Revisions to GETEM Model

General

The model has been modified to allow the user to project the cost of power from either an EGS or hydrothermal resource. Most of the modifications that have been made are utilized in evaluating both resource types. The major exception is the inclusion of a simple of model of the flow and heat transfer in the subsurface, fractured heat exchange system in an EGS resource. While a user might use this to characterize a hydrothermal resource, it is not intended for that purpose. An attempt has been made to provide the user with warnings when the model is not being used as intended.

The original version of GETEM developed LCOE's based upon cost correlations that were developed using representative costs in 2004. Because the subsequent surges in the cost of steel and the rising price of oil (and demand for drilling rigs), these costs are no longer representative of what it costs to produce power from a geothermal resource. Recent model revisions attempt to bring the 2004 costs forward (or backward, if desired) in time using Price Indices (PI) that are available from the US Department of Labor's Bureau of Labor Statistics. The PI's are currently provided in the model for the period 1995 through 2008; updating of the PI's must be done by the user.

For the binary conversion system, GETEM allows the user the option of using a macro that minimizes the predicted Levelized Cost of Electricity (LCOE) by varying the performance of the plant (the net power that is produced per unit mass of fluid). This performance metric, which is referred to in the model as brine effectiveness, but is also called specific output by others, establishes the flow that is required to produce the desired power output, or defines the amount of power that can be produced from a specified well field. As a consequence this parameter affects effectively all of the contributors to the cost of generating power.

The basic layout of GETEM has not changed a great deal, though pages have been added and the naming of those pages has changed. Where possible, the user defines the reference scenario and the technology improvements for the improved scenarios on the *2A.Scenario Input* sheet. This sheet has hyperlinks that take the user back and forth between this sheet and the other input sheets, *2B.Resource & Well Input*, *2C.Binary Input*, *2D.Flash Input*, *2E.Conversion Systems* and *2F.O&M Input*. Generally the reference scenario is defined on these other input sheets, however in some instances the improved scenario is also.

Economic Parameters

Definition of the economic parameters used remains largely unchanged. The inputted values are specified on sheet *2A.Scenario Input*. In addition the user defines the year for which the estimate is made. This provides the basis for the use of the Price Indices to adjust either the plant or well costs to reflect cost estimates for that year.

Resource

GETEM accommodates two resource types; Hydrothermal Enhanced Geothermal Systems (EGS). The user specifies the resource type on sheet *2A.Scenario Input*. Input to define each resource is on sheet *2B.Resource & Well Input*. Hyperlinks on this page allow the user to switch back and forth between these sheets.

For the Hydrothermal resource the user defines both the resource temperature and depth. For the EGS resource, the user defines whether the resource temperature or depth will be calculated. The user defines the earth's temperature gradient and an average ambient temperature, as well as either the EGS resource temperature or the EGS resource depth. The model then calculates the value not specified by the user (temperature or depth) based on the input provided. For the EGS scenario, the user also defines the temperature that is the basis used for the plant design (this value should be less than the resource temperature) and both the subsurface water loss and the cost to makeup that water.

Power Sales

On sheet *2A.Scenario Input* the user establishes whether calculations will be based upon a defined level of power sales or a fixed number of production wells, and then inputs that value.

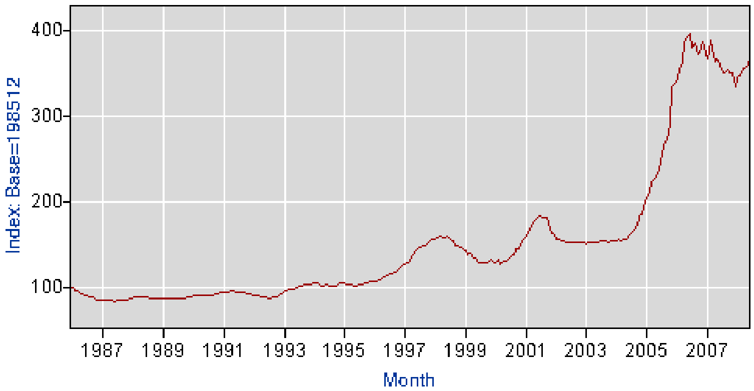
Exploration and Confirmation

GETEM accommodates two resource types; hydrothermal and Enhanced Geothermal Systems (EGS). On sheet *2A.Scenario Input* the user provides the input to calculate the Exploration and Confirmation costs based on the resource type selected. Note there is not separate input for each resource type – the input must be revised as necessary if the resource type is changed. The input allows the user to either input an exploration success ratio or to define the number of exploration wells drilled. The user also defines the resource potential found, the number of confirmation wells drilled, the confirmation success ratio, and multipliers for both the exploration and confirmation wells. The cost multipliers allow the user to adjust well costs to accommodate the use of slim holes, as well as to reflect the higher drilling costs during the initial phase of the field development. The user also defines the non-drilling costs associated with both the exploration and confirmation phases. The user also defines whether the exploration costs are to be pro-rated based upon the resource potential found. This allows the user to spread these costs over multiple power plant projects. It is recommended that for evaluating EGS these costs not be pro-rated. Confirmation costs are not pro-rated.

As indicated the potential resource found can be used to in calculating exploration costs (if the user inputs an exploration success ratio and elects to pro-rate those costs). More importantly for an EGS application, the potential resource found determines how many times the EGS reservoir can be replaced during the duration of the project. If the defined resource potential is not at least twice the twice the plant output, the model will not replace the EGS reservoir during the project even though the decline in the reservoir productivity meets the requirements for replacement.

Well Field Development

The method the model uses to determine the well field development costs is similar to that previously used. Production and injection well costs are independently determined, with the assumption that all wells of each type have the same cost (all production wells cost the same; this cost may differ from the injection well cost). Each well type cost is based upon a well depth and a user defined cost curve (Low, Medium, or High cost curve). This cost estimate is in 2004 dollars. The model adjusts this cost to that of the user specified year for the estimate using a Price Index for the drilling of oil and gas wells. This index, which is shown below, was obtained from the US Department of Labor Bureau of Labor Statistics.



If the user desires, a further adjustment to the updated cost can be made with a simple multiplier. Note that the production well costs that are determined are also used in calculating the drilling costs for the exploration and confirmation wells.

The number of production wells required is either a user input or is calculated based upon the user's specified net power sales, the plant performance and the inputted flow rate per production well. This calculation also uses the model's determination of the geothermal fluid pumping power (in determining the net plant output). The user defines the ratio of injection wells to productions wells; the number of injection wells required is product of this ratio and the calculated number of production wells that are required. The model determines the number of production wells that are drilled as the difference between the number of production wells that are required and the number of successful confirmation wells. The number of injection wells drilled is the same as the number required.

The user also defines the number of spare wells that are required (their cost is the same as the production well), and the field development costs not associated with well drilling. This includes the surface equipment cost (per well).

The user provides input on the *2A.Scenario Input* sheet, as well as on sheet *2B.Resource & Well Input*. Hyperlinks allow the user to switch back and forth between these sheets.

Note that the well field development costs that are determined are exclusive of the exploration and confirmation costs. In addition any costs for well stimulation and the geothermal pumps are calculated separately. These costs however are included in the well field development costs in the summarization of the contributions of the different aspects of the project to the total generation costs.

Well Stimulation

The user has the option of either inputting a fixed cost for the well stimulation or providing the input necessary for the model to calculate a cost based on the fracture area that is created. If a fixed cost is inputted, that cost should be provided as a cost per well. Note a fixed stimulation cost should be used for a hydrothermal resource.

If the model is to calculate the cost, the user must define the distance between a production and injection well, the number of fractures created, the width of the fracture, and the orientation of the fracture (angle relative to horizontal). The orientation and the distance between the wells determine the effective fracture length, which combined with the width and number of fractures allows a total surface area created to be calculated. The calculation of stimulation cost uses this area and user supplied costs for both the set up for the stimulation and a cost per unit area. The model assumes the stimulation occurs between a production and an injection well; thus the cost per well is half that calculated to create the fracture system.

The stimulation cost per well is applied to sum of the production and injection wells required to give the total stimulation cost for the project. This cost is included in the well field costs in GETEM's summary of the costs contributing to the projected LCOE.

User input is provided on sheets *2A.Scenario Input* and *2B.Resource & Well Input*; the calculations are made on sheet *2B.Resource & Well Input*.

Geothermal Pumps

The calculations for the geothermal pumps are made on sheet *7A.GF Pumps*. The user input is provided on sheets *2A.Scenario Input* and *2B.Resource & Well Input*.

Injection pumping requirements are based on the user's input of an injection pump head (*2B.Resource & Well Input*). To assist the user in determining whether pumping is required, the model determines the amount of excess pressure at the bottom of the injection well. The calculation of the bottom-hole pressure is determined using the model's calculation of density head, friction losses and the well head pressure, which is either the production well pressure less the pressure drop in a binary conversion system (user input) or the lowest flash pressure in a flash-steam plant. The calculated density head in the injection well is based on this depth and the density of water at the calculated injection temperature. This temperature is the maximum of either the temperature determined based on plant performance or the calculated temperature limit needed to prevent silica precipitation. The model also calculates a friction loss in the injection well. This loss is a function of the fluid flow rate, the depth, the well diameter, and a friction factor calculated for a pipe. This bottom-hole pressure is compared to the hydrostatic pressure, which the model calculates using the injection well depth and the earth's temperature gradient

$$P_{,bh} = P_{,w\text{-}h} + \boldsymbol{\rho} * \text{depth} - \boldsymbol{\Delta} P_{,friction}$$

$$\boldsymbol{\Delta} P_{,excess} = P_{,bh} - P_{,hydrostatic}$$

The difference between the calculated bottom-hole and the hydrostatic pressures defines the excess pressure available; if the bottom-hole pressure is greater than hydrostatic, the user has to decide if additional pressure is required. If no excess pressure is available, i.e., the hydrostatic pressure is greater than the bottom-hole pressure, an injection pump should be used. The model does not automatically provide the required pumping, but does prompt the user to add the necessary injection pump head.

The final bottom-hole pressure in the injection well is the sum of the calculated bottom-hole pressure and the injection pump head.

P,bh_inj = P,bh + **Δ**P,injection pump

This value is used with the pressure drop determined for the reservoir to establish the bottom-hole pressure in the production well for an EGS resource.

P,bh_prod = P,bh_inj - **Δ**P,reservoir

If a hydrothermal resource is being evaluated, the bottom-hole pressure in the production well is based on the hydrostatic pressure instead of the bottom-hole pressure in the injection well, i.e.,

P,bh_prod = P,hydrostatic - **Δ**P,reservoir

The pump setting depth is based upon the production well bottom-hole pressure and the pump suction pressure. The pump suction pressure is determined as the sum of the saturation pressure of the produced fluid and a user defined pressure that is added to the saturation pressure to prevent pump cavitation. The saturation pressure is calculated based upon the user defined fluid temperature that is the basis for the plant design; this temperature is not necessarily the same temperature as the resource temperature for EGS scenarios. (Note that the model assumes that the production wellhead pressure is the same as this pump suction pressure.)

P,pump_in = P,saturation + P,excess_pump

Based on the user defined production well flow rate and well diameter below the production pump, the model calculates the friction loss per unit length in this section of the production well. The pump setting depth is determined from the following relationship.

ρ*setting depth – **Δ**P,friction per unit length*setting depth = P,bh-prod – P,pump-in

The setting depth in this relationship is determined from the bottom of the well. The pump lift is equal to the well depth less this setting depth plus calculated friction losses in the pump casing.

Lift,pump = Well depth – setting depth + **Δ**P,friction_production casing

The production well pumping power is based upon the calculated lift, and the user defined flow rate and geothermal pump efficiency. The injection well pumping power, if required, is based upon the user's defined excess pressure needed in the injection well, the total geothermal fluid flow leaving the plant, and the pump efficiency used for the production pumps. If water makeup is required for an EGS resource, this flow is included in the determination of the injection pumping requirement.

The friction factors used for the injection and production wells are derived using equation 8.21 from Incropera and DeWitt, 2002.

The model allows the user to input the cost of the production pump or to allow the model to calculate that cost. The model's estimate of the pump cost is based upon the following relationship:

$$\text{Pump cost} = (\$12{,}000 * (\text{Size,hp})^{0.5}) * PI_{pumps}$$

The calculated installed cost of the pump include user defined costs for installation and casing ($ per foot) and a defined fixed installation cost.

The installed injection pump costs are determined based calculated horsepower, the above relationship for cost as a function of horsepower, and an installation multiplier of 1.4. There is no user input for the injection pump cost.

The user defines whether the production pump is a submersible or lineshaft pump. This is only used in determining of the O&M costs for the well field. The user provides the information needed to define those O&M costs on sheet *2F.O&M Input*.

Reservoir Hydraulics

In order to determine the production pump setting depth the, model requires the pressure drop through the subsurface reservoir be determined. The user has the option of inputting this pressure drop or of allowing the model to calculate a value using simple characterizations of the subsurface reservoir hydraulics. The model's calculations are made on sheet *7B.Reservoir Hydraulics*. The user input is provided on sheets *2A.Scenario Input* and *2B.Resource and Well Input*.

The characterizations of the reservoir hydraulics are not intended to replicate a detailed reservoir model; for instance they do not account for the pressure losses immediately adjacent to the well bore. The model's characterizations are intended to depict trends that reflect how the reservoir reacts to changing different parameters that impact the pressure drop in the reservoir, which directly impacts the setting depth of the production pump. This setting depth defines the cost associated with the pump, both in terms of parasitic pumping power and installation cost.

The model's characterization of the subsurface reservoir is based on a coupled production and injection well, even if the number of injection wells in the project differs from the number of production wells. Calculations are based upon the fluid flow from one production well.

In one characterization used, the pressure drop in the reservoir is based upon the permeability, reservoir cross section, and the distance between the production and injection wells. These parameters are defined by the user. The model determines the reservoir pressure drop using the following relationship:

$$\mathbf{\Delta}P\text{,reservoir} = \acute{\boldsymbol{\omega}} * \boldsymbol{\mu} * L/(k*A)\text{, where}$$

where $\acute{\omega}$ = volumetric flow rate per production well
μ = viscosity
L = distance between wells
k = permeability, and
A = flow area

For a hydrothermal resource, fluid properties are based on the user's defined resource temperature; for EGS, they are based on the average fluid temperature in the reservoir.

A multiplier (defined by the user) is applied to the k*A product to depict an Improved Scenario. The multiplier should be >1 to reduce the reservoir pressure drop, which reduces the pump setting depth.

For an EGS reservoir, the user can calculate the hydraulic losses based on simple flow in a fracture. The user defines the number of fractures, the fracture aperture and width, and the fracture length. The pressure drop is calculated assuming laminar flow in the fracture.

$$\Delta P_{,reservoir} = f * (L/D) * V^2 / (2*g)$$

where f = friction factor
L = fracture length
D = hydraulic diameter of fracture
V = fluid velocity in fracture, and
g = gravitational constant

For laminar flow (Reynold number < 2,000) in a fracture, the friction factor is determined as f = 64 / Reynolds number. The hydraulic diameter is determined as D = 4* (Cross Sectional Area) / (Wetted Perimeter). For a wide fracture with a relatively small aperture, the hydraulic diameter is ~ twice the aperture. The fracture length used is based on the distance between the wells and a fracture angle (off the horizontal); both values are user defined. The user can adjust the pressure drop calculation with a multiplier that is applied to the fracture length. When this method of characterizing the reservoir pressure drop is used for an EGS resource, the user defines the Improved Scenario by changing the number of fractures and/or increasing the size of a fracture (width or aperture). Changing these parameters affect the fluid velocity in a single fracture; this directly impacts the pressure drop calculation. Note that changing these parameters will also change the calculation of the production fluid temperature, if the subsurface heat exchanger model is used to determine this temperature.

EGS: Subsurface Heat Exchange

GETEM assumes that the subsurface heat exchange system consists of a system of fractures between the production and injection wells where heat is conducted through the rock to the fluid circulating through the fracture. The correlations used to characterize this heat transfer process were based on work done by Bloomfield and Shook (unpublished report). This work was based on 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. At time zero, just prior to injection, the entire surface of this plane is at the initial reservoir or native rock temperature. As the injected fluid passes over the fracture surface it is heated and the rock is cooled. It is assumed that the limitation to heat transfer is the conduction of heat from the semi-infinite body of rock to the fracture surface, and that there is negligible resistance associated with the heat transfer between the rock and the fluid. This solution allows one to estimate the temperature of the rock as a function of both time and distance from the point where the injection fluid is introduced.

Based upon the Carslaw and Jaeger solution, the model uses the following correlation to characterize the produced fluid temperature.

$T_{prod} = T_{rock} + (T_{inj} – T_{rock})$* erfc[($K_{rock}$ *Area)/(rho_w*Cp_w*Q*(alpha*time – L/V $)^{0.5}$)],
where
T_{prod} is the temperature of the produced fluid
T_{rock} is the temperature of the rock at time zero
T_{inj} is the temperature of the injected fluid
K_{rock} is the thermal conductivity of the rock
Area is the surface area of one side of a fracture (length x width)
rho_w is the density of the fluid
Cp_w is the specific heat of the fluid
Q is the volumetric flow rate of the fluid
alpha is the thermal diffusivity of the rock
erfc is the complementary error function, or one minus the error function (erf)
alpha = K_{rock}/(rho_{rock}*Cp_{rock}), where
rho_{rock} is the density of the rock
Cp_{rock} is the specific heat of the rock
L is the fracture length
V is the fluid velocity in the fracture

For this scenario, Carslaw and Jaeger also provide a solution of the temperature profile perpendicular to the flow (rock temperature).

$T_z = T_{rock} + (T_{inj} – T_{rock})$* erfc[(k*x + z*V)/(2*V*(alpha*{time-x/V}$)^{0.5}$)],
where
T_z is the temperature of the rock perpendicular to the flow direction
k = K_{rock}/(b*rho_w*Cp_w), where
b is the fracture aperture
x is the distance in the direction of fluid flow
z is the distance perpendicular to the direction of flow
V is the fluid velocity

At the injection well, x =0, and the above solution can be expressed as

$T_z = T_{rock} + (T_{inj} – T_{rock})$* erfc[z/(2*(alpha*{time}$)^{0.5}$)]

This can be used to identify the “thermal penetration” (z) at the injection well, or the distance where the temperature of the rock is equal to the native state rock temperature ($T_z = T_{rock}$). This occurs when the temperature of the injected fluid is equal to that of the native rock, or when the erfc[ ] is equal to zero. The erfc[ ] is zero when the argument, [z/(2*(alpha*{time}$)^{0.5}$)], approaches infinity, which occurs when either time equals zero or when z approaches infinity. The thermal penetration can be approximated by determining a value for the argument where erfc[ ] is sufficiently small that the T_z approaches T_{rock}. If the argument is equal to 2, the erfc[ ]would be ~0.0047; if the argument were equal to 2.5, the erfc[ ] would decrease by an order of magnitude (to ~0.00041). In the model developed, an argument value of 2 is used. This defines a “z “value (thermal penetration thickness) where the rock temperature is within ~0.5% of the native rock temperature. For this argument value, the resulting thermal penetration is

$$\text{thermal penetration thickness} = 4 \times [\text{alpha} * \text{time}]^{0.5}$$

This value is of interest because the thermal penetration is greatest at the injection well, and the value would be indicative of the fracture spacing required. Assuming more than one fracture is used, If the spacing at the injection well is less than twice this value, the water would not be heated to the degree predicted by the model, and the thermal drawdown would be greater than suggested by the model. Note that at the injection well, this thickness is a function of the rock properties and time; it is not a function of either the native rock temperature or the injected fluid temperature.

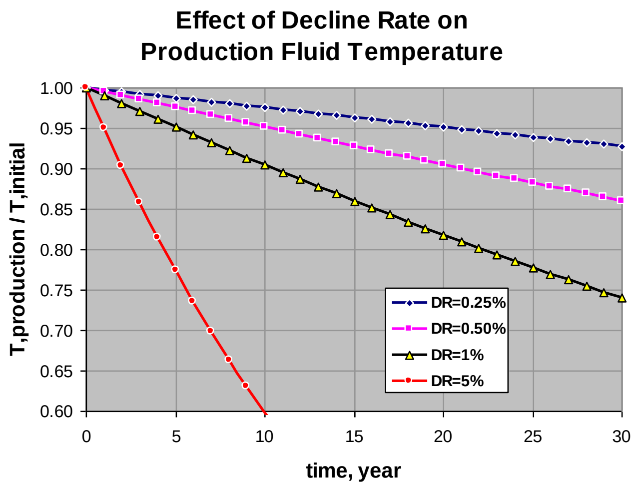
If one ignores the contribution of the native rock permeability and assumes that all heat transfer occurs in the fracture system, these correlations can be used to perform project the produced fluid temperature as functions of time, flow rate, and fracture surface area. They can also be used to estimate the thermal penetration at the injection well, which can be used to establish the required distance between fractures. The user defines an Improved Scenario by changing the number of fractures and/or increasing the size of a fracture (width or aperture).

The model’s calculations are made on sheet *6Bb.Makeup-EGS HX*, as well *7C.EGS Subsrfce HX*. The user input is provided on sheets *2A.Scenario Input* and *2B.Resource and Well Input*. Input is required on sheet *7C.EGS Subsrfce HX*.

Thermal Drawdown and Makeup

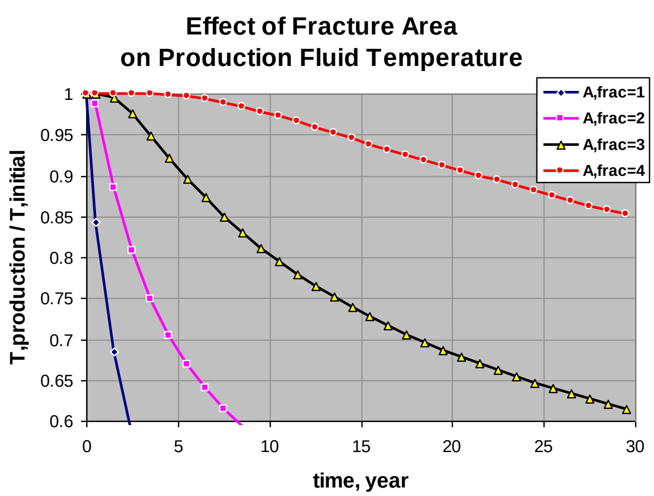
Thermal drawdown refers to a decline in the resource productivity over time. With a hydrothermal resource this decrease in productivity can occur as a declining production temperature, pressure, and/or flow rate. Typically this decrease in productivity would be off-set by the drilling of additional wells to increase geothermal fluid flow and sustain power production. GETEM however does not replace individual wells; rather it replaces the entire well field when the resource decline reaches the maximum allowed.

For hydrothermal resources that utilize a binary conversion system, it is assumed that this resource decline occurs as a declining resource temperature with time and the production flow rate remains constant. The same assumption is used for EGS resources will also be manifested as a decline in the production fluid temperature over time. For hydrothermal resources, this temperature drawdown is expressed as an annual percentage decline in temperature; this decline rate is a user input. (Note the decline rate is used to reflect the change in the resource temperature in units of °C or °F, not in absolute temperature units.)



The above figure shows the effect that this annual decline rate (DR in the figure) will have on the fluid temperature with time. Discussions with the operators of binary plants using hydrothermal resources suggest that the temperature decline rates are <0.75%. This rate represents an upper limit for the evaluation of a hydrothermal resource (i.e., the worst case for this resource type); more probable values are thought to be <0.5%. It is postulated that the temperature drawdown with an EGS resource will be greater; perhaps annual decline rates an order of magnitude higher. If the decline rates for EGS are of this magnitude, it would be necessary, as suggested in the above figure, to replace the wells/reservoir over the life of the project, perhaps several times.

For the EGS resource GETEM will also calculate the temperature drawdown over time using the Carslaw and Jaeger solution of the transient heat conduction in the reservoir, with the assumption that there is sufficient separation between fractures to sustain the heat transfer process.



The effect of the fracture surface area on the calculated production fluid temperature is shown in the above figure. Again this is a very simplistic model whose projects are unlikely to match real performance of the subsurface system. However its predicted trends should be representative, and allow one to trade off the decline in performance and the need to drill added wells with the cost to create a larger subsurface reservoir (assuming the relationship between reservoir size and cost is adequately characterized).

The user selects the method to be used to account for the decline in resource temperature with time, and provides the annual decline rate or the information needed to calculate the decline in an EGS reservoir. The user input is provided on sheets *2A.Scenario Input* and *2B.Resource&Well Input*. The calculations for the subsurface EGS heat exchange system are on sheet *7C.EGS Subsrfce HX*. The calculations of the temperature drawdown and its effects on power output for an annual % decline rate are made on sheet *6Ab.Makeup-Annl%* and *6Ef.Flash Makeup*. Calculations for an EGS heat exchange system are made on sheet *6B.Makeup-EGS*. Drawdown for an EGS resource can be characterized with either an annual temperature decline rate or the performance of the subsurface heat exchanger. If a flash-steam conversion system is used, the annual temperature decline should be used, regardless of the resource type.

As the production fluid temperature declines, the power output from the plant decreases. The decrease in power occurs because of the decrease in the geothermal fluid's available energy, as well as the inability to the conversion system to maintain its design conversion efficiency. For the binary conversion system an assessment was made of the effect of a declining production temperature on the performance (2nd law efficiency) of a plant having a fixed configuration (heat exchanger, pump and turbine sizes). (Though this assessment was made for one initial resource temperature, the trends in conversion efficiency with temperature are thought to be representative of other initial resource temperatures). In determining the plant output at given production fluid temperature, the model determines the fluid's available energy at that temperature (a 10°C heat sink temperature is assumed). The degree to which the production temperature deviates from the design temperature (T_{gf} / T_{design}, in absolute units) is used to determine the conversion (2nd law) efficiency. The product of this efficiency and the available energy is the brine effectiveness, or specific output, in terms of the net plant output per unit mass flow. This brine effectiveness is multiplied by the total geothermal flow rate at the design condition to give the net plant output. Geothermal pumping power is subtracted from this value to get the net power for sale at that point in time.

A similar, less rigorous methodology is used to estimate the effect of a varying production fluid temperature on the performance of a 'fixed' flash-steam plant.

In determining the effect of the temperature decline on the generation cost, the power output from the plant is discounted at a rate provided by the model user.

If the level of the decline in the production fluid temperature exceeds a maximum value, the model assumes that the entire well field is replaced (wells, surface equipment and pumps). These costs are discounted using the year in which this replacement occurs and the user defined discount rate. The number of times that the well field can be replace is limited by the resource potential found (an Exploration and Confirmation input) and the net output from the plant at design conditions. For example if a resource potential of 25 MW is found and the design output from the plant is 10 MW, the well field can be replaced once.

The user can choose to input the maximum decline temperature to be allowed, or can use the default value that is calculated by the model. The default calculation uses the following:

$$\Delta T_{,max} = 0.21 \cdot T_{,resource} - 12.2$$, where T's are in °C

For a 200°C resource, a temperature decline of 30°C, or 15%, would trigger the replacement of the well field if this default calculation was used. The equation used to define this maximum decline was derived for the initial version of GETEM. It is based upon the end of project temperatures given in EPRI's Next Generation Geothermal Power Plant study (NGGPP) for air-cooled binary plants. This data was revisited in an attempt to develop a relationship that would be more 'generic'. In examining the NGGPP temperatures it was found that at the end of the project life, the corresponding Carnot efficiency was ~90% of the Carnot efficiency at design. GETEM now uses this relationship to calculates a maximum allowable temperature decline, but does not yet incorporate the calculation into the model's determination of generation costs – the original equation for the maximum allowable temperature decline is still used.

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 currently triggered solely on the decline in the production fluid temperature.

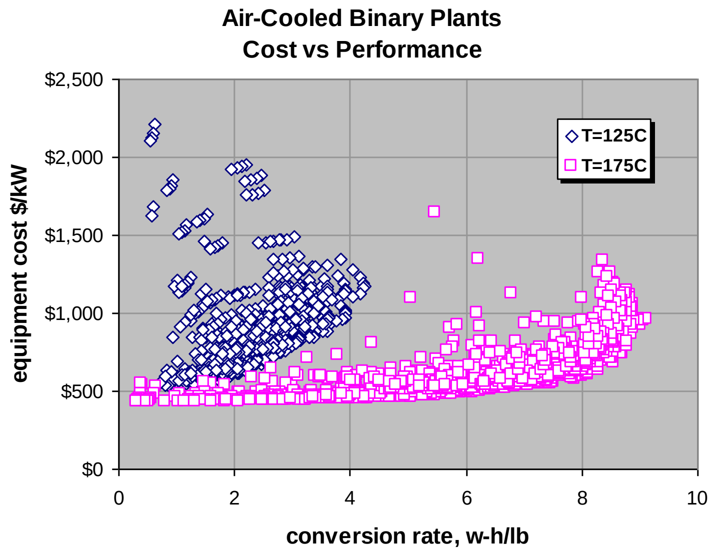
GETEM also assumes that the reservoir will not be replaced in the last 5 years of the project life (currently fixed at 30 years).

Conversion System - Binary

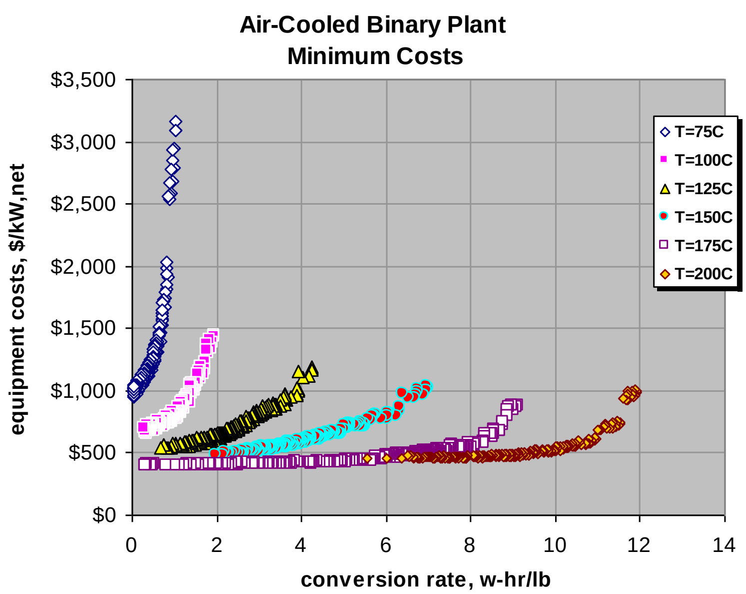
GETEM bases its predicted performance and cost of the binary conversion system on the assumption that the plant is air-cooled, i.e., heat is rejected sensibly to the ambient. There is no provision in the model for the use of evaporative heat rejection systems with the binary conversion system.

Originally the performance of the power plant was a function only of the resource temperature; the cost was a function of the temperature and the size of the plant (net power output from the plant). 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 binary 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 in predicting the power plant capital cost. An installation multiplier is calculated that is applied to the equipment costs to determine the total direct installed plant costs. GETEM allows the user the option of using this multiplier or inputting a value to be used. To determine the total installed plant cost the user must provide input to define the indirect costs (engineering, home office, permitting, transmission lines, etc). This is either an inputted total cost or a percentage that is applied to the total direct installed plant cost.

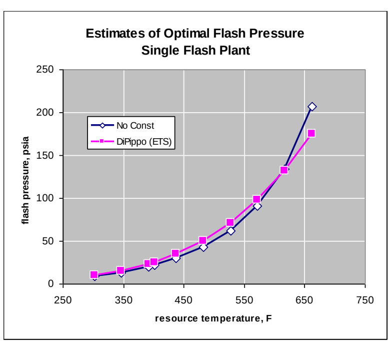
As indicated in the above figure, the plant cost is a function of the plant performance metric, brine effectiveness. Because this value is also used with the flow per well to either define the plant output (for a fixed number of wells) or the number of wells (for a fixed power output), it directly impacts the well field development costs. GETEM allows the user to define this performance metric. GETEM also has a macro (on sheet *2C.Binary Input*) that varies the performance of the plant until the generation costs (LCOE) are minimized. This feature only works for the air-cooled binary conversions system.

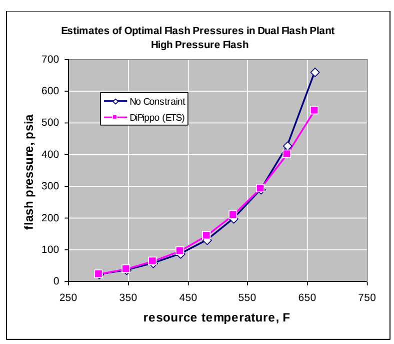
Conversion System – Flash Steam

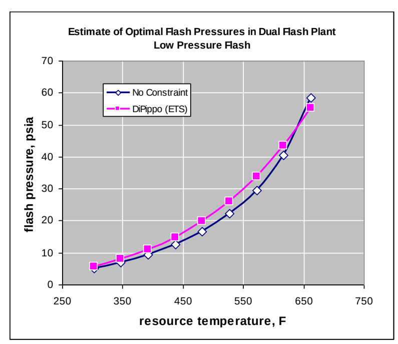
GETEM determines the performance of the flash-steam conversion system based on the user's defined number of flashes (1 or 2), the condenser type (direct contact or surface), and the type of non-condensable removal system (jet, vacuum pump, or hybrid). The user also provides the ambient wet bulb temperature, the level of non-condensable gases, and performance criteria for the heat rejection system, pumps and turbine-generator. This information is used with the resource and power sales scenario defined to predict the performance of the flash system and to size its components.

Note that GETEM bases its calculations on a defined resource temperature, with the premise that the geothermal fluid is in a liquid phase. It does not base its calculations on a two-phase flow conditions at the production well-head.

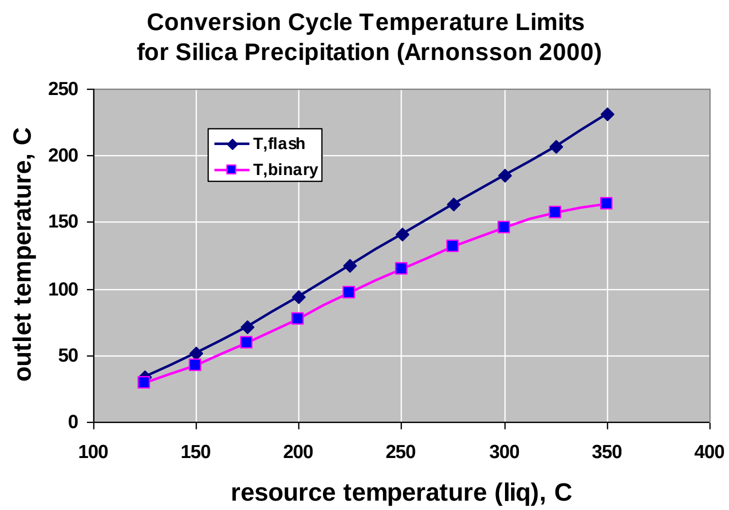
The flash pressures for the conversion system are estimated in GETEM using the resource temperature and the condenser temperature. The condensing temperature is based upon the user inputs for the wet bulb temperature, the cooling water temperature rise and heat rejection system pinch points (approach temperatures). The correlations GETEM uses to determine the flash pressures are based upon modeling results that evaluated the generator output as a function of the resource and condenser temperatures. Modeling results are shown below, along with the value calculated using DiPippo's 'equal-temperature-split' (ETS) rule.







GETEM imposes a condition that the flash pressures must be above 1 atmosphere. If the calculated flash pressure is less than 1 atmosphere, the flash pressure used defaults to 1 atmosphere. GETEM also allows the user to elect whether or not to impose a constraint on the temperature of the geothermal fluid leaving the plant (this constraint is always imposed with binary plants. For the same resource temperature, the constraint of the geothermal fluid temperature leaving a flash plant is higher than for a binary plant. This higher temperature is used because the dissolved solids in the liquid geothermal fluid become more concentrated with flashing and a higher temperature is needed to prevent their precipitation. (Calculations are based on the solubility of silica and quartz). The impact of the flashing on this constraint is shown in the following figure, which shows the outlet temperature needed to prevent the precipitation of amorphous silica for the binary and flash-steam conversion cycles. The difference between the two curves is indicative of the concentration of the dissolved solids in the flash-steam cycle.



If the user elects to impose this temperature constraint on a flash plant, the saturation pressure corresponding to this temperature represents the lowest flash pressure allowed. If GETEM calculates a lower flash pressure, the pressure used defaults to the value determined by the outlet temperature constraint.

If one elects to not impose the outlet temperature constraint on the flash-steam conversion system, the user should provide for additional operating and maintenance costs, as well as lower the utilization factor to account for the increased scaling of equipment that will result.

The user has the option of using the flash pressures that GETEM calculates or inputting the pressures. Note that GETEM does not currently allow one to input a performance (brine effectiveness). In lieu of inputting performance, one can adjust the flash pressure or the heat rejection system parameters to produce a desired level of output.

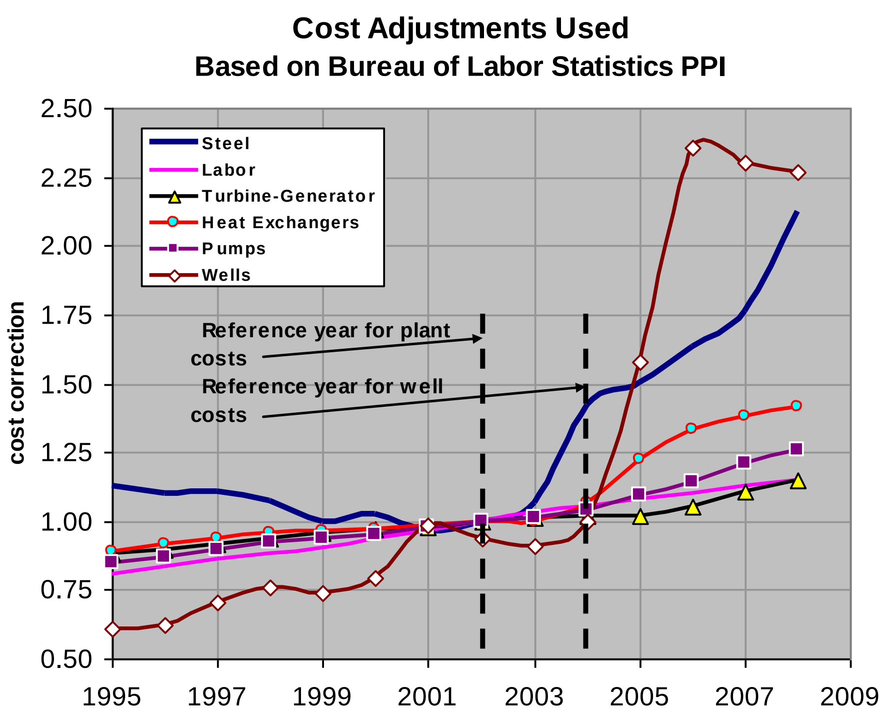
GETEM's calculation of the parasitics associated with the heat rejection system are based upon user input for the fan power per million btu/hr of heat rejected and the pump head determined based upon user input. Design information from a limited number of operating steam plants indicate the fan power required is typically from 0.80 to 0.84 hp per million btu/hr.

The calculation of the power required for the non-condensable gas removal system is based upon the level of gases (user defined) and the type of removal system selected.

The determination of the flash plant equipment costs is based upon the estimated sizes of the pumps, compressors turbine, total heat rejected, the condenser size and type, and an estimated size of the flash vessels. As with the binary plant, a installation multiplier is applied to the equipment cost to get the total direct installed cost of the flash plant. GETEM calculated this multiplier, or the user can opt to input the value. Indirect costs are calculated in the same manner for the binary plant.

Capital Cost Adjustments – Producer Price Indices

The power plant equipment costs correlations that were developed were based on cost estimates referenced to 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 effects of 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.

Operating and Maintenance Costs

GETEM has been modified to allow O&M costs to be inputted for both the well field and the power plant (just one can not be inputted – both must be). One can also opt to allow the model to calculate these costs.

The worksheet *2F.O&M Input* was added to facilitate the user's input for O&M costs. Based on the user's input on this work sheet and the calculated plant size, GETEM calculates the labor hours and costs on *4B. Binary O&M* and *5B.Flash-Steam O&*". If the labor rates provided by the user on *2F.O&M Input* digger from the year for which the calculations are being made, GETEM can use the labor price index to adjust those rates in its calculations (the user must indicate whether the price index is to be used). GETEM allocates the total labor costs to either the field or the power plant based the user's defined portion of the operator costs that is assigned to the field (<100%). Note GETEM assigns all of the labor costs for the maintenance, facility management, engineering and clerical to the power plant – only operator labor is assigned to the field. The labor cost used in the model's cost of power calculations is dependent upon the type of conversion system selected.

While GETEM allows one to change the labor rates and the labor cost distribution for the improved scenario, these are not expected to occur as the result of any advancement in technology. The impact of technology improvements on the operations cost (labor) is expected to occur as a consequence of plant automation or some scheme for reducing the labor portion of maintenance costs. This effect is reflected in GETEM by a multiplier that is applied to the calculated number of O&M staff for the reference scenario.

As noted GETEM determines the total staffing requirements based on plant size. In the original version of GETEM staffing was a step function, and as a consequence an improvement scenario could increase operating cost if any associated change in plant output was sufficient to move the model's projection to another level in the step function. This has been changed so that the total staffing requirement is a continuous function based on plant size. The model assumes that operators are needed continuously (24 hr – 365 days). Maintenance, office, engineering, and management staff are estimated based upon a 2,000 hr per year basis. The model also increases staffing levels if modular plants are utilized, i.e., one 30 MW plant requires fewer staff than is needed for the same sized plant comprised of ten 3 MW modular units.

GETEM determines the annual maintenance costs (non-labor) for the well field as a % of the capital cost of the well field. GETEM also has inputs for chemicals used to treat the geothermal fluid to prevent scaling and/or corrosion. The user can also adjust these inputs (with multipliers) for the improved scenario. Costs are calculated on *4B. Binary O&M* and *5B.Flash-Steam O&M*.

The annual power plant maintenance cost (non-labor) is calculated as a % of the plant capital cost. Note that if plant staff is reduced as a technology improvement this % may increase if it is assumed that more of the maintenance activities will be contracted rather than performed with staff personnel.

If the conversion system is a flash plant that utilizes a cooling tower, the user should use a higher % for the power plant maintenance costs to reflect the additional costs associated with the chemicals needed to treat the circulating cooling water and any hydrogen sulfide abatement system(s).

The input for the calculation of the O&M costs for the geothermal pumps are also on *2F.O&M Input*. The calculation of the re-work cost for a pump is somewhat convoluted. The pump cost that GETEM calculates or the user inputs is the installed pump cost. This cost includes pump, driver (motor), production casing, pump shaft and bearings (line-shaft), power cable (submersible), bubbler tubing, etc.. When maintenance is done on the production pump, with the exception of the production casing, everything that goes in the well is subject to replacement.

If one uses GETEM's calculated pump costs, the O&M costs for the production pumps re-work, are based upon the pump and driver costs and the installation cost (exclusive of the production casing). The user is allowed to adjust the GETEM's calculated pump cost to better reflect the user's scenario for a pump re-work (example: pump repaired and same motor used). The adjustment multiplier should be 1 or less if GETEM is used to calculate pump cost. In addition to the pump re-work cost, there is a cost associated with removing the pump and installing a new pump. For GETEM uses either the user's input for this cost or the value used in GETEM's calculation of the installation cost. GETEM then doubles either is calculated cost or the inputted cost to get the total non-pump cost associated with the re-work (cost is double because the pump is both removed and then installed).

If the user inputs the installed pump cost, GETEM subtracts the installation cost it calculates (with the production casing) from the inputted pump cost to determine the re-work pump cost. The user can then adjust this cost to get the re-work pump cost that is desired. The remainder of the determination of the cost to replace the production pump is the same as if GETEM is used to calculate the installed pump cost. Note that under certain conditions (deep pump setting depths), GETEM's calculated installation costs may exceed inputted cost if the user provides installed costs typical of shallow hydrothermal resources. This would result in a negative pump rework cost. GETEM notifies the user when the re-work pump cost falls below 50% of the installed pump cost.

The annual O&M cost associated with the pump replacement/repair is the total rework cost divided by the operating life. (GETEM does not discount the total cost over the pump life.) When a line shaft pump is used, the user also needs to provide the input used to calculate the cost of the oil used to lubricate the shaft bearings. This is a water-soluble oil that is pumped from the surface to the shaft bearings. The user provides the dosage rate in ppm and a cost in $ per gallon.