DOE Geothermal Electricity Technology Evaluation Model (GETEM):

Volume III - Detailed Technical Appendixes

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B. DEVELOPMENT AND VALIDATION OF WELL COSTS

C: GEOTHERMAL ENERGY CONVERSION SYSTEMS

D. STANDARD METHOD FOR MOVING EXCEL FIGURES INTO THESE REPORTS

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APPENDIX A.

GETEM-2005 USER'S MANUAL

This Appendix, lettered "A" according to the working outline for the GETEM-2005 documentation reports, is now a stand-alone report.

If you need the User's Manual, and it was not included the materials sent to you, contact Greg Mines, at either:

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(Dan Entingh, the lead for this project, has retired.)

Note: there are no page numbers on this page or the next, to avoid confusion with the pagination in Appendix A, i.e., A-1, A-2, etc.

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APPENDIX B.

DEVELOPMENT AND VALIDATION OF WELL COSTS

This Appendix provides further detail about how the estimates of well cost that are used in GETEM-2005 were derived. As in other cases, a combination of reported estimates and modeling of costs from basic engineering factors were used.

B-1. WellCost Lite

B-1.1. Why a separate well cost information / model is needed

A well costing model (WellCost Lite) has been developed to support the DOE Geothermal Program. Geothermal drilling cost information is somewhat unique in comparison to minerals or oil and gas drilling. For example, lithology, depth, final diameter and the date of the drilling are often significant issues, often rendering averages and broad based plotting of well cost misleading.. In order to accommodate the interest to assess variations in these inputs for a particular example requires the ability to also account for potential major differences also realized through changes in the cost of materials, services and the performance of necessary services during the drilling of the well.

A simple example that demonstrates the need for a separate means to calculate geothermal well costs may be represented as follows. Large well bottom diameters are often needed to accommodate the rather large production flow rates. The larger production casing requirement forces a well design requiring larger upper casings, rig size, bits, wellhead equipment, bottom hole assembly equipment and greater volumes of cement, muds, etc. This results in a significant well cost, significantly greater than a similar depth oil & gas well. Such a cost estimate can be determined for any geothermal well using the WellCost Lite model.

B-1.2 An overview

An overview of how the cost information is developed and then used within the GETEM model

Interest in using a well cost model that could account for changes in depth, diameter and geological area was first shown in the 1970's. A hand calculated model was used to determine well costs for eight generic geothermal drilling areas. This effort permitted an objective early look at the major cost categories of well construction.

Later a computer based well cost program known as IMGEO was developed and using it facilitated the ease of varying parameters to evaluate research and development needs. The IMGEO model included geological studies, exploration, development drilling, the gathering system, and finally, power on line. Evolution from IMGEO led to the Wellcost-1996 model, which was developed as part of the Advanced Drilling Study at Sandia (SAND 95-0331). This again was intended to be used to evaluate changes to the drilling system as a whole.

A more robust costing model, WellCost Lite, was developed to readily accommodate changes in the drilling system in a more streamlined manner. . WellCost Lite is an event and direct cost based model. This means that time and cost are computed sequentially for all events that take place in the drilling of the well. The well drilling sequence is divided into intervals, which are usually defined by the casing intervals. In this way (at the WellCost pages) times and cost for a related series of events leading up to the end of an interval are accounted for.

Modeling the well cost begins by considering basic requirements presented by the geologic stratigraphy to be drilled, the desired depth, and the finish diameter. Using these requirements the well is designed. Using that design, WellCost Lite is used to model the costs. The requirements at the bottom of the well dictate, to a great degree, how the upper portion of the well is designed and costed.

The output of the cost model can take a number of useful forms. Since most drilling authorizations are put in an AFE (authorization for expenditures) format, we have used that as one of the output formats. Other formats have evolved for specific uses. The GETEM model called for a more comparative model for the various depths. The model has been used to compare:

1) depth variations,
2) final production zone diameters,
3) geological environments and
4) advanced drilling technologies such as casing drilling.

The variations needed for the GETEM consideration were reduced to a representative curve, a simplification, for ease of use. There will be a unique curve for different geological areas. Ultimately there will need to be a suite of curves to account for production zone diameter, geological variations, new drilling concept claims, and greater depths than are currently drilled for geothermal production.

B-1.3. Background and Brief history of the development

Major steps along the way, starting with the Carson, Lin, and Livesay hand calculated model up to the WellCost Lite approach. There are more than 10 citable references to the use of the well cost approach.

Charles C. Carson, Y. T. Lin, and B. J. Livesay, *Representative Well Models for Eight Geothermal Resource Areas*, SAND81-2202, Sandia National Laboratories, February 1983

Dan Entingh and Lynn McLarty, *Geothermal Cost of Power Model IM-GEO Version 3.05: User's Manual*, Meridian Corporation, November 1991

Susan Petty, Dan Entingh, and B. J. Livesay, *Impact of R&D on Cost of Geothermal Power, Documentation of Model Version 2.09*, SAND87-7018, Contractor Report, Sandia National Laboratories, February 1988

K. G. Pierce and B.J. Livesay, "*An Estimate of the Cost of Electricity Production from Hot-Dry Rock*," SAND93-0866J.

K. G. Pierce and B. J. Livesay, *An Estimate of the Cost of Electricity Production from Hot-Dry Rock*, Geothermal Resources Council Bulletin, Vol. 22, No. 8, September 1993

S. Petty, Livesay, B.J., and Long W.P., *Supply of Geothermal Power from Hydrothermal Sources*, Contractor Report Sandia National Laboratory 1991

Susan Petty, Richard G. Adair, and Bill Livesay, *Evaluation of Small Diameter Core-holes for Reservoir Information*, Contractor Report Sandia National Laboratory

Susan Petty, B.J. Livesay, William P. Long, and John Geyer, *Supply of Geothermal Power from Hydrothermal Sources: A Study of the Cost of Power In 20 and 40 years*, Contractor Report SAND 92-7302 Sandia National Laboratory, November 1992

Kenneth Pierce, Bill Livesay, and John T. Finger, *Advanced Drilling Systems Study*, SAND95-0331, Sandia National Laboratories, May 1996

K. G. Pierce and B.J. Livesay, *A Study of Geothermal Drilling and the Production of Electricity from Geothermal Energy*, Contractor Report SAND 92-1728 DOE-GET and Sandia National Laboratory, Jan 1994

B-1.4. Strengths of the model approach

The main strengths of the model approach are its flexibility and level of detail. The model approach is an event based sequence analysis that takes into account the time, services and materials cost for each action relating to the drilling of the well.

Prespud expenses (e.g., site preparation and rig relocation costs) are listed and accounted. These are expenses that are incurred before the hole is actually begun. Among these are site preparation, initial water supply setup, conductor hole drilling and cementing, cellar construction, and mobilization of the rig. (Quite often the demobilization is also accounted before the initiation of drilling operations.)

Beginning with the rig daily rental rate and the other running costs such as insurance, overhead, management, drilling engineering charges, rig supervision and other miscellaneous charges, an hourly operating expense is developed for the overall operation.

For each time involved there is a running cost based on the additional equipment that is on the "clock" during that operation. Some of these events also require mobilization or initiation cost and demobilization cost. There may also be freight expenses as well. Each event or equipment selection results in a direct cost for materials such as bits or packers or wellheads.

With this degree of detail the model can be altered to account for changes in procedures and service and equipment performances.

Separate modules can be created for unique events such as lost circulation, stuck pipe, failed cement etc. A small separate module is developed with a time line and cost pattern. The frequency of these occurrences is difficult to establish, since there are not enough examples to establish a statistical frequency. When trouble is included, interviews are used with knowledge of the area to establish the likelihood of these trouble events. A "trouble event" is then entered into WellCost Lite in the appropriate interval. An example of this manner of accounting for trouble is lost circulation in the surface casing interval of the well. In many geothermal areas, for the tophole it is common to have severe lost circulation. The number of events in the interval is estimated from interviews and what records are available. The degree of the trouble (a judgment as to the magnitude of the event(s)) is also estimated.

B-1.5. Weaknesses of the model approach

Trouble costs, of all kinds, are not easily accounted for. Lost circulation, twist-offs and the resulting fishing, temperature limitations and failed cement jobs can be significant cost items. In reality, any material cost and performance delays beyond costs planned in the original cost estimate (AFE) incur a trouble cost. For geothermal drilling only the identifiable troubles are listed and an attempt is made to account for these times and materials. Lost circulation, stuck pipe, twist offs and fishing are the major items. Failed cementing jobs and collapsed casing are complicated and difficult to properly include. Trouble event times and costs are estimated for each type and severity of problem.

But ultimately, trouble events and costs are related most direct to specific prospects, and actual drilling of a prospect. For Government policy work with respect to the technical direction of R&D programs/projects, the only practical approach will be to define broad ranges of prospects with similar characteristics, and develop a statistical base to deal with the relative incidence of troubles.

B-1.6. How the model is constructed

Each cost model is constructed by taking (or developing a well profile based on preliminary information from an operator or interested party), and developing the cost one step at a time from the pre-spud, to spud, to completion and well test. Sequentially as the well is drilled, details for each interval, are summed in the WellCost Lite pages, and presented as an AFE format or other output format.

B -1.7. Application of WellCost Lite to GETEM

The GETEM model use a series of cost estimates for wells from 2,000 ft to 20,000 ft that were developed for a Basin-and-Range type geology similar to Northern Nevada. The lithology was estimated to be essentially sedimentary (and relatively easy drilling) to within 1,000 ft of the production casing point. This provided for a barrier above the stimulated areas of the reservoir. These examples were then plotted on a depth versus cost basis. The resulting curve was fitted to an analytical equation that was used in the GETEM analysis. Other curves can be estimated for other geologic areas. Times required are estimates from experience, and choices to include an event or not are also experience based.

Areas where there are oil and gas possibilities (present or past), will offer a more difficult estimating efforts, since the combinations of pore pressure distribution, fracture gradient distribution and the required mud weights will dictate casing points. Failure to set casing at the appropriate points can lead to loss of the hole. The casing profile may change as the well is drilled. More strings may be necessary than originally planned. This is of course more common during an exploration well. As the well field is developed, each subsequent well helps set the casing setting requirements.

B-1.8. WellCost Lite Inputs

Initially the starting point is a well design. The inputs are then entered into the Input Pages of WellCost Lite. The times and costs are entered from the top down. Each activity in each interval is specified. As a result the Wellcost Pages of WellCost Lite are completed. From the Wellcost pages each interval is summed in such a way that times and expenses were separately accounted for each interval if that was of interest. The costs that were summed in the Wellcost page were automatically summed and collected on the AFE page in a manner similar to the way a company authorization for expenditure (AFE) proposals are prepared.

For the purposes of GETEM a more distinct summary page was developed that sorted cost categories. There were separate collections for prespud expenses, casing and cementing, drilling ahead costs, non drilling ahead costs, management and overhead, evaluation etc. and totals with and without contingencies. Each of these could then be used to estimate the cost per foot for each category of expense. Drilling times and total times and trip times are also summed.

Recently, a simplified input page was developed that could be used when describing the well to be drilled when interviewing the operator or the geologist. It has only the basic information needed to go forward with estimating the well cost.

B.2 Curve Fitting Geothermal Well Costs as a Function of Depth

Curve fitting of geothermal well cost data versus depth was undertaken to develop a means to extrapolate costs beyond our current knowledge base (namely to greater depths). Data collected and related by a scientific process(es), wherein that scientific process may be used to justify a particular mathematical expression relating two variables, lends credence to the mathematical expression chosen as well as the extrapolation, given that the same scientific process/relationship operates in the extrapolated domain. It is unclear whether the relationship between geothermal well costs and depth is fully understood in a fundamental scientific/engineering manner such that the appropriate mathematical relationship is intuitive and straight forward, thus we are forced to empirically curve fit.

The method used to curve fit data can have major impacts on predictions made using curve fits. For example consider Figure B.1 which shows the effect of fitting 1970's geothermal well cost data with a polynomial, in one case the individual data points are plotted and fitted and in the second case the data are grouped by depth range and then fitted to a polynomial. There is as much as a 20% difference between the curve fits to the ungrouped and grouped data. While there may be situations where valid arguments can be presented to group data, here lacking such an argument to group the data, all curve fitting done to support GETEM has used the actual data.

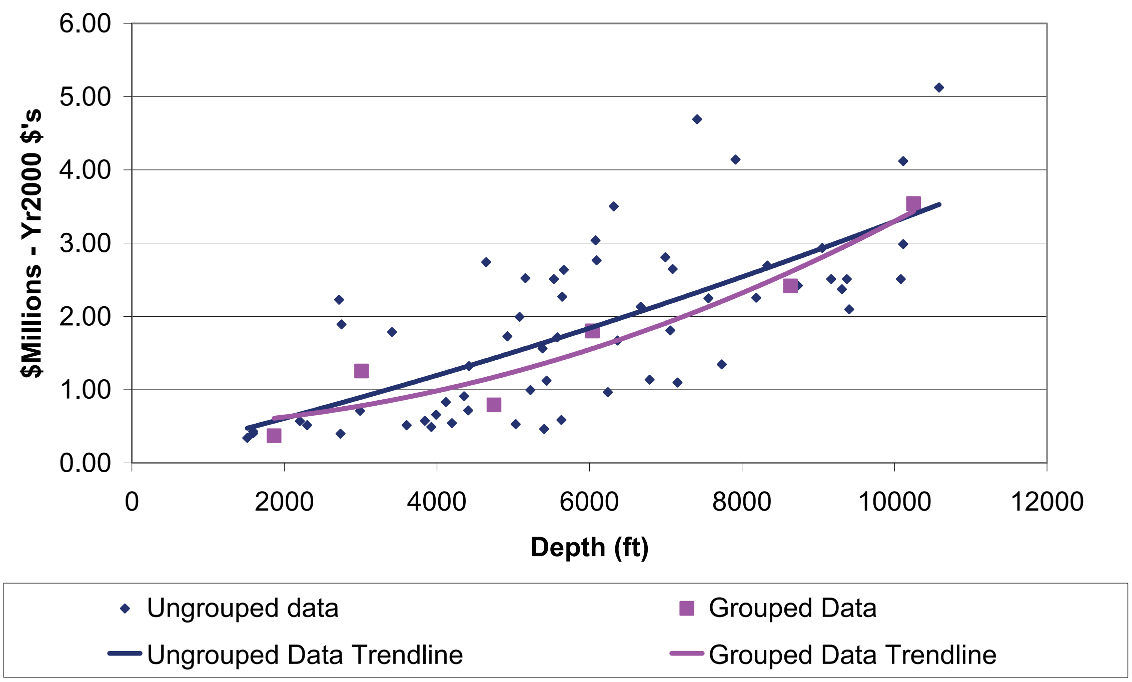


Figure B.1: Comparison of polynomial fits with and without grouping.

A second issue in curve fitting is the choice of mathematical expression assumed. Figure B.2 compares a linear vs. exponential curve fit to the 1970's geothermal well cost data. Both curves have two degrees of freedom (two adjustable parameters). Both the R^2 value (0.562 vs.0.455) and visual inspection (balancing the number of points on each since of the curve) suggest that the exponential is better. However, the drilling literature indicates drilling costs normally increase exponentially with depth; extrapolation of the linear curve to zero depth leads to a negative number. In this case, if historic practice is ignored and a linear curve fit was blindly applied, errors would result.

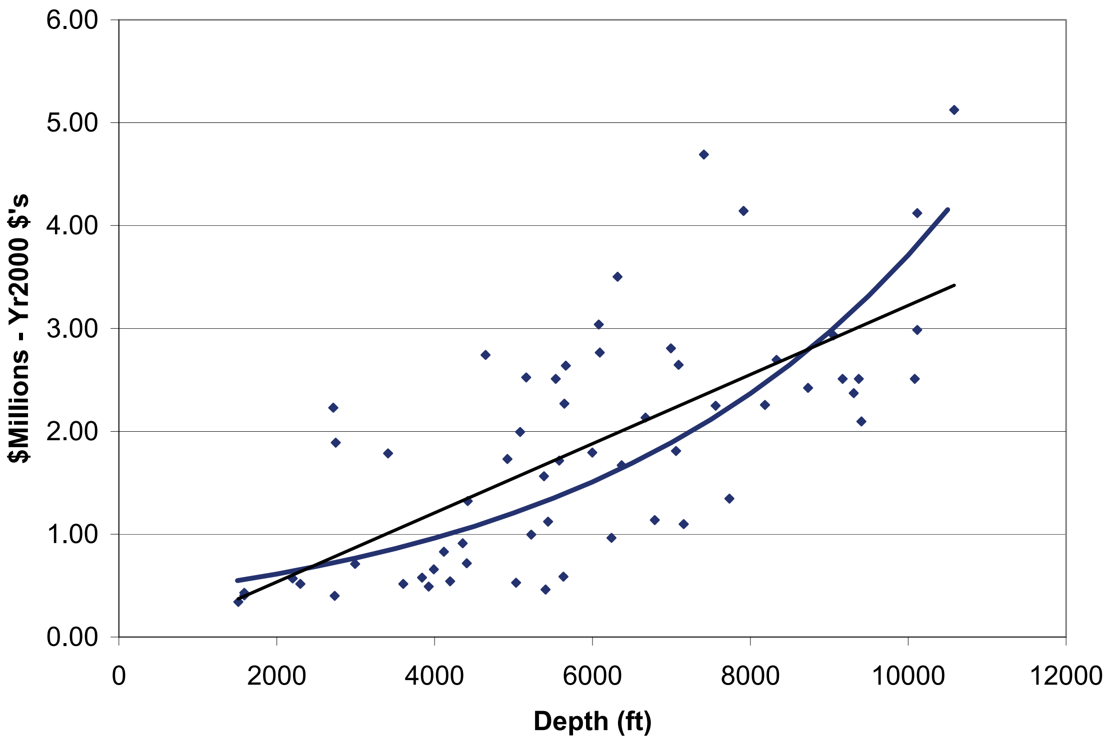


Figure B.2: Comparison of linear vs. exponential fit.

Another issue in curve fitting is how many degrees of freedom to use. Figure B.3 compares a second order with a fourth order polynomial fit. There is no justification for believing that drilling costs vary with depth according to the wavy red line. Thus while the red line may have a higher R^2, minimizing the deviations from the fit, it does not better represent the dependence of drilling costs on depth. As a general rule, fewer degrees of freedom are better. Both linear and exponential fits have two degrees of freedom, but in some sense that is not the minimum number of fit parameters. If outside information can be used to "fix" one of the parameters the curve used will have a decrease in degrees of freedom.

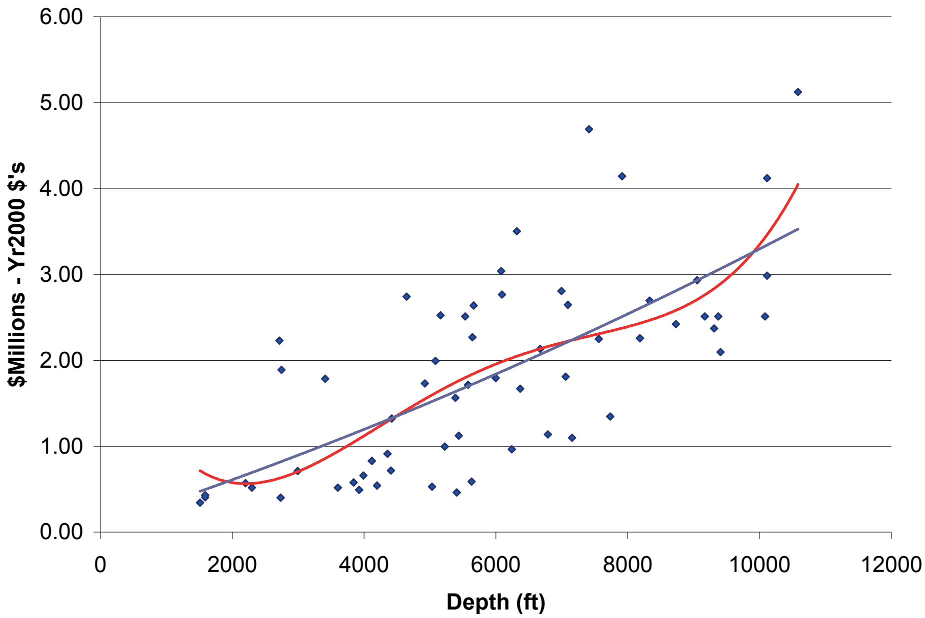


Figure B.3: Comparison of second and fourth order polynomial fit.

Further justification for using an exponential fit is provided by dividing the data into points below and above 6,000 feet. Figure B.4 compares linear fits above and below 6,000 feet. The two curves are almost parallel, off set by approximately half a million dollars. Deeper data has a reasonable zero depth costs (mobilization, site preparation, well testing, etc.), but the shallower data does not. At 6,000 feet there is the awkward offset in the data. Constraining the intercept ($ at zero depth) does not help (Figure B.5).

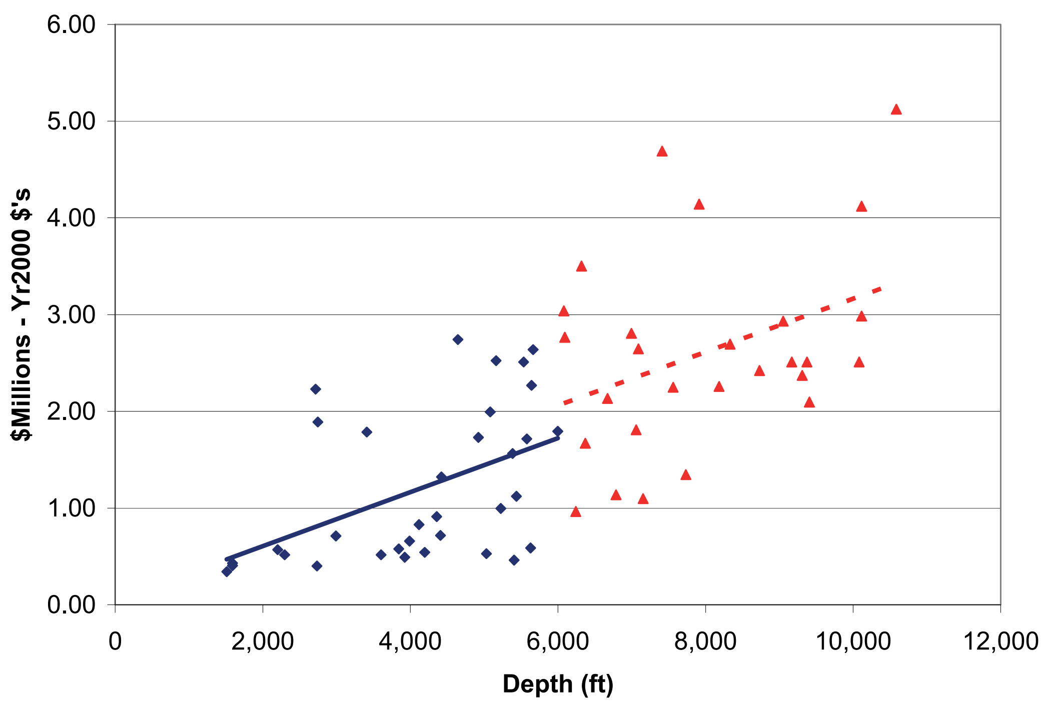


Figure B.4: Comparison of linear fits above and below 6,000 feet.

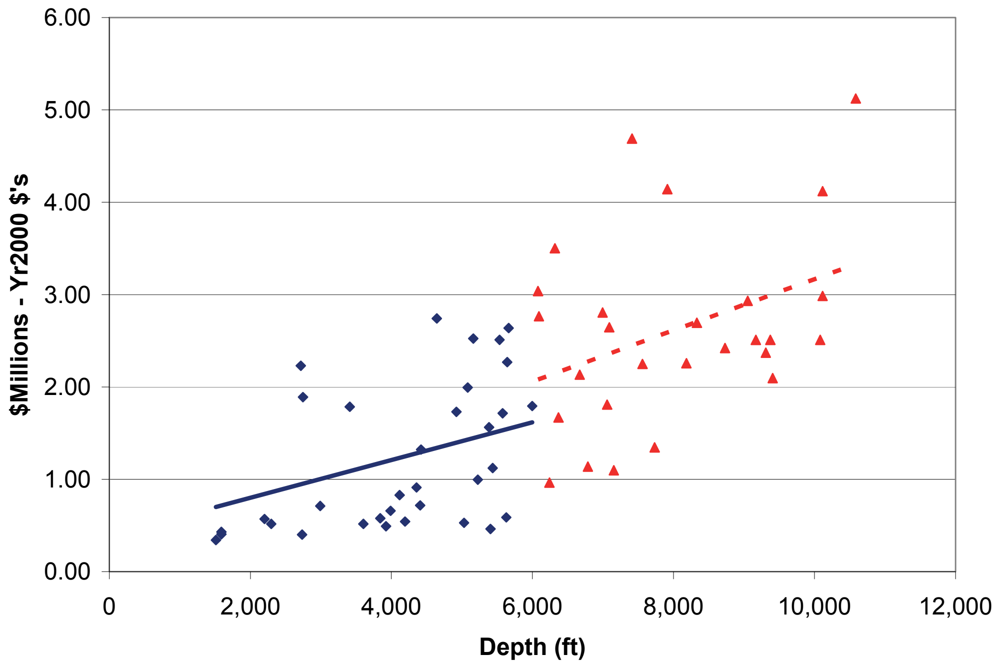


Figure B.5: Comparison of linear fits above and below 6,000 feet with constrained intercept.

Figures B.6 and B.7 make the same comparisons for exponential curves. Again the unconstrained exponential fits have problems at 6,000 feet. Furthermore, the exponential fit to the data above 6,000 feet has an unreasonable high intercept. On the other hand, constraining the intercept to reasonable zero depth costs makes the two curves fit together nicely.

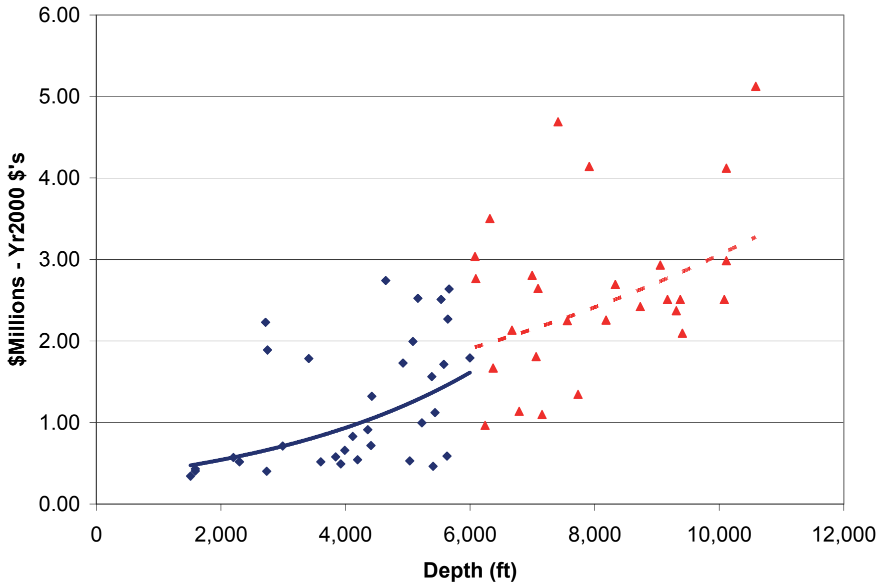


Figure B.6: Comparison of exponential fits above and below 6,000 feet.

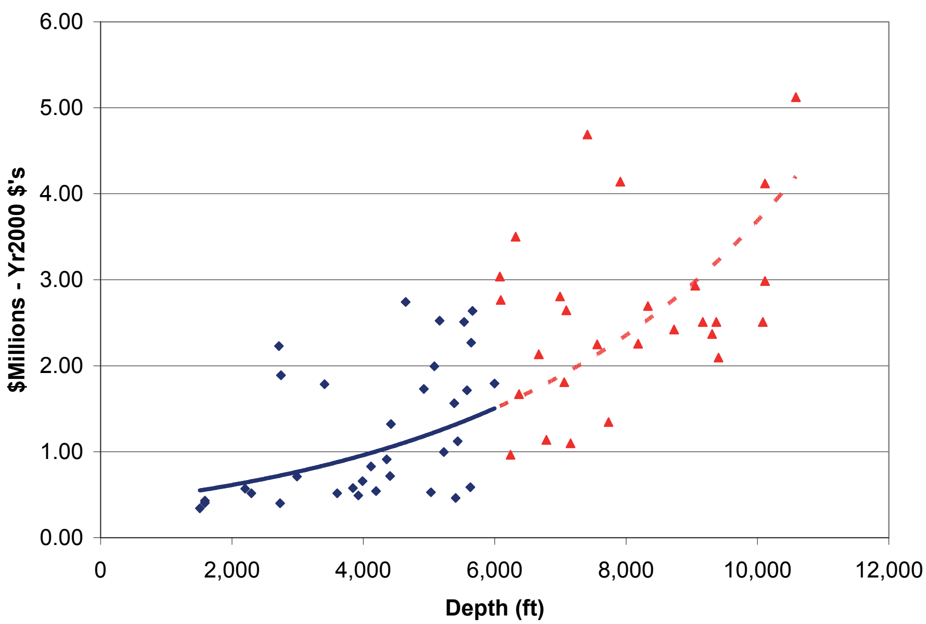


Figure B.7: Comparison of exponential fits above and below 6,000 feet with constrained intercept.

In conclusion the most reasonable fits are obtained using exponential curves constraining the zero depth cost. A nice feature of this process is that if only the data below 6,000 feet were available and a fit was made, predictions to 11,000 feet would be indistinguishable from fits to the whole data set. This suggests that the constrained exponential fit may allow extrapolation to depths beyond the last data point. It should be pointed out that an implicit assumption in the curve fitting presented and extrapolation is that the nature of the formation being drilled does not radically change with depth and that all of the drilling parameters and casing conditions also remain similar with depth.

B-3 Variability of Well Drilling Cost Data

Figure B.8 shows that there is significant variability in geothermal well costs, as reported by industry. Well costs in the 1970's data set reported in Figure B.8 range from 0.34 to 5.12 million dollars. The apparent increase of well costs with depth implies well costs are a function of depth. Hence, the data has been fitted as a function of depth. Appendix B (2) discusses curve fitting the data as a function of depth. It is readily apparent from Figure B.8 that fitting the data as a function of depth does not remove all the variability of the data – a significant number of the data points on Figure B.8 fall further away from the best fit line than would be expected due to normal errors in reporting well costs.

Note that colors referred to in Figures are visible if you view the original Word document.

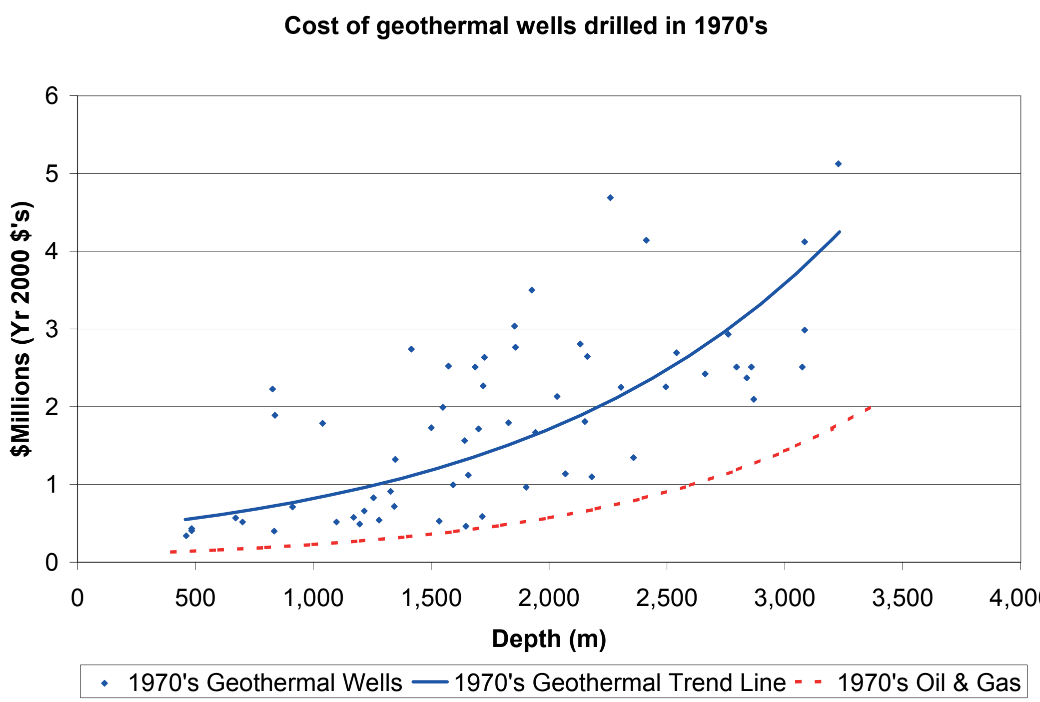


Figure B.8: Cost of geothermal wells drilled in the 1970's (blue) vs. average oil & gas wells (red).

The variability remaining after removing depth dependence (assuming there is no error in the reporting of the depths) is determined by drawing a vertical line from each data point back to the depth dependence curve (Figure B.9). A simple way of investigating the degree to which removing the depth dependence from the data reduces variation is to plot the distribution of the deviations of well cost data from the average well cost compared to the distribution of deviations of well cost from the depth dependence fit, vertical pink lines shown on Figure B.9.

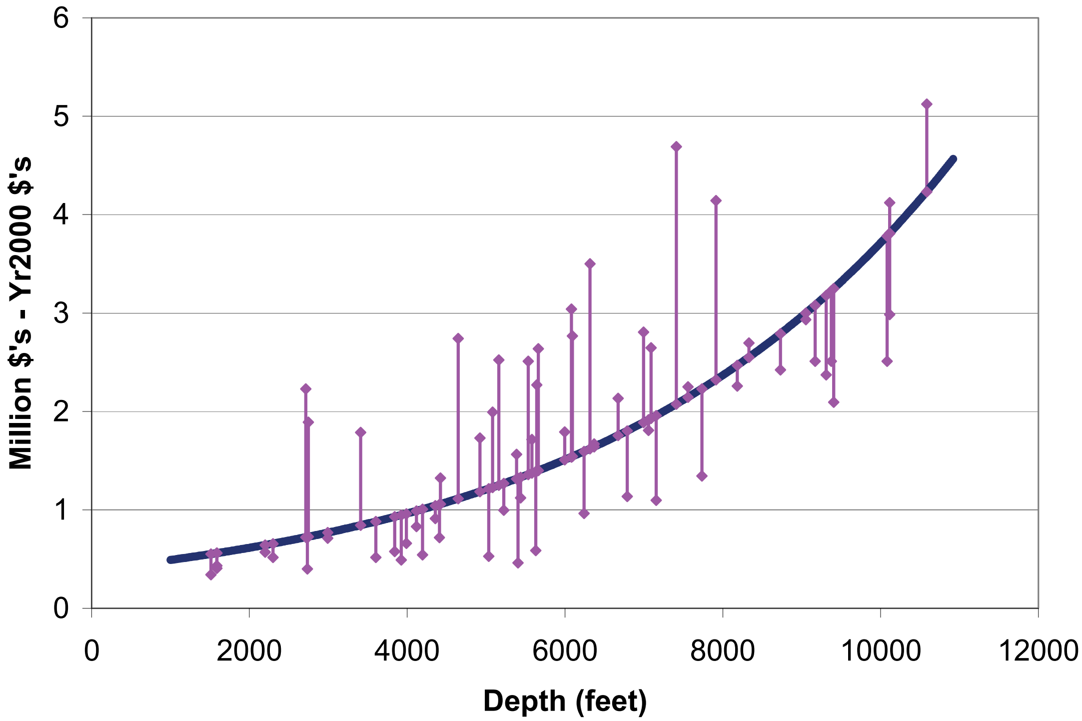


Figure B.9: Variability in well costs after depth dependency is removed.

Figure B.10 is a plot of these two deviation distributions. Figure B.10 shows significant skewness in the deviations from the average, blue curve, – a consequence of the depth dependence of well costs. Deviations from the depth dependency, pink curve, show a reduction in skewness and in the width of the distribution. Both of these observations support the claim that, reporting well costs as function of depth, reduces variability or uncertainty in well costs. As measured by calculating standard deviations, the depth dependence curve reduces the variability by 46%. Unfortunately that is less than half of the uncertainty in well costs on Figure B.8.

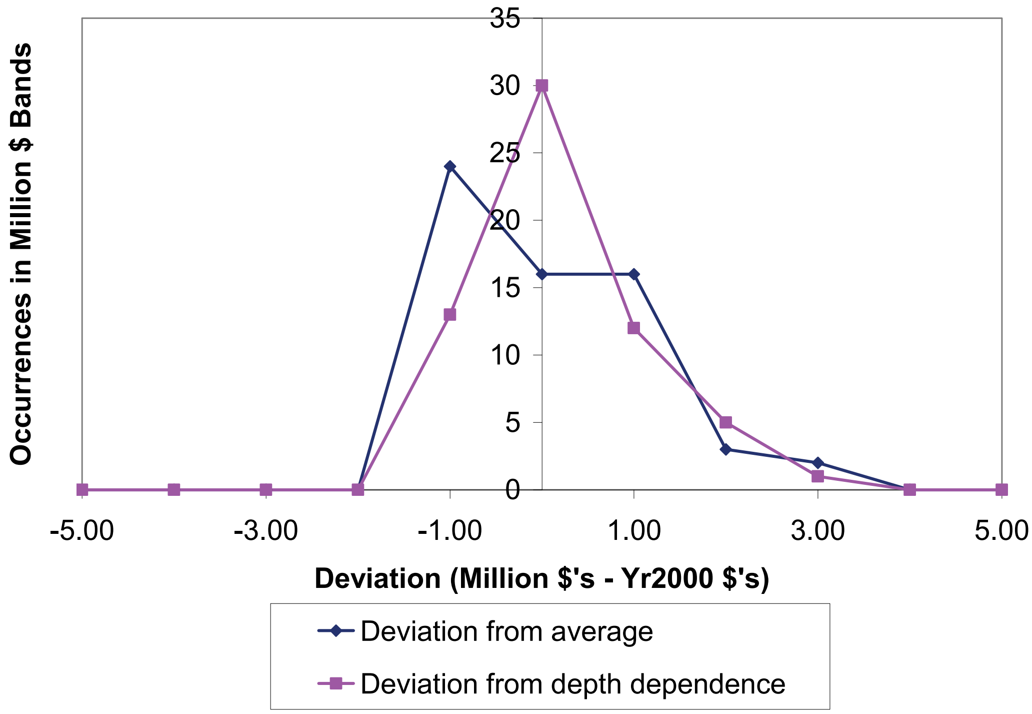


Figure B.10: Comparison of the distribution of deviations from average well cost to the deviations from the depth dependence curve.

It should be noted that plotting the distribution of deviations as shown in Figure B.10 is not a robust way of investigating variation when there is significant noise in the data. The results are too dependent upon the bins chosen (in this case equally spaced one million wide bins centered about zero).

A more robust way of investigating the variability of well costs is to use a cumulative distribution plot. The ragged pink curve rising from -1.3 million to +2.6 million on Figure B.11 shows the cumulative distribution function of deviations from depth dependency curve of Figure B.9. The green line on Figure B.11 is the cumulative distribution function for "perfect" data; that is represents the cumulative distribution if all the data points on Figure B.8 lay on the depth curve fit line. The blue shaded area is a measure of the total variation in well cost after depth dependency is removed. For reference, to provide an understanding of the magnitude of this blue shaded area, the yellow line shows the expected cumulative distribution if each data point had a ±30% random error from the curve fit. Clearly, the variability or uncertainty remaining after the removal of the depth dependence is significantly greater than a ±30% random error.

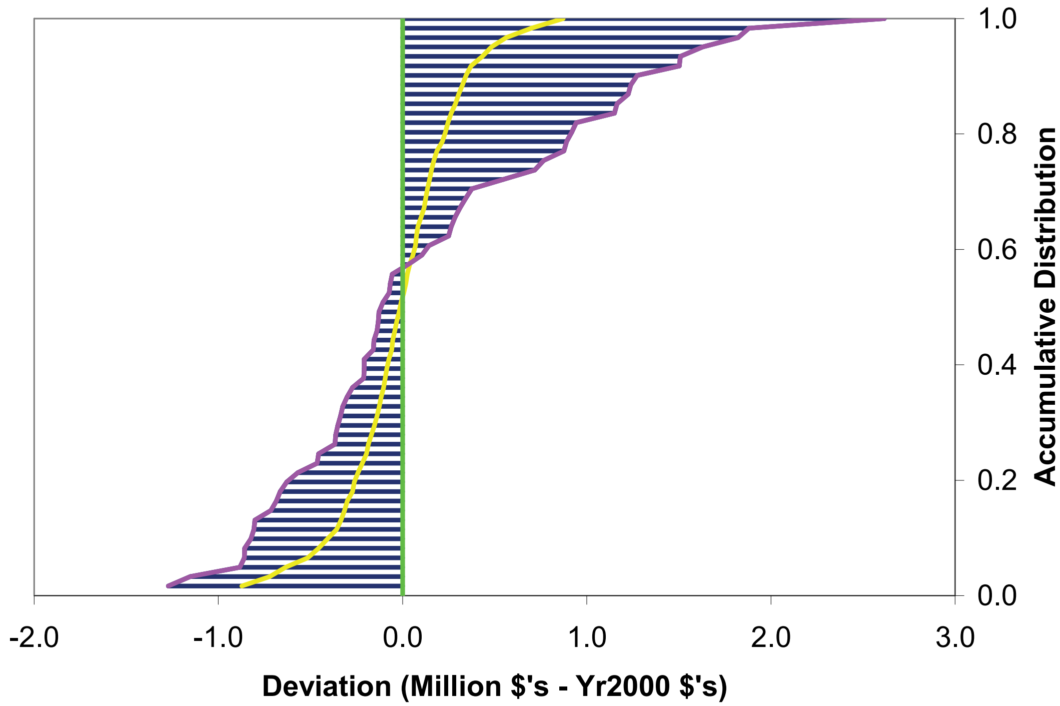


Figure B.11: Cumulative distribution function of deviations from depth dependency curve.

Figure B.12 shows that well costs are very dependent upon the field or geologic section in which they are drilled. The exponential growth factor of the brown curve on Figure B.12 is over twice that of the yellow curve. The expected well cost in the "brown geology" at 6,000 feet is over 300% the expected well cost in the "yellow geology."

This is a significant problem for GETEM. GETEM has a single set of well costs that are independent of geology. Unfortunately, there is no single parameter, such as rock hardness that captures the effects of geology. One can say that, in general, that sedimentary lithologies tend to have lower well costs than crystalline rocks, but one of the biggest factors making some fields more costly is trouble and trouble can occur in almost any geologic setting. At this time the only way to account for the effects of geology is to start with a description of the geology that includes rock hardness, the window between pore pressure and frac-gradient window, trouble frequency, etc and estimate the effects of these parameters on well cost. Unfortunately, that is tantamount to saying "if I know the answer of the impact of geology on well costs, I can tell you the impact of geology on well costs." Thus, at this stage, what can be done is to model the well costs in known lithologies where drilling already has been done. For new geologic settings, one must seek analogies that have already been drilled.

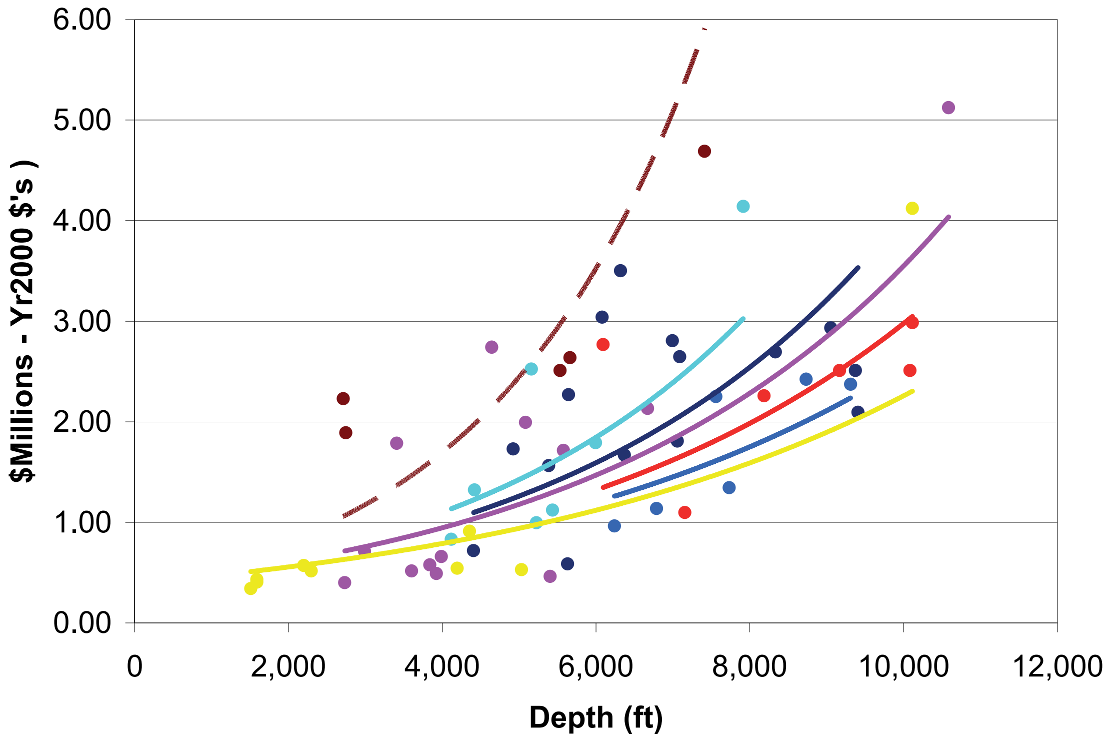


Figure B.12: Effect of well location on fit to geothermal well costs.

A quick look at Figure B.12 is misleading. It appears to suggest that by grouping the wells into fields and developing separate depth dependency curves, one could capture most of the well cost variation. Unfortunately this is not so. To study the impact of fields on well cost variability one starts by determining, for each field, the deviations of well costs from the curve fit for that particular field (Figure B.13). For the brown data, the deviation is the vertical line back to the brown curve fit and similarly for the yellow data.

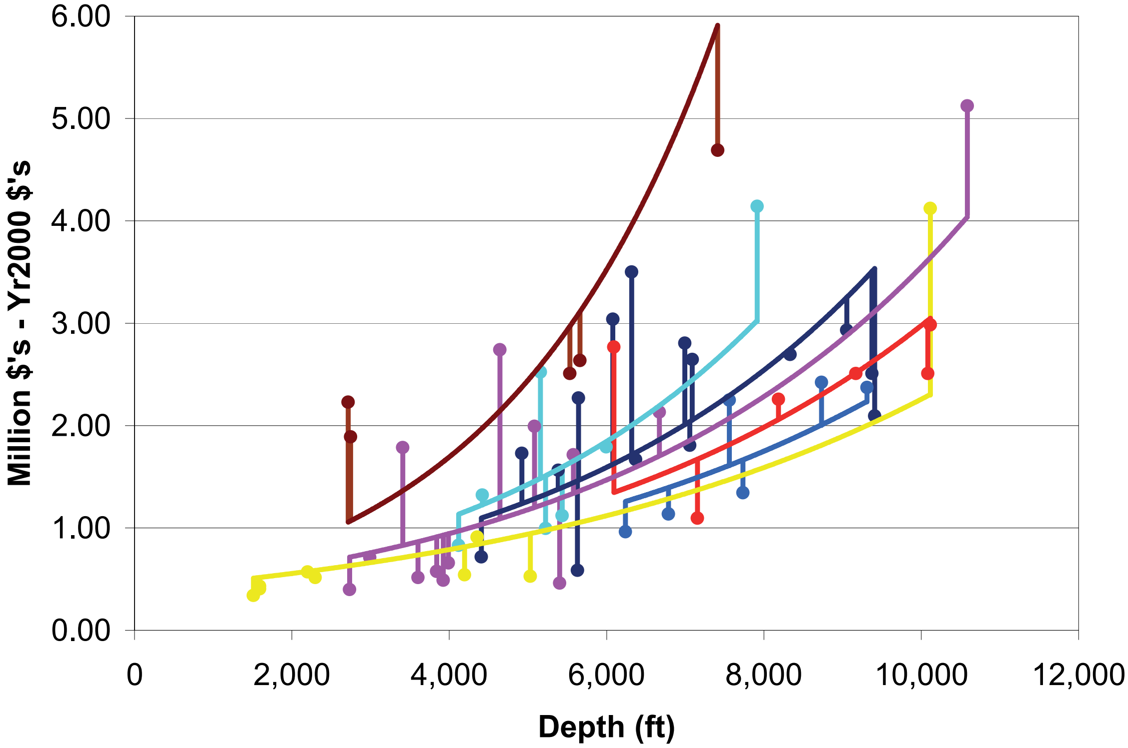


Figure B.13: Determining deviations on a field basis.

Figure B.14 compares the cumulative distribution function of deviations from depth dependency curve (vertical lines on Figure B.9 and pink line on Figure B.14) to the cumulative distribution function of deviations from field dependency curves (vertical lines on Figure B.13 and light green line on Figure B.14). The yellow shaded areas highlight where the deviations from field dependency curves reduces variability and the red shaded areas highlight where deviations from depth dependency curve are less. Overall the light green line is closer to the vertical dark green line (perfect data), but not much. The reduction in variability is only 11%. The remaining variability (100% - 46% - 11%) is still 43%. Thus, while differences between fields are important (Figure B.12), accounting for field variations does not significantly reduce variability in the data.

Studies of trouble during drilling show that trouble can add as much as 30% to drilling costs. Simply adding trouble costs skews the distribution. The light green curve has almost 50% more area above the vertical dark green line (perfect data) and is skewed to the right. Thus, while trouble is most likely to be a significant contribution to the variation remaining, there must be other additive costs, for example testing costs. Not all wells will have the same testing costs, but testing is always additive to other costs, skewing the distribution.

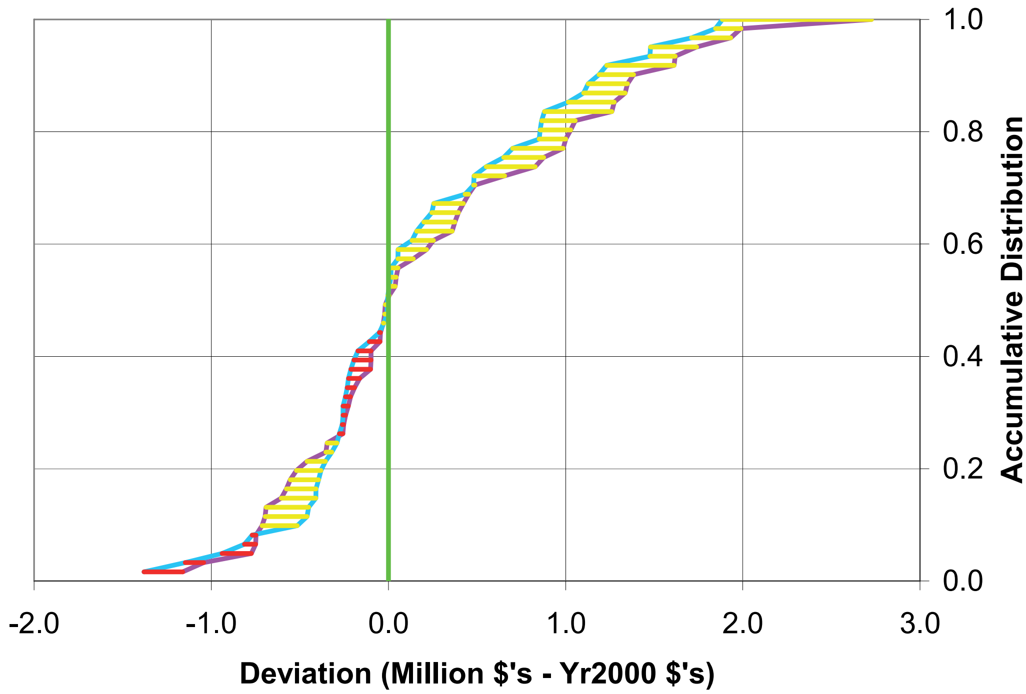


Figure B.14: Cumulative distribution function of deviations from depth dependency curve vs. cumulative distribution function of deviations from field dependency curves

(End of Appendix B)

APPENDIX C.

GEOTHERMAL ENERGY CONVERSION SYSTEMS

1.0 Binary Conversion System Cost and Performance

Note that in discussions of the binary conversion system performance and cost there is reference to net power, or net output. With respect to the derivation of the binary conversion system cost and performance, the net power is the plant generator output less the plant parasitic power requirements. It does not include any geothermal pumping power (production or injection). The net plant power is the plant size that is inputted by the GETEM user to define the plant size. In deriving the correlations to depict binary plant performance and cost, work by others was used where the plant output was reported on a different basis. To use these results, the output from these plants was adjusted to be consistent with the above definition for net plant power.

1.1 Air-Cooled Binary Cycle Performance

The net geothermal fluid, or brine effectives (net plant power produced per unit mass of fluid) defines plant performance in GETEM. This parameter is used because it allows performance to be defined independent of plant size. Net plant power is defined as the plant generator output, less the fan and working fluid pump parasitic loads, i.e., it is the net power from the plant. This net power is exclusive of the power required for the geothermal production and injection pumps. This definition eliminates the effect of the site specific geothermal fluid pumping requirements, allowing the plant cost can be determined on a more generic basis. Note that though the plant performance does not include any geothermal fluid pumping, the associated power requirement is calculated and is included in the determination of the levelized cost of electricity.

The performance of an air-cooled binary conversion system is dependent upon a number of factors including:

- the temperature of the geothermal fluid entering the plant,
- the ambient air temperature,
- the working fluid,
- the number of levels of vaporizers/boilers
- the turbine inlet conditions (pressure and temperature),
- the pinch points in the geothermal heat exchangers and the air-cooled condenser,
- the efficiencies of the turbines, pumps and fans,
- the pressure drops in components and fluid piping systems, and
- any restrictions imposed on the temperature of the geothermal fluid leaving the plant (to prevent the scaling of heat exchange and piping surfaces).

While some of these factors ultimately should be incorporated into the GETEM model, the initial objective was to characterize performance as simply as possible - as a function of the most important of these factors, the geothermal fluid temperature.

Previously INL performed a limited study to estimate the performance of air-cooled binary plants over a resource temperature range from 80° to 240°C (in support Pritchett's work (Pritchett, 1998) on power production from slim holes). Assumptions were used to simplify this analysis, including the use of single component hydrocarbon working fluids, a 37.8°C condensing temperature, and a single vaporizer.

This work was compared to performance or performance projections of other air-cooled plants including:

- EPRI's Next Generation Geothermal Power Plant study (NGGPP) (CE Holt Co, 1996),
- modeling and performance analysis at the INL of an existing air cooled plant (Mines, 2002, and Bliem and Mines, 1991),
- DiPippo's Geothermics paper (DiPippo, 2004) on 2nd law analysis of low temperature binary plants, and
- other INL analysis of different air-cooled plants

The performance of these various studies is shown in Figure C-1, where the net output (exclusive of geothermal fluid pumping) is plotted as a function of the geothermal fluid temperature. The data/curves in this figure that have S^3 in the label represent work done at INL in support of Pritchett's study. Note that there are 3 data sets shown for this earlier work. The 1st assumes there is no restriction on the temperature of the geothermal fluid leaving the plant, the 2nd assumes the effluent brine temperature is limited in order to prevent precipitation of amorphous silica, and the 3rd incorporates the use of recuperation to off-set the effect of this temperature limit.

The net power reported in the NGGPP study (CE Holt Co, 1996) is the net project power, which is the net plant power less the geothermal fluid pumping power. In order to be consistent with the other analysis and GETEM's use of net plant power, the performance of the NGGPP plants were adjusted to remove this pumping parasitic. This was accomplished by first determining the production well pumping power at the NGGPP plants using those assumptions indicated in the report. Injection pumping power was then estimated by assuming that the pressure added by the injection pump was 100 psi. The NGGPP study (CE Holt Co, 1996) reported specific outputs were adjusted (upwards) to account for the total calculated geothermal fluid pumping – those adjusted values are shown in Figure C-1 as the NGGPP w/o pumping power

A comparison of performance data in this figure suggested that there was reasonable agreement in the plant performance up to ~180°C. At higher temperatures, the temperature limit on the effluent brine has an increasingly significant impact on performance. The general agreement of the various performance values in this figure at the lower temperatures suggested that the projections of performance in Pritchett's report (Pritchett, 1998) provided a reasonable depiction of the performance of these plants; this data was curve fitted to develop the desired relationship between net power output and resource temperature.

At the higher resource temperatures this relationship was derived by curve fitting the data where recuperation was used to offset the effect of the temperature constraint on the geothermal fluid. Though the use of recuperation is not a standard practice within the geothermal industry, neither is the use of binary cycles with the high temperature resources. It is postulated that if industry elected to use binary cycles with these resources, recuperation would be incorporated into the design of those plants. The curve fit of this data, which is the basis of the performance calculation in GETEM is also shown in Figure C-1 (the solid line labeled GETEM).

This curve/performance equation has the following form:

$$\mathbf{be = C_0 + C_1{*}T + C_2{*}\,T^2 + C_3{*}\,T^3 + C_4{*}\,T^4}\text{, where}$$

be is net brine effectiveness, w-h/kg
T is fluid temperature, °C
C_0 = 9.41376
C_1 = -0.182542
C_2 = 0.0001765735
C_3 = 0.000012204486
C_4 = -0.0000000335559

In comparing this curve to the other performance values in Figure C-1, the values are generally all within ~±10%, except for the geothermal fluid temperatures above 200°C where it was assumed that recuperation would be used.

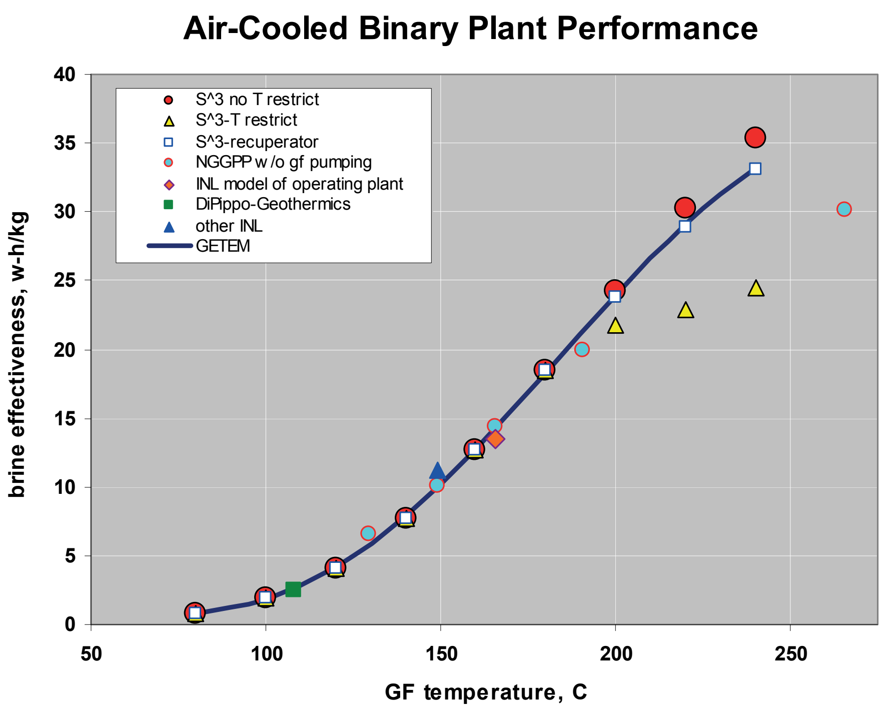


Figure C-1

1.2 Air-Cooled Binary Plant Cost

As is the case with performance, the binary conversion system cost will be dependent upon a number of factors, including most of those identified for cycle performance. As was the case for the binary cycle performance, the intent was to characterize the plant costs in GETEM with minimal required input by the model's user. For the initial development of the GETEM cost correlation, it was decided to characterize the capital cost of the binary plant using the geothermal fluid temperature and user inputted plant size (again, this plant size is the net plant power output).

INL had previously used a cost estimating software, ICARUS Process Evaluator, to estimate costs of air-cooled binary plants. The estimates generated with this software were generally higher than those "quoted" by industry. An effort had been made to determine why and where these estimates were high, and to make the necessary revisions to the software model. This effort had limited success; costs were made available for one plant – comparison with those actual costs suggested that the ICARUS estimates of both equipment costs and installation costs were reasonable. INL's work with ICARUS had focused primarily on plant sizes in the 10 to 20 MW range using 150° to 165°C resources. ICARUS was also used to develop cost estimates for the main equipment items in a binary plant at a number of different sizes and operating conditions (pressure, temperature, and flow).

At the 2004 GRC meeting, a contributor to the EPRI NGGPP study indicated to Dan Entingh that the plant costs in the NGGPP were representative of current costs. Based upon that information, the decision was made to base the development of the cost correlations for GETEM around the costs published in the NGGPP study (CE Holt Co, 1996).

As indicated in the discussion of the use of the NGGPP results in developing the performance correlation for GETEM, the net power for the NGGPP plants is the net project power. In order to use the NGGPP costs to define a specific plant cost ($/kW, net) it was revised reported net plant output so that it did not account for the geothermal fluid pumping. After adjusting the net output for each of the NGGPP plants (see discussion on plant performance), the revised plant costs in $/kW, net decreased (reflecting the additional net power). In Figure C-2, the plant costs ($/kW) for the NGGPP locations are shown before adjusting for the pumping power (red/blue, circular symbols) and after accounting for the pumping power (magenta/blue, square symbols).

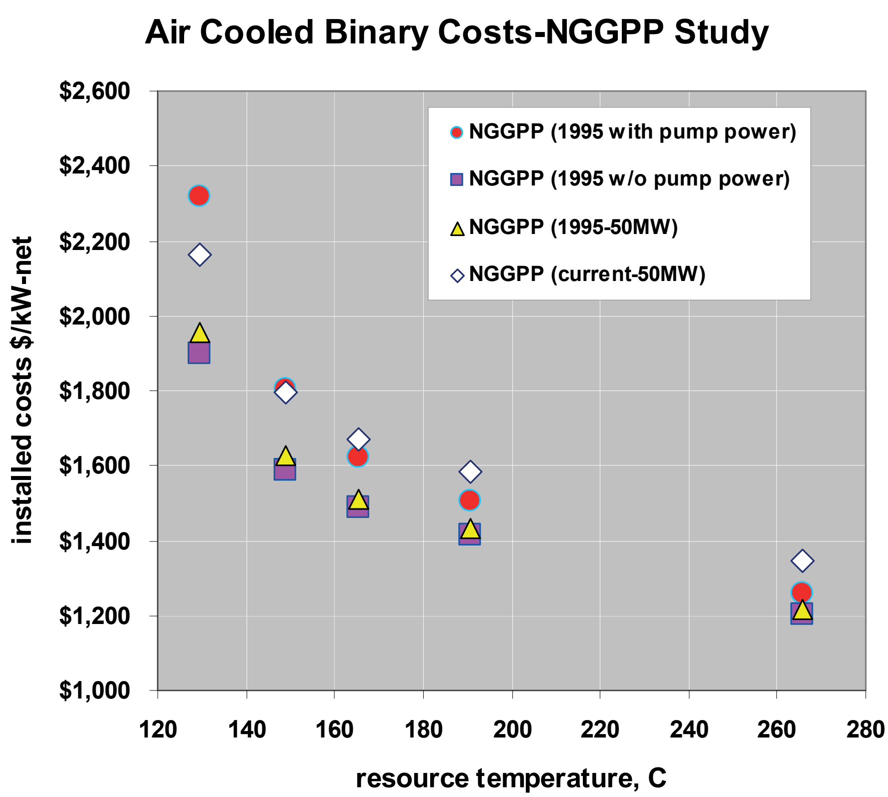


Figure C-2

After revising the 50 MW net project power output to exclude the geothermal fluid pumping, the net plant output from the NGGPP plants varied from ~52 MW to ~61 MW. In order to use the NGGPP costs to develop a cost correlation that was a function only of the resource temperature, it was necessary remove the effect of size on the cost, ie., the NGGPP costs had to be adjusted to a common size (50 MW). This was accomplished by using cost vs size scaling factors for each of the main components defined in the NGGPP study (CE Holt Co, 1996). The scaling factors were developed using the ICARUS cost estimates that were made for a range of sizes for the various equipment items. (Those scaling factors were in general agreement with those found or derived in Milora and Tester's *Geothermal Energy as a Source of Electrical Power*.) The factors were applied to the major components identified in the NGGPP study (CE Holt Co, 1996), and the costs for each location (resource temperature) normalized to a 50 MW net plant. (In scaling costs, it was assumed that the equipment size varied directly with the net plant output.) These plant costs are shown in Figure C-2 as the yellow/black, triangle symbols.

The NGGPP study (CE Holt Co, 1996) was published in 1996. Cost Indexes for related industries (industries using similar equipment) were examined to assess how costs changed since that study was published. (Indexes evaluated included the Chemical Engineering magazine index and the Marshall Swift index, which includes costs from the process industry, refrigeration industry, and power generation.) In all of the indexes examined, costs increased ~1% annually over this period from mid-1994 through 2002. Although the price of steel began to increase disproportionately in around 2004, the effect of these increases was not included in the GETEM cost correlation. It was postulated that with the increase in steel prices, additional production capacity will be added, and prices will return to historic norms. Based upon this presumption, the NGGPP costs (normalized to a 50 MW net plant) were escalated at 1% annually over a 10 year period. These costs are shown in Figure C-2 as the blue/white diamond symbols. (Note that at the low resource temperatures the adjusted current cost is less than the original cost in the NGGPP study (red circles); this is a result of the differences in the handling of the geothermal fluid pumping power.)

The cost correlation used in GETEM is based upon a curve fit of these costs for the NGGPP 50 MW plant with the adjusted current costs. This cost correlation used has the following form:

For $T \leq 190°C$

$\mathbf{Cost = K_0 + K_1{*}T + K_2{*}\,T^2 + K_3{*}\,T^3}$, where

Cost is 50 MW plant cost in \$/kW

T is fluid temperature, °C

$K_0 = 21520.78$

$K_1 = -331.34$

$K_2 = 1.854876$

$K_3 = -0.003491132$

For $T > 190°C$

Cost = Cost@190°C – 3.08*(T – 190)

The GETEM cost correlation is shown in Figure C-3, along with the adjusted NGGPP costs for a 50 MW-net plant (CE Holt Co, 1996).

While this cost correlation accounts for the variation in the resource temperature, the 50 MW size is considerably larger than any current commercial facility. In order for GETEM is to provide an estimated cost for varying other plant sizes, and overall plant cost vs size scaling factor was defined. As part of the effort involved in normalizing the NGGPP costs to a 50 MW plant size, cost-size scaling factors were determined for each of the major conversion system components. These were used to identify an overall scaling factor for the binary plant, which varied from 0.85 to 0.78 for the different plants, with the extremes at the low and high resource temperatures. At the intermediate temperatures, the cost-size scaling factor was ~0.8; this is the value that was subsequently incorporated into GETEM to account for plant sizes other than 50 MW-net. A GETEM cost projection for a 15 MW plant (dashed line) is shown in Figure C-3 as a function of the resource temperature. Also shown in this figure is an ICARUS Process Evaluator (IPE) estimate of the cost of a 15 MW plant on a 165°C resource. This estimate was developed using a cost model where the plant equipment costs and direct installation costs had been validated using information from an existing plant. At this single point there is reasonable agreement with the GETEM correlation for the 15 MW plant.

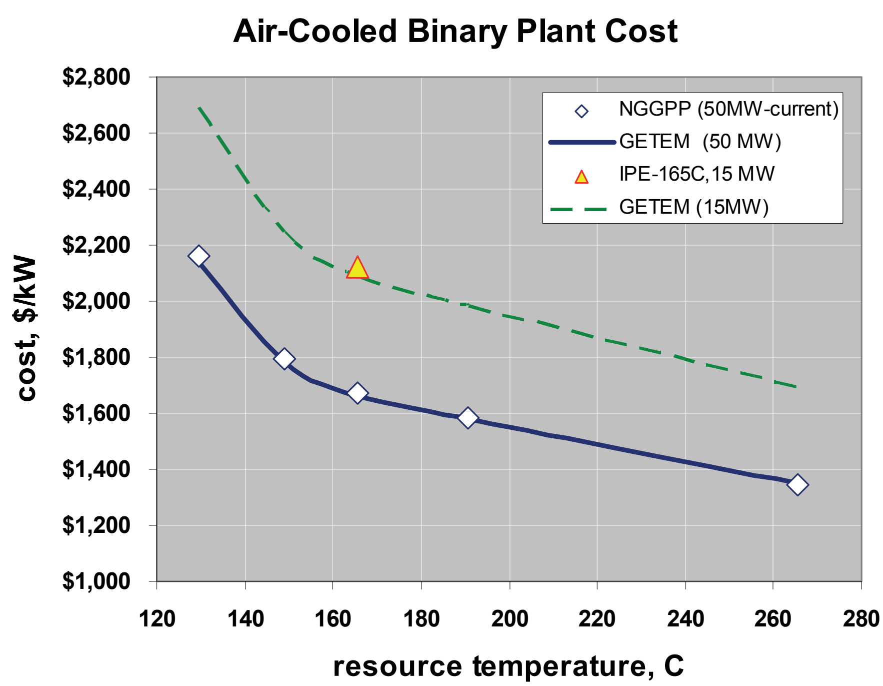


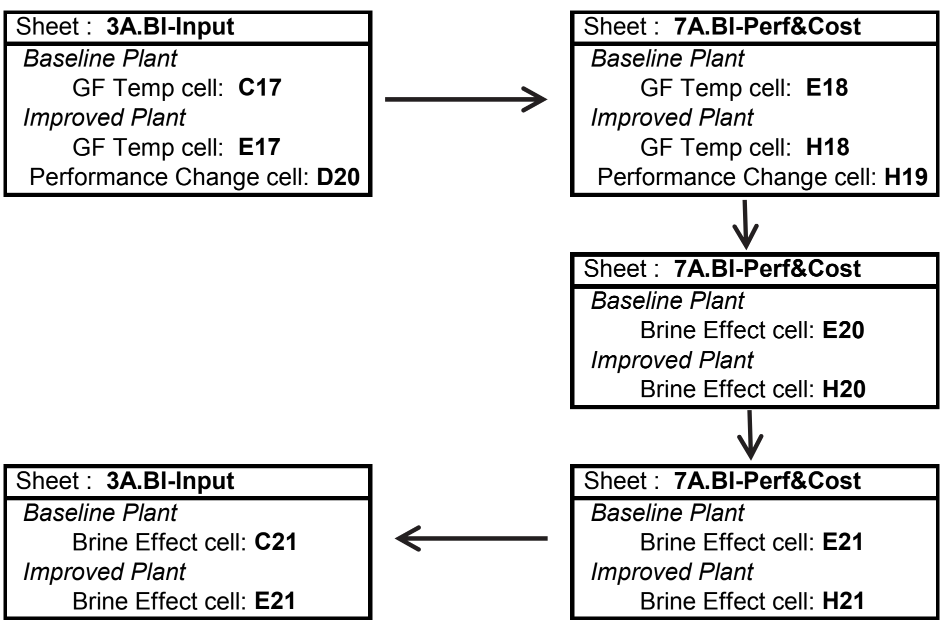
Figure C-3

1.3 Calculations in GETEM

GETEM determines performance and capital cost based upon user input on sheet **3A.BI-Input**. The input on this sheet that is used for these calculations is shown below.

	A	B	C	D	E
16	**System Input Parameters**				
17	**Temperature of GT Fluid in Reservoir**	Deg-C	**150**	**1.00**	**150**
18	**Plant Size (Exclusive of Brine Pumping)**	MW(e)	**15.0**	**1.00**	**15.00**
19	**Number of independent power units**		**1**	**1.00**	**1.00**
20	**Change in Plant Peformance**			**1.00**	
21	**Calculated Brine Effectivenss**	w-h/lb	**4.63**		**4.63**
22	***Brine Effectiveness (exclusive of brine pumping)***	Calculate Y or N	***Y***		***Y***
23	***If N (no), enter value in cell C19 and/or E19***	w-h/lb	**-**		**-**
24	**Brine Effectiveness Used**	w-h/lb	**4.63**		**4.63**
25	***Apply improvement to reducing flow requirement or increasing power output***	F - flow or power P		***P***	
26	**Change in Plant Cost**			**1.00**	
27	**Calculated Plant Cost**	$/kW	**$ 2,254**		**$ 2,254**
28	***Plant Cost***	Calculate Y or N	***Y***		***Y***
29	***If N (no), enter value in cell C24 and/or E24***	$/kW	**$ -**		**$ -**
30	**Plant Cost Used**	$/kW	**$ 2,254**		**$ 2,254**

Performance - Plant performance is calculated as a function of the resource temperature. The performance calculation (net brine effectiveness) is done on cost and performance work sheet **7A.BI-Perf&Cost**, and is then exported back to the input sheet **3A.BI-Input**. In calculating the performance of the improved plant, the change in performance is also exported to the cost and performance work sheet, along with the temperature of the improved plant. (Note that a value >1 indicates an increase in performance, i.e., brine effectiveness.) In the cost and performance worksheet, this value is multiplied by the calculated performance using the improved plant temperature. The flow of information between sheets in calculating plant performance is depicted below.

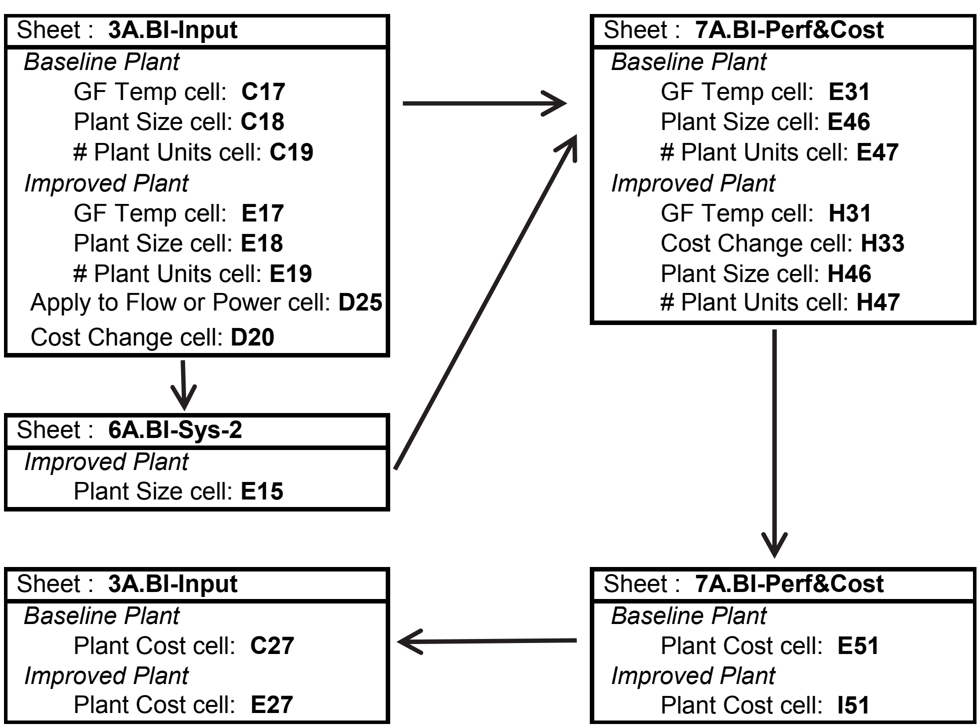


The GETEM user has the option of using the calculated plant performance that is exported back to the input sheet, or to input a plant performance. If the user elects not to use the calculated brine effectiveness, a "N" (No) response is provide in cells ***C22*** and/or ***E22***. The user then provides the desired brine effectiveness in cell ***C23*** and/or ***E23***. The values for brine effectiveness that GETEM uses in its subsequent calculations are those indicated in cell ***C24*** and ***E24***. The primary use of this performance parameter in GETEM is to establish the total geothermal flow rate required for a given plant size, or if the improved plant flow rate is fixed, the net output from the plant.

Cost - The binary plant capital cost is calculated in GETEM as $ per kW-net, where net power is the net plant output, exclusive of the geothermal fluid pumping power (also the user inputted plant size). The cost calculation is done on cost and performance work sheet **7A.BI-Perf&Cost**, and is then exported back to the input sheet **3A.BI-Input**. The cost of the baseline plant is determined based upon the user input for the fluid temperature, plant size, and the number of independent units. The sequence for the cost calculation is as follows:

- fluid temperature is used to determine the cost of a 50 MW, net plant
- the inputted plant size and number of independent units is used to establish the size of the plant that will be used in the cost estimate
- the 50 MW cost is adjusted upward with the cost index, and
- the 0.80 cost-size scaling factor is applied to that 50 MW plant cost to get the cost for plant size that reflects the number of independent units used

The improved plant costs are also calculated in the cost and performance work sheet (**7A.BI-Perf&Cost**). The cost change for the improved plant is multiplied by the cost determined for the 50 MW plant at the improved plant resource temperature. (Note that a cost change <1 indicates the plant capital cost is decreased.) The determination of the cost of the improved plant scenario differs in one respect from the baseline plant. The user has the option of either using an increase in plant performance to increase power production from the same well field, or to decrease the number of wells and maintain the baseline plant output. If the user elects to increase power output, the improved plant cost is calculated based upon the increased output. The level of the increased output is calculated on the work sheet for the improved plant (**6A.BI-Sys-2**). The flow of information between sheets in calculating plant capital cost is depicted below.



The GETEM user also has the option of using the calculated plant cost that is exported back to the input sheet, or to input a plant cost. If the user elects not to use the calculated plant cost, a "N" (No) response is provide in cells ***C28*** and/or ***E28***. A power plant cost is then inputted in cell ***C29***, and/or ***E29***. The values for plant cost that GETEM uses in its subsequent calculations are those indicated in cell ***C30*** and ***E30***. In these subsequent calculations, the total plant cost is the product of this value and the inputted plant size (cell ***C18*** and/or ***E18***). Note that there is a plant performance improvement (cell ***D20***) and one opts to produce more power (cell ***D25***), the improved plant cost is determined based on this output (in lieu of that in cell ***E18***).

It should be noted that although the GETEM power plant cost correlation does not contain contingency, a contingency term is subsequently applied as part of the determination of the levelized cost of electricity. A contingency is applied to all project capital costs (including the power plant) and included in the total project cost. The contingency term is inputted on the input sheet (**3A.BI-Input**).

1.4 Issues with Air-Cooled Binary Portion of the GETEM Model

Performance

Issues associated with the binary conversion system performance include:

- There is an inherent increase in the uncertainty of the performance projections when only the resource temperature is used to predict the performance of a binary plant. Several other factors will influence plant performance. The variation in these different factors will likely have a larger impact on the projected plant performance with the lower temperature resources. In particular, variation in the design ambient temperature will have a larger impact on the plant performance at the lower resource temperatures.

  As an example with a 125°C resource, the available energy decreases by ~9% with an increase in the design ambient temperature from 10° to 15°C. With a 200°C resource, the same change in the ambient decreases available energy by ~5.6%. Changes in available energy (the ideal work that can be done by the conversion system) are indicative of the changes that one would get in a plant. The air-cooled plant is typically designed for an average annual ambient temperature; in the Basin and Range region of the western US, the average ambient temperature typically ranges from 7° to 13°C.

- The assumption made regarding the use of a single vaporizer (pressure) may impose a performance penalty at with some of the lower temperature resources, where the use of multiple boiling pressures decreases cycle thermodynamic losses (irreversibilities). At higher resource temperatures this may not be much of an issue because the performance optimums for some fluids occur when the fluid is vaporized at supercritical pressures. (Note this refers to a performance optimum, which may not represent and economic optimization.)

- In the prior work that was used to establish the performance correlation, the condensing temperature was fixed and did not represent any optimization of net power (air flow/fan power vs. turbine exhaust pressure).

- There is uncertainty in the GETEM calculations of binary plant performance for resource temperatures above ~200°C. The current characterization/correlation is based on limited analysis that suggests recuperation will offset the adverse impact from minimum effluent brine temperature limits. While this uncertainty has minimal impact on analysis of lower temperature hydrothermal systems, it will impact the feasibility analysis of higher temperature EGS projects that use the air-cooled binary conversion system.

Cost

Issues associated with the binary conversion system cost include:

- In practice, the cost of the conversion system is directly linked to the plant performance, irrespective of technology improvements. At a given resource temperature, increases in performance will almost always have an associated increase in the conversion system cost ($/kW). For example, one can continue to make heat exchangers larger and derive some increase in power output; however at some point the additional cost offsets the benefit of the additional power. The importance of this linkage is in how the plant output impacts the contributions of all other costs to the levelized cost of electricity. The revenue stream generated from the power produced by the plant covers all operating expenses, as well as retires the debt associated with the total project capital costs (not just the plant cost). If the operating costs and other capital costs are significant, the minimum levelized cost of power will not be associated with a minimum plant cost.

  This linkage could be accomplished by adjusting the user input and not using the GETEM calculations for either cost or performance, however there is minimal information available to guide the user in making these adjustments. While it is recognized that this issue exists, it is postulated that the plant cost and performance projections presently made by GETEM are representative of those one would expect for binary applications and well depths targeted in DOE's Multiyear Program Plan.

- Plant cost like its performance is a function of several parameters. Basing costs on a limited number of these parameters increases the uncertainty in the estimates that are developed by GETEM.

- Currently GETEM does not include provisions to account for inflationary increases in plant cost or for the use of alternative materials of construction (it is assumed the material of construction for binary plants is carbon steel).

  The current year costs projected by GETEM are 2004. It is recognized that because of the increases in steel costs, a plant built today will likely cost more that is predicted in GETEM. The increases in steel costs will have the largest impact on the heat exchanger costs and the costs of structural steel, piping and pressure vessels. The impact on pump and turbine-generator costs will be less, as the labor component in fabricating this equipment is considerably larger than the material costs. A crude estimate of the effect of the ~50% increase in the cost of steel at the end of 2004 (relative to 1995), is that it would add up to ~$200 per kW to the cost of a 15 MW plant.

  Though it is postulated that additional steel production capacity will be built to meet current demand and the price of steel will eventually return to historic norms, steel production is energy intensive. Assuming that energy costs are likely to remain high, it is probable that steel costs will not return to pre-2004 levels, and additional costs will be incurred that are not currently accounted for in the cost projections.

- The GETEM projection of the change is plant cost with size is dependent upon the overall cost vs size scaling factor used (0.8 for binary conversion systems). There is uncertainty with this scaling factor, in part because of differences in plant design approaches with varying plant sizes (output). As plants increase in size, it is probable that multiples of different components will be used (for example, multiple turbines operating in parallel). Conversely, if plant size decreases, it is probable that only a single piece of equipment would be used. The GETEM cost correlation was developed using the NGGPP plant costs as a reference. It is not known whether the NGGPP costs reflect the use of multiples of the different components, however because this approach appears to be typical industry practice in larger plants, it is assumed that the NGGPP costs also reflect this approach. (The existing plant that provided the basis for INL's ICARUS plant cost estimate had multiple turbines and pumps).

  Because of potential differences in a plant's use of multiples of specific equipment items, there is uncertainty in the GETEM cost correlation. This is especially true as the plants decrease in size; at some point, plant designs will incorporate only single components of a given equipment type. The depiction of how this impacts the overall scaling factor is beyond the scope of this effort, however in using the GETEM model it must be recognized that there is a plant size below which the uncertainty in the cost projections will increase.

- The overall scaling factor for binary plants is impacted by the scaling factor used for the turbines. In establishing the turbine scaling factor for this work, there were considerable differences in the scaling factor obtained from the various sources for turbine costs. Values for binary turbines varied from 0.5 to 0.75 (steam turbine cost scaling factors had less variation - 0.75 to 0.85). Because the turbine is a major contributor to the cost of a binary plant, the uncertainty in the scaling factor for this piece of equipment increases the uncertainty in the overall scaling factor that is used.

- Like the performance correlations, the binary plant cost projections at resource temperatures above ~200°C have a higher level of uncertainty.

- The prior work used also assumed pinch points of 10°F in the geothermal fluid heat exchangers. This does not necessarily represent an economic, which does not necessarily represent at economic optimum. (The thermodynamic optimum will occur when the pinch points approach 0°F.) If plants are designed with higher pinch points (smaller heat exchangers) the models predicted performance will be high for a given resource temperature.

2.0 Flash-Steam Conversion System Cost and Performance

Note that in discussions of the flash-steam conversion system performance and cost there is reference to net power, or net output. With respect to the derivation of the flash conversion system cost and performance, the net power is the plant generator output less the plant parasitic power requirements. It does not include any geothermal pumping power (production or injection). This net plant power is the plant size that is inputted by the GETEM user to define the plant size. In deriving the correlations to depict plant performance, work by others was used where the plant output was reported on a different basis. To use these results, the output from these plants was adjusted to be consistent with the above definition for net plant power

The derivation of the performance and cost correlations for the flash plant required that the plant parasitic loads be characterized, allowing a gross plant output to be determined. Although the different plant parasitic loads are calculated, the final performance and cost projected by GETEM for the plant are in terms of the net plant power definition given.

2.1 Flash-Steam Cycle Performance

The net brine effectiveness that characterizes the binary conversion system performance is also used for the flash-steam conversion system. The net brine effectiveness is the net plant power divided by the total geothermal flow, where net power is the generator output less plant parasitic loads. Though it does not directly impact the flash conversion system performance projection, GETEM allows the user the option of utilizing self-flowing or pumped wells (wells are pumped with the binary conversion system). When pumped wells are used, the required power is determined separately from the flash plant performance.

The performance of a flash-steam plant is based upon the assumption that heat will be rejected evaporatively. Performance is dependent upon a number of factors, including:

- the pressure, temperature, and quality of the geothermal fluid entering the plant,
- the ambient wet bulb temperature,
- the number of flash pressures,
- the flash pressure (turbine inlet pressure),
- the temperature rise of the water
- the approach temperatures in the condenser and cooling tower
- the efficiencies of the turbines, pumps and fans,
- the pressure drops in components and fluid piping systems,
- the levels of non-condensable gases in the geothermal fluid entering the plant,
- and any temperature limit placed on the temperature of the effluent geothermal fluid (to prevent silica precipitation).

Initially, an attempt was made to model the flash-steam conversion system based upon only the resource temperature using the EPRI Next Generation Geothermal Power Plant (NGGPP) study (CE Holt Co, 1996). (For the flash systems, this temperature is that of the sub-cooled liquid in the reservoir, with the assumption that the subsequent flashing occurs either in the well bore or in the flash vessels.) This initial effort suggested that the performance could not be characterized only using this temperature. Performance was also dependent upon the number of flash pressures and the level of non-condensable gases (ncg) in the fluid entering the plant.

In order to account for the effect of these additional parameters, a flash-steam plant spreadsheet model was used to depict the performance of both a single and dual flash steam plant with varying ncg's levels and resource temperatures. The output from this model was then used to develop the necessary correlations to predict plant performance. The plant model results were based upon the following assumptions:

- 75°F air temperature having a 40% relative humidity
- 10°F approach to wet-bulb in the cooling tower
- 7.5°F approach in the condenser (cooling water to condensation temperatures)
- 20°F cooling water temperature rise
- 28°F air temperature rise in cooling tower
- ncg's removed with 3 stage vacuum pump

- 75 ft cooling water pump head
- 1 psi pressure drop between flash vessel and turbine inlet
- 0.75 inch H_2O air pressure drop in cooing tower
- flash pressure > 1 atm (14.7 psia)
- no temperature limit imposed to prevent silica precipitation

Sensitivity studies were done for some of the assumed temperature rises and pinch points to identify those that gave maximum net output (for a 200°C or 392°F resource). Results of the sensitivity study were compared to information for existing plants to check their "reasonableness". If there were significant differences, either the plant information, or an average of the two was used. (The sensitivity studies did not include any cost analysis; cost optimums may not correspond to the performance optimum. Conversely, information from an operating plant may be the result of site specific factors.)

In developing the performance correlation that would be used in GETEM, the flash plant spreadsheet model was first used to determine performance as a function of the resource temperature with no ncg's present. At a given resource temperature, the high and low flash pressure in the dual flash plant were varied until a maximum net power (exclusive of the geothermal production and injection pumping) was achieved, with the constraint that the flash pressure always be >1 atm. A similar analysis was done for a single flash plant. The model results are shown below in Figure C-4 as the yellow diamond symbols, along with the curves for the dual and single flash system correlations that were incorporated into the GETEM model. Note that the brine effectiveness shown in this figure is the net value, with zero non-condensable gas loading (no parasitic associated with ncg removal)

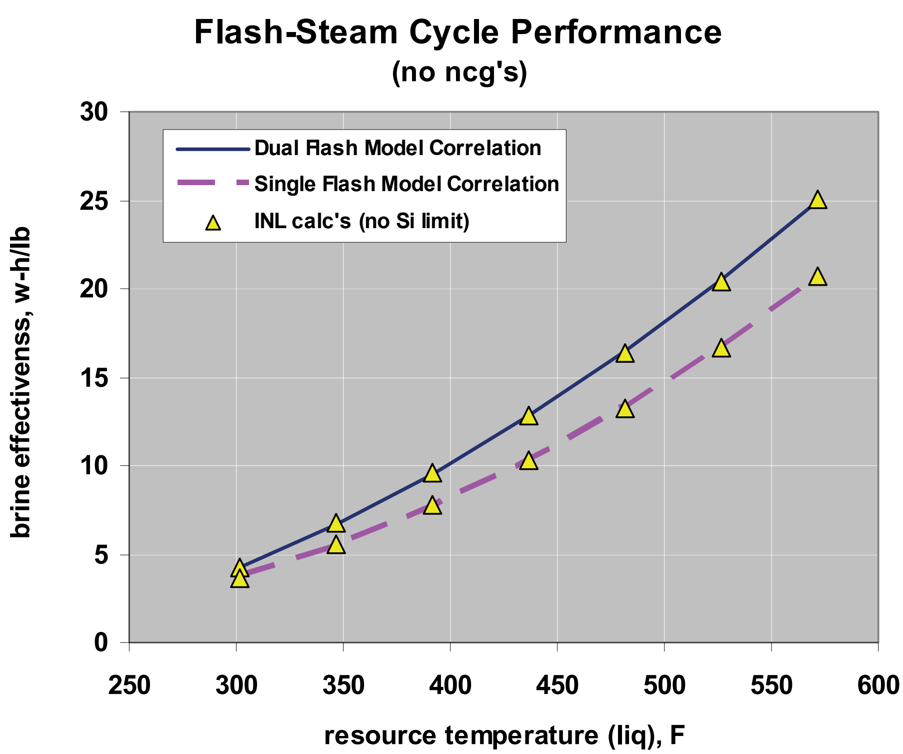


Figure C-4

The correlation shown in this curve for the dual flash cycle (and that is currently used in GETEM) has the following form:

be = C_0 + C_1*T + C_2* T^2, where

be is net brine effectiveness, w-h/lb,gf
T is fluid temperature, °F
C_0 = -1.406848
C_1 = -0.01166551
C_2 = 0.000101009

The correlation in this curve for the single flash cycle has the following form:

be = C_0 + C_1*T + C_2* T^2, where

be is net brine effectiveness, w-h/lb,gf
T is fluid temperature, °F
C_0 = 2.6718
C_1 = -0.027828
C_2 = 0.000104

Again neither of these correlations account for the effects of non-condensable gases (ncg's).

The flash plant spreadsheet model was then used to examine the effect of ncg levels varying from 50 to 20,000 ppm. In this model, the power required to remove the ncg's is calculated assuming the use of vacuum pumps (3 stages). Results were used to establish a correlation that accounted for the effect of non-condensable gases. The results for the dual flash cycle are summarized in Figure C-5 for ncg levels of 1,000 and 10,000 ppm. The magenta squares and the white circles represent the performance calculated with the spreadsheet model for both of these ncg levels.

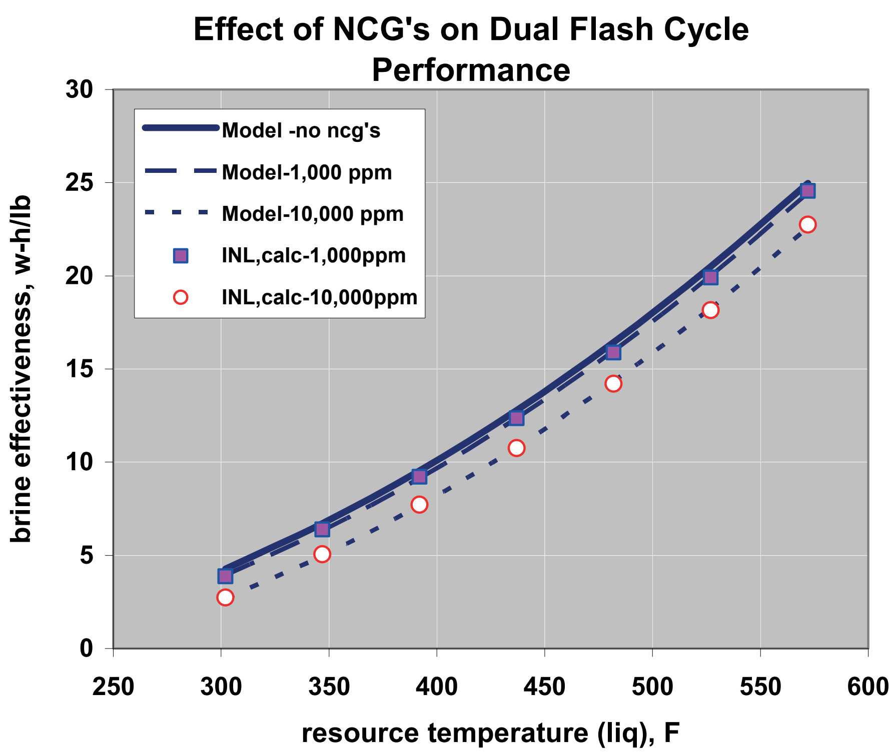


Figure C-5

The correlation that was developed for the power required to remove the non-condensable gases has the following form:

power,ncg = $(D*T + D_1)*PPM^{\wedge}D_2$, where

power,ncg is power requirement, w-h/lb,gf

T is fluid temperature, °F

D = 0.0000065

D_1 = 0.0017

D_2 = 0.66

Again, this correlation assumes the use of vacuum pumps to remove the ncg's.

In Figure C-5, the lines (no symbols) are the GETEM performance projections for net brine effectiveness as a function of temperature and the ncg level. These values are representative of those used to depict the plant performance in the GETEM model – net plant output, exclusive of any geothermal fluid pumping power.

The calculations in GETEM for this brine effectiveness are made in the following sequence:

- net plant performance is calculated as function of resource temperature with no ncg's present (either single or dual flash)
- the power required to remove non-condensable gases is calculated
- the power necessary to remove the ncg's is subtracted from the plant performance determined in step #1 to account for the effect of the ncg's on performance – this is the value that depicts plant performance in GETEM

As part of the development of the performance correlations for GETEM, the results obtained using the flash plant spreadsheet model were compared to the performance of the flash plants in the NGGPP study (CE Holt Co, 1996). The assumptions at each of the NGGPP sites varied, and were different than those used to depict the flash steam plant performance. In some instances, the different parameters were identified, and in others they were not, making a direct comparison of results difficult. A comparison of the flash plant spreadsheet model results with the NGGPP results on an as equivalent basis as possible is shown in Figure C-6 for the free-flowing NGGPP sites (no brine pumping).

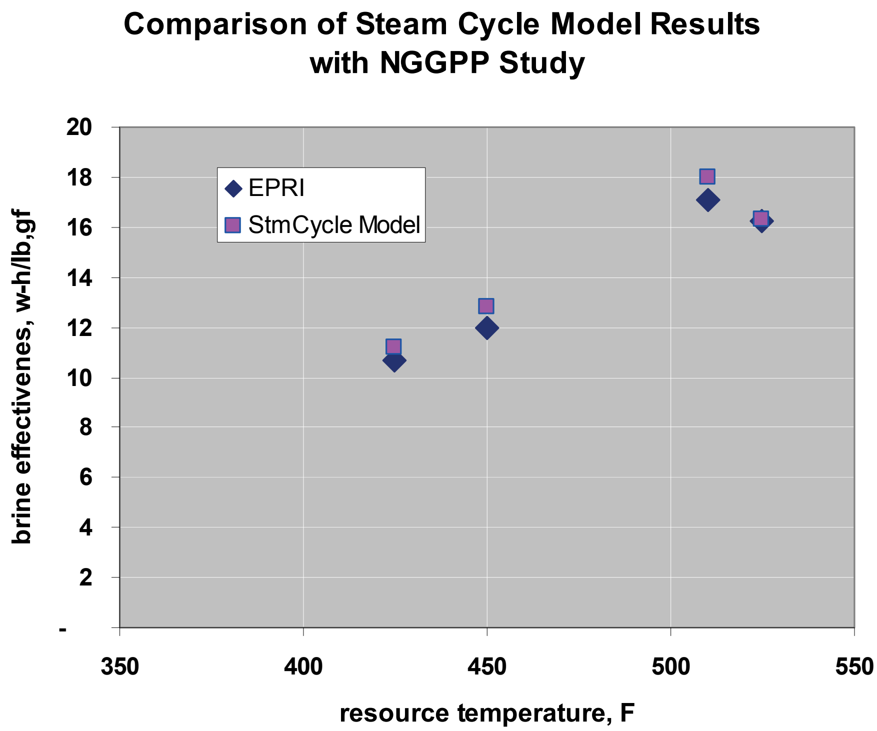


Figure C-6

There is a reasonably good match between the flash plant spreadsheet model projection and the NGGPP study (CE Holt Co, 1996) for the Coso plant (highest temperature case in this figure). For the other 3 cases the flash plant spreadsheet model results are higher (up to ~7%). One of the possible reasons for these differences is the steam plant model uses vacuum pumps (3 stages) to remove the ncgs, while each of these 3 NGGPP cases used steam ejectors for ncg removal (the Coso NGGPP plant used 3 stage vacuum pumps).

It should be noted that the approach used to derive the GETEM performance correlation does not account for any temperature limit placed on the effluent geothermal fluid to prevent silica precipitation. Not imposing this temperature limit appears to be consistent with the approach used in the NGGPP. It also is thought to be consistent with industry practice, where chemical inhibitors are used to keep the silica in solution until the fluid has been injected back into the reservoir.

GETEM also calculates the gross brine effectiveness that is used in the ***only*** determination of plant costs. The plant house loads exclusive of the ncg removal power requirement and the geothermal fluid pumping power are expressed in the model as:

house load = $E_0 + E_1 * T + E_2 * T^2$, where
house load is in w-h/lb,gf
T is fluid temperature, °F
E_0 = -0.7854
E_1 = 0.0038423
E_2 = -0.0000010642

This correlation was developed using results from the spreadsheet model of the flash plant. The gross power from the plant is the calculated net power plus this calculated house load and the calculated power required to remove the ncg's.

In GETEM the calculations of the power required to remove the ncg gases and of the house load power are based on the dual flash cycle; the same correlations are also used for single flash plant.

GETEM also includes the following correlation for determining the ratio of cooling water to geothermal fluid flow rates.

flow ratio = $F_0 + F_1 * be_{,gross} + F_2 * be_{,gross}^2$, where

flow ratio is $lb/h_{,cw}$ / $lb/h_{,gf}$

$be_{,gross}$ is the gross plant power, w-h/lb,gf

$F_0 =$ 0.5589

$F_1 =$ 0.8957

$F_2 =$ -0.01114

This flow ratio is used in estimating the chemical costs needed to treat the cooling water as part of the plant O&M costs. Though this correlation is based on the calculated gross power, it is also a function of the cooling water temperature rise (this correlation is based upon the assumed cooling water temperature rise of 20°F).

2.2 Flash Steam Plant Cost

Previous work by INL with the ICARUS Process Evaluator (IPE) software focused on developing costs for air-cooled binary plants. Limited work had been done on estimating the costs of specific components in a flash plant; however entire plant estimates were not generated. Based upon the comment received from the contributor to EPRI NGGPP study that those costs were representative of current costs (2004), a decision was made to base the development of the flash steam conversion system costs for GETEM around the costs published in the NGGPP study.

Though it was initially intended that, like the binary plant, the flash plant performance and cost would be based upon only the resource temperature, this approach was abandoned when it became apparent that it would be necessary to account for the effect of the non-condensable gases. In order to depict the plant cost, an approach was used where costs were initially derived for each of the major equipment items and systems based upon the *gross* brine effectiveness of the plant, where *gross* brine effectiveness is the plant generator output divided by the total geothermal fluid flow. The use of the *gross* brine effectiveness eliminates the effects of variations in house parasitics, and reflects equipment sizes and cost that are more representative of the total geothermal fluid flow rate. The development of the correlations to define the *gross* brine effectiveness is discussed in Section 2.1 of this appendix.

The determination of the flash steam plant capital cost required user input for the geothermal fluid temperature, plant size (net plant power), ncg levels and the hydrogen sulfide (H_2S) level. The determination of the installed plant capital cost also requires user input of an equipment multiplier, which is multiplied by the sum of the cost of the major plant equipment to get an installed plant cost.

The gross plant output provided in the NGGPP study (CE Holt Co, 1996) was used with the reported major component/system costs to establish equipment costs in terms of \$ per kW, gross. This information and the IPE costs for the turbine-generator were used to develop the following correlations to represent the major component/system costs in a flash plant:

Geothermal fluid handling equipment: $\$/kW = 85*be^{-0.91}$
Turbine-generator: $\$/kW = 588*(MW,gross)^{-0.29}$
Heat rejection
***Surface condenser*: $\$/kW = 37*be^{-0.17}$**
***Direct contact condenser*: $\$/kW=102.5*be^{-0.13}$**
Plant auxillary: $\$/kW = 10.5*be^{-0.17}$ (fire and plant air systems)
Other equipment: $\$/kW = 13.5*be^{0.005}$

In these equations **be** is the *gross* brine effectiveness that is based upon the plant generator output.

The information in the NGGPP study (CE Holt Co, 1996) was also used to develop correlations to predict the cost of the ncg removal system and a hydrogen sulfide (H_2S) abatement system. The costs for these systems are derived as functions of the ncg and H_2S levels in the geothermal fluid. The correlations used to depict these costs are:

Non-condensable gas removal
***Vacuum pumps*: $\$/kW = 15*e^{(0.58*lb,ncg/kW)}$**
***Jets:* $\$/kW= 1.40*e^{(3.26*lb,ncg/kW)}$**
H_2S removal: $\$/kW = 1135*(lb\ of\ H_2S/kW)^{0.59}$

As was the case for the rest of the plant equipment, the power (kW) term is the gross power.

The table below shows the equipment costs from the NGGPP study (CE Holt Co, 1996) and the corresponding costs generated in GETEM (note that all equipment costs are on a $\$/kW_{gross}$ basis). Exclusive of the turbine-generator costs, the equipment costs projected by GETEM are typically within 7% of the equivalent NGGPP costs. The turbine-generator costs used in developing the GETEM model cost projection are less than those used in the NGGPP study. The GETEM cost correlation used was developed using the ICARUS Process Evaluator (IPE) cost estimates for a range of steam turbine-generator sizes. At an equivalent turbine-generator size, the IPE costs are consistently lower than the NGGPP costs; in addition the IPE costs also decrease (on a \$ per kW basis) with size. As indicated in the table below, some of the turbine generator costs (on a \$/kW basis) in the NGGPP study (CE Holt Co, 1996) increase with an increasing gross plant output. This occurs because 2 turbine-generator sets are used at some of the locations in the NGGPP study. (Note that GETEM does not account for the use of multiples of a given equipment item.)

Tgf	570°F	525°F	510°F	450°F	425°F	375°F	330°F	300°F
Gross Power, MW	50.25	56.36	54.17	50.72	50.89	57.77	58.6	60.66
NGGPP Turbine Generator Count	1	1	1	1	1	2	2	2
NGGPP Study								
GF Handling Equip	\$3.82	\$5.50	\$5.66	\$7.13	\$7.22	\$14.65	\$15.96	\$19.83
Heat Rejection	\$70.55	\$79.98	\$68.86	\$73.46	\$74.69	\$103.37	\$110.87	\$98.26
Plant Aux	\$6.71	\$6.11	\$6.51	\$6.66	\$6.76	\$7.52	\$8.23	\$8.12
Vacuum System	\$1.79	\$28.75	\$1.66	\$2.00	\$1.77	\$3.69	\$18.32	\$50.36
H2S Abatement	\$19.44	\$52.61	\$22.50	\$10.82	\$9.59	\$34.38	\$39.95	

Other Equip	$13.75 $12.85 $12.87 $13.72	$13.70 $13.69 $13.74 $13.60
Total (without T-G)	$116.06 $185.80 $118.06 $113.80	$113.74 $177.30 $207.07 $190.18
Turbine-Generator	$228.70 $215.05 $218.92 $230.69	$231.07 $327.24 $328.65 $325.16
TOTAL ($/kW-gross)	$344.76 $400.85 $336.98 $344.49	$344.81 $504.54 $535.72 $515.34
GETEM		
GF Handling Equip	$5.74 $6.25 $6.11 $8.43	$9.35 $13.22 $17.59 $24.40
Heat Rejection	$69.75 $84.13 $70.37 $73.68	$74.78 $96.77 $102.07 $108.5
Plant Aux	$6.35 $6.45 $6.42 $6.82	$6.95 $7.42 $7.82 $8.32
Vacuum System	$1.76 $28.98 $1.90 $2.34	$1.52 $3.25 $18.42 $20.13
H2S Abatement	$17.24 $55.27 $20.47 $11.13	$10.44 $33.77 $40.64 $3.32
Other Equip	$13.70 $13.70 $13.70 $13.67	$13.66 $13.64 $13.62 $13.59
Total (without T-G)	$114.54 $194.77 $118.96 $116.06	$116.71 $168.07 $200.16 $178.28
Turbine-Generator	$188.82 $182.64 $184.75 $188.31	$188.13 $221.71 $220.79 $218.60
TOTAL ($/kW-gross)	$303.36 $377.41 $303.71 $304.37	$304.84 $389.78 $420.95 $396.88
Total Cost Delta (*w/o T-G*)	($1.52) $8.97 $0.90 $2.26 $2.97	($9.23) ($6.91) ($11.90)
Total Cost Delta (*with T-G*)	($41.40) ($23.44) ($33.27) ($10.12) ($21.28)	($114.76) ($114.77) ($118.46)

Once GETEM establishes the equipment costs on basis of the *gross* brine effectiveness, it is adjusted to a basis of net brine effectiveness by multiplying the equipment and system costs by the ratio of gross to net power (or brine effectiveness). The resulting value is the expected equipment cost for a 50 MW, net plant. In the NGGPP report (CE Holt Co, 1996), the equipment cost multiplier for all of the flash plants is 2.53. This installation multiplier is a user input in the GETEM model. It is multiplied by the sum of the equipment and system costs determined by GETEM to obtain the installed cost of a 50 MW,net plant. It is recommended that the NGGPP multiplier be used unless the user has a better value to use.

The IPE costs for steam turbine-generator sets indicated that their cost varied with size to the ~0.7 power (for size >10 MW). It was assumed that the remaining plant equipment cost varied with size to the 0.8 power. Because the turbine-generator costs represented about half of the total equipment cost, an overall plant cost/size scaling factor of 0.75 is used in the model to calculate costs at different plant sizes.

The NGGPP study was published in 1996. To account for increases in cost since then, the cost indexes used for the binary conversion system costs were also applied for the flash-steam plant costs.

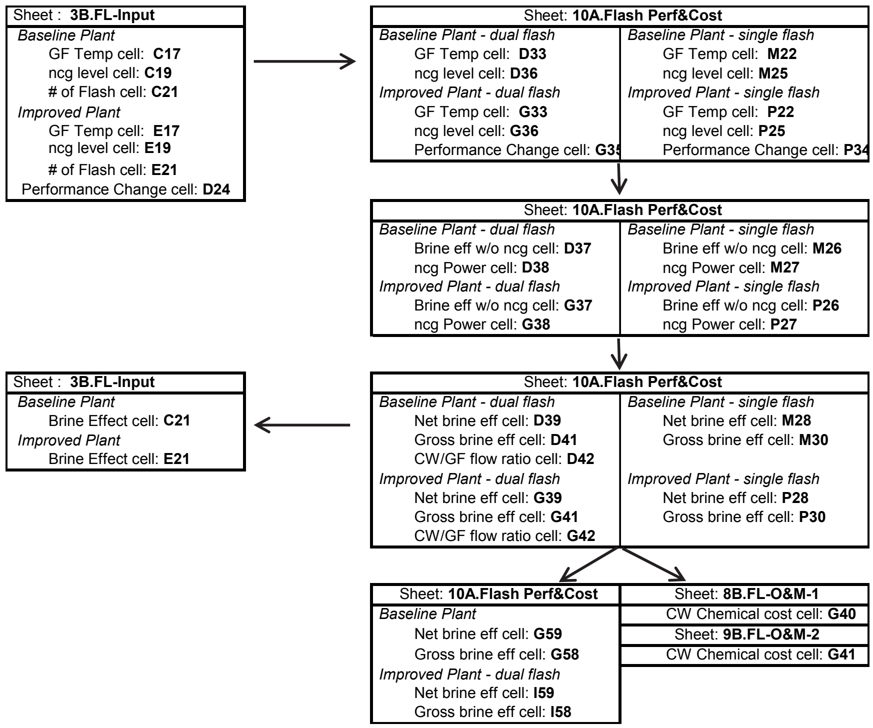
2.3 Flash-Steam Calculations in GETEM

GETEM determines flash plant performance and capital cost based upon user input on sheet **3B.FL-Input**. The input on this sheet that is used for these calculations is shown below.

	A	B	C	D	E
16	**System Input Parameters**				
17	**T,gf reservoir**	C	**200**	**1.00**	**200**
18	**Plant Size (Exclusive of Brine Pumping)**	MW(e)	**50.0**	**1.00**	**50**
19	**ncg level (based on total flow)**	ppm	**200**	**1.00**	**200**
20	**H2S level (based on total flow)**	ppm	**2**	**1.00**	**2**
21	***Number of flashes***	1= **1** flash, 2= **2** flash	***2***		***2***
22	***Condenser type***	S=surface; DC= direct contact	***S***		***S***
23	***NCG Removal***	J = jet; VP=vac pmp	***VP***		***VP***
24	**Change in Plant Peformance**			**1.00**	
25	**Calculated Brine Effectivenss**	W-h/lb	**9.40**		**9.40**
26	***Brine Effectiveness (exclusive of brine pumping)***	Calculate Y or N	***Y***		***Y***
27	**If N (no), enter value in cell C24 and/or E24**	w-h/lb		**1.00**	**-**
28	**Brine Effectiveness Used**	w-h/lb	**9.40**		**9.40**
29	***Apply improvement to reducing flow requirement or increasing power output***	F - flow or P - power		***F***	
30	**Change in Plant Cost**			**1.00**	
31	**Calculated Plant Cost**	$/kW	**$ 995**		**$ 995**
32	***Plant Cost***	Calculate Y or N	*Y*		*Y*
33	**If N (no), enter value in cell C29 and/or E29**	$/kW	-		-
34	**Equipment cost multiplier for installed cost**		**2.53**	**1.00**	**2.53**
35	**Plant Cost Used**	$/kW	**$ 995**		**$ 995**

Performance

Plant performance is calculated as a function of the resource temperature, the number of flashes and ncg level. The performance parameter calculated is the net brine effectiveness, exclusive of any geothermal fluid pumping power. The performance calculation is done on flash system cost and performance work sheet **10A.Flash Perf&Cost**, and is then exported back to the input sheet **3B.FL-Input**. In calculating the performance of the improved plant, the change in performance is also exported to the cost and performance work sheet, along with the temperature, number of flashes and ncg level assigned to the improved plant. (Note that a value >1 indicates an increase in performance, i.e., brine effectiveness.) In the cost and performance worksheet, this value is multiplied by the performance calculated based upon the number of flashes and the resource temperature for the improved plant. This performance is then adjusted to account for the ncg removal from the improved plant. The flow of information between sheets in calculating flash plant performance is depicted below.



The GETEM user has the option of using the calculated plant performance that is exported back to the input sheet, or to input a plant performance. If the user elects not to use the calculated brine effectiveness, a "N" (No) response is provide in cells ***C26*** and/or ***E26***. The user then provides the desired brine effectiveness in cell ***C27*** and/or ***E27***. The values for brine effectiveness that GETEM uses in its subsequent calculations are those indicated in cell ***C28*** and ***E28***.

Cost

The flash steam plant capital cost is calculated in GETEM as $ per kW-net, where net power is the net plant output, exclusive of any geothermal fluid pumping power. The cost calculation is done on flash plant cost and performance work sheet **10A.Flash Perf&Cost**, and is then exported back to the input sheet **3B.FL-Input**. The cost of the baseline plant is determined based upon the following user input:

- plant size,
- number of flashes,
- type of condenser,
- type of ncg removal,
- level of ncg's and H_2S in the geothermal fluid, and
- resource temperature.

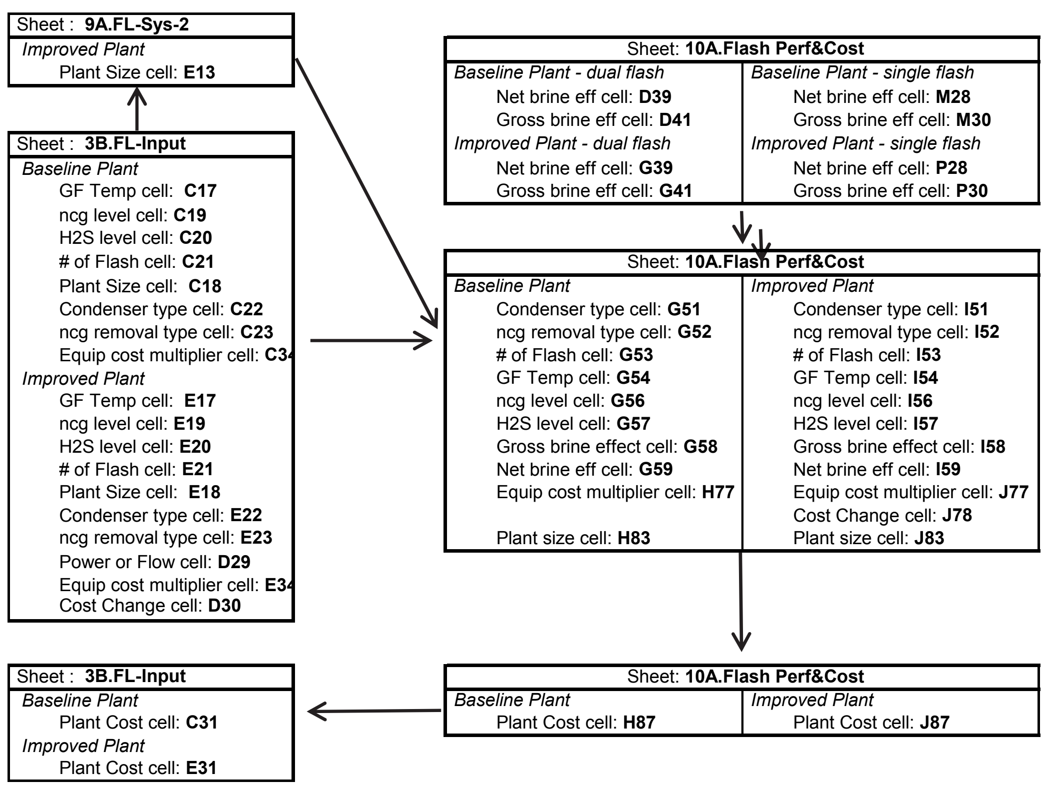
The user input of the fluid temperature is indirectly used to determine the plant cost in that it is used to calculate a gross brine effectiveness which is a major parameter used in determining the plant cost.

The GETEM calculation for the plant capital cost is made in the following sequence:

- costs of the major components and systems are determined based upon the gross plant output/brine effectiveness or the level of ncg's (or H_2S) in the geothermal fluid entering the plant
- equipment/system costs are derived for a 50 MW net-plant by multiplying the costs obtained in step #1 by the ratio of the calculated gross to net brine effectiveness
- the installed plant cost is determined by multiplying the sum of the equipment/system costs determined in step #2 by the equipment cost multiplier; this is the installed cost of a 50 MW-net plant
- the 50 MW cost is adjusted upward with the cost index, and
- the 0.75 cost-size scaling factor is applied to the inflation adjusted 50 MW plant cost to determine the cost for user inputted plant size

The improved plant costs are also calculated in the flash plant cost and performance work sheet (**10A.Flash Perf&Cost**). On this sheet the cost of a 50 MW improved plant is first determined using the same type of input and procedure just describe for the baseline flash plant. This cost is then multiplied by the user assigned cost change to establish the installed cost of the 50 MW improved plant. (Note that a cost change <1 indicates the plant capital cost is decreased.) As is the case with the binary conversion system, the user has the option of using an increase in plant performance to increase power production from the same well field, or to decrease the number of wells and maintain the baseline plant output. If the user elects to increase power output, the improved plant cost is calculated based upon the increased output. The level of the increased output is calculated on the work sheet for the improved plant (**9A.FL-Sys-2**).

The flow of information between sheets in calculating the flash plant capital cost is depicted below.



The GETEM user also has the option of using the calculated plant cost that is exported back to the input sheet (**3B.FL-Input**), or to input a plant cost. If the user elects not to use the calculated plant cost, a "N" (No) response is provide in cells ***C32*** and/or ***E32***. A power plant cost is then inputted in cell ***C33***, and/or ***E33***. The values for plant cost that GETEM uses in its subsequent calculations are those indicated in cell ***C35*** and ***E35***. In these subsequent calculations, the total plant cost is the product of this value and the inputted plant size (cell ***C18*** and/or ***E18***). Note that there is a plant performance improvement (cell ***D24***) and one opts to produce more power (cell ***D29***), the improved plant cost is determined based on this output (in lieu of that in cell ***E18***).

2.4 Issues with Flash Steam Plant Portion of the GETEM Model

Performance - Issues associated with the flash conversion system performance include:

- Although more parameters are used to project the flash plant performance than were used for the binary plant, there are a number of factors influencing the performance of this conversion system that are not and can not be accounted for in the simple characterization developed for plant performance.

- The performance of the flash plant will be sensitive to the various assumptions made regarding approach temperatures and temperature rises during heat exchange processes. Results from the model used to develop the performance correlations indicate the optimal output occurs when some of these parameters differ significantly from those used in some commercial plants (for which data is available). This suggests the economic and performance optimums may occur at different conditions for these parameters.

- The model used to develop the flash plant performance correlations used vacuum pumps for ncg removal. A comparison of model results with the results in the NGGPP study (CE Holt Co, 1996)indicated reasonable agreement when the NGGPP plant also used vacuum pump systems for ncg removal. GETEM performance correlations only use the vacuum system for ncg removal – steam ejectors are not part of the modeled performance.

- The performance analysis upon which the GETEM performance correlation is based assumes that the lowest flash pressure is always greater than 1 atm (14.7 psia). With lower temperature resources, this assumption has an adverse impact on the performance potential,

- The performance modeling assumes that the fluid pressure entering the plant is always above the optimal flash pressure determined for a given resource temperature. This does not necessarily reflect industry practices. If additional flow can be obtained from a well by lowering the well head pressure to a value less than the optimum flash pressure, industry may chose to do so. The additional flow per well can result in additional power generated from each well. If more power is generated from each well, then either a larger conversions system can be installed using the same well field, or the well field size can be reduced and still support the same plant size. Because more total flow is being handled, the plant cost will increase. With the increased flow rate, it would be expected that the resource productivity (temperature, pressure and/or flow) would decline more rapidly.

Cost - Issues associated with the flash conversion system cost include:

- GETEM bases its cost projection only using the GETEM calculated plant performance – the user inputted plant performance is not used in GETEM's determination of plant cost (this input is used in the determination of the total flow required and the well field costs).

- The turbine-generator costs obtained using the IPE software are less than those reported in the NGGPP. The lower IPE costs were used. The IPE software was also used to derive the scaling factor for the turbine-generator.

- The equipment cost multiplier is a user input – the nominal value of 2.53 that is suggested is from the NGGPP study (CE Holt Co, 1996).

- The cost correlations used in GETEM do not reflect the recent (since 2004) increases in steel costs.

- The GETEM cost projections are based upon those presented in the NGGPP for a 50 MW plant. Though the effect of the turbine-generator cost with size was incorporated into the overall cost vs scaling factor, there were not sufficient resources (time or data) to adequately define the scaling factors for other components. As a result there is increasing uncertainty in the cost projections for sizes that differ significantly from 50 MW.

- Though GETEM includes a maintenance cost for scale inhibitors, the chemical treatment to control the precipitation of silica are not specifically estimated.

- With the current program focus on the lower temperature resources, it is not expected that there will be additional refinement of the flash model unless 1) there are significant errors in the current correlation, and/or 2) the flash cycle is considered for higher temperature EGS applications.

3.0 Operating and Maintenance (O&M) Costs

3.1 Binary Conversion System

The O&M costs for the reference binary plant are calculated in sheet **5B.BI-O&M-1**. The information used as the basis for these calculations is either inputted from sheet **3A.BI-Input**, or calculated elsewhere in GETEM (primarily on sheet **5A.BI-Sys-1**). The O&M costs for the improved binary plant are calculated in sheet **6B.BI-O&M-2**, using information from the binary input sheet, or information imported from other calculations in GETEM (primarily on sheet **6A.BI-Sys-2**). Costs calculated on these O&M worksheets are exported, primarily to the system sheet for the reference (**5A.BI-Sys-1**) or improved (**6A.BI-Sys-2**) plant.

The O&M costs for the binary plant are calculated based upon assumptions made for both staffing of the facility and annual costs for maintenance and repair activities. Facility staffing requirements are based upon the following:

Staff hr/day		rate	Plant Size <5 MW	<10 MW	<20 MW	<30 MW	<40 MW	>40 MW
Operators	24 $52		0.23	1	1	1.5	1.5	2
Maintenance								
Mechanical/welder	8	$62.40	0.125	0.5	0.9	1.3 1.	3 1.	5
Electrical/instrument	8	$62.40	0.125	0.5	0.9	1.3 1.	3 1.	5
General	8	$45.50	0.125	0.5	0.9	1.3 1.	3 1.	5
Office								
Facility manager/engineer	8	$104	0.20	0.33	0.67	1 1 1		
Operations manager	8	$78	0.20	0.33	0.67	1 1 1		
Clerical	8	$31.20	0.20	0.33	0.67	1 1 1		
Total Staff (based on 2,000 hr/yr)			**2.0**	**6.9**	**9.1**	**13.5 13.**	**5 16.**	**3**
Annual Labor Cost (k$)			**$233**	**$768**	**$1,046**	**$1,552 $1,**	**552 $1,**	**848**

The indicated rate in this table is the assumed direct labor rate with an assumed multiplier of 2.6. It is recognized that a plant may not be operated with a fractional number of operators or maintenance personnel, and that the mix of personnel may be atypical for some facilities (in particular for smaller facilities). For instance, for the facilities less than 5 MW in size, the assumption is that the indicated operations, maintenance, and office functions would be done by 2 individuals, or some combination of individuals that adds up to 2 people (~4,000 hours per year).

The staffing requirements in the table above assume that the plant output capacity is based upon a single conversion system, and not multiple smaller units. If multiple units are used, it is postulated that additional operations and maintenance personnel would be required. The additional staffing for operations and maintenance that is applied in GETEM for the use of multiple conversion units are identified in the table below. These staffing requirements are added to those identified in the above table for a given plant size (the numbers in the table below are not tied to a specific plant size).

Staff hr/day		1 2		Number of Units 3	5	10	>10
Operators	24 0		0.1	0.2	0.3	0.4	0.5
Maintenance							
Mechanical/welder	8	0	0.05	0.1	0.15 0.2 0.3		
Electrical/instrument	8	0	0.05	0.1	0.15 0.2 0.3		
General	8	0	0.05	0.1	0.15	0.2	0.3
Total Additional Staffing		**0**	**0.45**	**0.9**	**1.35 1.8 2.4**		

In the determining the contribution of the operating costs to the cost of power, GETEM allocates 25% of the operations labor cost to the well field, with the remainder assigned to the conversion system. None of the maintenance or office costs are assigned to the well field.

Plant maintenance costs are determined simply as a fraction of the total capital cost for the plant. This fraction of the total capital cost is a user input. At present, we are using a factor of 1.5%. For the hydrothermal reference case of 150°C resource and a 30 MW plant, the plant cost is $73.34 M. Using the 1.5% factor, the annual maintenance cost for the plant would be ~$1.1M.

In addition to the labor component that is assigned to the well field O&M costs, GETEM also calculates a well field maintenance cost. As with the conversion system, this well field maintenance cost is a fraction of the capital costs associated with the well field development, including any well work-over. The value is also a user input; at present 1% is being used. The well field development capital cost used is the total well cost less the cost of the exploration wells, i.e., it is the sum of the production, injection and confirmation well costs. Again using the hydrothermal reference case of 150°C resource and a 30 MW plant, the well field development cost is $15.11M (11.8 wells). The annual cost for the well maintenance activities is $151K.

GETEM also applied this well-field maintenance cost factor to the well field capital costs that are not associated with the well drilling (I.e., surface equipment, exclusive of the production pumps). For a selected hydrothermal case, these capital costs are ~1.72M; the associated annual maintenance costs are 1% of this or ~$17K per year.

GETEM includes a generic cost for chemical inhibitors as a well field maintenance cost. This cost is based upon an assumed chemical cost of $10/gal and an assumed dosage rate of 0.5 ppm. If lines-haft pumps are used, a cost for oil required to lubricate the line shaft is also included. This cost is determined based on an assumed oil cost of $4/gal and a dosage rate of 2 ppm. Both the dosage rates and the cost per gallon for these two chemical costs are initial assumptions and, are effectively placeholders until better cost information is obtained.

The cost of replacing the geothermal productions pumps is included in GETEM as a well field maintenance cost. Different costs are assigned for both line-shaft and submersible pumps. The annual cost for line shaft pumps is based upon an expect pump life of 4 years and a repair/replacement cost of $175K each (pump and work-over rig), or $43.75K per year for each well used for production. The annual cost for submersible pumps is based upon an expect pump life of 3 years and a repair/replacement cost of $167K each (pump and work-over rig), or $55.6K per year for each pumped well.

Currently the pump replacement cost, pump life, chemical dosage rate and cost, lube oil dosage and cost, and labor rates, and the labor fraction assigned to the well field are inputted by the user on the binary operating and maintenance worksheets (**5B.BI-O&M-1** or **6B.BI-O&M-2**). When running a Case study, the user should assure that these user inputs are the same on both of these worksheets before applying any technology changes (Column D of the binary input sheet, **3A.BI-Input**).

The annual royalty costs are calculated on the system sheet (**5A.BI-Sys-1** or **6A.BI-Sys-2**).

3.2 Flash Conversion System

The O&M costs for the flash steam plant are calculated using the same approach as used for the binary conversion system. The O&M costs are calculated on sheet **8B.FL-O&M-1** for the baseline plant, and sheet **9B.FL-O&M-2** for the improved plant. The assumptions for staffing levels are the same as those used for a binary plant of an equivalent size. Consistent with the binary cycle O&M cost calculation, 25% of the operator labor cost is assigned to the field, and none of the maintenance or office costs are assigned to the well field. Unlike the binary cycle O&M costs, the staffing for the flash plant is based on single plant units – there is no additional labor cost if modular steam units are used. (In part this is because it is assumed that it is less likely modular units would be used with a steam conversion system.)

Plant maintenance costs are determined simply as a fraction of the total capital cost for the plant. This fraction of the total capital cost is a user input. At present, we are using a factor of 1.0%.

As discussed previously, in the flash plant performance work sheet (**10A.Flash Perf&Cost**), a cooling water to geothermal fluid flow ratio is calculated. This ratio and the geothermal fluid flow rate are used to determine a total cooling water flow rate. This flow rate is used to determine a chemical usage for the evaporative heat rejection system. The model currently uses a cost of $1.50 per gallon and a dosage rate of 5 ppm to determine this chemical cost. The model currently estimates the annual chemical costs for the hydrogen sulfide abatement system based on a chemical cost of $2.00 per lb/h of H_2S entering the plant. The model currently estimates the chemical inhibitors for the wells based upon a dosage rate of 4 ppm (artesian flow) and a cost of $1.25 per gallon. It is expected that if the wells are pumped the dosage rate would decrease (be similar to that for the binary systems). Note that the chemical dosage and chemical costs per gallon are placeholders until better cost and chemical usage information are available.

In addition to the labor component that is assigned to the well field O&M costs, GETEM also calculates a well field maintenance cost. As with the conversion system, this well field maintenance cost is a fraction of the capital costs associated with the well field development. The value is also a user input; at present 0.5% is being used. The well field development capital cost used is the total well cost less the cost of the exploration wells, i.e., it is the sum of the production, injection and confirmation well costs.

This well-field maintenance cost factor is also applied to the well field capital costs that are not associated with the well drilling (I.e., surface equipment, exclusive of the production pumps). If the wells are pumped, the associated O&M costs for pump repair/replacement are calculated in the same manner as they were for the binary conversion system.

O&M costs for the baseline flash plant are calculated in sheet **8B.FL-O&M-1**. The information used as the basis for these calculations is either inputted from sheet **3B.FL-Input**, or calculated elsewhere in GETEM (primarily on sheet **8A.FL-Sys-1**). The O&M costs for the improved flash plant are calculated in sheet **9B.FL-O&M-2**, using information from the flash input sheet, or information imported from other calculations in GETEM (primarily on sheet **9A.FL-Sys-2**). Costs calculated on these O&M worksheets are exported, primarily to the system sheet for the reference (**8A.FL-Sys-1**) or improved (**9A.FL-Sys-2**) plant.

The annual royalty costs are calculated on the system sheet (**8A.FL-Sys-1** or **9A.FL-Sys-2**).

3.3 Issues about O&M Costs

The development of the O&M costs estimates within GETEM are largely based upon personal observations and discussions with industry. In some instances the costs shown are effectively placeholders until sufficient information can be developed that will allow more representative costs to be determined (for example chemical costs for the well field and evaporative heat rejection systems).

The O&M costs estimates for the flash system are based upon a number of the assumptions used in developing the costs for the binary conversion system. Because of the use of evaporative heat rejection, the flashing of the geothermal fluid, and the hydrogen sulfide abatement the flash-steam system will have higher chemical costs than an equivalent sized binary plant. It is probable that because of the increased chemical usage that the staff requirements for the flash plant will be higher (addition of a chemist and possibly operator for the various chemical systems). Currently GETEM does not reflect these higher operating costs.

The total O&M cost predicted by GETEM for a flash plant was compared the O&M cost provided in the NGGPP report for a 50 MW plant. The GETEM estimated annual cost is lower ($3.7M vs $4.75M). There are several reasons for the difference including an under estimate of chemical costs and associated operations personnel. A portion of the difference may also be attributed to funds set aside annually for drilling make-up wells.

4.0 Utiliz ation Factor

4.1 Binary Conversion

The utilization factor for these plants is the ratio of the total annual power output (kW-h's) to the annual output that would have been achieved if the plant operated continuously over the year at its rated, or name-plate capacity (i.e., a 30 MW plant would produce 30,000 * 24 *365 = 262,800,000 kW-h annually at its name-plate capacity; the utilization factor would be the ratio of the actual output to this value). Though it is a user input, an analysis was done of a pseudo air-cooled binary plant operating at a Basin and Range location with an ambient temperature profile similar to Reno NV. The power output from the plant was estimated on an hourly basis over 1 year and summed to provide a total output that could be compared to the output at the rated, 30 MW capacity. The results of this analysis are summarized in the following table.

T,gf (°C)	**125°**	**150° 175°**	**200°**	
T,air-design (°F)	53°	53° 53° 5	3°	
Avail Energy (w-h/lb)	9.485	13.637 18.4	17 23.8	17
Design 2nd law efficiency	23.9% 34%		41.4%	45.6%
Brine effectiveness (w-h/lb)	2.271 4.63	3	7.629	10.860
Geothermal flow rate (lb/h)	13,211,146 6,47	5,068	3,932,219	2,762,346
Design Plant Output (KW)	30,000	30,000 30,0	00 30,0	00
Availability	96%	96% 96%	96%	
Continuous operation at Design Output				
Annual Power Output (kW-h/yr)	262,800,000	262,800,000 2	62, 800,000 2	62, 800,000
Scenario: Cold weather operation limited to +20% of design power @53°F				
Annual Power Output (kW-h/yr)	250,446,092	251,318,687 2	51, 544,487 2	51, 507,254
Utilization Factor	0.953	0.956 0.95	7 0.95	7

In this analysis it was the plant was designed to produce the rated 30 MW net output at the average annual ambient temperature of 53°F (11.7°C). The availability term in the table is the fraction of the time that the plant operates. The results suggested that the utilization factor was only slightly less than this availability term. This indicates that the degradation in power that occurs during operation in the hotter portion of the year is effectively offset by the higher number of hours annually that the plant can generate at greater than design capacity.

4.2 Flash Steam Conversion

A similar determination was not made for the utilization factor in the flash plants. A value of 0.90 is currently suggested; it is a user input on sheet **3B.FL-Input**.

4.3 Issue s

The analysis of the effect of the ambient on the utilization factor was done at one resource temperature. It is assumed that the ambient temperature will have a similar affect on the conversion efficiency (2nd law efficiency) at other resource temperatures. It is suspected that this assumption over represents the utilization factor of the conversion systems using the lower temperature resources. An analysis needs to be done of the performance of a plant operating at the lower resource temperatures to validate this assumption, or to revise the model's utilization factor.

5.0 Geothermal Pumps Performance and Cost

5.1 Perform ance

In GETEM the flow rate, depth, and efficiency for the production pumps are user inputs. For the binary conversion system, this information is inputted on sheet **3A.BI-Input** in cells **C51** (efficiency), cell **C52** (pump type: line shaft or submersible), **C53** (line-shaft pump flow) or **C55** (submersible pump flow), **C57** (pump setting depth), and cell **C58** (the injection pump differential pressure). This information is exported to sheet **5A.BI-Sys-1** where the number of pumped wells and pumping power are determined.

The model currently relies on the user to increase the pump setting depth if the pumped flow rate is increased for the Improved scenario. The user may utilize an input on the Systems worksheet for the Improved scenario (**6B.BI-Sys-2**) to let the model calculate the added depth with increased flow. The input is the change in drawdown, in feet, per 100 gpm change in flow. Using this input requires some knowledge of the productivity of a specific reservoir/well.

Number of pumped wells: The number of wells that are pumped are determined from the inputted flow rate per well for the selected pump type, the plant performance (brine effectiveness), and the plant size (exclusive of the geothermal fluid pumping power). The required total flow rate is quotient of inputted plant size divided by the brine effectiveness. This calculation is done in cell **H15** of sheet **5A.BI-Sys-1**. The number of production wells is this total flow divided by the flow per well. The model does assume that fraction wells are possible. The number of pumped wells is used in determining the geothermal production pump cost (and associated O&M costs).

Production well pumping power: The user inputted depth (**C57**) is used with the total geothermal fluid flow (total flow to the plant, not the flow per well) in cell **H15** of sheet **5A.BI-Sys-1**, to determine the total pumping power for the production pumps. The calculation assumes that the suction pressure on the down-hole pump is equivalent to the well head pressure, i.e., the pumping power is only that required to lift the fluid from the pump setting depth to the surface. Friction losses in the pump casing are not calculated and included in the determination of pumping power.

Production Pump Power = (total flow)*(pump depth)/(pump efficiency)

Conversion factors are applied to convert power from ft-lb/h to kW. This value is calculated in cell **H23** of sheet **5A.BI-Sys-1**.

Injection pumping power: The injection pumping power is calculated using the inputted pressure rise through the injection pump and the total flow rate to the plant.

Injection Pump Power = (total flow)*(dP/rho)/(pump efficiency)

In this calculation the fluid density is assumed to be 62 lb/ft^3. The pump efficiency is the same as that inputted for the production pumps. This value is calculated in cell **H26** of sheet **5A.BI-Sys-1**.

A similar set of calculations are done for the improved plant that are based upon the input in columns **D** and **E** of the input sheet, **3A.BI-Input**. The information from **E51** (efficiency), **E53** (line-shaft pump flow) or **E55** (submersible pump flow), and **E57** (depth), **E52** (pump type) and **C58** (injection pump differential pressure) are exported to sheet **6A.BI-Sys-2** where the pumping power is determined for the improved plant. Calculations for the improved plant differ in that the user has the option of using increased plant performance to decrease geothermal fluid flow and keep the plant output constant, or to increase plant output and keep the geothermal fluid flow rate constant. Calculations are based upon the user's input in cell **D25** of the input sheet, **3A.BI-Input**.

If the wells for the flash-steam plant are to be pumped a similar set of calculations are made based upon the user input in the input sheet, **3B.FL-Input**. This information is exported to sheets **8A.FL-Sys-1** for the baseline plant and **9A.FL-Sys-2** for the improved plant.

5.2 Cost

The cost of the production pumps is a user input for both the line-shaft and submersible pumps. Injection pump costs are also an input as $ per hp. The suggested value of $700 per hp for the injection pump cost is based upon installed cost estimates made with the ICARUS Process Evaluator (IPE) software for pumps in the range of 200 to 600 hp. It is assumed that if a greater hp is required for injection, multiple pumps will be used.

O&M costs associated with the production pumps are calculated in the O&M work sheets **5B.BI-O&M-1**, **6B.BI-O&M-2**, **8B.FL-O&M-1** and **9B.FL-O&M-2**. (O&M costs are calculated for the flash plant if pumps are used.)

6.0 Net Project Power Output

The net project output that accounts for the geothermal fluid pumping is calculated as the net plant output less the sum of the production pumping and the injection pumping. This calculated net project output is subsequently used in the cost of power calculations. This calculation is done in cell **J28** of the baseline binary (**5A.BI-Sys-1**) and flash (**8A.FL-Sys-1**) system work sheets; for the improved plants it is in cell **M32** of the baseline binary (**6A.BI-Sys-2**) and cell **M30** flash (**9A.FL-Sys-2**) system work sheets. <u>Note, however, that calculations related to reservoir drawdown and makeup further reduce the total power output of the project.</u>

7.0 References

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Mines, G.L., “Impact of Off-Design Operation on an Air-Cooled Binary Power Plant”, INEEL/EXT-02-00815, June 2002.

Bliem, C. J. and G. L. Mines, “Advanced Binary Geothermal Power Plants Limits of Performance*”*, EGG-EP-9207, January 1991.

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(End of Appendix C)

APPENDIX D.

Standard Method for Moving Excel Figures into These Reports

EXPERIMENTS and FINDINGS

A. <u>The right way to move tables or pieces of them from XLS into a WORD DOC file.</u>

The method laid out here minimizes the amount of space (bytes) that exhibits from EXCEL consume in WORD files.

1. AT XLS file:

    a. At Print Setup, select Show Row and Column Headings

    b At the Sheet, select the block of cells you want to copy.
    <u>This can include the R & C Headings.</u>

    c. Then use Control C to copy

2. AT the WORD doc. File:

    a. Position cursor text where you want the material to appear.

    b. At the Edit Menu

        1. Select Special
        2. Select Picture (Windows Metafile)
        3. Select OK.

DONE

<u>You can see the Row and Column headers if you wish to, on the Screen and on printed pages, if you previously selected them at the Sheet level, b, above.</u>