

GETEM -Geothermal Electricity Technology Evaluation Model

General Information:

GETEM has been developed as an Excel spreadsheet. It is recommended that a User save a 'clean' version of the model upon receipt. The most current version of the model is '**Beta Version of GETEM 2012-08-29.xlsm**'. This version of the model was developed in the Office 2007 Excel. Attempts to get the model to run in an earlier version of Excel (Office 2003) have not been successful because the model now utilizes some functions that were not available in the earlier versions of Excel.

Appendix 1 has some general instructions regarding getting the macros to work. If the macros are not enabled, or do not function, the model can still be used – the User will have to manually change inputs or variables to determine the cost of electricity.

Several of the worksheets are password protected. That is done primarily for the User's benefit, but also to maintain some control over the content of the model.

This document is intended to provide some basic information specific to the input to the current model configuration. Although the model has changed significantly for the earliest versions, the manuals that were written for those early versions are still relevant. It is suggested/recommended that a User peruse those manuals (they can be downloaded from the DOE Geothermal Technologies Program web site) to gain some insight as to why the model was developed and some basics as to how it works.

Background:

GETEM was originally developed for the Department of Energy's Geothermal Technologies Program (GTP) to provide both a method for quantifying the power generation cost from geothermal energy, and a means of assessing how technology advances might impact those generation costs. Generation cost is determined as the Levelized-Cost-of-Electricity (LCOE). The model is intended to provide representative estimates of cost and performance for geothermal produced from scenarios defined by a User, and not as a tool for assessing specific projects or sites. In its current form it is amenable to a project specific evaluation; however its intended purpose remains the more generic assessment of geothermal power production.

Updated Version of GETEM:

The DOE is currently reviewing and updating the methods used by GETEM to calculate both capital costs and the LCOE. The August 2012 beta version of the model contains some of the revisions that have been made; others are either in progress or will be done in the near future. Currently the model's methods of predicting well costs are under review, and a review of the power plant cost estimates is planned.

The August 2012 version of the model includes changes to how the model determines the LCOE. Previous version of the model used a Fixed Charge Rate that was applied to the project capital costs to determine the annual revenues needed for those costs associated with capital. The FCR method has been retained, and an alternative method integrated into the model that uses an approach being developed within the DOE Energy Efficiency and Renewable Energy

(EERE) programs. This EERE Approach replicates a discounted cash flow sheet. This alternative methodology is currently being used by the DOE GTP. Again, a User has the option of using either method. The model also contains a Discounted Cash Flow sheet (**DCF**) that can also be used to determine the LCOE. The discounted cash flow requires the User utilize macros to determine the LCOE, and the resulting value is not reported in the results. This method was integrated into the model primarily as a check during the integration of the EERE approach, and has been retained.

Incorporating the EERE approach into GETEM allows:

- The project life to be varied (it is fixed at 30 years with the FCR method)
- Varying discount rates (costs of money) to be applied to each phase of the project
- The durations of each project phase to be changed.

The model's depiction of the Exploration and Confirmation phases has also changed. The changes allow for both exploration and confirmation work to be done at multiple sites, which is believed to better depict what actually occurs, ie. developers must consider and explore multiple locations in developing a successful site.

The model has also been modified so that costs associated with permitting, leasing and taxes/insurance are identified separately. The User must provide sufficient input to determine those costs.

General Layout:

The main interface with the model remains via the **INPUT** sheet where the a User defines the scenario to be evaluated. The model input is generally arranged by the phases of a geothermal project. The layout on the **INPUT** sheet is summarized here:

- Economic Parameters
- Exploration
- Confirmation
- Well Field Development
- Reservoir Definitions
- Operation and Maintenance
- Power Plant

The model output is now provided primarily on the **SUMMARY** sheet, which has the same layout as the **INPUT** sheet. Information on both sheets is 'grouped' so that it can be expanded or collapsed as the User desires.

At the top of the **INPUT** and **SUMMARY** sheets is a block of cells that identify the scenario being evaluated, and display both the LCOE and the power sales; these values update as the input is changed. Input and output are for both a Reference Scenario and an Improved Scenario. The User defines the Reference Scenario and then inputs a multiplier that is applied to a particular input parameter to represent a technology change for the Improved Scenario. For instance if the cost to drill a production well was \$1,000,000 for the Reference Scenario and one wanted to see what the impact on LCOE from reducing that cost by 20%, one would input a multiplier of

0.8 in the appropriate cell, and the effect of having \$800,000 production wells on the LCOE would be displayed at the top of the **INPUT** sheet, as well as on the **SUMMARY** sheet.

Again results are summarized in the **SUMMARY** sheet. If the FCR method is used to calculate the LCOE, they may be found the **Binary Output** and **Flash Output** sheets as well (both of these sheets are typically hidden). If the EERE Approach is used to determine the LCOE, the **EERE COE** sheet will also have a summary of the different contributors to the LCOE, as well as their capital costs.

Note that one cannot evaluate both a binary and flash conversion system simultaneously and view the results on these Output sheets; the model cannot perform concurrent calculations for both conversion systems. Nor does the model allow for the simultaneous assessment of both hydrothermal and EGS resources.

The model includes an **Error-Warnings** sheet that summarizes potential issues associated with the input provided by the User. A count of the number of Errors and Warning Messages is given at the top of the **SUMMARY** and **INPUT** sheets. If one goes to the **Error-Warnings** sheet, a message will be displayed for any current error/warnings and a link provided to that section of the **Input** sheet containing the input in question. The User should check and confirm that there is not an error associated with the input before proceeding.

In addition to these sheets, 6 others will typically be present. The **GETEM – Read Me** sheet contains general information about the model. The **Tables** has the Producer Price Indices that are used by the model. One can update these as desired; this sheet is protected, but not password protected. Note that the power plant cost estimates are based on 2002 \$ and updated to the year defined by the User, while the well costs estimates are based on 2004 \$. The **Binary A1** sheet has the macro that can be run to solve for the binary plant performance that minimizes the LCOE. It must be displayed (“Unhide”) if one elects to use this option. The **EERE COE** work sheet is used to calculate the LCOE when the EERE methodology is used; the **DCF** sheet performs a similar calculation of the LCOE using the same User input as the EERE approach. The model includes the **Suggested Input** sheet which has suggested User inputs for two hydrothermal scenarios (binary and flash) and one EGS scenario (binary). Again, these are suggested inputs.

The remaining sheets are typically hidden. These sheets are where the calculations are made or have data used in those calculations. The User can opt to “Unhide” if desired by right clicking with mouse on any of the worksheets in the model.

The following is a format that was used when developing the model. We have attempted to maintain this format, though Users may find this not to always be the case.

- Cells with **Yellow** background are cells where the User provides input.
- Cells with **Red** font are imported values from other worksheets within the file
- “note” adjacent to an input cell indicates there is a comment having information relevant to that input cell The comment can be seen by clicking on the cell containing “note”.

For certain inputs, the User must select from a drop down list. This list must be used in order for the model to decide how to proceed with the calculations. In some instances all the options in the drop down list will be the same – this is because the option does not apply for either the resource or conversion system being used. To the left of some input cells there is a drop down list for the units in which the input is being provided. The choice of units is limited to facilitate the units conversion to those used in the model calculations (Imperial).

Methodology:

Estimates are based upon the scenario the User defines by providing input for the each of the project phases. A User can define scenarios for either Hydrothermal or EGS resources, and for either air-cooled binary or flash-steam conversion systems. Calculations will be based upon either a targeted Power Sales or a fixed number of production wells (the User defines this in the Power Plant input section on the **INPUT** sheet).

In characterizing the resource, its temperature and depth are defined.

It is assumed that exploration is done in phases. In the initial phase of exploration, multiple locations may be evaluated and considered for drilling. The User defines the costs for each site considered, as well as the number of sites. The User also establishes whether exploration drilling will occur, and if so at how many of the locations considered during the pre-drilling activities. The User defines the number of wells drilled at each site, and provides information relative to the type of drilling and the drilling cost. Permitting and leasing costs are also defined by the User.

For the Confirmation phase, the User specifies the number of sites where confirmation drilling occurs. These are assumed to be full-diameter wells. Allowance is made for having to do drilling of full-sized wells at more than one site in a successful project. The User defines the number of 'dry' or unsuccessful wells drilled at those sites other than the 'successful' site. For the 'successful' site the User defines the drilling success rate and the number of successful wells needed before moving to the final well field development phase of the project. Successful confirmation wells are always assumed to be production wells that support the plant operation, even though for EGS, one or more of the wells may ultimately be injection wells. It is assumed that the wells drilled during the confirmation phase will be more expensive than those drilled during the final phase of developing the well field. The model estimates drilling costs during that final phase; the User defines a multiplier (> 1) to establish the confirmation well drilling cost. When an EGS resource is evaluated, the successful confirmation wells should be stimulated – the User provides that cost.

In characterizing the Well Field Development phase, the User must define how the well drilling costs are to be determined for both the production and injection well, as well as the number of injection wells and whether any dry holes or spare wells are drilled. The model calculates the cost of the surface equipment (piping, valves, vessels, etc.) for each well, or the User can provide that cost.

The costs to stimulate a well are identified by the User. The User also defines the flow rate per well, the hydraulic drawdown, and the thermal drawdown. The flow rate per well, well diameters, well depth and hydraulic drawdown are used to establish the geothermal pumping

power required per unit mass flow of geothermal fluid. These calculations include friction losses for the fluid flow in both the production and injection wells.

The power plant performance metric used is the brine effectiveness, or specific output. This is the net power produced from the plant per unit mass flow rate (net power is exclusive of geothermal pumping, but includes losses associated with fan and pumping power within the plant conversion system). Once the User establishes the conversion system type and provides the input necessary to define this metric, the project size and cost are determined.

If the scenario being evaluated is based on a specific Power Sales, the amount of flow required to produce these sales is

The number of production wells required is the total flow required divided by the flow rate per well; the number of injection wells is the required number of production wells multiplied by the ratio of injection to production wells (User defined). The Well Field Development phase costs are determined using the well count and the costs per well for drilling and the surface equipment. The well count is the number of injection wells required and the number of production wells drilled during this phase (the number of production wells required less the successful confirmation and full-sized exploration wells), as well as any spare wells and dry holes identified by the User. The surface equipment costs are based on the total number of production and injection wells required, plus any spare wells identified by the User – dry holes have no surface equipment costs.

The power plant size needed to support this level of sales is the product of the total flow rate and the plant brine effectiveness, or the sum of the power sales and the geothermal pumping power. The plant cost is determined based upon this size, the plant design temperature and the plant brine effectiveness. If there is any geothermal pumping power, the plant size is larger than the targeted power sales.

Operating labor costs are estimated based upon the type of conversion system being used and the plant size. Maintenance costs are estimated as a % of the capital costs for the plant and the well field. Pump maintenance costs are based upon the type of production pump being used (User defined), the defined pump life, and the pump cost (calculated or defined). Taxes and insurance are also included in the O&M costs. They are determined as a % of the capital costs for the project (User defines the % rate). Royalties are also included in the O&M summation. The User defines the Royalty rate – the suggested values for Royalties are the rates imposed by the BLM.

The thermal drawdown for the resource is defined by the User. This represents a decline in the resource productivity with time. For hydrothermal resources, in particular those used with air-cooled binary plants, the expectation is that the resource temperature will decline at rate of 1% per year, or less. A flash plant that does not have production pumps would likely see this resource decline as a decreasing wellhead pressure – this effect is captured with the temperature decline rate. It is postulated that the temperature will decline more rapidly in an EGS resource. At some point the power produced by the plant may decrease to a level where it

is not feasible to continue operation. If this occurs, the model triggers the replacement of the entire well field at a point in the future. The maximum temperature decline allowed is calculated, or the User can opt to input the temperature decline allowed before reservoir replacement. Again, when then the temperature drops below the minimum allowed, the model replaces the entire well field – it does not drill one or two additional wells, but all the wells. This is done to simplify the model’s determination of the effect of the temperature decline on power output. The number of times that the well field and reservoir can be replaced is based upon the power plant size and the resource potential that is found by the exploration activities. If 100 MW of potential is found and the plant size is 40 MW, the field and reservoir can be replaced once. If the final well field and reservoir replacement occurs before the end of the defined project life, the resource temperature and plant output continue to decline. No well field and reservoir replacement is allowed during the last 5 years of the project life.

The annual power production is based upon the power sales, which includes the effect of the declining resource temperature and the utilization factor defined by the User. The utilization factor is the ratio of the kW-hrs that is produced annual to that produced if the plant had operated continuously throughout the year at its design output. The utilization factor accounts for the output lost during outages, as well as the impact of the ambient air temperature on the plant output at the geothermal conditions used for the plant design. DOE typically uses a value of 95% for this factor; there is discussion of this factor and the value used in the original GETEM manuals. The inputted value is indicative of the impact of the ambient on output at the design geothermal condition, as well as maintenance activities. In order to account for the impact of the resource temperature decline, the power sales are predicted at one month intervals at the resource temperature that is determined for each period based on the temperature decline. Sales at each time interval is determined using the available energy (for binary plants the sink temperature is 10°C), the 2nd law conversion efficiency, the geothermal flow rate and the geothermal pumping power. If the decline reaches the maximum allowed, the well field is replaced and the geothermal fluid temperature returns to the original value, as do the power sales. The calculated sales are discounted at a User defined rate over the defined project life when determining the LCOE.

With the FRC method, the discounted sales are summed over the project life, along with the discounted sales from a plant operating at the design output for the same period. The ratio of these two totals (predicted to design) is then applied to the inputted Utilization Factor to correct it to reflect the effect of the declining resource temperature. This corrected factor is referred to as the ‘Levelized Utilization Factor’. It is used with the design Power Sales to calculate the levelized total power sales for a year; that value is used in calculating the LCOE.

In previous versions of the model, the User could define the geothermal temperature used for the plant design with EGS resources. That option has been removed; the plant design temperature is the calculated wellhead temperature. This temperature is the difference between the resource temperature and the calculated temperature drop of the fluid flowing up the well. The calculation of the temperature drop is based upon an approach defined by Ramey (1962), where it is assumed that the well has flowed sufficiently long that the temperature losses in the well have reached a quasi-steady state condition.

Once the input has been provided for the Exploration, Confirmation, Well Field Development, Reservoir Definition, and Operation & Maintenance activities, the User has the option of allowing the model to determine the level of binary plant performance that minimizes the LCOE. If the model performs this optimization, a trade-off is made between the cost of the plant (which varies directly with plant performance) and the cost of the well field and reservoir (which vary indirectly with the plant performance). For each defined scenario, there is a level of plant performance that produces this minimum generation cost. If this option is not used, the User must provide the plant performance as an inputted brine effectiveness. The determination of binary plant cost is based this performance metric. Neither performance nor cost is specific to a particular working fluid. The plant cost is based on the net plant power (turbine generator output less in-plant parasitic), which is the sum of the power sales and any geothermal pumping power. The turbine-generator cost is based on the estimated gross generator output (net plant output plus estimated in-plant parasitic power). As with the binary plant performance, a User has the option to use the calculated plant cost, or to input another value.

For flash-steam conversion systems, the model estimates the optimal flash pressures based upon the resource temperature and the number of flash pressures identified (1 or 2). Note that this estimate approximates the conditions that produce the maximum power – the User may be able to achieve lower LCOE varying the flash pressures slightly from the values the model calculates. The model can be run with no geothermal pumping; doing so allows flashing to occur in the well. This option is intended to be used with the flash steam plants and not the binary plant. The model estimates the well head pressure, and if it is less than the estimate of the optimal 1st stage flash pressure, the model defaults to well head pressure for the 1st stage flash. The model's estimate for the 2nd stage (low pressure) flash pressure defaults to a value 1 psi above atmospheric pressure if the calculation of the optimal value is less than one atmosphere. If the User inputs a flash pressure that is outside of this range (1 atmosphere and the well head pressure), an Error-Warning message will be displayed.

Costs for the flash plant are made in a similar manner as for the binary plants. These costs are estimated based upon the plant size, the flash pressures, and User defined values for the levels of non-condensable gases (ncg's) and hydrogen sulfide, as well as the type of condenser, cooling water temperature range, wet bulb temperature, and type of ncg removal system. The User has the option of using the calculated flash plant cost or providing that cost.

The model's projection of binary plant performance is based upon the premise that there is a minimum temperature limit placed on the geothermal fluid leaving the power plant. This limit is based upon the solubility of amorphous silica. This limit can be placed on the flash plant – if so, it does account the increased concentration of silica in the unflashed geothermal fluid. The estimate of the 2nd stage flash pressure will default to a value that prevents silica precipitation if the calculated optimal pressure would be less. If not placed on the flash plant, it is assumed that the User will account for the added chemical cost to prevent scaling from the geothermal fluid.

Limitations:

- Except as described here, the model does not have input default values.

- The Producer Price Indices are from the Bureau of Labor Statistics and should be updated by the User to provide estimates outside of those years currently in the model (1995-2011).
- Binary power plants are air-cooled. Flash plants use evaporative heat rejection systems where condensed steam is used for makeup water; with EGS resources this water loss is included in the calculation of the makeup water cost.
- Though in reality successful confirmation and full-sized exploration wells could be utilized as injection wells, in the model they are always assumed to support fluid production for the power plant and decrease the number of production wells that must be drilled during the Well Field Development phase. Injection wells are always assumed to be drilled in the final phase of the well field development.
- The model does not allow for the use of small-diameter exploration wells for either production or injection.
- In calculating the casing configuration in the well, the model assumes the conductor casing at the surface cannot exceed a diameter of 48-inch. It also assumes that the minimum diameter for the upper casing interval in a production well is 13-3/8 inch; this constraint is imposed to assure sufficient clearance for a production pump. The constraint is imposed in all production wells, even if not pumped. The model also assumes the upper casing diameter cannot exceed 16 inches for both production and injection wells. These constraints are imposed regardless of the method used to determine the well costs, i.e., they are always in effect when determining the geothermal pumping power.
- The binary power plant performance and cost are based upon modeling results for geothermal temperatures between 75° and 200°C. The model will predict outside of those temperatures, however the User should be aware that those temperatures represent scenarios that are beyond the model's capabilities.
- Binary plant performance is based on a design ambient air temperature of 10°C, or 50°F. This approximates the average annual air temperature in the US.
- The costs for the binary plants are based on sizes that are 3 MW and larger. Smaller plants are outside the range of the cost data used in developing the model's cost correlations.
- The binary plants for which cost and performance correlations were derived have single vaporizer pressures, i.e., dual boiling cycles were not evaluated. These plants were however allowed to operate at supercritical pressures with a wide range of heat exchanger pinch points. It is believed that it is unlikely that dual-boiling plants would provide significantly lower costs than those estimated at equivalent levels of performance.
- For binary plants, both cost and performance correlations were developed with a temperature constraint imposed of the geothermal fluid leaving the plant to prevent silica precipitation. The removal of this constraint is not an option for binary plants as it is for flash-steam conversion systems.
- Previous version of the model included an option to change the tube material (and cost) in the geothermal heat exchangers. This option became inactive when the method of applying

the PPI's was modified. The model now defaults to always using carbon steel tubes in the geothermal heat exchangers.

- The scaling of turbine costs (\$/kW) with size has the largest impact of any of the plant equipment on the variation in binary plant costs (\$/kW) with size. The cost correlations have an inherent assumption that the maximum size for a binary turbine is 15,000 hp. Once the turbine for the plant reaches this size, the turbine cost (\$/kW) is constant. Plant costs continue to decrease with increasing size, however the rate at which costs decrease is diminished.
- The water properties that are used in the calculations are based upon curve fits of those for saturated water. These curve fits were developed using water properties to provide estimates that were within 0.1% of those predicted using NIST properties for temperatures up to 500°F (260°C). The effect of salinity on the water properties is not included in these calculations. The correlations used continue to provide reasonable approximations of water properties at temperatures up to ~575°F (300°C). It is recommended that GETEM not be used to evaluate flash plants at higher temperatures. In evaluating those scenarios, the User should provide input for both plant performance and cost.
- When the resource temperature declines to the maximum value specified, the entire well field is replaced and that cost incurred. The model does not allow for drilling one or two wells to offset the temperature decline either by increasing temperature or flow produced to the power plant.
- The model predicts the effect of a varying resource temperature on power output after a plant has been installed. As the resource temperature deviates from the plant design temperature there is increasing uncertainty in the levels of power predicted. The calculation of plant output with the varying resource temperatures always assumes that the total fluid flow to the plant is constant.
- When using the FCR methodology for the LCOE
 - Project life is 30 years.
 - The model is unable to use the staggered BLM royalty rates; instead it uses an effective rate of ~2.9% over the project life.
 - The LCOE is based upon annual levelized costs for the well field makeup costs. These annual costs for the well field makeup are effectively spread over the entire project.
- Inflation is not included in the determination of the LCOE.
- The model's determination of drilling costs during the exploration and confirmation phases at sites or locations other than the site that is successfully developed are based on the drilling costs at the successful site.

Modifications to the Model:

Originally the model considered only hydrothermal resources. It has subsequently gone through several revisions. In these revisions, the emphasis has been primarily for the air-cooled binary conversion system. The modifications include the following:

- Inclusion of EGS (Enhanced Geothermal Systems). To accommodate EGS, the model
 - Requires the User to provide input defining the well stimulation costs
 - Predicts production pumping power using the bottom-hole pressure in the injection well rather than hydrostatic pressure.
 - Allows the production fluid temperature to be estimated using the Carslaw-Jaeger solution for conduction from a semi-infinite solid. This solution requires the User define a fracture system. This method is not currently being used by DOE to assess the effect of EGS temperature decline.
- Costs estimates are adjusted using the Department of Labor’s Bureau of Labor Statistics Producer Price Indices (PPI) for equipment, labor, and well drilling. The PPI’s allow costs from varied sources to be incorporated and adjusted to the year that is of interest to the User.
- Provision to use both SI and Imperial units for input (the model calculations are done primarily in Imperial units).
- The effect of the production fluid temperature decline on plant power output is estimated.
- A maximum allowable temperature decline was integrated into the model that triggers the replacement of the geothermal well field if exceeded. This decline rate was derived from the end-of-operation temperatures in EPRI’s *Next Generation Geothermal Power Plant* report (see original GETEM manuals). The values used represent a decline of ~10% in the Carnot efficiency at the well field replacement.
- The effect of having to replace the well field at a future date is included in the LCOE.
- Production pump setting depths are calculated as a function of well flow rate, casing sizes, well depth, resource temperature and hydraulic drawdown. This change was made to better assess the benefits of improvements in production pump technologies and in well stimulation to increase reservoir permeability and reduce hydraulic drawdown.
- Injection pumping power is calculated using the same parameters. This change was made in order to more accurately reflect the impact of changing the number of injection wells relative to the number in production wells.
- Binary power plant costs are determined as a function of the plant performance, as well as resource temperature and plant size.
- The prediction of the staffing for the operation and maintenance of the plant and field was changed from a step function with size to a continuous function of plant size. This was done to eliminate the increases in the LCOE that occurred when the plant size changed slightly and produced a step change in the plant staff size.
- An estimate of the temperature drop in the production well was included that is based on a technique described by Ramey (1962). This temperature drop is a function of the bottom-hole temperature in the well, the well depth, the earth temperature gradient, properties of the earth surrounding the well, well casing/liner size, cement thickness, the well flow rate, and time. The model assumes that the temperature loss in the well reaches a quasi-steady

state level after one year. This provision was included to better characterize the temperatures produced from deep wells having lower flow rates.

- An estimate of transmission line cost is provided. This cost is based on the line voltage, distance, population setting and terrain.
- A suite of exploration methods/tools was added to the model. Once a User opts to utilize a method listed, the User then decides whether to use the model's default cost for the selected methodology. Note that DOE is not currently using this option in its evaluation of the LCOE. The costs and definition of the suite of exploration tools is currently being validated. The intent of this ongoing effort is to provide DOE and a User with more clarity as to what tools are most likely to be used.
- An alternative method for determining well drilling costs has been added to the model. This was done to allow the effect of using different hole sizes for the injection and production wells to be evaluated. Of specific interest is whether the additional cost associated with a larger injection wells is offset by the potential to drill fewer injection wells and/or reduced injection pumping requirements. It may also allow DOE to examine the effect of technology improvements (for example, bit life and rates of penetration) if it can be shown to provide representative well drilling costs. This has yet to be confirmed. How the model determines well costs is currently under review to see if it can be improved.
- An option was included to allow the successful exploration well to provide fluid to the power plant. This requires all exploration wells to be production well sized. This well is treated as a successful confirmation well in the model's determination of cost associated with the Confirmation and Well Field Development phases.
- The approach of calculating LCOE that is being considered by EERE for all renewable programs has been integrated into the model. This approach effectively replicates a discounted cash flow sheet. A discounted cash flow sheet was incorporated into the model as part of this effort, and though its calculation of LCOE is not included in the summary of results, it has been retained and can be used.
- As part of the effort to incorporate the EERE approach for determining the LCOE, the model uses defined (User) discount rates and durations for each of the pre-operational project activities. This allows one to assess the impact of higher costs for money and/or prolonged effort for each project phase.
- The characterization of the initial costs for a project were improved by allowing the User to identify the number of sites where pre-drilling exploration work occurs, as well as the number of locations where exploration drilling occurs. The prior version of the model did allow for the inclusion of failed exploration projects; the updated approach should provide better clarity of the costs associated with these 'unsuccessful' locations.
- The model has been modified to provide for a project life of other than 30 years. Costs for permitting, leasing, and taxes/insurance have also been made User inputs.

Model Input:

The User defines the scenario to be evaluated. Again there are currently no default values in the model so the User must go through the input to assure that the values in the model represent the scenario being evaluated. As indicated, provide input in those cells with **Yellow** backgrounds. The User is advised not to make changes outside of the highlighted cells.

The input is 'grouped' both by the phase of the project (i.e., Exploration, Well Field Development, O&M, ...), as well as by activities during the phase (i.e., drilling activities and non-drilling activities during Exploration). The grouping allows the input sections to be expanded and collapsed. This grouping allows the User to 'skip' those sections that are not relevant to the scenario being defined. For example, if one opts to use a flash-steam conversion system, there is no reason to expand the binary plant input as none of that input is used in the model's calculations. Generally conditional formatting is used to 'white out' those sections of input that are not relevant based on the User's input. The model uses drop down lists for input in deciding how calculations will be made; this input is also the basis for most of the conditional formatting.

The **SUMMARY** sheet has project phase grouping similar to those on the **INPUT** sheet. The **SUMMARY** sheet summarizes both the input and results for the project phases. Once the input has been provided to define a specific scenario, one can review results on the **SUMMARY** sheet and return to the appropriate section on the **INPUT** sheet to adjust as necessary; frequently the results for one phase are dependent upon the input in another section (phase). For instance, the production pump setting depth that is calculated is a function of the well depth and fluid temperature, the hydraulic drawdown in the reservoir, and the well diameter(s).

Information is provided for some of the input via comments located adjacent to those cells. The comments are revealed when the cursor is placed on the cell containing the word "note".

The **Suggested Input** sheet has suggested values for input for both Hydrothermal and EGS scenarios. These are suggested values; if the User has information/data that is specific to the scenario being evaluated, that information/data should be used

The following provides a more detailed description of the model input for each section of the **INPUT** sheet.

Economic Parameters - These are parameters used in the calculation of the LCOE. Input includes:

- General Parameters:
 - Year of Estimate – determines the PPI's that are applied to capital costs. The model has PPI's from 1995 to 2011
 - Utilization factor – the ratio of kW-hrs produced annually to the kW-hrs that would have been produced if the plant operated 24 hrs/day for the entire year. This utilization factor is for performance at the design plant temperature – it includes the effect of varying ambient temperatures, but not the decline in resource temperature.
 - Contingency – applied to all calculated capital costs; it is indicative of project risk and uncertainty

- Royalty – BLM rate is 1.75% for 1st 10 years and 3.5% thereafter.
- Discount rate – this is the rate used to discount the future power production and future costs. The DOE currently uses a discount rate of 7%.
- Fixed Charge Rate –this value is multiplied by the project capital costs to determine the annual cost of capitalized equipment and services. It includes rate of return to equity and interest on debt, income taxes, property taxes, and insurance. The value used in the original model was 0.128; this value was used in the EIA NEMS runs for the Annual Energy Outlook 2005 report. The value currently being used in the EIA NEMS runs is 0.108. The original GETEM manuals include a discussion of this factor and what it includes.
- Project Duration: Input in this section is used for determining the LCOE using the EERE approach (and the discounted cash flow analysis). The User provides time durations for different project phases. It is assumed that confirmation follows immediately after exploration, and that the well field development (including stimulation) and power plant construction proceed concurrently once the confirmation phase is completed. If the time interval for the well field development is less than that for the plant construction, the model assumes both start at the same time, and the well field development is completed first. Time is also defined for the permitting activities. Confirmation and exploration permitting are assumed to be done at the same time, with a permit required for each site. Similarly the Utilization Permit is assumed to cover both well field completion and plant construction, and is obtained prior to starting work on either.
- Pre-Operation Discount Rates: These values are used in the determination of the LCOE using the EERE approach.
- Depreciation Schedule: A 5 year MACRS depreciation schedule is used with the EERE approach (consistent with other EERE programs).

Resource Definition- In this input section the type of resource is defined, along with the resource temperature and depth.

Exploration - Input for the exploration phase includes definition of the general parameters for the activity, the costs not associated with drilling, and the information needed to both determine the number of wells drilled and their cost.

The User is asked to define the initial resource status; this input is used in assessing the logic for the subsequent input - it does not directly impact cost. The User also defines the potential resource found by the exploration activities; this is an important input for evaluating scenarios with more rapid thermal drawdown as it determines the number of times a well field can be replaced. This value can also be used to proportion the exploration costs, i.e., spread those costs over several projects that might occur to fully develop the potential found. This option is not used by the DOE, and it is recommended that it not be used for any scenario having more rapid thermal drawdown for the resource.

- Pre-Drilling Costs: The User may define a project where a number of sites are evaluated before any drilling occurs (this is considered a probable scenario). Costs are defined for

each site evaluated. The costs for the pre-drilling costs can be defined by activity or as a lump sum value; separate costs are to be provided for permitting.

- Exploration Drilling Costs:
 - If exploration wells are drilled, the User must define either the number of locations where drilling occurs, and the number of wells drilled at each location. If the User indicates no wells are drilled for a Greenfield project, a warning will be displayed
 - A User defines the type of well drilled – slim hole, core hole or production sized; combinations of well types can not be used. If small diameter wells and full-sized wells are to be drilled, the full sized wells must be included as confirmation well drilling, and not exploration wells.
 - A User defined multiplier is applied to the calculated well cost for the defined depth. This multiplier allows for drilling small diameter, non-production sized wells. It is recommended that a multiplier of 0.6 (or larger) be used for slim hole wells; if wells are production sized, multiplier should be >1. Exploration well costs are based on the model's determination of a production well cost.
 - The model assumes all exploration wells are drilled to resource depth. If shallow wells to be evaluated, those costs can be reflected by using lower values for the exploration well cost multiplier.
 - If the wells are production sized, the model assumes that one successful well drilled at the successful site will support plant power production. If the wells are small-diameter, they will not be used to supply fluid to the plant (or for injection).

Confirmation –The model allows for confirmation drilling at multiple sites. All wells drilled during this phase are assumed to have the same construction as production wells. Successful confirmation wells are subsequently used to support power plant operation.

- Confirmation Well Drilling Costs
 - The number of wells drilled at unsuccessful sites are defined; this allows those drilling costs to be included in the LCOE calculation.
 - Success rate represents the fraction of confirmation wells drilled that can subsequently be used to provide production to the power plant.
 - The number of confirmation wells that are drilled is defined by the User, or is based on the % of the fluid production capacity that must be confirmed during this phase of the project. If a production capacity of 50% is required, then sufficient successful confirmation wells must be drilled to provide 50% of the geothermal fluid flow required by the plant. The production capacity per well is based on the plant performance, geothermal fluid pumping power and the flow rate per well. Note that if exploration wells are full sized wells, the count of successful confirmation wells needed to confirm production capacity is reduced by 1.
 - Confirmation well cost is based upon the calculated production well cost and a multiplier defined by the User. This multiplier should always be >1, reflecting the

higher drilling cost during the initial stages of a project, i.e., there is a learning curve associated with drilling for at the successful site.

- Confirmation – Non-drilling Costs
 - Confirmation costs not associated with drilling are either inputted as a lump sum or calculated as a % of the total confirmation costs.
 - If an EGS project, the ‘successful’ confirmation wells should be stimulated. The User provides the cost per well for the stimulation. The count of successful confirmation wells stimulated includes the successful exploration well, if it is a full-sized well.
 - Well testing is based on the number of sites where confirmation drilling occurs, and a testing cost per site.

Well Field Development – In this phase, the User provides input necessary to define costs per well, surface equipment costs and establish the number of injection wells. The drilling success rate that is defined determines the number of wells drilled in this phase that are ‘dry’. If the project is evaluated based upon the number of production wells, the model assumes this is the number of wells required, and adds the ‘dry’ wells and the number of defined spare wells to determine the total number of production wells drilled. If the project is based upon power sales, the number of production wells required is determined by the flow per well, the plant performance, geothermal pumping power and the desired power sales.

- Well Field Details
 - Unsuccessful or ‘dry’ wells cannot be used for either production or injection.
 - Spare wells are drilled as part of the initial well field development to provide reserve flow capacity in the future. Because the model is not able to include the effect of using the spare wells at a later date to off-set the decline in power production due to thermal drawdown, it is recommended that a User not include any spare wells unless some adjustment is made to the thermal drawdown used in evaluating the project.
 - The ratio of the injection well to production well depths allows for drilling injection and production wells to different depths.
 - The ratio of injection to production wells defines how many injection wells are required. The number of injection wells is based upon the total number of production wells required (which includes successful wells drilled during the confirmation and exploration phases).
- Well Drilling Costs
 - Opt to use either the Cost Curves built into GETEM or a methodology that estimates the drilling cost based on the well configuration and user information relative to bit life, rates of penetration, etc..

- The 3 Cost Curves (Low, Medium, and High) bracket the Sandia National Laboratory drilling data (see GETEM reference manuals). These costs are updated from 2004 using the Producer Price Index for drilling Oil and Gas Wells.
- GETEM's Estimate requires the User define:
 - The configuration at the bottom of both the production and injection well
 - whether the production/injection interval is open hole or perforated/slotted liner
 - the hole diameter or casing OD in the production/injection interval
 - This input is used to establish the well's casing/liner configuration based upon assumptions relative to the cement thickness, casing diameters and commercial bit sizes. The model has two constraints on the maximum casing size – one for the conductor casing and the other for the upper casing interval. If the User input for the bottom hole diameter results in an estimated casing sizes that exceed either maximum value, the User is prompted to use a smaller bottom hole diameter; if the User does not provide a smaller diameter, the model uses a default value that is the maximum diameter that does not produce upper interval diameters that exceed either constraint. The model also always assumes that production wells have upper casing diameters of 13-3/8 inch or larger in order to accommodate a production pump and casing.
 - The method has embedded values for determining time for different drilling activities and costs. The User can adjust those values by changing the multiplier/index for Trouble, Rate of Penetration, Bit Life, Casing Cost, and Cement Cost. These indices are applied to all intervals in the well. The Trouble multiplier/index is applied to the total estimated rig time for each identified activity, and is reflected in the costs for that activity, as wells as the total time to drill the well.
- The User can adjust the well cost estimates produced by either method.
- The User can opt to provide the surface equipment costs as a lump sum value per well, or can allow those costs to be calculated based upon the inputted distance from the well to the plant and the maximum pressure drop allowed. This calculation is based upon the assumption that geothermal fluid is a liquid in the surface piping.
- Other costs during the Well Field Development phase are determined as a % of the total costs for this phase. The User provides that % value.
- The User also provides the cost for the permit for the well field development. It is assumed that this permit will be for both well field development activities and power plant construction.

Reservoir Definition – In this section the User defines the 'performance' of the reservoir. This includes the flow rate for each production well, and information relevant to the hydraulic and thermal drawdown. In this section the User also defines the well stimulation cost and the

subsurface water loss in EGS reservoirs. Hydrothermal resources can be stimulated. For hydrothermal resources the total production and total injection flow rates are equivalent for binary plants; for flash plants, the injection flow is less than the production flow rate because it is assumed that steam condensate is used as makeup for the evaporative losses in the heat rejection system. EGS resources have higher injection flows in order to makeup the subsurface losses (which are defined by the User); for both conversion systems, the total injection flow equals the total production flow plus defined subsurface water losses. Well flow rate and hydraulic drawdown dictate the calculated production pump depth and associated power requirement. The thermal drawdown establishes the production fluid temperature decline with time. The model assumes that there is a maximum limit for this decline, and that once this limit is reached the entire well field is replaced. This maximum decline limit is calculated by the model, or the User can input a value. The number of times that the well field replacement can occur is dependent upon the resource potential established during the exploration phase (a User input). The model estimates the power produced by the plant as the temperature declines.

- The cost to stimulate a well can be inputted or can be calculated. It is strongly recommended that this cost be inputted, as there is minimal information upon which to base a calculated cost. The calculation used is relatively simple – based upon a cost per unit surface area and a defined fracture system. This option is intended to allow a User to perform a trade-off between the stimulation cost and the thermal drawdown. At this time the ‘calculated’ costs are entirely conjecture based on the User’s input.
- Unless the User has information specific to the reservoir (permeability, height, fracture system created, etc.), it is recommended that the User opt to input a Hydraulic drawdown rate rather than use the model’s determination of the drawdown. If the User does not have data that provides a drawdown rate, it is suggested that a rate of 0.2 to 0.6 psi per 1,000 lb/hr be used for Hydrothermal resources. There is little information upon which to recommend a value for EGS reservoirs. Data from wells drilled by DOE in the Basin and Range during the 1970’s had drawdown rates of ~0.8 psi per 1,000 lb/hr. It is postulated that EGS reservoirs will have similar or higher drawdown rates. When using the model’s kA method to estimate drawdown and the User has kH information, use a width of 1 (with units consistent with the kH data).
- It is recommended that the Annual Decline Rate be used to characterize the thermal drawdown; it must be used for Hydrothermal resources.
- If the user opts to calculate the thermal drawdown, the model utilizes the Carslaw-Jaeger solution for transient conduction from a semi-infinite solid. This approach requires the User provide information relative to the number of fractures created, the fracture width and aperture, and the distance between the wells (used as the fracture length). The model has properties for rock that the User can change. Note these rock properties only affect the transient heat conduction solution – they are not used in determining well costs.

- It is postulated that there will be water losses in EGS reservoirs. The model estimates the impact of these losses on the LCOE based upon the User's input of the % of the injected flow that is lost and the unit cost of the makeup water. If the User uses a flash-steam plant with an EGS resource, the model estimates the water required for the evaporative heat rejection and can include that water consumption in this makeup water cost (this is always done for Flash-EGS scenarios regardless of the User input).

Geothermal Pumping – This input section is used to identify how the geothermal pumping power and pump costs are to be determined. Again if the model calculates the pump setting depth, those calculations rely on the input provided for Reservoir Definition (flow and drawdown), Resource Definition (temperature and depth) and Well Field Development (casing configuration).

Note that certain combinations of input to the model may produce a 'Circular Reference'. These circular references are primarily associated with calculating either the pressure in the wells and/or reservoir, or in the temperature drop calculation in the well. If the User's input produces a circular reference that can not be resolved, please contact Greg Mines (Gregory.Mines@inl.gov, or 208-526-0260).

- The User defines whether the wells are pumped. It is recommended that for binary conversion systems, the User use pumped wells. If the model calculation determines no pumping is required, the pump setting depth defaults to 0. If a flash-steam conversion system is used, the model allows flashing to occur in unpumped wells. The model estimates a surface well head pressure, and requires that the 1st flash pressure be lower than this well head pressure. If flashing does occur, a warning/error message displays. If the User opts to not have pumped wells with a binary plant and flashing is calculated, a second warning/error message is displayed.
- If the pump depth is calculated, the User must identify the excess pressure at the pump suction. This value is effectively the NPSH for the pump, and includes the pressure required to keep non-condensable gases in solution. The same excess pressure is required at the production well head, and must be provided by the pump (in this case, the excess pressure accounts for surface pressure losses between well and plant).
- The User also identifies the ID for the production casing and provides a surface roughness for the casing (0.00015 ft is recommended – from Crane Technical Paper 410).
- If the well costs are determined using the Cost Curves, the User must define the bottom hole well diameter and whether the production interval is open hole or has slotted/perforated casing. This information is used to estimate the production well casing configuration used to determine friction losses in the well
- The User inputs the type of production pump used – either Submersible or Lineshaft (there is a limit on the setting depth for 2,000 ft for the Lineshaft pump). This input is used in determining the O&M costs for the pump; it does not have any impact on the calculated pump costs.

- The User decides whether to use the model's calculated production pump cost or to provide that cost. The calculated cost requires that the User define the casing and installation costs for the pump; the model estimates the pump cost based on the calculated horsepower. The User can adjust the calculated cost.
- The injection well pumping power requires the User provide information relative to the binary conversion system and surface piping pressure loss (recommend a value of 30 to 50 psi). This information and the production well head pressure are used to establish the injection well head pressure. If a flash-steam conversion system is used, the model uses the lowest flash pressure as the injection well head pressure.
- If the well costs are determined using the Cost Curves, the User must define the bottom hole injection well diameter and whether the injection interval is open hole or has slotted/perforated casing. This information is used to estimate the injection well casing configuration, which in turn is used to estimate friction losses.
- The model's calculation of the injection pumping power is based upon having a downhole pressure that exceeds the hydrostatic pressure by 1 psi. The model prompts also prompts the User to identify whether the reservoir pressure buildup is to be included in the determination of the injection pumping power. This buildup is analogous to the hydraulic drawdown in the production well; it is strongly recommended that the User input "Yes", in particular with EGS resources or hydrothermal resources where fluid is injected into the same formation from which fluid is produced. When included, the minimum bottom hole pressure required in the injection well is the hydrostatic pressure plus the reservoir buildup pressure plus 1 psi. The model displays the excess pressure at the bottom of the well. If the value is negative, injection pumping is included; if desired, the User can include additional excess pressure, which will further increase the pumping power.
- The model calculates the injection pumping cost based on the injection pressure that must be provided and the injection flow. The user can adjust this cost.

Operation and Maintenance – The model's calculations for Operations and Maintenance (O&M) are based in part upon the experiences of the original developers of GETEM, which suggested that O&M costs for conventional hydrothermal plants (including the well field) were between 1 and 3 ¢ per kW-hr. Based upon those experiences and discussions with plant operators (primarily binary plants) regarding the significant contributions to O&M, a methodology was developed to estimate the O&M costs. Labor is a major contributor to the operations cost; the methodology used defines the O&M staff based on both conversion system type and plant size. Maintenance costs are defined as a % of the capital costs for both the plant and the well field. Costs are also included for maintenance of the geothermal pumps. (The power for these pumps is not considered an operating expense; rather it is subtracted from the net plant output to establish the Power Sales, which is used to determine the LCOE.) The User can adjust (decrease) the plant staffing to reflect the use of increased automation in operating the plant. Operators represent ~50 to 60% of the total plant staff, with the remainder for maintenance, engineering, management and office personnel; operators are assumed to also perform some

maintenance activities. If the User elects to significantly reduce staff, then the % assigned for the maintenance costs should be increased to reflect the higher cost associated with contracting for maintenance in lieu of maintaining staff to perform those activities.

- The User opts to use either the model's calculated O&M costs or provide those costs (¢ per kW-hr) for both the power plant and the well field.
- If the O&M costs are calculated, a fraction of the operator time is assigned to the well field (suggest 25 %). Labor rates are also identified for staff – default values are given, which the User can change. The total predicted staffing level is displayed – the User can adjust this total. The adjustment is applied to all staff categories.
- The annual maintenance costs for the well field and surface equipment (outside of the plant boundary) is determined as a % of the total capital costs.
- The User can also provide input to define costs to treat the geothermal fluid. Binary systems are less likely to have these chemical costs. They are more likely to be incurred with flash plants. It is unknown what they might be for EGS resources.
- The annual maintenance costs for the power plant are determined in a similar manner – as a % of the plant capital cost.
- For flash plants, the User should identify the chemical costs associated with the evaporative heat rejection system. The model estimates the cooling water flow needed and establishes the cost based on a dosage and chemical cost (\$/gallon) (both are User inputs). Note when binary plants are used, these chemical costs default to 0 because air-cooled condensers are assumed.
- The production pump maintenance is based upon the type of pump used. The User must identify the probable pump life: based on prior discussions with operators it is expected that lineshaft pumps will have a longer operating life than submersible pumps. The model calculates the pump cost (the model cost calculation does not differentiate between the pump types) and a cost to remove and install a pump. The User can use these costs or provide costs. When lineshaft pumps are specified, the User also needs to provide input for the cost for the oil used to lubricate the shaft between the pump and the motor (located on the surface).
- Taxes and Insurance are determined as a % of the total capital costs; the User must define these costs. If the User opts to input the O&M costs, it is assumed that taxes and insurance are included in those inputs.

Power Plant – As part of the Power Plant input, the User indicates whether transmission lines will be included in the LCOE determination. If so, then input is provided to determine that cost. The User defines the whether the conversion system is air-cooled binary or flash-steam, and identifies whether the LCOE will be based on the Power Sales or the Number of Production Wells required. For binary plants, the User can either define the plant performance (brine effectiveness) or allow the model to determine the plant performance that minimizes the LCOE for the plant. The optimization is performed with a macro that uses the Excel Solver Add-In (see Appendix 1 for instructions regarding this add-in). The flash-steam plant performance is based

upon the flash pressures that are either calculated or inputted by the User (the model estimate of the optimal flash pressures based upon the resource temperature). For both plant types, major components are sized based on plant performance/flash pressures, calculated plant size and the resource temperature. The model estimates the direct construction cost based on these equipment cost. The direct construction costs and User input for indirect costs are used to determine the total installed cost for the power plant.

- If the User elects to include transmission costs, inputs are required both from drop down lists to establish the line voltage, terrain and population density, and to establish the distance for the transmission line. These inputs are used to establish the transmission line cost (\$/mile). The costs and the approach used were developed from a PG&E presentation made in 2009. They do not include costs for substations.
- The User defines whether the LCOE determination will be based on Power sales or the number of production wells (exclusive of dry holes or spare wells) and defines the number of units, i.e., is 15 MW of sales coming from one 15 MW unit or three 5 MW units. Note the number of units defined should not drop the output per unit below ~3 MW (to assure that the costs predicted are within the size range for which the equipment correlations are based).
- The User also defines how the model is to handle any changes in plant performance for the improved scenario. One option keeps the total power sales constant and adjusts the geothermal fluid flow rate. The other keeps the flow constant, and determines sales based on the improved scenario plant performance.
- The User selects the conversion system to be used in the analysis: air-cooled binary or flash-steam.
- Binary Plant Input
 - The User establishes whether the plant performance is going to be inputted or calculated. If inputted, the model lists the maximum plant performance (brine effectiveness) for the geothermal fluid temperature; this value is the maximum level of performance for which the model's cost correlations were developed.
 - If performance is to be calculated, click on the CALCULATE box. This is a hyperlink to sheet **Binary A1**. On this page enter a value in the cell with the yellow background that is less than the maximum displayed (suggest about half that value) and click on the red button for the Reference Scenario. A box with the Solver results will be displayed. If a solution is found, click OK to accept the results. In lieu of using solver, one can manually change the plant performance in the cell with the yellow background till an optimal value is found. (This manual changing of the performance metric to minimize the LCOE can also be done on the **INPUT** sheet if the User opts to input this metric.) Once completed click on the RETURN box to return to the **Input** sheet. Note that on **Binary A1** one can also optimize plant performance for the Improved Scenario. This option would be utilized if one were to define improvements that impact the cost of the exploration and confirmation phases and/or the well field development and stimulation.

- The next section of input is to define the plant cost for the reference scenario. The model uses the plant performance, plant size (net plant output – not power sales), and the geothermal fluid temperature to estimate the costs of the major components in the plant – the turbine-generator, air-cooled condenser, geothermal heat exchanger and working fluid pump. The model defaults to using carbon steel tubes in the geothermal heat exchanger. (Prior versions of GETEM allowed the tube material to be varied and the associated impact on costs reflected in the heat exchanger cost; this feature has not been integrated back into the model.) The estimated costs of these four components are displayed; a User can adjust each of these costs. Note that a PPI adjustment has been applied to each component cost shown.
- The model applies a multiplier to these equipment costs to determine the direct construction costs. The multiplier that the model determines includes other equipment installed as part of the plant construction, steel, ‘other’ materials, labor (including fringe and benefits), and consumables (including rentals). The PPIs are used to adjust the contributions from each to the total multiplier. This multiplier also includes the User defined freight and tax (both applied to non-labor costs). The calculated multiplier is displayed – the User can opt to use this value or input a value.
- The indirect costs for the plant construction are defined by the User as either a fixed value or as a % of the direct construction cost. These indirect costs include costs for engineering, home office, management and supervision, startup, etc..
- The User must define how the plant cost for the scenario with improvements specific to the power plant is to be defined relative to the reference scenario. If the model calculates the plant performance, then any calculated plant cost for different levels of performance will produce an increased LOCE. To show the impact of improvements for power plant technology, a User must define either the increase in performance for the same plant cost (\$/kW), or the decrease in cost (\$/kW) for the same level of performance. When the improvements are made in the other project phases (and not associated with the power plant), the macro for the Improved Scenario on **Binary A1** can be used to establish the plant performance (and cost).
- The binary plant input also allows one to assess the footprint of an air-cooled binary plant. This estimate is based upon the estimated size of the air-cooled condenser and the User defined ratio of the total plant footprint to that of the air-cooled condenser. This is for information purpose only, and is not used in the determination of the LCOE.
- Flash-Steam Input
 - The model allows the design ambient conditions to be varied in the determination of the flash plant performance. The User identifies these ambient conditions.
 - The User also identifies the isentropic efficiencies of the turbine and pumps, as well as the generator efficiency.

- Plant performance is based upon the flash pressures. The User must identify whether there will be a temperature constraint place on the geothermal fluid leaving the plant and establish whether there will be 1 or 2 stages of flashing. The model will estimate the optimal flash pressures (those producing the maximum power). The User can opt to use those values or input other flash pressures. (Note that it is probable that the User will be able to adjust the pressures and produce a higher output and lower LCOE; however these increases are not anticipated to be significant.) If the inputted high pressure flash pressure exceeds the estimated production well head pressure, a warning will be displayed
- The User must define the pressure drop between the flash vessel and the turbine.
- The User must define the condenser type and provide input relative to the cooling water temperature rise, pinch points (approach temperatures) in the condenser and cooling tower, the cooling water pump head and the non-condensable gas partial pressure in the condenser. For the different condenser types, the pinch point in the condenser will vary, as well as possibly both the cooling water pump head and cooling water temperature rise.
- Hydrothermal resources contain varying levels of non-condensable gases that come out of solution when the fluid flashes and pass through the turbine to the condenser with the steam. These gases must be removed from the condenser or they will adversely affect plant performance. The User defines the level of non-condensable gases in the geothermal fluid, including the level of hydrogen sulfide (H₂S). The model assumes hydrogen sulfide must be abated, and uses this concentration to estimate the capital cost of the abatement system. The User also defines how the non-condensable gases are to be removed, the number of stages in the removal process, and if a vacuum pump is used, its efficiency.
- In order to estimate the cost of the equipment the User defines the steam condenser heat transfer coefficient. This value is used to estimate the size of all the surface condensers (the model assumes that surface condensers are used in the non-condensable gas removal system).
- The maximum droplet size is also inputted. This droplet size is used to calculate a terminal velocity, which is used with the steam flow rate to establish the diameter of the flash vessel and its cost.
- Similar to the binary cost model, estimates are provided for the major components in the flash-steam plant. The User can adjust these estimated costs, which include the PPI adjustments.
- The model applies a multiplier to these equipment costs to determine the direct construction costs. The multiplier that the model determines includes other equipment installed as part of the plant construction, steel, 'other' materials, labor (including fringe and benefits), and consumables (including rentals). The PPIs are used to adjust the contributions from each to the total multiplier. This multiplier also

includes the User defined freight and tax (both applied to non-labor costs). The calculated multiplier is displayed – the User can modify.

- The indirect costs for the plant construction are defined by the User as either a fixed value or as a % of the direct construction cost. These indirect costs include costs for engineering, home office, management and supervision, startup, etc..

Calculation of Levelized Cost of Electricity:

A User has the option of using either the FCR method or the EERE Approach to determine the LCOE.

With the FCR method, the inputted fixed charge rate is multiplied by the total project capital costs to determine the annual revenues need to satisfy those costs associated with the capital. The annual operating costs are then added to those revenues needed for capital. This sum represents the annual power sales that must be realized. In order to determine the LCOE, it is necessary to determine the annual power generation. To account for the degradation in power output, the model discounts the output over the plant life, as well as the output of the plant if it had operated at the design output over the entire life. The ratio of those discounted values is applied to the inputted Utilization Factor to produce a ‘Levelized Utilization Factor’ which is used with the design power output to calculate the levelized annual power production (the ‘Levelized Utilization Factor’ effectively accounts for the impact of a declining resource temperature on the Utilization or Capacity Factor). The LCOE is the annual sales revenue need to cover capital and operating expenditures divided by the levelized annual power production.

The EERE Approach replicates a discounted cash flow analysis, with one caveat. The EERE methodology can not directly utilize the model’s estimate of the impact of the temperature decline on power output. To account for this decline in output, an annual decline rate for the capacity factor is determined based upon the plant output at the time of well field replacement or at the end of project life, whichever occurs first. As indicated a discounted cash flow is included in the model which uses the same costs, phase durations, and discount rates as the EERE Approach. It differs from the EERE Approach in that it utilizes the model’s estimates for the annual power production (which include the effect of the resource temperature decline). Because of this, there will be some difference between the generation cost determined with the discounted cash flow sheet and the EERE Approach.

Appendix 1

To use the macros in the model, the user must enable those macros when the spreadsheet is opened. Even with the macros enabled, the model may not work. The macros in GETEM require Excel's Solver Add-in be active. To make the Solver Add-in active, it is strongly suggested that the User consult the Help files associated with the version of Excel being used.

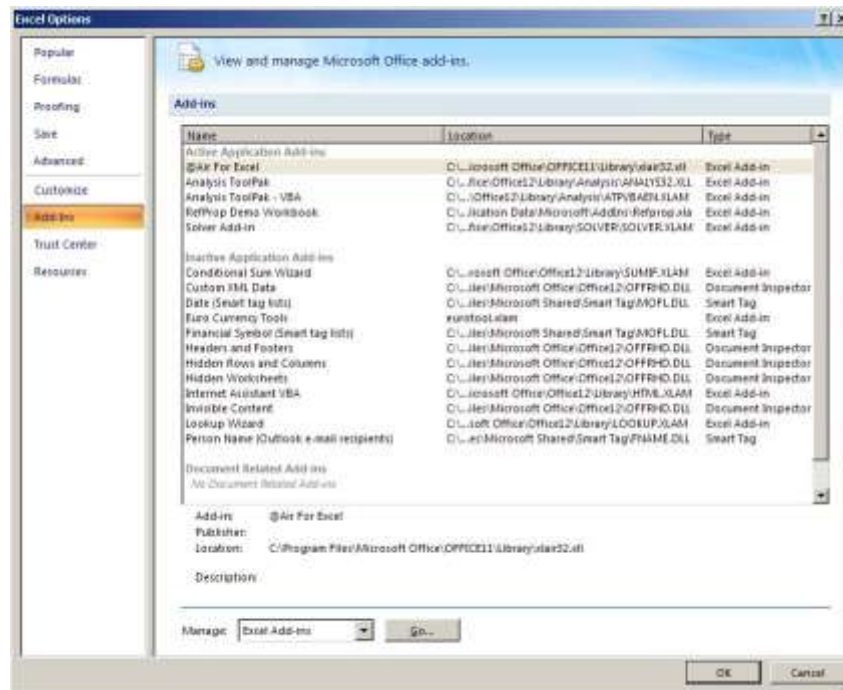
The following information maybe used; if these fail to work consult Excel's Help files.

Office 2010:

- Click on File menu, then
- Options, then
- Add-ins
- On the bottom of the Add-In page, go to
- Manage Excel Add-Ins (it will be necessary so select Excel Add-ins from the drop down menu)
- A box will be displayed with the Add-Ins that are available.
- If the Solver Add-in box is not checked, do so then click OK
- Solve should be active

Office 2007

- Click on Windows Icon in upper left portion of screen, and select Excel Options (lower portion of the window)
- Click on Addins (see below); note this screen is similar in Office 2010.



- In the Manage window, select Excel Add-ins and click Go

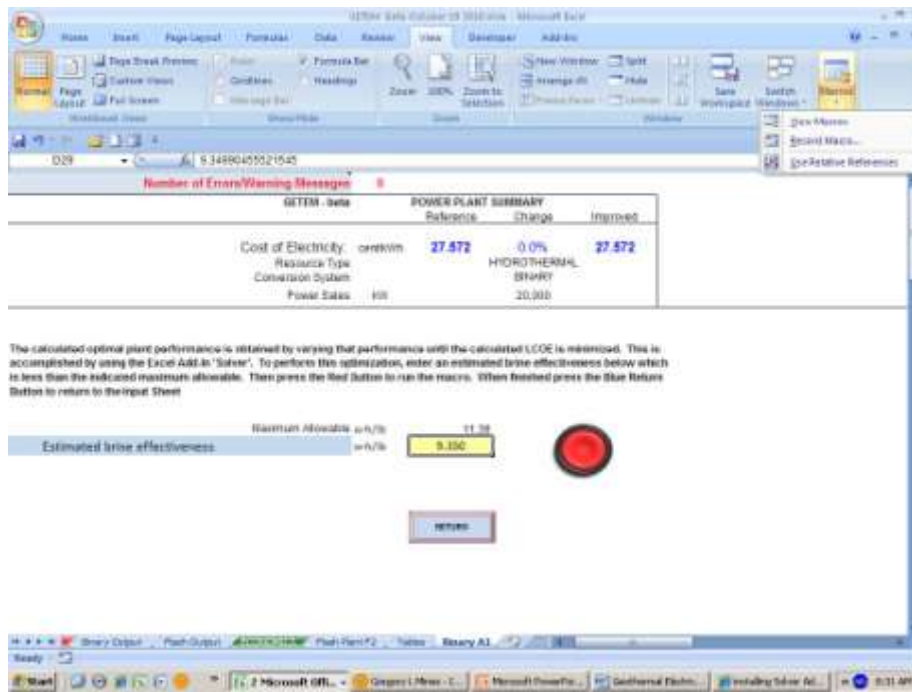
- The following box will appear (again this is similar to that in Office 2010)



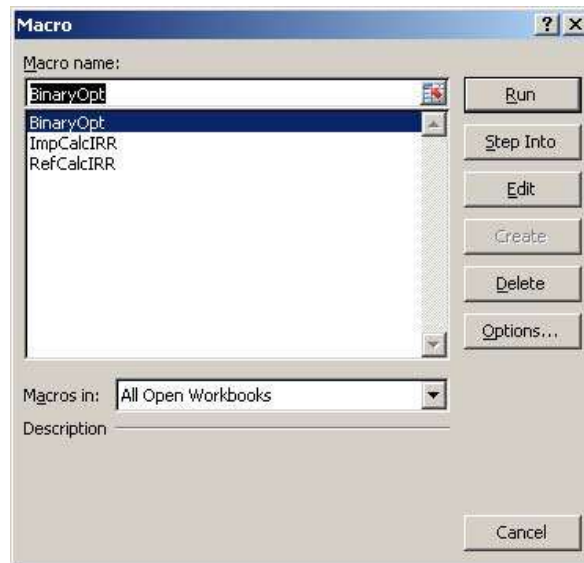
- Check the box for Solver Add-in, and then click OK
- Solver should be active

Once Solver has been added in, the macros still may not work. The following is for Office 2003-2007, but is expected to also work for Office 2010.

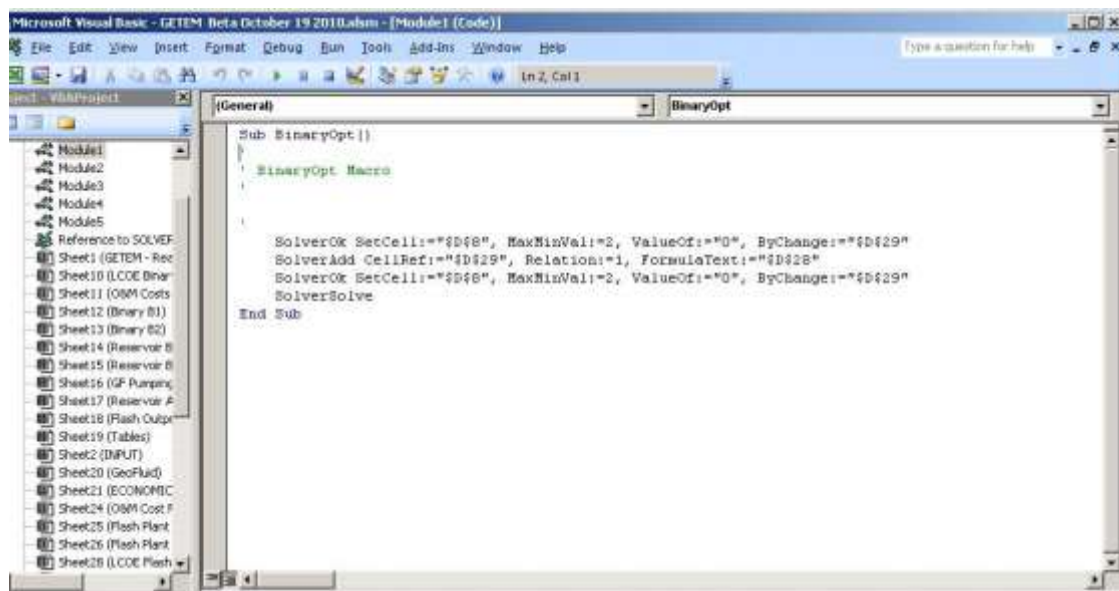
- Open the View tab and click on Macros, then View Macros (see below)



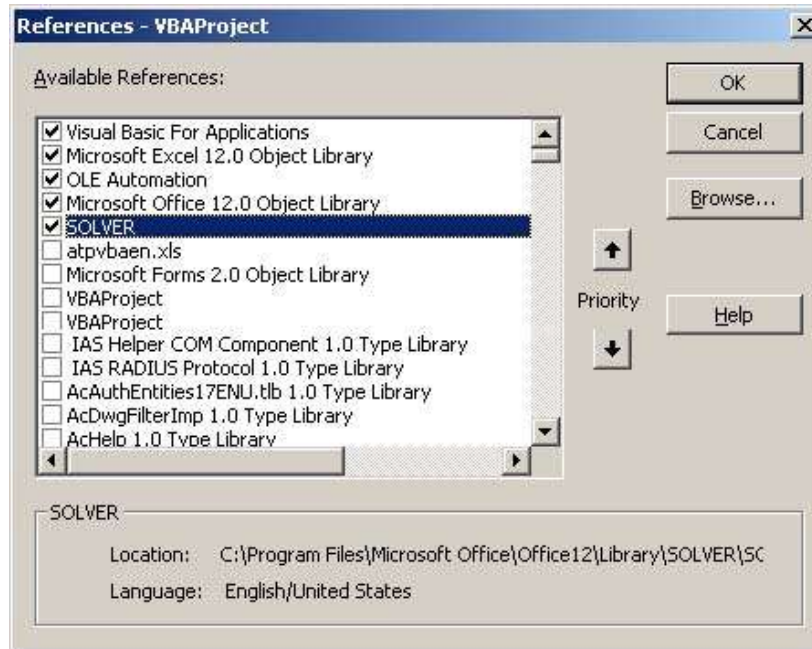
- The following screen will appear. Select the macro and click edit.



- The following screen will appear. Click on Tools,



- and then References. The following screen will appear



- Click on the box next to SOLVER, and then OK. Then close the visual basic editor and return to the Excel file.

The macro should now work.