall apart because there is not enough processing power to calculate solutions. Simpler solutions yield results that decisions can be based on; although there is still the potential for error, the results usually provide reasonable solutions. In fact, in some cases people have sophisticated models available, but make their decisions based on Excel spreadsheets, even though large investments have been made in the more sophisticated model, because there isn't enough time to run the model before making the decisions. Both types of models have their place in reservoir management.

There may be situations where higher-level models are not helpful, however. For example, if an EGS field consists of sets of three wells per reservoir (an injector and two producers), and the reservoirs are not connected, each reservoir has only two producers; in this situation, a streamline model would not be helpful. In most cases, however, the reservoirs will be interconnected.

A simpler modeling technique, such as one based on streamlines, can be used to identify short circuits in the system. In systems with hundreds of wells, perfect physics are not required; what is needed is information on where the short circuits are and how wells can be managed to mitigate short circuits. Models like this that are closer to the operational side and provide a high-level view of the reservoir may be more valuable than purely empirical or pure history matching models.

C. Rock mechanics and stress modeling

Streamlines are three-dimensional; the streamlines are able to connect sources and sinks with the distribution of fractures and permeability. This characterization is a key element of first-order effects that must be understood. Even if it is only a two- or three-well case, it can still be considered a set of sources and sinks. The Laplace equations provide a three-dimensional capacity problem, and it is possible to solve only along high-flow paths to get a much faster technique. The real property that is of interest is the flow path, which is a first-order effect. Streamline modeling solves for the pressure field and extracts a three-dimensional velocity field. This technique is approximate, but much faster. It provides a method for determining which wells are of interest and which can be ignored. The idea is to build a bridge between detailed and basic modeling. Codes capable of modeling the interaction between fluid flow, heat transfer, and rock mechanics are available, and when used with care and good field data they can be used for designing and guiding stimulation treatments. However, data on the physical (elastic) and thermal properties of rock is often insufficient for effective modeling. The effects of changes in depth and changes due to alteration on reservoir properties are not well known. Cores should be collected and tested in the laboratory to determine rock properties under reservoir conditions. Rock property data must also be complemented with in-situ stress data to support realistic modeling of rock mechanical effects often is not available, or is not accurate.

In a hydrothermal system that has been running for a long time, the pressure gradient has to be included in the streamline model, which requires coupling a conventional model with a streamline model, which becomes unwieldy. In an EGS, the pressure should stay constant, so it may be easier to model.

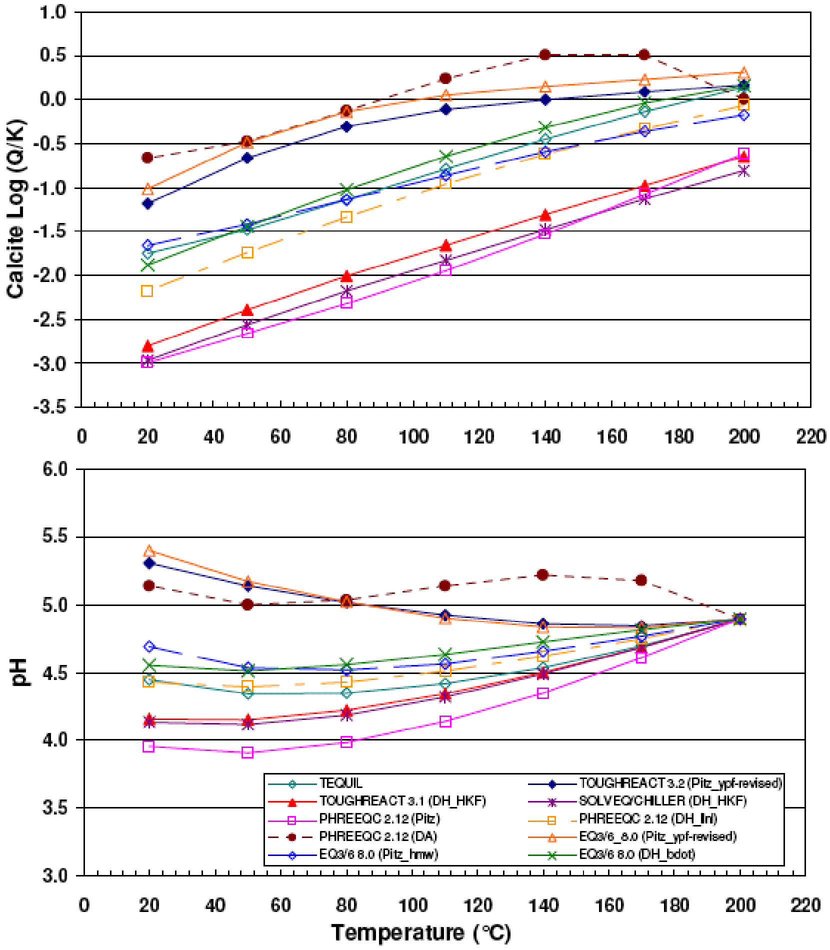

Figure 1: Brine/rock interaction model results across different models.

Codes capable of modeling the interaction of aqueous fluids with rock minerals are available. These codes are useful for exploring dissolution-precipitation processes. They can aid in designing chemical stimulation, and provide guidance for management of injected water composition. Accuracy in coupling physics with chemistry is limited (the impact of changing aqueous composition on fluid density, viscosity, specific enthalpy, etc.); it is only possible to expect general answers to these questions.

Codes capable of modeling the interaction between fluid flow, heat transfer, and rock mechanics are available, and when used with care and good field data they can be used for designing and guiding stimulation treatments. Stress and thermal cracking can be simulated. However, in situ stress data to support realistic modeling of rock mechanical effects often are not available, or are not accurate.

Thermal elastic effects on fractures are not included in models. It would be easy to add this to models if the mechanism were well understood and the equations were available. Modeling the coupling between rock mechanics and chemistry is still at an early stage. It is not currently possible to model stimulation with non-aqueous fluids, such as CO_2.

Thermodynamic data are limited, especially for high-ionic strength fluids and CO_2/water mixtures, and reaction kinetics and the dependence of reaction parameters on scale are not fully understood.

Little data are available for systems with dry anhydrous CO_2, and there has been no chemistry modeling of this type of system.

D. Role of modeling in planning and risk reduction

Well spacing is an example of a case where modeling allows estimation of the proper approach. Well spacing of about 500 meters is required to develop sufficient reservoir volume and allow connection between the wells. Optimization studies specific to the type of fracture system should be undertaken on well spacing and configurations (three-spot, five-spot, micro-drill holes, horizontal vs. vertical, etc.) based on available data. These studies will optimize one element of EGS creation, but they are not a substitute for field data. Advancing the state of the art requires constraining the models with real data from field sites.

Chemical modeling capabilities are fairly advanced, but applications to field problems remain challenging due to limited availability of data and the scale dependence of parameters. Limited availability of field data imposes a serious constraint; data on large-scale systems is required, as compared to lab-scale or computer-based testing. Overall, modeling capabilities are limited by lack of field experiments for guiding model development, and for model testing and calibration. Limitations are more severe for more “exotic” schemes, such as EGS with CO_2.

The effect of a change in porosity on permeability due to dissolution and precipitation is similar to the two-phase flow problem. Modeling of steam and water is usually dealt with on an *ad hoc* basis, using data to match the history. It may be possible to do this for fluids and solids as well. History matching is required for accurate modeling; it can’t be done *ab initio* for two fluids, or for a fluid and a solid.

Thermal decay kinetics can be simulated well in the lab.

Without data on the subsurface, investors will not invest even if a good model is available. The point of modeling is to reduce risk, and modeling is the only risk reduction method available today, but there are no large systems in place to run tests on. In addition, information derived from one reservoir cannot be applied to the next reservoir. Perhaps the easiest way to get data to convince investors to participate is to track the arrival of the thermal front. Tracers can be used as a proxy for the thermal front in order to estimate the ratio of fluid volume to thermal volume, allowing prediction of reservoir lifetime.

Surface area reactions and other theoretical methods for identifying critical reservoir properties use ideal assumptions that don't exist in the real world. Data on the physical (elastic) and thermal properties of rock are insufficient for effective modeling. The effects of changes in depth and changes due to alteration on reservoir properties are not well known. Cores should be collected and tested in the laboratory to determine rock properties under reservoir conditions.

In stress modeling, a high thermal gradient near the wellbore, where cooling is concentrated, suggests high stress changes over a short distance, but the stress changes actually extend a long distance from the wellbore. In an experiment with heating rock above the water table, most seismic emissions occurred a long distance from the heaters. Modeling done by Ahmad Ghassemi shows the same effect, and effectively modeled some of the acoustic emissions from Soultz that were otherwise hard to explain.

Stress cracking models give very detailed predictions, but other models are very broad scale; thermal stress modeling is not included. Heat transfer is included, but how that affects fractures is not considered. The effect of heat transfer on fractures is considered only on a short-term basis.

Thermal elastic effects on fractures are not included in models. It would be easy to add this to models if the mechanism were well understood and the equations were available. If the fractures and temperature changes can be described with modeling methods, it should be possible to calculate the shear stress and the effect on fractures, which is where the elastic properties of rock are going to be of significance.

III. Development/Improvement of Techniques & Tools Required for EGS Reservoir Management & Operations

A. Logging Tools

Sensors will be required to identify downhole problems. It would be useful to do continuous downhole monitoring for certain situations where real time information is valuable (for example, when and where breakthrough is occurring). Instrumentation must enable downhole temperature and pressure measurements. This capability is commercially available now, but it has limitations. Fiber optic Raman monitoring systems were suggested as a possible mechanism for monitoring temperature. Previous Raman systems have been rapidly poisoned by hydrogen, but the system could be made to work.

Reservoir pressure, which can be a driver of geometry, is often not well known. Coring provides general trends and identifies the azimuth of the induced fracture plane, but even very low-permeability sites show that reservoir pressure varies widely within the same wellbore.

Downhole flow meters are also important, particularly for identifying fluid inflow zones that can be matched to temperature and pressure logs. Spinners need improvement; currently they only provide relative flow between production zones, and they are designed for one-time logging rather than long-term monitoring. Mass flow meters are limited to surface instrumentation. A downhole version could resolve the contribution from multiple production zones. The current method of determining which zones are active is to inject cold water and then log the well for temperature to see which zones are taking fluid. Spinner surveys don't work very well. Tracer surveys work well, but they have to be performed before the well is cased off. The priority of this research is not clear because there is no clear pathway for development. Calipers may be valuable, but they may not be commercially available for use in geothermal conditions.

The elastic properties of granite are not well known; data are not available. What wellbore data is available has been collected only at shallow depths, and often on weathered rock. Measurements on unaltered rock at wellbore temperatures and pressures have not been made, or where they have been made they exhibit widely varying properties based on differences in chemical composition.

Long-term high-temperature operation of several sensor types would provide major benefits for reservoir management. Enabling high-temperature technologies for downhole tools include electronics, batteries, packaging (circuit boards, solders, connectors, etc.), seals, and various types of sensors. It would be preferable to have tools that can be run on slicklines and don't require calling in a logging company. If components are to be installed in high-temperature wells, it is preferable to install components that have been tested at a higher temperature.

Recent advances in borehole televiewers for identification of fractures and faults may make operation possible at up to 300°C, but these tools are dewared systems that are not robust, and are expensive and difficult to use, requiring a lot of post-processing of data. It would be preferable to have a system that quickly and directly produces output.

Downhole tilt sensors don't work at high temperatures, but the necessary components to build a high-temperature version are apparently available. Inflation of existing fractures is a major issue for EGS. Inflation should produce deformation of the rock mass that can be detected by tilt meters. Tilt meters could also resolve some seismicity questions.

Downhole seismic sensors have a short lifetime (six months), and improved communication with the surface is required; existing systems have limited bandwidth because the fiber optics are inadequate. The lifetime is long enough for early development, but not for the life of the reservoir.

Gamma and spectral gamma downhole tools are currently used in a dewar flask. A gamma system has high temperature systems and has been demonstrated at up to 250°C. General Electric has worked on a spectral gamma system, which would be useful for tracer analysis. It should be possible to develop this into a long-term monitoring system. This technology should be transferred to industry.

B. Microseismicity

MEQ monitoring is required to track the evolution of fractures and enable planning of ongoing in-field drilling. The oil and gas industry uses MEQs to provide information on features of interest, but not to provide information on the flow field itself. The geothermal industry also has an interest in tightening the resolution of seismic events to resolve features.

Microseismic techniques developed over the past 30 years to monitor release of stress induced by stimulation and continued fluid injection show “clouds” of dispersed seismic events, rather than planes showing the location of fractures. The cloud of microseismic events is partly an artifact of poor resolution of the events. Potentially valuable Vertical Seismic Profiling (VSP) tools were developed by Halliburton, but were shelved due to lack of profitability. Low-cost microwells could be researched as an option for VSP.

Reliable reflective seismicity that can often improve upon fracture identification and location is expensive because it requires observation of changes through long-term monitoring (at least six months is needed to map open fractures). Seismicity must be correlated with production, but experience suggests that seismicity and production are not related.

C. Tracers

Tracer movement is related to flow, and a nonflowing (but open) path may not be identified by tracer tests. Ideally, it would be possible to both introduce a tracer into a single fracture and capture the tracer from a single fracture. Using current technology, injection tubing can be used to place the tracer and sample at different depths, improving the specificity of tracer tests. The technology has to be designed around the operations. However, the use of tracers could be significantly enhanced with new technologies allowing for zonal isolation in high temperature open hole geothermal wells.

Temperature-reactive tracers can be used to identify temperature along the flow path, but their interpretation is currently ambiguous. The development of “smart dust” (nanoparticles capable of reporting on conditions within a fracture) was mentioned as a possible tool in the far future. If the oil industry pays for development of smart dust, the geothermal industry should try to take advantage of it, but otherwise it should be a low priority for research. Additional work on tracers may be is warranted, for example to allow characterization of heat exchange area, which currently cannot be done. It may be possible to do this with tracers that quantify the heat exchange area for a single-well test (pump in the tracer and then pull it out again), but it may be necessary to have more than two wells to effectively use tracers. Because tracers are a multi-use technology, it is a research topic that is guaranteed to have value.

The path conductivity is also a variable of interest.

D. Packers and Remediation Tools

Tools will be required to enable corrective actions. Tools of particular value for reservoir management (as opposed to reservoir creation) may include pumps, packers, diverters, a robust hard-rock underreamer to enlarge the borehole, and expandable tubulars to shut off short circuits.

Downhole changes will require downhole hardware and equipment to deepen or redrill the well to make multilateral completions.

Packers appear to be one of the most important tools to develop. High-temperature packers to isolate zones would be the best solution to enable stimulation of all fractures. Existing packers can be used in some situations, but the elastomers turn solid at high temperature, and the rest of the apparatus has to be pulled out leaving the elastomers behind.

Another way to isolate a section would be to run expandable tubulars. This will require a working underreamer, not currently available for use in high temperature environments.

E. Pumps

Downhole pumps are will be very useful and may be required for EGS operation. This is also a research pathway that should receive industry support because it has dual-use applications (for EGS and hydrothermal systems). High-temperature electric submersible 1,000-3,000 horse-power electric pumps must be set in deep wells that can operate for extended periods. Existing pumps have been tested to ~175°C (225°C is necessary), but they are not reliable, not because of the motor but because of failures in other areas such as the cable head connection or the electrical system. Oil and gas work on high-temperature downhole pumps is not likely to develop large enough pumps that operate at high temperature unless the GTP participates in the research.

Pumps should be able to be seated in the casing rather than run into the well on a line pipe. Improved technology would put the cable inside coiled tubing, which would allow replacing the cable without pulling the pump.

If either flow rate or temperature decreases, the standard procedure requires removing the pump in the production well as a first step. Pumping the production well is required to achieve high flow rates, but if the pump is running it is not possible to log the well. The ability to log past a pump would be valuable.

IV. Induced Seismicity

Some technologies should be a high priority because they are required to perform due diligence (induced seismicity is an example.) Seismicity has delayed or terminated several EGS projects. As EGS activity increases, seismicity may become an issue for communities as well as for the field operator. Critical gaps in knowledge on EGS-induced seismicity must be addressed to allow mitigation and reservoir management. A consensus opinion on mitigation and monitoring protocols must be developed.

The critical parameters necessary to estimate the seismicity hazard are not known, nor is it known what measurements and data are lacking, whether additional data are needed, and how much and how long monitoring should continue.

Instruments for long-term monitoring are not always reliable. Installing seismometers in boreholes could improve the signal-to-noise ratio, but the high temperature of the boreholes decreases instrument life.

Reducing the occurrence of significant seismicity will require managing pressure at start up and shut in. Modeling should be improved further to better predict the potential for inducing significant events. There may be experiments that can be performed which will shed light on key mechanisms causing EGS seismicity. Induced seismicity mitigation in naturally fractured systems may differ from the requirements in hydrofracturing environments.

V. Need for Site Development/Experimentation

The best type of site for development is not known. A controlled field-scale test is required to identify parameters for modeling. It may be necessary to develop the enabling technologies first, and then proceed with field work. Simply starting field work without development of new technologies is likely to lead to failed projects.

Production rate over a reasonable separation should be demonstrated first, because the economics will fail if production rate is insufficient. The best way to increase production rate is to create multiple fractures; this has never been done. An experiment of this type should be performed, because if it doesn't work it will not be possible to get the required flow rates.

Conceptual models should be developed to produce from multiple fractures, it will be necessary to have near- horizontal wells (plus or minus 30 degrees). Another conceptual model of evaluate the reservoir would be to develop its potential for EGS reservoirs in sedimentary rock because the relatively high porosity of sedimentary rock may enhance heat exchange efficiency and productivity. If money were not an issue, the geothermal program would have a three-well program in three dimensions; a two-dimensional approach is too limited.

Leveraging research being performed internationally should be a high priority. There has never been a long-term test of any of the EGS projects developed up to now, because all previous projects have run out of funds within a few years. An obvious way to run a long-term test inexpensively would be to fund a long-term test at Soultz, since the site is state-of-the-art and ready to operate. One of the reservoirs at Soultz is an open system; it would be useful to determine what lessons can be applied to operation of a closed system.

EGS Reservoir Management and Operations Workshop
September 17, 2007
Crowne Plaza, San Francisco Airport

The objectives are to understand the status and experiences within reservoir management and operation, with extension to EGS reservoirs; define the technology needs, gaps and barriers; and define the technology development paths to meet those needs.

Invited speakers will provide a framework for open discussion by the audience, with the session chair acting as facilitator. Audience members may expand, rebut or make their own point with an impromptu mini-presentation of less than 5 minutes. A lap top computer with PowerPoint will be available, as well as an overhead projector with transparencies and markers. Open discussion for each session will include a summary wrap-up to explicitly state the gaps, barriers, and technology paths. These will be further discussed and expanded during the general discussion period.

Monday September 17, 2007

Time	**Session**	**Chair**	**Speaker**	**Topics**
8:30-8:40am	**Opening Remarks**	Allan Jelacic		
8:40-9:00am	**Reservoir Characterization**	Mack Kennedy	Roland Horne	Reservoir mapping and fracture distribution, /imaging, stress-state, well testing, tracers
9:00-10:00			Discussion	
10:00-10:20	Break			
10:20-10:40	**Reservoir Modeling and Development Strategy**	Joel Renner	Karsten Pruess	Coupled thermal-fluid-structural reservoir models/validation, field layout/design
10:40-11:40			Discussion	
11:40am-1:00 pm	Lunch			
1:00-1:20pm 1:20-1:40pm	**Reservoir Operations**	Carol Bruton,	Susan Petty or Ken Williamson and Chip Mansure	Rock-fluid interactions, scaling, short circuiting, proppants, performance characterization reworks and in-fill drilling, high-temperature logging tools, down hole pumps and equipment
1:40-2:40pm			Discussion	
2:40-3:00pm	Break			
3:00-3:20pm	**Induced Seismicity**	Doug Blankenship	Ernie Majer	Monitoring as an analytical tool, potential for “felt” or actual damage, public

				relations
3:20-3:50pm			Discussion	
3:50-4:50pm	**General Discussion**	Clay Nichols	Discussion	Technology gaps/barriers technology development paths, synergy with other industries
4:50-5:00pm	**Closing**	Allan Jelacic		

Enhanced Geothermal Systems
Reservoir Management and Operations Workshop
September 17, 2007

Firms Represented:
Ormat
Calpine
GEA
GeothermEx Inc.
Geomechanics International
HCItasca
RESPEC
Halliburton
Schlumberger
SAIC
Humboldt Drilling and Pump Company
Black Mountain Technology
Chevron

Academic:

TAMU
Stanford University Petroleum Engineering Dept.
Energy and Geoscience Institute University of Utah