Overview of Recent Modifications to GETEM

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August 27, 2008

The recent modifications to GETEM include:

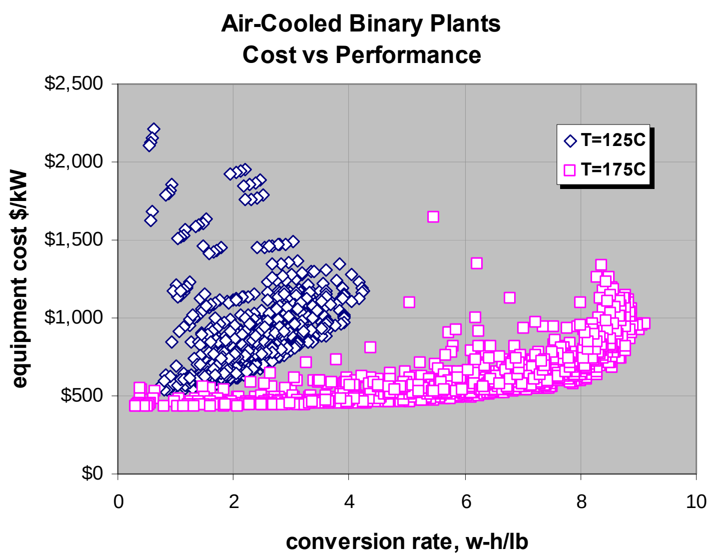
1. Incorporating relationship between plant performance and plant cost. This relationship is used to define the plant performance that minimizes the cost of generation power (for fixed conditions relative to the cost of individual wells, well stimulation, production pump depth, etc.).
2. Updating power plant and well field development capital cost using Producer Price Indices (PPI's) obtained from the US Dept of Labor's Bureau of Labor Statistics.
3. Allowing some input to be made in either SI or Imperial Units.
4. Inclusion of subsurface hydraulic model that is used to establish the production pump setting depth.
5. Calculation of the effects of thermal drawdown on production fluid temperature and net power.

In part, these modifications were made to facilitate the evaluation of power generation from EGS resources. Included was the inclusion of a simplified model of the subsurface heat exchange system. GETEM provides for the option of basing the hydraulic pressure losses in the reservoir and/or thermal drawdown on the inputted characterization of the subsurface fracture system. Using this input the model determines the facture surface area created, which can be used to establish a well stimulation cost (currently this cost varies linearly with the surface area). The determination of the hydraulic losses in the reservoir is used to establish the production pump setting depth and the associated pumping power. These losses can be based on flow in the fracture system, an effective reservoir permeability, or a pressure drawdown. With each of these methods the pressure losses are a function of flow rate.

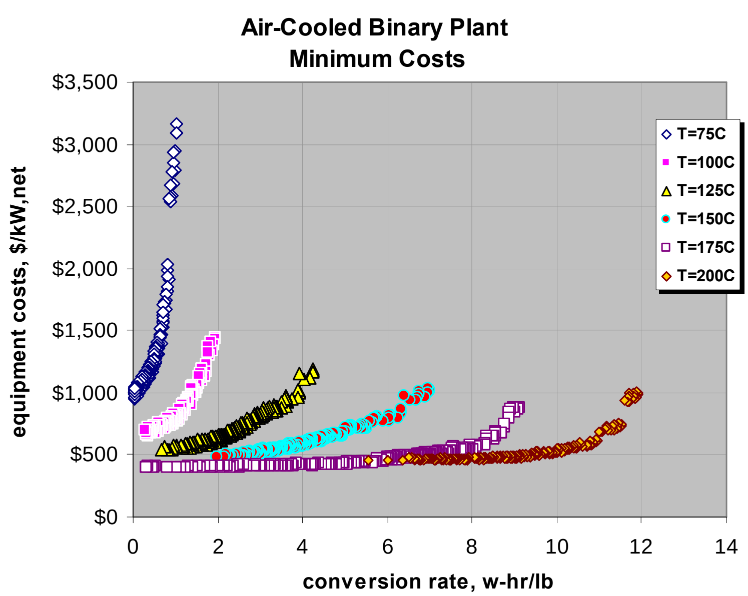
The modifications made to GETEM have increased the amount of input required from a user. While the level of input detail has increased, GETEM remains a tool for evaluating power generation costs for generic scenarios; the model is not appropriate for evaluating site specific scenarios. The level of input has been increased to address some of the deficiencies identified in the model's projections and to allow for a more specific evaluation of EGS. Once "user" needs in evaluating this resource are better established, it is hoped that the current level of input can be decreased.

Relationship Between Plant Performance and Plant Cost

In general, the cost of a power plant varies directly with how efficiently it is able to convert the energy contained in a given amount of geothermal fluid into electrical power. This conversion rate, or brine effectiveness, is the plant performance metric used in GETEM. The conversion efficiency used is not the thermal efficiency, which is an indication of how efficient the cycle is in converting the heat extracted into power. Rather it is the fraction of the maximum potential power that is converted into electricity. More succinctly, it is net power generated per unit mass of geothermal fluid. Prior work at INL (both for the Geothermal Program and for others) was used to develop the relationship between plant performance and cost. This involved modeling the performance and developing equipment costs of an air-cooled binary plant as functions of the geothermal fluid temperature, working fluids, heat exchanger pinch points, turbine inlet conditions, etc.. As a result several thousand performance vs cost data points were developed. Shown below are the data for two of the resource temperatures considered.



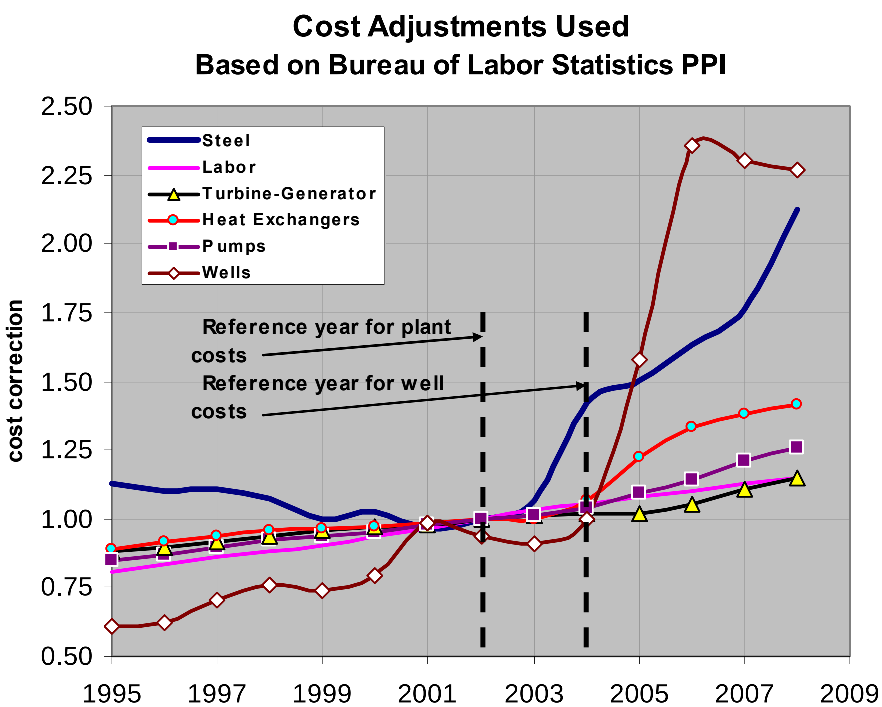
Though there is significant scatter in the data, for a given level of performance, there is a cost minimum at each of these temperatures. For each of the resource temperatures considered, those minimum cost conditions were extracted from the data set; they are shown in the following figure.



These conditions were subsequently used to develop the costs for each of the major equipment items (turbine-generator, geothermal heat exchangers, air-cooled condenser, and working fluid pumps) as a function of the conversion efficiency and the resource temperature. GETEM uses these equipment cost correlations to predict the power plant capital cost.

Updating Costs Using Bureau of Labor Statistics Produce Price Indices

The equipment costs correlations that were developed for the power plant were developed from cost estimates that were based on the 1st Quarter of 2002. To bring the plant costs forward (or backward) in time, the published Producer Price Indices (PPI's) were applied to the costs predicted by the correlations used. The PPI's being used in GETEM are shown below. The rapid increase in the cost of steel that has recently occurred is shown along with the costs of labor, turbine-generators, heat exchangers, pumps and drilling. Those equipment components whose fabrication are more labor intensive have not experienced as rapid of increases in cost as those where the materials are a larger contributor to the total equipment cost. Note that cost correction for the wells is based upon a drilling PPI for oil and gas wells. Well perhaps not totally applicable to geothermal wells, it is likely that the cost increases for geothermal wells have been similar. Though there is a considerable amount of steel in well, it is likely that the increases in oil costs and the associated demand for drilling rigs is a large contributor to the increases in the drilling PPI.



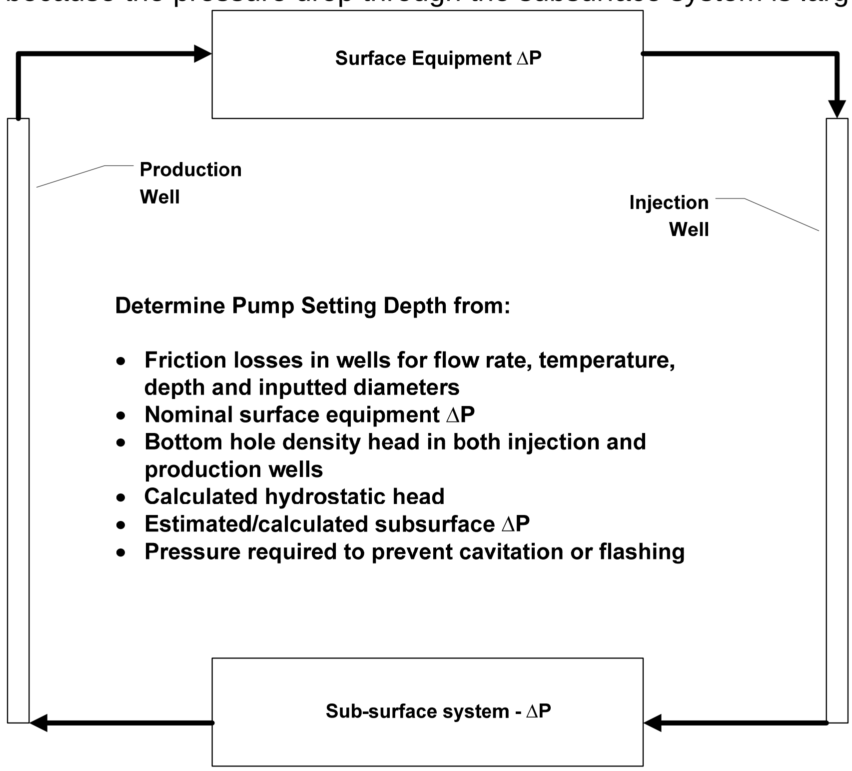
The cost correction for the wells is referenced to 2004; this was the base year for the well cost correlations that were used in the original version of GETEM. Those original cost correlations are still used, with the indicated correction.

Use of SI or Imperial Units

A user can now provide most input to GETEM in either SI or Imperial units. While either unit set can be used, the subsequent calculations continue to be based on the same units set that was previously used. Similarly the results are generally presented in the same units that were used previously; though it should be noted that the primarily results reported are the power sales and the costs associated with generating that power. (Note that a single units set is not used in either the calculations or the results generated.)

Subsurface Hydraulic Model

The setting depth of a production pump will be contingent upon a number of factors; these factors are summarized in the following figure. As with all fluid systems, the pressure losses in the system will be a function of the flow. To sustain flow, these pressure losses must be offset by the use of a pump. If the production and injection well are directly coupled, then simplistically these losses could be offset with an injection pump that would “push” fluid through the loop, or a production pump that would “draw” fluid through the loop. In conventional hydrothermal systems, frequently both production and injection pumps are used. This may be done because the wells are not directly coupled, or because the pressure drop through the subsurface system is large.



For an EGS system, it is presumed that one would use as little injection pressure as possible. This is based on the assumptions that subsurface water losses would increase with higher bottom hole pressures in the injection well, and that higher pressures at the injection well could cause preferential flow paths through the fracture system that would bypass heat transfer surfaces.

For both hydrothermal and EGS resources, the injection well bottom-hole pressure should be greater than hydrostatic pressure. GETEM determines this bottom-hole pressure using a well head pressure, friction losses, and density head of the fluid in the well (assumed to be at the temperature of the fluid leaving the plant). Hydrostatic pressure is determined using the earth's temperature gradient and the well depth (Xie, etal, 2005 GRC). GETEM determines the excess pressure at the bottom of the injection well and allows the user to increase that value using an injection pump (if there is a negative excess pressure, i.e., the hydrostatic pressure is greater than bottom-hole pressure, the user is prompted to use an injection pump).

Some of the methods used to determine the subsurface reservoir pressure drop are common to both resource types. This **Δ**P can be determined based upon a user supplied reservoir drawdown factor. This factor is essentially a pressure drop per unit flow rate, i.e., the pressure drop increases linearly with the flow. An alternative method is for the user to provide an effective permeability, reservoir flow area and distance between production and injection wells. The reservoir flow area is the effective cross sectional area of the reservoir. The product of the permeability and the flow area is in effect the inverse of a flow resistance per unit flow per unit length. Either of these methods can be used to determine the pressure drop for a hydrothermal or EGS resource. In addition one can estimate this pressure drop in EGS resource using a defined fracture system. The information required is the number of fractures, fracture aperture, fracture width, and distance between wells. With the assumption that the flow through a single fracture is laminar, the friction factor is determined as a function of the Reynolds number, where the diameter used is the hydraulic diameter of the fracture and fluid properties are determined based on an average fluid temperature in the reservoir.

With the subsurface reservoir **Δ**P estimated, the bottom-hole pressure in the production well is determined. For a hydrothermal resource, this pressure is the hydrostatic pressure less the reservoir **Δ**P. For an EGS resource, this pressure is the bottom-hole pressure in the injection well less the reservoir **Δ**P.

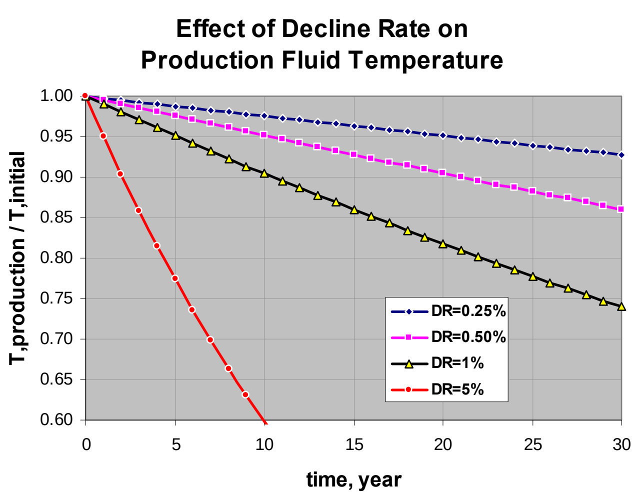
A user has to define the excess pressure at the suction of the production pump that is required to prevent caviation in the pump. This excess pressure is added to the saturation pressure of the produced fluid to establish the pump suction pressure. It is assumed that this is also the well head pressure for the production well; this pressure that is identified to prevent cavitation is also used to prevent flashing in the surface equipment. It is recommended that a minimum of 2 to 3 bars (30 to 50 psi) be used for the excess pressure. The difference between the bottom hole pressure and the pump suction pressure is essentially the density head available; if the fluid density is know, this value can be used to establish how far above the bottom of the production well that one must set the pump in order to have the minimum pressure at the pump suction. This density head is adjusted to account for friction losses in the well below the pump. GETEM assumes that this flow is essentially in a pipe, and uses a friction factor derived from the Reynolds number. (This correction reduces the density head available and requires the pump to be set at a deeper depth – as measured from the surface.) GETEM also estimates the friction losses in the production casing, and adds this pressure loss to the setting depth in determining the pump lift and pumping power required.

The user must also provide a pressure losses through the surface equipment, which is subtracted from the production well head pressure to give the injection well head pressure, which is subsequently used in the determination of the excess pressure at the bottom of the injection well. The determination of this excess pressure also requires that the fluid temperature at the injection well head be known. GETEM calculates the temperature of the geothermal fluid leaving the power plant based upon the plant's conversion efficiency and the produced geothermal fluid temperature. The temperature required to keep amorphous silica in solution is also calculated based on the produced fluid temperature. The higher of these two temperatures is used as the injected fluid temperature.

Resource Decline

Hydrothermal resources experience a decline in resource productivity with time. This decline is manifested as a decreasing production fluid temperature, decreased flow, or in the case of two-phase production a drop in the fluid pressure. For now, GETEM only considers a declining production fluid temperature.

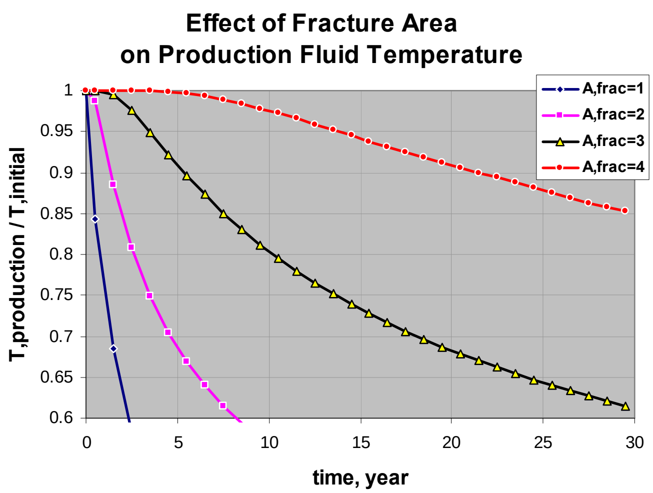
Thermal drawdown is handled by one of two methods. In one, the production fluid temperature is assumed to decrease by a defined annual rate. This method can be used with both resource types; it is the only method that should be used with hydrothermal resources. The figure below shows the effect that different annual decline rate (DR in the figure) have on the produced fluid temperature with time. Discussions with the operators of binary plants using hydrothermal resources suggest that the temperature decline rates could approach 0.75% annually; more probable values are <0.5%. It is postulated that the temperature drawdown with an EGS resource will be greater; in a worse case the annual decline rates might be an order of magnitude higher, in which case it would be necessary to replace the wells/reservoir over the life of the project, perhaps several times.



The second approach to characterize thermal drawdown should be used only with EGS resources. This approach assumes that the subsurface heat exchange occurs in the created fracture system by the conduction of heat from the rock to the fluid being circulated through the fracture, and the native rock permeability is ignored. The correlations used to characterize this heat transfer process are based on work done by Bloomfield and Shook (unpublished report). This prior work used the Carslaw and Jaeger solution for a transient conduction process from a semi-infinite solid, where the solid represents one side of a fracture surface. Initially the entire surface of this fracture is at the reservoir or native rock temperature; as the injected fluid subsequently flows past the fracture surface it is heated, and the rock is cooled. The Carslaw and Jaeger solution allows one to estimate the temperature of the rock (and fluid) at the fracture surface as a function of both time and distance form the point where the injection fluid is introduced.

For this scenario, Carslaw and Jaeger also provide a solution of the temperature profile perpendicular to the flow (rock temperature). This can be used to identify the "thermal penetration" at the injection well, or the distance where the temperature of the rock approaches the native state rock temperature. Currently a thermal penetration is determined as the distance from the fracture where the rock temperature is within 0.5% of the native rock temperature. This penetration is the greatest at the injection well, and that is the value that GETEM determines.

In the figure below, and example is shown where the Carslaw and Jaeger solution of the transient heat conduction in the reservoir is used to predict the effect of the subsurface heat transfer area on the production fluid temperature (with the assumption that there is sufficient separation between individual fractures to sustain the heat transfer process).



The declining production fluid temperature reduces the amount of power that can be produced for sale. To estimate this effect on power sales, it is assumed that both the plant's 2nd law efficiency and the production flow rate remain constant. The brine effectiveness is the product of the 2nd law efficiency and the production fluid's available energy, which is calculated as a function of the fluid temperature and an assumed heat sink condition (10°C and 1 atmosphere). As the production temperature decreases, the calculated available energy and brine effectiveness also decrease, and with a fixed flow rate the net plant power production similarly drops. With a fixed flow rate, the geothermal pumping power can be assumed to be constant, allowing the power sales to be determined as a function of time.

The user defines the maximum temperature decline that will be allowed before the entire well field is replaced. The number of times that this replacement can occur is determined by the design plant output and potential power production that is defined during the exploration activities. If one needs to replace the field for a 10 MW plant 3 times over the project life, then the resource potential found during exploration must be greater than 30 MW. If 25 MW of resource potential was found, the well field could be replaced 2 times over the project life. Once the well field has been replaced the maximum number of times, the resource temperature is allowed to continue to decline, even though it exceed the maximum temperature decline allowed.

The model can also trigger the replacement of the well field if the plant output decreases by a defined amount. The default that was being used was 50% of the net plant output. This provision for replacing the well field has been “turned off”; replacement of the well field is triggered solely on the decline in the production fluid temperature.

LCOE Optimization

The model utilizes the plant performance metric, brine effectiveness, to establish the minimum levelized cost of electricity (LCOE). The effect of this performance metric on plant cost was discussed previously. This performance criterion establishes the geothermal fluid flow rate that is required to support a given level of power production/sales. For given well flow rates and well costs, this total flow rate establishes the well field size and development costs. If the well field size (and cost) is fixed, the plant performance determines the level of power sales.

O&M costs are predicted based upon the capital costs of both the well field and the power plant, as well as the size of the plant. All of these contributors are affected by the plant performance criterion.

In addition the plant performance affects the temperature of the fluid leaving the binary power plant, which is also the injection fluid temperature. This temperature impacts the performance of the subsurface heat exchange system for an EGS resource. A more efficient plant injects fluid at a lower temperature, which lowers the production fluid temperature.

The effects of the plant performance on these various factors are integrated into the model. The user may elect to optimize the plant performance by running a macro that varies the brine effectiveness until the LCOE is minimized. The user may also opt to input a level of plant performance. This macro should be run every time the input is changed; i.e., it is the last user input to be made.