# DOE Geothermal Electricity Technology Evaluation Model (GETEM):

# Volume I – Technical Reference Manual

**July 6, 2006**


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Susan Petty, Seattle, Washington; and
Bill Livesay, San Diego, California



For: The Geothermal Technologies Program,
Office of Energy Efficiency and Renewable Energy,
U.S. Department of Energy, Washington, DC, and
The National Renewable Energy Laboratory, Golden, Colorado

Under: NREL Subcontract No. KLCX-4-44447-07
PERI Task 7040-007


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# PREFACE

This report is the technical reference manual for a new tool to help the Geothermal Technologies Program of the U.S. Department of Energy in estimating some of the technical and economic values of its research projects and subprograms. The tool is named the “Geothermal Electricity Technology Evaluation Model” **(GETEM).** It is intended to estimate and summarize the performance and cost of various geothermal electric power systems at geothermal reservoirs with a wide variety of physical characteristics.

This document is the Technical Reference Manual itself. This is accompanied by two other documents:

a. The User’s Manual for GETEM-2005, and
b. Detailed Appendixes to the GETEM Technical Reference Manual.

These three documents are being distributed separately in electronic form to make it easier for users to print only the parts they need to have.

# ABSTRACT

The GETEM model has been developed to aid the Geothermal Technologies Division of the U.S. Department of Energy in understanding the performance and the cost of the technologies it is seeking to improve. “GETEM” stands for “Geothermal Electricity Technologies Evaluation Model.” GETEM can be used to analyze and evaluate currently available technologies. It can also be used to make sense out of what technologies 5 to 20 years in the future might cost if certain R&D projects succeed. The overall interest and intent is to help DOE make better sense of which proposed technology improvement programs and projects offer the most improvements for the tax payer dollar.

# DISCLAIMER

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The remaining appendixes are collected in volume III of this report, Detailed Technical Appendixes.

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# 1. EXECUTIVE SUMMARY

To conform to the U.S. Government's requirements for complying with the Government Progress and Results Act of 1993 (GPRA), the Department of Energy's Geothermal Technologies Program (GTP), is developing a ***Geothermal Electricity Paper System*** model. The model will allow the Geothermal Technologies Program to assess and report annual improvements in geothermal electric systems.

The GPRA requirements come from the Administration's Office of Management and Budget (OMB) and Department of Energy (DOE). The Geothermal Technologies Program is part of the DOE Office of Energy Efficiency and Renewable Energy (EERE)

This Report documents the main technology performance, cost estimation, and life cycle costing component of the Geothermal Electricity Paper System. This component is called the Geothermal Electric Technologies Evaluation Model (GETEM).

## 1.1. GETEM and its Programmatic Uses

At the core of the *Geothermal Electricity Paper System* are three principal components:

a. Detailed assessments of the constituent subprograms and RD&D projects of the overall Geothermal Program, in the form of Technology Improvement Potentials (TIPs). The TIPs are estimates by the National Laboratory Geothermal Program managers of how much their planned R&D is expected to improve certain components and subsystems of designated commercial or near-commercial practical power systems. While the "TIPs" are occasionally mentioned in this report, they are not documented in any detail here. (See the 2005 Geothermal Multi-Year Program Plan, September 2005, for details of the most recent TIPs.) It is available from the Geothermal Program office.

b. A detailed model of the estimated performance and costs of currently available U.S. geothermal power systems. This model is named "**GETEM**," for Geothermal Electricity Technology Evaluation Model. Its main metric is the Levelized Cost of Electricity (**LCOE**) calculated for Current and future Improved systems. GETEM includes capabilities, described below (See Appendix A, GETEM User's Guide) that allow users to enter the quantitative (and specifically dated) values derived from the eothermal Program TIPs (Technology Improvement Potentials) to estimate the degree to which the expected effects of those particular clusters of R&D projects are likely to improve the LCOE of U.S. geothermal power systems in the future.

c. An annual evaluation of the technical progress of the Geothermal Program R&D projects and subprograms, whereby technical progress toward achieving the practical goals targeted by the TIPs are estimated. As of November 2005, this part of the system has yet to be defined in detail. However, the general idea is that partial progress toward completing a TIP will count as progress in improving the Geothermal Paper Electric System(s), even though the R&D is not yet complete, and the anticipated innovative technology is not actually in use by industry.

This overall approach is very similar to evaluations the DOE Geothermal R&D Programs have conducted in the past (see Section 2.2), and the evaluations that are currently being formulated for other DOE Renewable Electricity R&D programs, *e.g.*, Wind and Biomass.

## 1.2. Planned Uses of GETEM

There are a number of quite specific uses planned for GETEM by the DOE Geothermal Technologies Program. Some of the main uses are listed here, and are described in more detail in the GETEM-2005 User's Manual that is an Appendix of this report.

### a. Integrating Research Improvements

Here GETEM is used to integrate and study the effects on geothermal electric systems of the Technology Improvement Potentials (TIPs) estimated by the various Geothermal Technologies sub-Programs that deal with hydrothermal technologies (Geoscience, Drilling, Conversion Technology). Results are improvements in system performance, cost, and Levelized Cost of Electricity (LCOE). The studies are used to evaluate and set Geothermal Programmatic goals at 5, 10, etc. years out.

### b. Evaluating Technology Progress

In the long run, GETEM might be used to quantify the degree to which the DOE Program and industry have improved the overall performance and costs of a number of different geothermal power systems. For example, if one knew industry's performance and costs for the main components of geothermal power systems (exploration, wells, power plants, permitting and environmental costs) at the end of each of a number of decades, then one could portray the overall improvements in the LCOE of the various types of systems, e.g., at 1980, 1990, 2000, and 2010.

One could also use GETEM in a forward looking technology forecasting sense, without knowing what the sub-programs believe they might achieve. In this way a user could determine what levels of improvement must be achieved in a particular research area in order for there to be a significant impact on LCOE.

### c. Planning Parts of the Geothermal Program

GETEM has already proven valuable in planning future R&D, particularly for the part of the Geothermal Program that is developing plans for development of Enhanced Geothermal Systems (EGS). The work on EGS has the general goal to make economic many bodies of hot rock that today have insufficient permeability to make electricity on a commercial basis. As documented in the Geothermal Technologies Program MYP – 2005, GETEM has aided the EGS evaluation and planning team in understanding how future improvements in EGS reservoir performance will interact with improvements in drilling and power plants that are expected from the "non-EGS" core sub-programs of the GTP.

### d. Comparing Benefits of Single R&D Thrusts

During the development of the technology improvement objectives (a.k.a. goals)for the GTP Multiyear Program Plan – 2005 (MYPP – 2005) some program managers became interested in the what the improvement in LCOE would be if only the R&D TIPs they were working on became available for the "Improved" system, e.g., a 2010 system. GETEM can be used in this way, but only if some fairly strict rules for how to compute such comparisons are agreed upon. (Some of the pitfalls here are described in the appended GETEM-2005 User's Guide.

**e. Reporting Progress in R&D to the GPRA Process**

The OMB interpretation of GPRA for the DOE Energy Efficiency and Renewable Energy (EERE) programs, of which the Geothermal Program is one, require that the programs report improvements in technology on an **annual basis**. This will be one of the main uses of GETEM by the Geothermal Program. Details for procedures remain to be worked out.

**f. Producing Inputs to the DOE National Energy Models**

Some of the results from GETEM runs are used by the DOE Geothermal Technologies Program to communicate its successes and plans to the Offices in DOE that evaluate technology development plans and progress. This is part of the overall "GPRA Benefits" analysis process. This is done by communicating certain results from GETEM to the National Energy Modeling System (NEMS) team of the Energy Information Administration (EIA), an independent federal agency within the Department of Energy. NEMS is typically used to run analyses of impacts of many technology improvements on patterns of national energy use to about 2025. Another model, MARKAL, is used to run analyses to 2050 with special reference to environmental impacts and benefits of the R&D programs. MARKAL uses most of the same inputs as NEMS.

## 1.3. Status of GETEM in June 2006

As of September 1, 2005, the Geothermal Technology Analysis Team had formulated a useful working version of GETEM that:

- Includes capabilities of modeling Binary air-cooled hydrothermal, Flash water-cooled hydrothermal, and EGS cases using the same engineering functions for technology performance and costs.

- Accepts widely ranging characteristics of geothermal prospects, emphasizing reservoir temperature, well depth, and well flow rates.

- For geothermal hydrothermal resources, includes cases for 2005 (Current Case or Base Case) and 2010 (Improved Case) for Binary and Flash reference conditions. E.g., the Binary reference condition has reservoir temperature 150 C, well depths of 5,000 feet, and high flow rates, as reported by industry as targets for future development in the Basin and Range Province in Nevada, Idaho, and Utah.

- For Enhanced Geothermal System (EGS), includes cases for 2005 and 2010 (Improved), at 200 C and 12,000 foot well depth. For 2040 (Long Term), it has cases for both high and moderate temperatures, which are anticipated to apply to many Western sites and some Eastern regions, respectively. (EGS are volumes of rock that will require engineered modification – such as hydraulic stimulation – to increase the permeability and fluid contents of the prospective reservoir.)

- Includes routines for estimating performance losses and costs associated with reservoir drawdown and the associated make up wells. These are based on enthalpy decline n for binary systems and pressure decline for flash systems. These are essential for modeling short reservoir lifetimes expected for initial (e.g., to 2015 or so) EGS systems.

- Has had its core engineering functions developed by the Geothermal Teams at the respective National Laboratories: Power plants at INEEL and NREL, Wells at Sandia, and Exploration technologies at INEEL and LBNL and LLNL.

- Has inputs for technology improvements that are derived from the August 16, 2005 working draft of the Geothermal Multiyear Plan (MYP). These MYP estimates have been developed by the Lab geothermal teams, and an informal EGS technical evaluation and planning team.

- Has outputs that are designed to plug rather directly into the NEMS-GPRA and the MARKAL-GPRA models for integration with EERE GPRA Benefits analysis work. (This part needs more work, as of September 1, 2005.)

## 1.4. The GETEM Development Team

For the first time ever, the Geothermal Technologies Program (GTP) of DOE has put in place a process whereby the estimates of the degree to which geothermal power technologies (e.g., wells, power plants) could be improved are being made by the Geothermal R&D Teams at the National Laboratories rather than by technical consultants in the Washington, DC area.

The overall design, coordination, and integration of the work have been led by Dan Entingh, Princeton Energy Resources, Inc., Rockville, MD. Entingh has worked in this role for the DOE Technologies Program (under various programmatic names) since 1977. He has shared the lead role in this with Dr. Gerry Nix, of the National Renewable Energy Laboratory, Golden, CO, who leads the GTP Technical Analysis Team. Entingh developed the earlier specifications and descriptions of an “Integrated System for Analysis of Geothermal Programmatic Research,” in 2001, under the contract supervision of Dr. Walter Short of NREL.

Entingh was the principal designer/author/debugger of GETEM-2005’s geothermal power project “System” sheets, and of the reservoir decline and makeup protocols and algorithms. Entingh is the lead editor of this report, and the author of the “GETEM-2005 User’s Guide” attached as Appendix A of this report..

The main additional contributor to GETEM *per se* is Gregory L. Mines, Geothermal Research Program, Idaho National Laboratory (INL), Idaho Falls, ID. Mines has conducted substantial research over the years on how to improve geothermal power conversion systems (power plants). He contributed all the correlations for the performance and cost of binary and flashed steam conversion systems. He was also created the detailed design of GETEM’s stylized Input and Output Sheets.

A.J. Mansure and Steve Bauer of the Geothermal Research Department at Sandia National Laboratories, Albuquerque, NM, developed and contributed correlations for costs of geothermal wells. An integral part of their team and contributor to this work is Dr. Bill Livesay, a geothermal drilling engineer, San Diego, CA, who is the principle developer to Well Cost Light, a model that supports GETEM and other studies.

Susan Petty, Black Mountain Consulting, Seattle, WA, contributed significant inputs on real world systems, specifically on the impact of geologic conditions on drilling, flow rates for pumped wells, and development of "GETEM" cases for Enhanced Geothermal Systems, as elaborated in the GTP Multiyear Program Plan – 2005 and other side cases.

Martin Vorum, NREL, contributed to the outline of this report. He also contributed to the "Validation" materials.

Others have helped with DOE Programmatic level review and supervision of GETEM's development. These people interacted with acute interest as the GETEM Development Team produced the first runs that integrated the current characteristics of geothermal power projects with the technology improvements expected from the Geothermal Technologies Program in the next few years. These included DOE HQ staff, especially Dr. Roy Mink, the Program Director, and Dr. Allan Jelacic, Ray Fortuna, and Ray LaSala. Other help, suggestions, and encouragement came from Dr. Joel Renner, INL, Teresa Nealon of NREL, Jay Nathwani of the DOE Golden Field Office and Richard Price, of TMS, a Washington, DC, consulting firm.

*Entingh is the author of this report and the related supporting reports specifically to postpone the need for the other contributors to get reviews of their contributions from their federal organizations. Appropriate reviews will be sought later, after the initial "validation" processes are finished..*

## 1.5. GETEM Cases: Reference Cases and Working Cases

As is often the situation with a model as new as this, there is evolving definition and confusion about what to call, reference, and catalog "Cases" that have been developed using GETEM.

While some are using the phrase "GETEM Cases," strictly speaking there are no GETEM Cases, but rather Cases prepared for or by the DOE Geothermal Technologies Program using GETEM.

We here distinguish two main kinds of "Cases."

The first kind is "**Reference Cases**." These are Cases that have been defined by or for the DOE Geothermal Program uses in various "official" documents.

a. Two such cases have been defined for the Geothermal Program draft Multiyear Program Plan (MYPP) of August 2005. The first is a Hydrothermal Air-Cooled Binary Case, with the reservoir at 150 C, and 5,000 ft depth with estimates for 2005 and 2010. The second is an EGS Air-Cooled Binary Case with the reservoir at 200 C, and 4 km depth, also with estimates for 2005 and 2010.

b. Two other Reference Cases have been developed, by D. Entingh, for use in an updated Geothermal Electricity Technology Characterization (TC). The new TC, in progress in November 2005, will communicate Geothermal Technologies Program Goals and expectations to the EERE process that estimates Programmatic Benefits under the Government Plans and Results Act (GPRA). The first of these cases is a Hydrothermal Air-Cooled Binary Case at higher temperature and shallower wells (than the hydrothermal case described above) to better match the Program's estimates of what the U.S. industry is building now in Nevada, Idaho, and Utah (which is similar to the Geothermal Binary Electricity Case in the 1997 EERE Technology Characterization.) The second Case is for a Hydrothermal Flash Plant, again similar to that characterized in the 1997 TC. The TC also uses the EGS Reference Case described above as one of it main starting points.

The second kind of cases is called "**Working Cases**" in this report. These are cases that are being created and studied for policy development work, or for purposes of comparing results from GETEM to those reported in engineering studies or field developments. They have no "official" usage or policies implied in them.

Since a main purpose of this report is to help industry engineers compare their knowledge to GETEM's working values for purposes of validation, all Cases shown in this report are Working Cases. While one or more of the Working Cases herein may have been derived from or is similar to a Geothermal programmatic Reference Case, we are not here seeking validation of any policy directions or estimates that seem to be implied by the Cases.

## 1.6. Possible Changes to Future Versions

In the course of the development of GETEM so far, there have of course been limitations of budget, time, and knowledge on the part of the Development Team. This has led to a number of significant important general gaps in the model. Also many detailed possibly useful detailed changes in approaches, data, and correlations for the geothermal power project subsystems have emerged.

Addressing the changes described here will depend on support from the Geothermal Technologies Program for making the changes.

### 1.6.1. General Gaps in the Model

There are four major general gaps.

**a. Economics Factors**

The estimates of the economics assumptions and factors used in GETEM's calculations of discounting and life cycle costs are not dynamic. They should be. For example, the factors used in GETEM-2005 do not include impacts of the Geothermal Production Tax Credit, which is probably worth (under certain financial structures for geothermal power projects) about 1 cent/kW (levelized in real USD).

**b. Geothermal Fluid Chemistries**

We have not accounted for most of the cost and performance effects of difficult brine chemistries, except for the auxiliary power used for mitigating NCG and $H_2S$ emissions in Flash systems. This is a place where we would be eager to accept a lot of help from industry, particularly in the form of correlations we could plug into GETEM rather directly.

**c. Permitting and Environmental Costs**

We have not accounted for general permitting and environmental issues and costs. This is another technical area where industry has the expertise and generic data we need.

**d.** **<u>Carrying Costs of Long-Lead-Time Investments</u>**

We have not accounted for "time value of money" for the exploration and confirmation work that lead geothermal projects. We should do so in the future. We will probably do that by setting a duration for each of these phases on a special new "economics factors" sheet. Note that the factors might be different for Binary and Flash, and for Base and Improved Cases.

### 1.6.2 Possible Detailed Changes

The GETEM Development Team has come up with a number of possible detailed changes to make in any future versions of GETEM. Many of those changes are reported in Sections 3, 4, and 5, below.

# 2. BACKGROUND AND SCOPE

## 2.1. Goals of this Effort

The general goal of the GETEM development effort is to construct a performance and cost model of a moderate degree of abstraction and disaggregation to enable the key workers of the DOE Geothermal Technologies Program make better sense of how their research efforts fit into overall GTP and DOE goals. Estimates of expected improvements in basic technologies, as provided by the most experienced of the researchers, converge as basic inputs to GETEM, thereby better informing all concerned of some aspects of the value of their research.

The general uses to which GETEM is being put and will be put are listed in Section 1.2, above, and defined in more detail in Section 7.0 of the GETEM-2005 User's Guide. They are fairly obvious to most of those concerned with the DOE Geothermal Program, whether they are Government staff or staff of industry partners.

## 2.2. Prior Geothermal Cost of Power Assessments

The GETEM performance and cost assessment and modeling effort is a continuation of very similar projects that DOE has sponsored in the past.

Two of these efforts were conducted when the Government first organized a specialty R&D program for geothermal energy, in the late 1970s. These were the GELCOM model developed by the MITRE Corporation, McLean, VA, and the GEOCOST model developed by Battelle Pacific Northwest Laboratories, Richland, Washington. The DOE Geothermal office dictated <u>two primary features that have remained the general standard for such modeling</u>:

a. These models should estimate the performance and cost of geothermal power systems at a moderate level of detail (e.g., cost of wells of defined casing plans, but not cost and life of individual drill bits), and

b. The models should be directly coupled to a detailed inventory and characterization of specific geothermal sites so that estimates of improvement in technology would be coupled directly with estimates of reduction of the cost of power at the inventory of hydrothermal resources that the Program sought to help industry develop.

At the time, about 1975-78, geothermal power was viewed as competing with coal fired plants. It was found that a substantial amount of potential geothermal power at the studied sites (the KGRAs from USGS Circulars 726 and 790) was not more than 50% or so more expensive than the coal cost. Therefore, DOE was encouraged to invest heavily in researching and improving geothermal power systems.

The second generation of DOE geothermal power technology modeling and assessment was conducted by Technecon Corp., Philadelphia, PA, and others in 1978 through 1981. The emphasis in that effort was to make better sense of how geothermal power projects would fit into the markets in which they were trying to compete in California, Nevada, and Utah. The main corpus of the cost estimates was derived from industry's applications for Geothermal Loan Guarantees. There was considerable emphasis on modeling industry's decision making processes. The reports are still of interest with respect to estimation of cost baselines in 1980.

The third generation of geothermal cost of power modeling was done in 1987 through 1990. This was occasioned by the fact that the U.S. geothermal industry had finally built some power projects at liquid-dominated hydrothermal prospects, so it was reasonable to research the performance and cost of real systems. The effort was led by Dr. Richard Traeger of Sandia National Laboratories, and involved principally Susan Petty, Billy Joe Livesay, and Dan Entingh (all of whom are contributors to the GETEM work). This resulted in the IMGEO (IMpacts of R&D on the cost of GEOthermal electricity) series of models that were used for various policy studies in 1987 through 2001.

It is important to note that a 1990 version of IMGEO was the source for the geothermal site-specific cost and performance estimates that are embedded in the Geothermal Electricity Submodule of the National Energy Modeling System (NEMS) maintained and operated by the U.S. Energy Information Administration (EIA), an independent agency housed within the Department of Energy. The NEMS model is used for many policy studies within EIA and DOE as a whole.

In this later period, research on the potential use of geothermal power began to focus on competition with gas-fueled power, especially at a time when natural gas prices became quite low and combined-cycle power plants reduced the amount of fuel needed to produce each megawatthour.

## 2.3. General Approach

### 2.3.1. GETEM Incorporates a Variety of Geothermal Expertise

A key aspect of developing GETEM was to get the key staff of the Geothermal R&D programs at (some of) the DOE National Laboratories to assume the responsibility for knowing the general performance and cost of the subsystems they are working on. In particular, understanding Conversion systems fell to Idaho NL and NREL, Wellfield Systems (wells, well pumps, and surface piping) to Sandia NL, and Geoscience-related matters to Idaho NL, Lawrence Berkeley NL, and Lawrence Livermore NL.

The work on understanding Conversion and Well Construction has proceeded very well over the past five or so years. Work to develop useful conceptual models of the performance and cost of Exploration and Confirmation is in its infancy. A key problem with the Geosciences work is that much of the information that arose from exploration work in the U.S. in the 1970s and 1980s lies almost entirely in the hands of industry, and not the Government. Another key problem in that area is that geologists tend to think mostly in visual and verbal terms, and are relatively reluctant to apply quantitative models to the phenomena they hold most dear.

Seven areas of technical expertise contributed to GETEM-2005. These are the general structure of geothermal power systems and projects (Entingh and Mines), power plants (Mines), wellfield construction (Mansure, Bauer, and Livesay), production pumping (Mines and Petty), exploration and confirmation (Entingh and Petty), reservoir decline and makeup (Entingh), and project-level economics (Entingh).

The development team believes that GETEM is amenable to use for those who have a general understanding of the various main components of geothermal power projects. However, there may be instance that using GETEM easily and authoritatively, a group of persons with specific expertise in many or all of the above areas will be needed. The GETEM Team members stand ready to help anyone, to at least a limited degree, who wants to use GETEM for any practical or policy purpose.

### 2.3.2. GETEM is Based on Spreadsheets

GETEM was developed as an Excel (copyright, Microsoft Corp.) spreadsheet workbook so that many contributors and potential users can understand how it works.

The main design principles are that:

- A main "Systems" sheet ties all the high-level calculations together.
- The input and output sheets are stylized, so that users know where to go for the most elemental aspects of what they need.
- Most of the sheets and cells are "locked" so that users can not mistakenly write over formulas. Gerry Nix, NREL, controls who has access to the underlying codes. Consult Dan Entingh or Greg Mines for further information.
- Binary and flash systems are carried together in the same workbook. This is to ensure that changes made to the estimates and correlations for either type of system can be kept consistent among various uses of GETEM.
- We avoided the use of macros, so that all of the results of all of the calculations are visible to the user.

### 2.3.3. The Level of Detail is Moderate

The levels of detail and technological accuracy of the parameters in GETEM are sufficient to calculate electric power costs, but not necessarily sufficient for other purposes. For example, the depths for downhole pumps are useful enough to calculate parasitic power, but should not be taken as guidance for the actual construction of a well. Other external models are being used by the GETEM Development Team to perform lower-level or more detailed calculations, particularly for well costs and power plant estimates. For example, a model, WellCost Light (to be documented in one of the technical Appendixes), is used to determine the impacts of factors such as the casing design, cost of steel, rig day rate, etc. on geothermal well costs.

### 2.3.4. Definitions of the Calculated Cost of Electricity

The levelized cost of electricity (LCOE) that GETEM calculates is estimated in constant dollars, also known as real dollars. This means that the wholesale price shown in various places in GETEM need to be inflated in each succeeding year, by 3% per year. The wholesale prices shown include estimated profits for all parties involved, and a 5% overall contingency. An additional contingency of about 10% is estimated to be included in the cost of the production and injection wells.

For working purposes, the LCOE is estimated in end of year 2004 U.S. dollars. There are some approximations involved in this that will be resolved later. The drilling costs are in December 2004 dollars, but there was significant increase in drilling costs through at least July 2005. The power plant costs were estimated in mid-2004 dollars.

# 2.4. Approach to Validating the Model

## 2.4.1. The Need for Validation and Calibration

The DOE Geothermal Technologies Program (GTP) is developing GETEM as one of its primary tools for planning, assessing, and managing its research and development activities.

A primary key for the usefulness of GETEM to the GTP is that the data and methods embodied in the model must represent, in reasonable manners, technical and commercial realities in the field of development and operation of geothermal electricity generation projects.

GETEM represents the Development Team's best estimates of information on analysis of resources, project design, construction, operation, and financial factors. However, the Team is acutely aware that there are many aspects of recent geothermal power projects in the U.S. of which it has little or no detailed knowledge. This is especially true of the new projects stimulated in the Basin and Range by the Nevada state Renewable Energy Portfolio Standard and the Federal Geothermal Production Tax Credit enacted in late 2004.

GETEM is different from engineering and costing models that industry would usually develop, in that GETEM is project screening model and emphasizes assisting users in DOE and the National Laboratories to examine the state of today's technology in the context of improvements possible through R&D. For example, GETEM can be used to help plot courses toward commercialization of new technologies.

DOE seeks criticism of GETEM from business, academia, and other public sector participants in the geothermal community for two main reasons.

a. DOE has no direct access to data and analysis about commercial geothermal power systems.

b. Those outside of DOE need to know what DOE believes are the characteristics of geothermal power systems, so that they can provide corrective influences when DOE's outlooks appear to conflict with others' interests.

## 2.4.2. How to Contribute to Validating GETEM

We need to get detailed feedback from industry, and to do that in ways that don't conflict with industry's proprietary interests in technologies and actual power systems. In general, we are seeking quantitative feedback on how well GETEM approximates results for real world cases that independent reviewers have direct experience with.

The data sources may consist of actual operating projects, projects under construction, or detailed engineering costing studies. We are not interested in back of the envelope calculations. Estimates that are generated from other models will generally be discounted, unless the models have been stated to have been calibrated recently, e.g., in 2004 or 2005.
Some specific aspects of GETEM that we are hoping to validate and calibrate are:

a. The general assumptions about project stages and major components that are specified in the "System" sheets in the model.

b. Specific costs of wells, as calibrated to at least the following factors: Depth, general drillability of the rocks encountered, bottom hole diameter, unusual aspects of the casing plan, and date (year and month) of completion.

c. Temperature of fluid in the geothermal reservoir, plant specific performance (net Watthours per kg before brine pumping), net capacity of plant (summer MWe), number of independent power trains, total cost of plant exclusive of field expenses and general project costs of owners.

d. Owners' costs. What they mean, when incurred, how they might be apportioned between the field and the plant.

e. Financial assumption and costs. Impact of tax burdens on project feasibility in unusual circumstances. Impacts of current modes of project financial structure, especially with regard to using Geothermal Production Tax Credits.

f. Any facts bearing on the "gaps" in GETEM that are described in Section 1.6, above. Fluid chemistry and environmental and other regulatory matters are especially important.

g. General adequacy of the algorithms in GETEM, and of how they are represented and documented.

The GETEM team believes that the strongest approach to review, evaluation, and validation of the model is for non-DOE geothermal experts to use the model "hands on" to try to replicate results for recent actual projects. Divergences in component performance and cost, and overall performance and costs are particularly important.

To repeat, we strongly encourage reviewers to use GETEM directly. We will provide assistance in profiling input cases and finding specific results in the GETEM output.

# 3. SUMMARY OF MODEL'S CAPABILITIES, STRUCTURE AND CONTENT

## 3.1. Summary of Capabilities

The Geothermal Electric Technology Evaluation Model (GETEM) estimates the levelized cost of electricity (LCOE) for a Baseline Case and an Improved Case. Stylized INPUT sheets allow the user to define the Baseline Case in terms of a mix of physical characteristics of a (the) geothermal reservoir and of the plant and wells designed to exploit the reservoir.

The middle column of the INPUT sheet lets the user set multipliers (1.0 = no change) on most of the inputs for the Baseline Case to define a (future) Improved Case. The OUTPUT sheet shows many aspects of the performance and costs of the Baseline and Improved Cases, and the percentage difference between all of the results for the two Cases.

Cost calculations in GETEM are broken down into five sections:

- **Resource definition and confirmation** includes the cost of determining the temperature, depth, well productivity (flow per production well and injection rate per injection well) and size of the reservoir up to the drilling of the first production diameter exploration well. Resource confirmation includes drilling and testing of the number of wells required for the bank to be willing to finance the power plant construction.

- **Wellfield construction** includes preparing the sites, drilling the wells and connecting them to the power plant. It also includes any well stimulation that needs to be done for the purpose of enhancing the reservoir for an EGS system.

- **Reservoir management** includes costs associated with well field operation and maintenance including any replacement wells that need to be drilled, either due to decline in flow rate or decline in reservoir temperature. The conversion system costs are those associated with the power plant including capital costs and O&M. Economics includes the cash flow analysis form used to determine levelized cost of power along with the decision to include risk as a contingency cost rather than as an increase in the fixed charge rate.

- **Conversion system** modeling includes estimates of performance and cost of power plants. Costs include capital and O&M costs.

- **Economics** includes the cash flow analysis form used to determine levelized cost of power along with the decision to include risk as a contingency cost rather than as an increase in the fixed charge rate.

## 3.2. High-Level Logical Structure of the Model

Because geothermal power projects are complex, any model of their performance and costs is, unfortunately, complex. We have tried to structure GETEM so that both geothermal-generalists and specialists will feel they are on familiar ground when they are using and testing the model. This means, for example, that the parts of the model that deal with the geothermal field, with the cost of the wells, and geothermal power plants are structured, described, and documented in somewhat different ways. The structure might not be to everyone's liking, but it has emerged and worked fairly well for the GETEM development team.

### 3.2.1. The Input Sheets

GETEM is structured so that all user input is provided on a single work sheet for a particular conversion system (**3A.BI-Input** for binary, or **3B.FL-Input** for flash). As the user updates input values, the cost of power is recalculated and displayed on the input page. This lets the user know immediately if a value they have changed has had the opposite effect of what was intended.

The model's output is also segregated by the conversion system (**4A.BI-Output** for binary, or **4B.FL-Output** for flash). These output pages supply more detail on the breakdown of cost of power by cost element and show the cost elements by percentage of total cost.

For a given conversion system type, the user provides information in the appropriate input sheet that is necessary to determine the cost and performance projections that are necessary to develop a levelized cost of electricity for the scenario defined by the input. The user input is used to define a Baseline Case (which typically defines a current, say 2005, technology), as well as an Improved Case that reflects the effect of technology improvements that affect the cost and / or performance of major components of the Improved system. The user inputs that define system improvements are placed in the selected input sheet (**3A.BI-Input** for binary, or **3B.FL-Input** for flash).

### 3.2.2. The Main System Sheets

Each input sheet is linked to other worksheets in the model, where specific calculations are performed. Calculations for both the baseline and enhanced conversion system performance and cost are made on sheets **7A.BI-Perf&Cost** for the binary plant and **10A.FL-Perf&Cost** for the flash plant. In lieu of having the model calculate the plant performance or cost, the user can input the performance (w-h/lb) or plant cost ($/KW). Performance and costs are based on the net plant output, exclusive of the geothermal fluid pumping power. These pumping power requirements are calculated separately in the model.

There are 4 system work sheets; again, two for the binary plant (**5A.BI-Sys-1** for the baseline scenario and **6A.BI-Sys-2** for the enhanced scenario) and two for the flash plant (**8A.FL-Sys-1** for the baseline scenario and **9B.FL-Sys-2** for the enhanced scenario). In the system work sheet, the number of wells needed and capital costs for a given input scenario are calculated. These costs include those for the resource exploration and confirmation, well field development, and the conversion system.

The geothermal fluid pumping power is calculated in the appropriate system worksheet. The total geothermal pumping power (production and injection) is subtracted from the plant output to establish the "net" power that is used in the subsequent calculation of the cost of power.

In the final conceptual step on the System work sheet, all costs are summed up in working accounts, and the levelized cost of electricity (LCOE) is calculated.

Effects of drawdown and makeup processes and costs are not accounted for in the main system sheets, but rather directly in the Output sheets for binary and flash.

### 3.2.3. Sheets for Detailed Calculations

Operating and maintenance (O&M) costs are determined on separate work sheets. There are 4 worksheets in the model used to calculate O&M costs; two for the binary plant (**5B.BI-O&M-1** for the baseline scenario and **6B.BI-O&M-2** for the enhanced scenario) and two for the flash plant (**8B.FL-O&M-1** for the baseline scenario and **9B.FL-O&M-2** for the enhanced scenario). O&M costs are determined for both the plant and the field and exported from these sheets to other worksheets in the model.

A second set of detailed sheets calculate performance effects and costs related to reservoir drawdown and related makeup operations. For Binary Systems, these calculations are based on a user-estimated rate of decline temperature in the reservoir fluid ("Enthalpy decline"). This is handled for both the Baseline and Improved Cases in Sheet **7B.BI-MAKEUP**. For Flash System the decline and makeup calculations are based on the decline of pressure in the reservoir and flow up the production wells. This is handled for the paired Flash cases in Sheet **10B.FL-MAKEUP**.

### 3.2.4. Overview of Relationships among GETEM Sheets

A schematic view of the Binary System pages in GETEM is shown in Figure 3.1. There you can see that the System Sheet dominates the logic of the calculations. The separate O&M sheet is not shown in the diagram – it would be to the right, with the other two detailed calculation sheets.

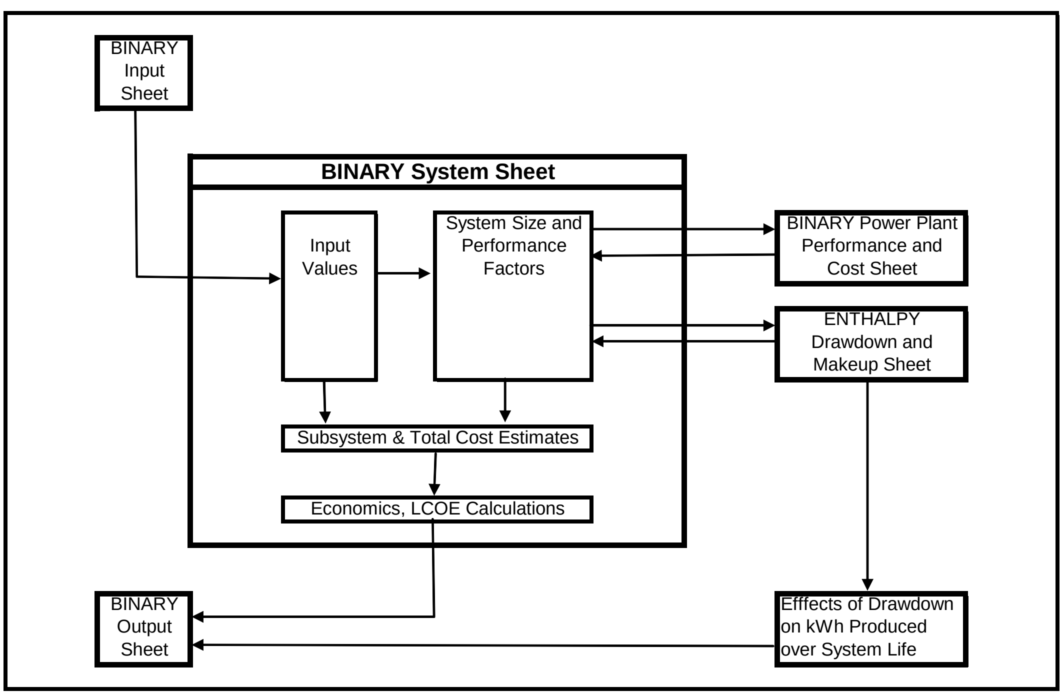


**Figure 3.1. Schematic View of the Binary Pages in GETEM**

If you are going to study data flows in GETEM, you will run up against two moderate difficulties.

a. The relationships among the sundry sheets are not as totally structured as Figure 3.1 implies. For example, the Power Plant Performance and Cost Sheet takes some inputs directly from the Input sheet, and sends some outputs directly to the Output sheet.

b. Most of the calculation sheets are entirely locked. Therefore you cannot use the EXCEL trace feature to study all the flows of data. We may relax this restriction in the future, but for now we have locked most of the GETEM sheets and / or cells to prevent users from losing critical formulas and to prevent potentially perverse users from modifying the main correlations and pretending they are in conformance with the main DOE geothermal policy model.

If you want to find intermediate values for any GETEM Case, you should look at the "System" sheet. Remember that there is one such sheet for the Baseline Case and one for the Improved Case for each of the Binary and Flash systems.

A block diagram of the System sheets is shown in Figure 3.2. The boxes in Figure 3.2 refer to locations on the sheet of groups of lines of inputs, intermediate calculations, and final results.

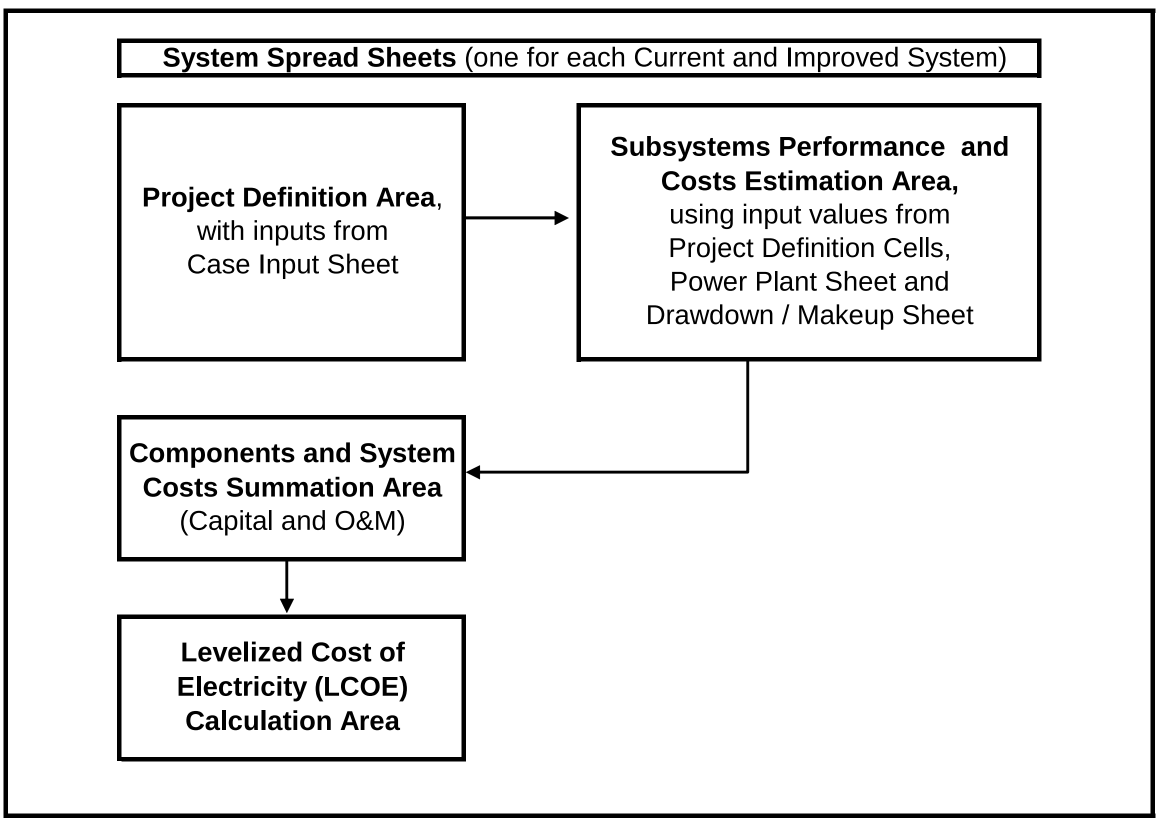


**Figure 3.2. Block View of the GETEM "Systems" Sheets**

The variables that define most of each Case are in the upper left of Figure 3.2. Some of these come from the INPUT sheet, some are set here. Note that many of the values that are hidden in GETEM-2005 (those not on the Input sheets, e.g., discount rate, will be made available for user manipulation in the 2006 version.

Most of the performance and key cost calculations are done on the upper right. A few of the defining variables are also in this block.

Cost summations are done at the left center part of the sheet. The totalized capital and O&M cost accounts are here.

The LCOE calculations are done from those costs estimates, at the lower left part of the System sheet.

### 3.2.5 Main Relationship Between Field and Power Plant

The key relationships between the field and the power plant are shown in Figure 3.3. The essence here is that the temperature of the reservoir essentially controls the engineered efficiency of the power plant. That efficiency dictates the inlet flow requirement of the pant, i.e., how many pounds per hour of geothermal fluid must enter the plant to deliver the gross or net capacity of the plant.

The number of wells needed is then controlled by the average flow [lb/hr] of the production wells, and the number of injection wells needed per production well.

The determining logic for the overall number of wells needed is also shown in Figure 3. In essence, the exploration failures and discovery wells are assumed to not be used as producers or injectors. A fraction of the confirmation wells are estimated to become useful producers. All other wells (producers or injectors) needed to meet the flow requirements have to be paid for in addition to the exploration wells and the confirmation wells.

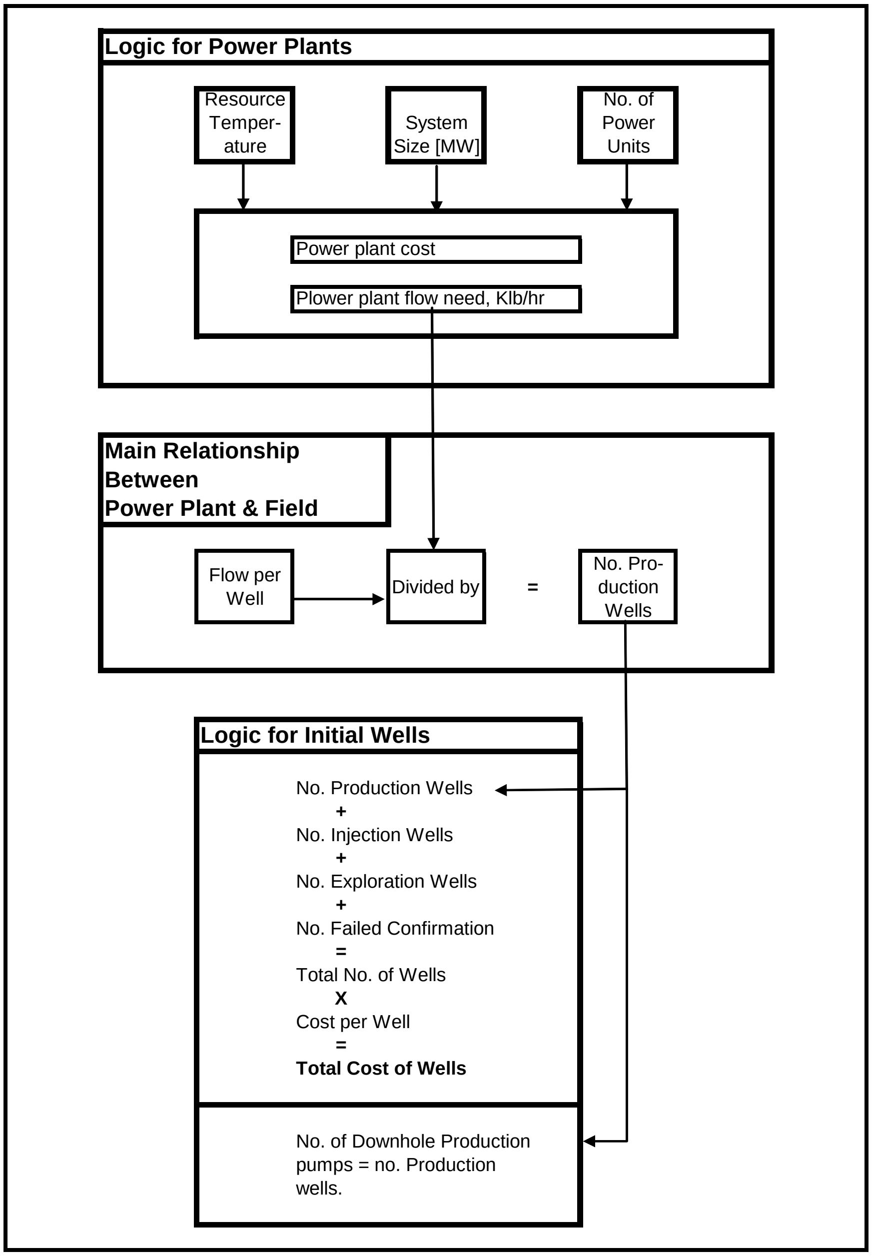


**Figure 3.3. Main Relationships Between Field and Power Plant**

# 4. GETEM'S VIEW OF THE COMPONENTS OF A GEOTHERMAL POWER PROJECT

## 4.1. The Main Components of a Power Project

Cost calculations in GETEM are broken down into five sections: Resource definition and confirmation, wellfield construction, reservoir management, conversion systems, and economics.

**Resource exploration and confirmation** includes the cost of finding the resource, determining the temperature, depth, well productivity (flow per production well and injection rate per injection well) and size of the reservoir through the drilling of the first production diameter exploration well. Resource confirmation includes drilling and testing of the number of wells required for a lender to be willing to finance most of the rest of the power project construction. Site preparation may not be extensive during these two phases.

**Wellfield construction** includes preparing the sites, drilling the wells and connecting them to the power plant. It also includes any well stimulation that needs to be done for the purpose of enhancing the reservoir for an EGS system.

**Reservoir management** includes costs associated with well field operation and maintenance including any replacement wells that need to be drilled, either due to decline in flow rate or decline in reservoir temperature.

**Conversion system** costs are those associated with the power plant including capital costs and O&M.

**Economics** includes formulas used to calculate the levelized cost of power, and treats project cost risks as contingency costs rather than as an increase in the fixed charge rate.

## 4.2. Resource Exploration and Confirmation

The process of discovering and evaluating the near term economic value of a geothermal prospect are dealt with as "Exploration" and "Confirmation." These have become fairly common terms in the U.S. geothermal industry.

The amount of power and cost of power from a geothermal energy project are dependent on the characteristics of the resource. The temperature of the rocks and the fluids in it determine the type of conversion system used, the efficiency with which the system uses the heat in the fluid, whether the wells can be pumped or if they will flow by themselves and the cost of testing. The flow rate that can be developed from each production well and the depth to the resource also constrain the cost of the project. All of this information is determined as part of the exploration and confirmation of the resource. The accuracy of the estimates of these key resource parameters that are made prior to drilling production wells are a key component of the risk associated with geothermal development. GETEM uses industry anecdotes to code in these risk factors in the calculation of exploration and confirmation costs.

In the real world, when developers explores for geothermal energy, they may have one or a few sites they have already leased or purchased from someone else. Each site may be large enough to develop more than one power plant project (e.g., total of 100 or more MWe), or might only accommodate a single plant (e.g., 10 to 60 or so MWe). The goal of the developer is to determine if the resource is capable of producing power economically and if so what size power plant will best fit his resource and how much total production can be managed from the field without unduly stressing the reservoirs ability to give up heat, or causing more pressure drop through the system than is economic.

The developer then starts exploring these resources to determine the temperature, pressure, flow rate per producer, extent of the temperature and permeability anomaly that defines the resource, the depth and best places to drill to reach the defined temperature and permeability. The developer may use geologic mapping, remote sensing, geophysical exploration methods, temperature gradient hole drilling or a variety of other methods to determine the nature of the resource. If surveys are done or if geologic mapping and remote sensing are used, the cost of each survey or mapping effort is reduced because several areas are explored at once. This reduces mobilization costs and gives a discount due to quantity of samples, materials or analysis performed.

## Financial Aspects of Resource Discovery

Exploration and confirmation costs are "leading costs" in that they are all drawn from owners' equity and may occur relatively many years before power and revenues are produced. Different firms carry these costs in different ways. In the "project financing" that was common for many U.S. geothermal projects in the 1980s, the cost of exploration was charged entirely to the first plant built (which often was the only plant built on the specific land position.

In other cases, the cost of the exploration methods chosen is treated as a corporate sunk cost and as such will be distributed over all of the possible future power plants the developer may build on that resource. The corporation does this as part of their normal operating overhead, hiring contractors or employing exploration geologists within the company to get the various exploration tasks done. When this developer does a cash flow analysis to determine the price they need to receive to make their project economic, the cost of these exploration tasks is not directly included in the expenses. Instead, they are included in the corporate overhead charged to the project for labor and management.

GETEM-2005 accounts for exploration and confirmation expenses as explicitly capitalized costs. It does not, however, at this time account for the additional required returns to equity that are entailed by the extra years to power production (relative to the main buildout of the field and power plant).

## Discoveries of Various Sizes

For the purposes of dealing with: a. Prospects and installed capacity of varying sizes, and b. Green Field (entirely new prospects) with Brown Field (areas where one or more power systems are already operating) GETEM lets the user to allocate only part of the exploration costs, or confirmation costs to the specific project being studied.

This is done by adjusting the ratio of the plant size and power found, *i.e*, the total power discovered for that resource, and multiplying this times the exploration costs to spread the costs over all of the potential projects on the resource.

## Exploration

The number of total exploration wells is determined from the exploration success rate, the fraction of the exploration wells that are successful. Thus if the exploration success rate is 20%, (in the simple terms adopted in GETEM) five exploration wells are needed for one to be successful. To determine the cost of the other aspects of exploration such as geology, geophysics, geochemistry and well testing that lead up to drilling the exploration wells, an additional cost of $1 million is added to exploration costs. Moreover, since exploration wells are drilled in the absence of much information about lithology and hydrogeology at depth, the cost of each exploration well is increased by 20%. The reservoir exploration phase ends when the first successful exploration well is drilled.

GETEM assumes that none of the exploration wells contribute to the counts of production wells and injection wells needed in the project's production field.

The success rates used in various GETEM cases are discussed in Section 5.2.

**Confirmation***:* Following drilling of a successful exploration well, the developer needs to confirm the economics and viability of the project. To do this, he proceeds with planning for the project, including permitting, environmental work, preliminary design engineering work, arranging financing and possibly most important of all, procuring a power sales agreement. These tasks extend the time required to get the project on line generating power, adding to the cost of the project due to the time cost of money. Once the permits and the environmental clearances have been obtained, more production and injection wells can be drilled. A bank or venture capital firm might require that the developer have a certain fraction of the total wells required for the power plant drilled before financing the project.

These confirmation wells are riskier than the subsequent ordinary production wells, and may cost more due to the testing and additional exploration needed to site them. GETEM increases the total cost of each confirmation well by 20%, relative to the cost of the average production well.

When these required confirmation wells are completed, the confirmation phase of the project is completed. The design for the plant can be finalized and the final wells needed for the plant can be drilled while the power plant is being constructed.

The success rate for confirmation (a user input) is used as follows, defined by example. Say that four confirmation wells are required. If the success rate (of confirmation) is 0.6, then 2.4 of the confirmation wells are estimated to be successful producers, and 1.6 of the wells are estimated to be abandoned. If 10 production wells are needed to support the initial flow into the power plant, then 10 – 2.4 = 7.6 additional production wells must be drilled and paid for. If the system uses a binary power plant, downhole pumps must be installed in 10 wells.

The cost of the non-well confirmation activities is not considered in GETEM-2005. Some of these confirmation activities should be spread over the entire operation of the company at the particular reservoir.

## 4.3. Well Field Costs

Well field construction encompasses all aspects of reservoir development, from drilling and testing the production wells and injection wells, installing pumps in them if they will be pumped, stimulating the reservoir if that is included in the project, and building pipelines to connect them together.

The major components of well field construction costs are the wells themselves, the piping from the wells back to the plant, and the O&M costs of the well field. Wells are drilled during exploration, development, and operations, the latter to make up for the decline in productivity. Wells can be drilled for exploration, production or injection. The cost of wells drilled early in the development of a prospect are usually more expensive than those drilled later, because information gained about the site geology can lead to better drilling plans. The current version of GETEM makes the earlier wells, in the "Exploration" and "Confirmation" phases of the project cost 20 percent more than wells drilled during later field development. Uncertainties in how many wells need to be drilled overshadow the differences in well costs. Clearly the number of wells needed has a major impact on the well field cost. The number of wells needed is determined by the resource (enthalpy, flow rate and temperature the wells produce) and the size of the plant.

GETEM determines well costs through selecting a well cost curve, the depth of the wells, a user cost multiplier, surface equipment cost per well, the success rate of exploration drilling, the number of confirmation wells required, the success rate of confirmation drilling, ratio of injection to production wells, and the number of spare production wells. The current version of GETEM does not allow for dry holes during drilling of the production field, but later versions will do so.

GETEM does not calculate well costs from the detailed factors that govern well costs; it uses curves (cost as a function of depth) fitted to well cost information (records of actual wells drilled and modeled well costs). Because GETEM does not calculate well costs from governing factors, but instead uses generic well costs, GETEM includes a cost multiplier that allows the user to adjust generic costs to those applicable to a specific project.

Major factors that govern well costs include design (depth, diameter, etc.) and geological considerations (lithology, etc.). To determine the impact of factors not part of GETEM, separate calculations of well cost must be made and these costs input into GETEM using the cost multiplier. Currently this is being done by using another "model" WellCost Lite, which is described in Appendix B.

WellCost Lite is as much a methodology as a model. Figure 4.1 illustrates how, starting with general characteristics, WellCost Lite uses cost information on day rate items and fixed costs (e.g., rig rate and casing cost) and the design of the well to perform cost calculations to determine well costs. It requires an experienced geothermal drilling engineer to design the well and perform well cost calculations using WellCost Lite. As such, it is not practical to incorporate WellCost Lite into GETEM as an automated module. WellCost Lite hundreds of inputs, many of which must be coordinated by the engineer to assure that good practice, safety rules, and the laws of physics are not violated.

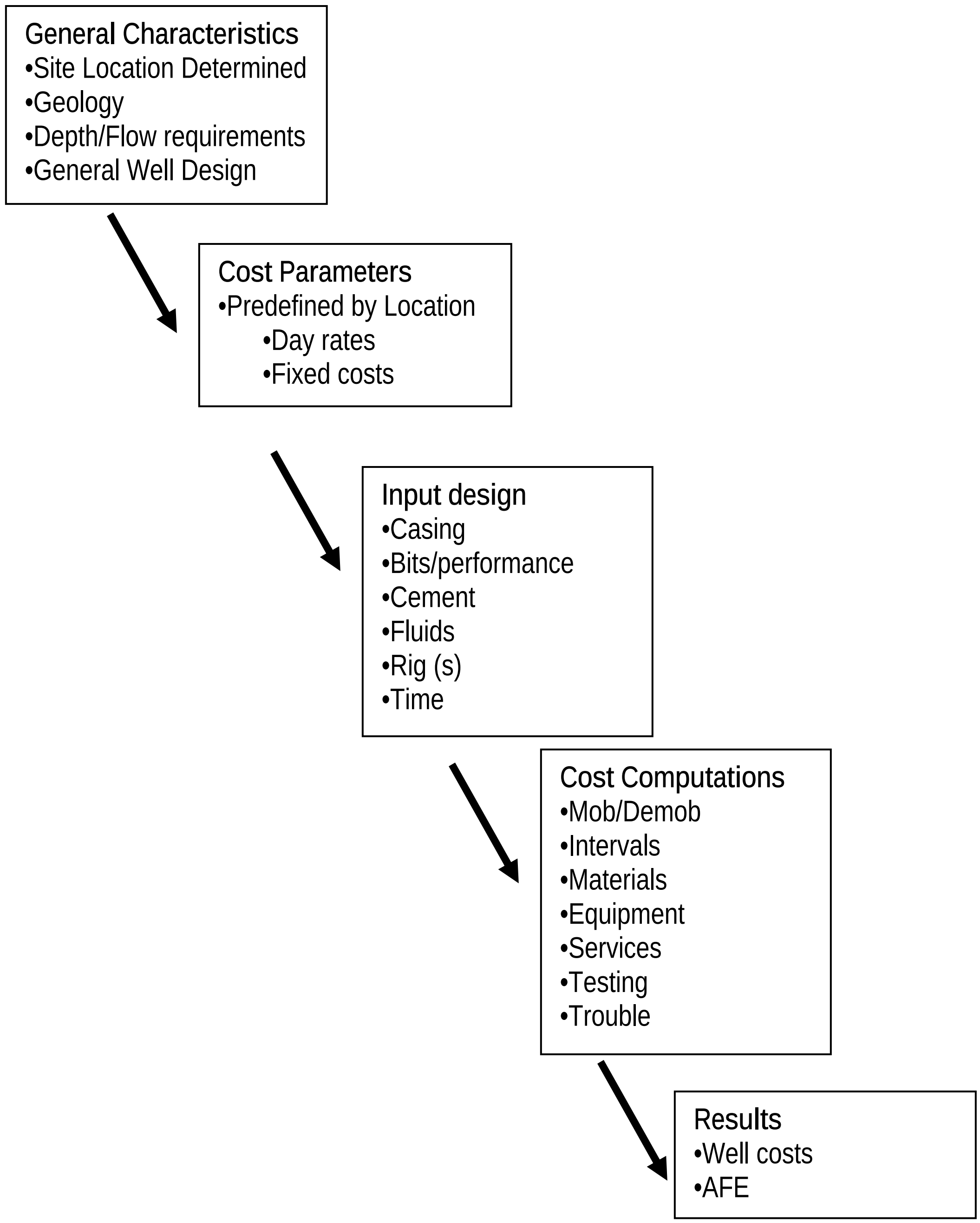


**Figure 4.1: Flow of information in WellCost Lite from general Characteristics to resultant well cost.**

Information about the cost of drilling actual wells is difficult to acquire and synthesize. Averages and broad based plotting of well cost can be misleading since there are many significant cost drivers: lithology, final diameter, technology used, problems encountered, location, date of drilling and more. Failure to account for all these factors (merely plotting cost as a function of depth) results in considerable scatter and uncertainty in well costs. Considering a wide enough scope of well cost driving factors to reduce uncertainty to reasonable levels requires a methodology that accounts for these major differences through changes in the cost of materials, services and the performance of certain actions during the drilling of the well. Thus, it is not practical to reduce the essence of WellCost Lite to a simple set of empirical equations that fully determine well costs.

A simple example is the final bit diameter (production interval) when drilling a geothermal well. Because there is a need for rather large flow rates of the resource fluid, larger diameters are often used. The larger production casing causes an increased cost of casing, cement, rig size, bits, muds, wellhead equipment, bottom hole assembly equipment, etc. These can be accounted for by using the WellCost Lite methodology.

## Use of Fractional Wells in GETEM

Users will note that many of the calculations of the numbers of wells needed and drilled are in fractional values, e.g., 7.4. In a real world system one cannot drill a fractional well, so all well counts must be integer values. The use of fractional wells is appropriate in policy studies, to avoid step functions in plots of system costs as various elements of the systems are improved through R&D or industry experience. This was first noted for geothermal studies by researchers at Lawrence Berkeley National Laboratory, in about 1979 – 1980.

### Wells for Enhanced Geothermal Systems (EGS)

While some well stimulation is becoming routine in hydrothermal reservoirs, well stimulation on a large scale is what distinguishes an enhanced, or engineered geothermal system from a natural hydrothermal system. A project with enough heat, but not enough permeability to allow water to circulate easily, will not produce fluid at economic rates.

However, if the wells can be stimulated to enhance the permeability, while reducing the risk of making too good a connection from well to well and allowing water from the injectors to cool off the produced fluid too fast, then the project may be able to produce economically. The concept of stimulating the reservoir to allow for economic flow rates while managing temperature drop may extend all the way to very impermeable rock, which is often referred to as Hot Dry Rock. The GETEM costing code was designed to allow costing of these EGS reservoirs.

A second important factor for EGS systems is that they are expected to be typically somewhat or a lot deeper than hydrothermal wells. Considerable attention is being devoted by the GETEM team to get a handle on costs of relatively deep wells, and aspects of that show up in Section 4.0.

### Well Costs as a Barrier to Exploration

Construction of the well field is one of the most significant components of the cost of electricity generated from geothermal energy. Drilling costs, the biggest part of well field construction costs, constitute a barrier to geothermal development beyond their contribution to calculations of LCOE. Exploration wells have to be drilled before bank financing is available, and they must be drilled to get bank financing. There is often a significant delay, five plus years, between exploration drilling and bank financing. These issues are beyond the current scope of GETEM. They should not undermine the value of GETEM in determining the potential of geothermal energy once the development of geothermal energy matures, but these issues do significantly impede the maturing of the development of geothermal energy, particularly for EGS. This can be understood by considering the question: “what if geothermal wells were cheap, $500k for example?” If geothermal drilling were cheap, we would now be conducting multiple EGS demonstration tests, but because EGS wells are $4m plus, we are currently not conducting a single EGS reservoir demonstration. Thus, while GETEM currently captures the essence of much of what is needed to evaluate the potential of geothermal energy, it does not fully capture the barriers to geothermal development that are due to relatively high well costs in many situations.

**Wellfield Operation and Maintenance Costs**

Wellfield O&M costs cover all aspects of production field wells and other field related equipment. There is no O&M cost associated with exploration and confirmation wells. O&M costs are estimated for production and injection wells, pipelines between wells and the power plant, costs to operate and to replace and/or service downhole production pumps. Part of the operating labor for the system is attributed to wellfield costs.

The costs of all make up wells and portions of reservoirs for makeup of EGS systems are all accounted for under the Field Non-Well O&M accounts. In future versions of GETEM they will be shown in a separate account labeled something like “make up costs.”

## 4.4. Reservoir Management

Reservoir management encompasses all aspects of operating the reservoir long term. In a liquid dominated reservoir with pumped wells, the most likely scenario is that over time the rock will cool, or cool injected fluids will break through to the produces and the temperature of the produced fluid will cool off. This includes most aspects of the design of “Heat Mining” approaches for EGS.

In a vapor dominated reservoir, a two phase or liquid reservoir with wells that flow through a boiling zone, the pressure in the reservoir will decline reducing the flow rate.

GETEM assumes that in the binary case, the reservoir decline is through temperature, while the flash plant case assumes that the flow rate declines.

## 4.5. Conversion Systems

The conversion system converts the geothermal fluid’s energy into electrical power. The GETEM model characterizes the performance and cost of two types of conversion systems:

- Flash-steam, and
- Binary.

The conversion system for reservoirs producing dry steam is not characterized by this model. Note however, that the cost of dry steam systems will generally be a little less than those of flash steam systems because the systems are similar, except with respect to the need of flashing tanks in the latter systems.

The selection of either binary or flash-steam conversion system is determined by the model user. In a commercial development, the ultimate selection of the conversion technology is based largely on cost and, to some degree the sustainability of the resource. Though it more efficiently converts the energy in the geothermal fluid into electrical power, the binary conversion system typically has a higher plant capital cost. It would be used if the additional power produced offsets the higher plant cost by reduces the contribution (on a $/kW basis) of all the other project capital costs including those for exploration and well field development. The additional power also lowers the contribution of the operating and maintenance costs to the cost of electricity. The performance advantage of the binary technology tends to increase with a decreasing resource temperature, especially if one limits flash pressures to a minimum of 1 atmosphere in the flash plants. As a result, the binary technology tends to be utilized with the lower temperature resources, and the flash-steam technology used with the high temperature resources.

In GETEM, the plant performance and cost correlations are based upon the net plant output, exclusive of the geothermal fluid pumping power. The geothermal fluid pumping power is considered to be site specific; not including this parasitic load allows more generic projections of both plant cost and performance. Although the geothermal pumping requirement is not included performance correlation for the conversion system, this parasitic load is subsequently calculated and accounted for when GETEM determines its levelized cost of electricity.

The projected conversion system performance and the inputted plant size establish the total required geothermal fluid flow rate. This flow rate, along with the user defined well (or pump) flow rate, establishes the size of the well field that is required to support the selected plant size

In order to facilitate the programmatic use of the GETEM model, the conversion system cost and performance projections are based upon minimal input by the model user. Because of the importance placed of the lower temperature resources in DOE's 'Multiyear Program Plan', emphasis was initially placed on the depiction of the air-cooled binary energy conversion system.

## 4.6. Project Economics

The primary results of interest from GETEM, from the economics and financial points of view are:

- Costs of all the main components of a geothermal power system , and
- The levelized cost of electricity that results from combining those estimates of costs, economic factors, and the financial factors that reflect the business structure of the project that finances and constructs the system.

Here the main requirements are:

- The levelized cost of electricity (LCOE) from the system is the sum of all <u>annual costs</u> divided by <u>the amount of electricity produced</u> per year.
- <u>Annual costs</u> are the sum of "annualized" costs related to the <u>capitalization of the system</u>, the <u>operations and maintenance (O&M) costs</u>, and any annualized costs that are due to the <u>replacement of capitalized items</u> of the systems (such as make up wells, downhole pumps, etc.)

- The annualized cost of the initial capital expenses (and certain tax items that are proportional to capitalized costs) is calculated as the product of the capital costs and a fixed charge rate (FCR).

- FCRs typically fall in the range of 0.07 to perhaps 0.14, depending on the financial structure of the project (e.g., municipal utility, compared to investor-owned utility) and the assumed rates of inflation, rate of return to equity, and interest rate on debt.

# 5. DOCUMENTATION OF TECHNICAL DETAILS

## 5.1. Defining Parameters for Geothermal Cases

GETEM system cases are defined by a few primary parameters. These include:

- Reservoir temperature, degrees C.

- Average well depth, feet. This can differ for production and injection wells.

- Type of power conversion cycle: Air cooled binary or water cooled flash. Flash plants can be one or two stage, with dual flash being more common in the U.S. and single flash being more common in most of the plants built since 1990 in the Philippines and Indonesia.

- Power plant capacity, megawatts (electric). The size is set for the system before considering power consumed by production and injection pumps. Larger plants cost relatively less per MW of capacity.

- Use of production pumps. These are used in all binary system, and can be used in flash systems. Pumps can be lineshaft (common today) or electric submersible pumps (expected for most binary geothermal service by 2010).

- Stimulation of production wells. This is required for EGS systems, and might be useful in some borderline conventional hydrothermal cases.

- Fixed Charge Rate (FCR). This primary factor in the calculation of levelized cost of electricity (LCOE) is set by the user to reflect the financial structure of the project, cost of funds (debt and equity), and provision of federal and state tax codes.

- Resource temperature, flow per well, depth of the wells, and relative difficulty to drill the wells are the primary factors in defining the economics of the resource. To some extent the depth of the wells trades with the temperature so that deeper hotter wells may not be more economic than shallow, lower temperature wells. Because a kilogram of hot water has a low energy content (relative to a kilogram of oil or methane), it is really important to be able to produce a great deal of hot water to make the project economic. Relative difficulty in drilling the wells is related to characteristics of the rock formations surrounding them.

- The reservoir definition variables are not limited by the code, but only the users *understanding of the geothermal industry, At present, two small geothermal power plants produce power from fluids with temperatures below 125°C. Plans are in the works for future plants producing electricity from less than 100°C where favorable weather conditions and new technology make this feasible. The correlations in the GETEM are most reliable for temperatures between 100°C and 200°C for binary plants, while the flash plant correlations are less reliable below 175°C.

In the real world of geothermal power project development, these parameters are set by the processes of resource exploration and prospect confirmation. The estimates for each reservoir and power project are refined through the stages of detailed design, wellfield layout, and ordering of major equipment.

## 5.2. Exploration

Geothermal exploration and confirmation activities are directed at finding a good resource and then pinning down the temperature, depth, flow rate per well, injection capacity and fluid chemistry of the resource. GETEM developers used an informal review of U.S. industry data to calculate the cost of exploration and added testing needed to confirm the reservoir. However, the user can input some of the risk factors, such as success rates, to influence the ultimate cost of the project.

### Approach and technical basis

The cost of exploration is both a cost of the risk of not finding a successful well and also the cost of the techniques used to site the wells in the first place. Geothermal energy exploration is still at the level of the oil and gas exploration was in the early 1900's. We are drilling the domes, *i.e.*, the obvious locations where it is easy to see that there is a resource present by surface indications such as hot springs, hot wells, or fumaroles.

Geothermal exploration drilling was highly successful in the early days of international geothermal exploration with a survey cited by the World Bank for the Pacific Rim giving a success rate of 50-70%. In the early 1980's the oil and gas industry felt that a wildcat (exploratory well drilled in a new field) success rate of 10% was quite good, world geothermal success for wildcat exploration was around 60%, however, good statistics were hard to come by. We suppose that success rates were high because the most obvious thermal features, flowing hot springs in areas of very high heat flow were explored first.

However, as the obvious high temperature sites were developed, the success rate dropped for geothermal wildcat drilling. In addition, the number of wildcat wells drilled has dropped with the advent of low energy prices (until very recently).

Now, while the oil and gas industry has a success rate of about 39% currently for wildcat wells (down from a high in 2001 of 45%) the geothermal industry has remained fairly constant for the last 10 years at around 20% success for wildcat wells. The only published basis for the "20%" estimate is in the geothermal policy assessments conducted by Technecon in the late 1970s (Cassel *et al*., 1982). And it is the case in those that statistics that Technecon counted as exploration "successes" a few geothermal sites that later proved to be not confirmable at the then current economic conditions (Amundsen *et al.*, 1984). So, the few documented statistics here suggests that the probability of success of geothermal wildcatting, in the U.S. in the 1960s and 1970s was about 12 to 15 percent.

The cost of this exploration risk is spread over the potential projects that might be developed at the particular resource. It is presumed that exploration success will improve as development progresses, but GETEM uses an average exploration success rate for all plants on the same resource. The DOE Geothermal Technologies Program (GTP) has required that a rate of 20% be used for policy studies in 2005.

## Data, Correlations, and Algorithms

In GETEM, the exploration success input is a fraction of total wildcat wells that are successful. An additional sum of about $1million is applied to the overall program, plus multipliers against the cost of exploration wells to estimate the cost of geology, geophysics and geochemistry as well as well logging and testing that go into the exploration of a geothermal field. This multiplier is fixed at 1.2, meaning a 20% increase in cost over a production well for exploration related activities.

This exploration cost, including the cost of the dry holes, is then spread over all of the projects developed at the same delimited prospect. The exploration cost is calculated, including dry holes, and then is multiplied by the ratio between the plant size and the total resource found. This reduces the total exploration cost if the resource is large, but could attribute all of the exploration cost to one plant if the plant size is the same as the resource found.

## Ranges of input data and correlations

Data on actual exploration success, the amount of total power discovered at new resources and the degree of success at predicting temperature, flow rate or depth to resource are scarce for the geothermal industry partly because there has been so little exploration done in the last 15 years. The last burst of exploration and development to occur followed the increase in oil and gas prices in the early 80's. Demand for power and the high cost of hydrocarbons triggered accelerated exploration for alterative energy sources. Many of the statistics used today can be traced to this surge in geothermal development.

One industry source suggested in 2005 that a success ratio of 50% applies today for geothermal exploration in Nevada. The value is that high because of the results of copious exploration there in the 1970s and 1980s. GETEM developers expect that the probability of success of exploration in the U.S. outside of California and Nevada will not be higher than 20 percent for the foreseeable future. The DOE Geothermal Technologies Program (GTP) has required that a rate of 20% be used for policy studies in 2005.

## Limitations and Uncertainties

The name of the game in the exploration phase is uncertainty. Handling uncertainty is one of the aspects of economic modeling that is most important to understanding the cost of natural resource development. The exploration and confirmation costs are one of the key ways that GETEM handles risk. The impact of risk on cost can be mitigated by exploring large resources and spreading the cost over a number of plants. The user of GETEM needs to be familiar with exploration success rates for geothermal drilling since this is a user input with no limitations on the value, so the user must have an understanding of the likely success rates for wildcat drilling. The most recent data for wildcat success is old since there has been little or no exploration drilling in the US from around 1990 to 2004. The last published data suggests that success rates for wildcat wells are typically around 20% so the user should consider this as a baseline condition unless they have other data available. The industry or the DOE should develop a program for tracking success rates for exploration.

## 5.3. Reservoir Confirmation

Once the first successful exploration well has been drilled, the confirmation phase of resource development is entered. During this phase, new wells are drilled to identify the boundaries of the resource, determine where best to inject, identify and solve drilling problems and determine the behavior of the reservoir through testing. Confirmation wells will be more successful than exploration wells, but less successful than wells drilled after the resource is confirmed.

The key end point of Reservoir Confirmation is that the resource is well enough defined to let lenders provide debt funding to the development project. Once the debt financing is secured, the project goes into detailed design and drilling out of the production field.

### Approach and technical basis

As with the cost of exploration, The cost per well of confirmation wells is calculated by using a multiplier, in this case 120%, to increase the cost of the confirmation wells to account for the higher cost of drilling and testing these wells. Because the resource is less well known, there will be more trouble costs for the confirmation wells. Longer and more expensive testing is done to ensure that the resource is well understood. Testing can include detailed temperature and pressure logging, natural gamma emission logs, fracture imaging logs such as borehole televiewer and micro electrical resistivity logs, and possibly other geophysical logs. However, most other geophysical logs are not particularly useful for geothermal rock types, and so are not used.

The cost of each well is calculated by multiplying the calculated cost from the depth by the fixed multiplier for testing and troubles. Although this is not a user input, there is a possible multiplier for well cost that could be used to increase the well cost beyond this confirmation cost increase. However, the well cost multiplier is used on all wells while the multiplier for the confirmation wells is only against those drilled during this phase.

GETEM allows the user to determine the number of wells needed to confirm the resource. Some financial institutions require that half the wells for the project be drilled, others require fewer. Complex and poorly understood geology will increase the number of confirmation wells needed while simple and well understood geology will reduce them.

The dry holes calculated from the confirmation phase are also taxed with the extra expense (the extra 20%) for testing and troubles. The successful wells are calculated and passed through in the total well count as producer wells needed for the project.

### Data, correlations, and algorithms

There are few current data on the success rate of confirmation wells, and on the cost of testing or troubles for confirmation wells as opposed to infill drilling wells. The algorithm for determining this cost is a simple multiplier determined from older experience developed during the last surge of geothermal development. Actual cost of testing and logging for current conditions needs to be compared to the estimates in GETEM currently.

The wells passed through from the confirmation phase to the development of the plant total wells required each need a pump cost added if the field is to be pumped. This is done in the costing of the development phase of the project.

**Range of input data and correlations**

There are no limits programmed into GETEM that limit the range of input for confirmation success rates. The user needs to be familiar with typical geothermal drilling success rates for actual projects. However, the success rate during geothermal confirmation work is generally much higher than that during exploration, often higher than 50%. For oil and gas exploration, this phase of project development may have success rates as high as 77%. Data available from past exploration and development efforts suggests that confirmation drilling is generally about 60% successful. (This value was originally derived in the IMGEO development work in 1987, so the statistical basis precedes that year. Complex and poorly understood geology will decrease this.

**Limitations and uncertainties**

The confirmation success rate is another area for determining the risk cost associated with geothermal development. A risky development with unknown or complex geology should have a higher cost which can be imposed by using a lower confirmation success ratio. Conversely, a project in an area with many other geothermal developments will have higher rate of successful confirmation wells. The range of these uncertainties will have an impact on the final cost of power and reflects the overall risk associated with reservoir development. However, since most of the cost of the project lies with the power plant, especially in the case of binary plant projects, the cost of risk associated with drilling dry holes during confirmation will be fairly low.

**Recommended model improvements**

It will be useful in the future to include the confirmation cost multiplier as a user input to allow for improved technology for testing and resource characterization. Such new technology could cost more, but improve success. Testing technology could also be less costly while maintaining current success rates.

Another cost improvement that could be added to this and to the exploration cost calculations would be to add up the cost of risk separately by adding the cost difference between the cost of exploration and confirmation wells and the development wells, the cost of dry holes during exploration and confirmation, the cost of troubles during drilling and the cost of lost revenue due to reservoir decline could be separated and added up as a cost of risk. This would allow quantifying the risk related costs so that the impact of technology improvement on the cost of risk could be directly calculated.

## 5.4. Wellfield Design, Construction, and Operation

Well field costs encompass all aspects of reservoir development and operation, from drilling and testing the production wells and injection wells, installing pumps in them if needed, stimulating the reservoir if needed, pipelines construction, through operating the well field. In general, well field element costs are inputs into GETEM rather than GETEM calculating these costs, i.e., the cost of a downhole pump is an input rather than a calculation.

This is because the defining parameters for the field used in specific cases used for policy studies vary a lot. The GETEM cases for 2005 assume semi-consensual estimates of what kinds of physical resources that the DOE Geothermal Technologies Program (GTP) is working into.

GETEM is used to sum the well field costs based on the size and brine effectiveness of the plant, and hence, the number of wells required. Thus, one inputs surface piping cost per well and GETEM determines the total surface piping cost. Some of well field cost elements require multiple inputs to establish the costs (well drilling and pump costs) and others are defined by a single input. The latter include Surface Equipment per Well and Stimulation Cost per Well.

As described in Sections 5.2 and 5.3, wells are drilled during exploration, confirmation, and development. As described in Section 5.8, additional wells are (usually) drilled during the phase of project operations, to make up for declines in productivity. Not all wells that are spudded are successful. Some drilling fails to intercept the resource and other attempts have to be abandoned because of drilling problems. GETEM allows the user to specify the success rate of drilling during both exploration and confirmation.

The cost of wells drilled early in the development of a prospect are usually more expensive than those drilled later, because information gained about the site geology can lead to better drilling plans. The GETEM-2005 makes the earlier wells, in the "Exploration" and "Confirmation" phases of the project, cost 20 percent more than wells drilled during later field development.

Wells used during operations have to be connected to the plant by surface piping. GETEM initializes this at $100k per production and injection well. This amount is multiplied by the actually number of wells used during operations. The distance from well pads to the plant depends on the layout of the particular proposed project. There can be a trade off between piping on the surface and directional drilling. To account for these two issues, the user is allowed to change the cost of surface equipment per well.

While some well stimulation is becoming routine in hydrothermal reservoirs, well stimulation on a large scale is what distinguishes an enhanced, or engineered geothermal system from a natural hydrothermal system. Thus, depending upon whether GETEM is being used to simulate a hydrothermal or EGS resource, the user is allowed to choose whether stimulation costs are to be included. If stimulation is selected, it is applied to only the production wells, at a cost of $250k per hydraulic fracture treatment.

For EGS cases, it is assumed that each production and injection well will be fractured. Some versions of GETEM show $500k fracture cost, assuming $250k per treatment, but only one injector per two producers. The $500k value is not correct; it should have been set at $250k + $125k = $375k per production well (per Entingh; others may disagree). Then the cost of stimulating two producers plus the one shared injector would come out to $750k.

The number of wells needed has a major impact on the well field cost. The number of production wells needed is determined by the resource (enthalpy flow rate and temperature the wells produce) and the size of the plant. From the number of production wells required, the total number of wells is determined using the ratio of injection to production wells, the success in drilling the resource, and the number of exploration wells required to locate the resource. The ratio of injection to production wells is initialized at 0.50 (the user can change this value). The success rates for exploration and confirmation wells are initialized at as 0.2 and 0.6, respectively (see sections on Exploration and Confirmation for the rationale for these values). The user can also choose to enter a number of spare production wells on hand (the initialized value is 0).

If the user chooses to enhance production by including downhole pumps, the number of production wells requires changes because the flow per producer will be higher. The increase in productivity that can be achieved depends on pump capacity and depth of the pump. The user must calculate such effects outside of the model.

There are two types of downhole pumps in GETEM, lineshaft and electrical submersible. A lineshaft pump has the motor on the surface and a rotating rod connecting the motor to the actual downhole pump. Lineshaft pumping is the currently accepted method of pumping geothermal producers. Unfortunately there are flow and depth limitations of lineshaft pumps. Electrical submersible pumps have the motor downhole and thus require an electrical cable down the well to the pump. Electrical submersible pumps are still in the testing stage for geothermal operations. Electrical submersible pumps have the potential to increase the productivity enhancement that can be achieved through downhole pumping. GETEM defaults the downhole pump cost per producer to $300k for lineshaft pumps and $250k for electrical submersible pumps.

In most systems, the outflow from the power plant is pumped back into the reservoir. The pumping power is a product of the flow out of the plant and the pumping pressure delta (initialized at 100 psi). The cost of these pumps is initialized at $700 per horsepower. Both production and injection pumping add parasitic loads to the system, which are calculated in the power plant sections of the model.

## Wellfield Operation and Maintenance Costs

O&M costs are calculated as annual costs, and expressed as $million/year or $/kW/year.

Five cost items are dealt with here:

- General operating costs for the field,
- Maintenance costs for wells,
- Maintenance costs for field non-well items, such as field piping and downhole pumps,
- Replacement and/or repair costs for downhole production pumps, which have expected lives today on the order of three to five years, and
- Periodic costs incurred for makeup wells and replacement reservoir volumes that are due to declining performance of the reservoir.

**Operating costs** are calculated for the system as a whole in the system O&M sheets, e.g., 5B**.B1-O&M-1**. There, a fraction of the entire operating costs (25% of the operating labor cost) is ascribed to the well field, and the rest to the power plant. The 25% factor is hard-wired in this version; users will be allowed to change that later. The value calculated is shown as **Field Labor Costs** in the Output sheets.

**Maintenance costs for ordinary items** (cost items 2 and 3 above) are handled as follows. On the system Input sheets (Binary or Flash) the user sets a value for **Annual O&M non-labor (fraction of field costs)**. The initialized value for that is 1%/year. That 1% is charged against the capital cost of wells (shown as **Well Non Labor Costs** in the outputs), and the capital cost of field piping, and downhole pumps (shown as **Other Field Non-Labor Costs** in the outputs).

Annual replacement or repair costs for **downhole production pumps** are based on the initial cost of the pumps, with installation, divided by the expected life of the pumps. That amount is added to the **Other Field Non-Labor Costs.**

**Costs that compensate for effects of reservoir decline** are calculated by special routines described in Section 5.8, below. The annualized value of these costs is included in the account

**Other Field Non-Labor Costs** in the outputs. In future versions of GETEM, these costs will be identified in a separate account, since their meaning (especially in some EGS systems) is quite different from other costs bundled into this account at this time.

## 5.5. Cost of Wells

The process of understanding and estimating geothermal well costs has gone through a long evolution (see Appendix B-1) for historical background information). Some of the lessons learned in this process include that while geothermal drilling, in general uses the same equipment as oil & gas drilling, geothermal drilling has different requirements, goals and designs that result in different costs than oil & gas wells. In the past, people have tried to estimate geothermal drilling costs by multiplying oil & gas costs by a scaling factor. That does not work. A second lesson is that geothermal well costing must be done in context. That is, one can not meaningfully discuss geothermal well costs without establishing the context including the location, the design, problems to be encountered, etc. A third lesson is that the well design and technology employed are very important. The significance of context and design is that inputs to GETEM (cost curve and depth) only generally describe the well field that is being costed. Part of any well construction activity includes assumptions about lithology, well diameters, depth, etc. These assumptions must be stated such that other system requirements (e.g. downhole pump type and depth) can be considered in the context of the well cost.

**Main assumptions**: Some of the assumptions behind the well cost curves built into GETEM include: (1) Basin and Range lithology representative of near-future geothermal drilling, (2) wellbore integrity issues (lost-circulation and sloughing) are only encountered in the upper section of the well and can be put behind the surface casing without the need of an extra intermediate casing, (3) very hard abrasive drilling is only encountered at 1,000 feet above the production casing point. This means that the top 5,000 to 6,000 feet of a 10,000 foot well would be essentially sedimentary rock, based on the documentation for WellCost Lite. The author (Entingh) believes this is a very optimistic assumption and will have to be reassessed in future versions of GETEM. The last assumptions, (4) is that the well can be completed with a 7" slotted liner, and the upper 2,000 feet of the well is large enough to accommodate a downhole pump. Note: not all potential targets within the Basin and Range will satisfy assumption (2). As a result of (2) and (3) trouble should contribute no more than 10% to the cost of drilling and is readily covered by contingency.

These points are made to re-emphasize the point that GETEM uses well costs as inputs and does not predict well costs based on location and design knowledge. To make such predictions one needs to use WellCost Lite.

Currently a three part approach is being employed to understand and estimate geothermal well costs. First, historic information on geothermal drilling has been reviewed both for the 1970's and recent geothermal wells (wells drilled since 1985). Second, a modeling methodology, WellCost Lite has been applied to predict geothermal well costs. Third, historical data and WellCost Lite predictions have been synthesized into the cost curves built into GETEM. Elements of this three part approach have been published in the GRC Transactions (Mansure, 2005a & 2005b). WellCost Lite is documented in Appendix B (1).

Factors that have major impacts on drilling a well include:

- Design
    - Depth
    - Trajectory (vertical vs. horizontal)
    - Casing profile (includes diameter)
    - Casing material
- Location
    - Lithology
        - Hardness, abrasiveness, friability, etc.
        - Wellbore integrity
    - Site (transportation, pad, water, weather, etc.)
    - Pore pressures & fracturing gradient vs. depth
    - Temperature vs. depth
- Drilling problems

Unfortunately in examining historical data there are non-quantifiable costs. That is, there are seldom sufficiently detailed records to explain all the costs. This may be due to poor documentation of, for example, unanticipated lithologic conditions, drilling problems, failure to follow proper drilling practices, the use of inappropriate equipment, equipment failures, etc. Also, there may be costs that are not accounted for; well costs that were charged to project overhead or other non well categories. Assuming an "actual" well scenario, WellCost Lite can make accurate predictions. However, while in hindsight one knows how the well should have been drilled, there is seldom enough information, a priori, design an optimum well even when drilling next to an existing well. Thus it is customarily to include at least a 10% contingency fee in estimating well costs. Past experience indicates that this contingency is sufficient in many locations, but there are other locations where lithologic variations will render this amount of contingency too low.

Of the physical factors above that affect well costs, the only one that is an input to GETEM is depth. Depth is the most significant factor, the cost of a 10,000 ft geothermal well being as much as ten times the cost of a 2,000 ft well (see Figure 5.1). However, other factors such as site location and lithology easily cause a factor of two to three change in geothermal drilling costs. GETEM contains three cost curves: low, median, and high. Median well cost times the number of wells should give the expected wellfield cost of a project. Individual wells could be higher or lower than this median. The low and high curves were selected to encompass ~2/3 of the scatter of recent (post 1985) geothermal well costs (see Figure 5.2). That is, only 1/6 of well costs should be below the low curve and only 1/6 of wells costs should be above the high curve.

The difference between the low and high cost curves should be enough to account for most of the effects of the factors listed above under design and location. Many of the wells on Figure 5.2 with costs above the upper bound include abnormal drilling problems costs.

As work on well costing progresses new cost curves will be generated for GETEM. New curves should include 1) locations other than Basin and Range, 2) smaller and larger well diameters, and 3) various new drilling technologies.

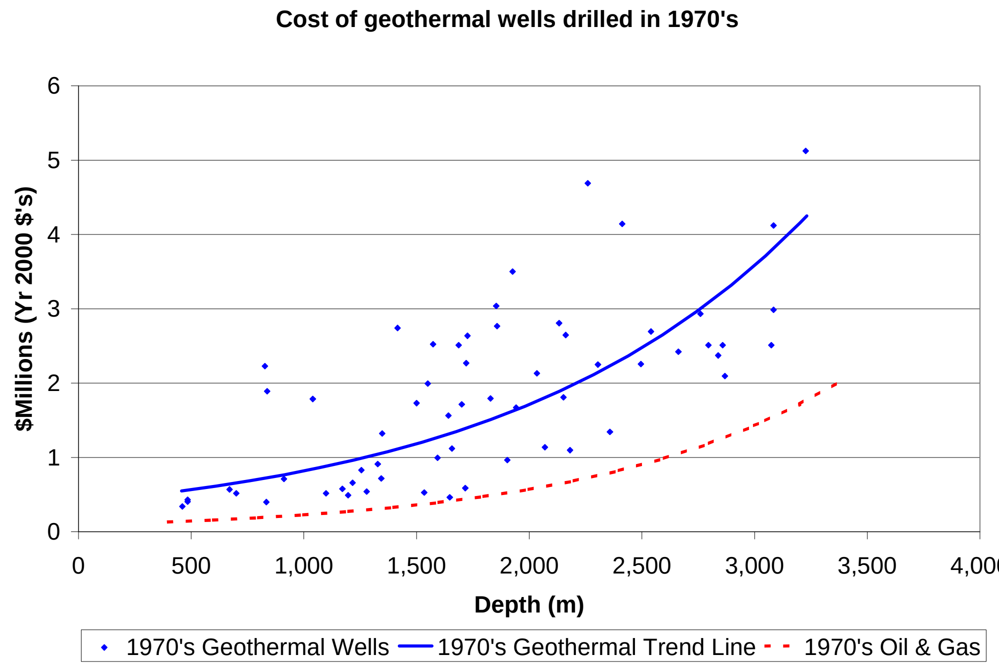


**Figure 5.1 Cost of geothermal wells drilled in the 1970's (blue) *vs*. average oil & gas wells (red)**

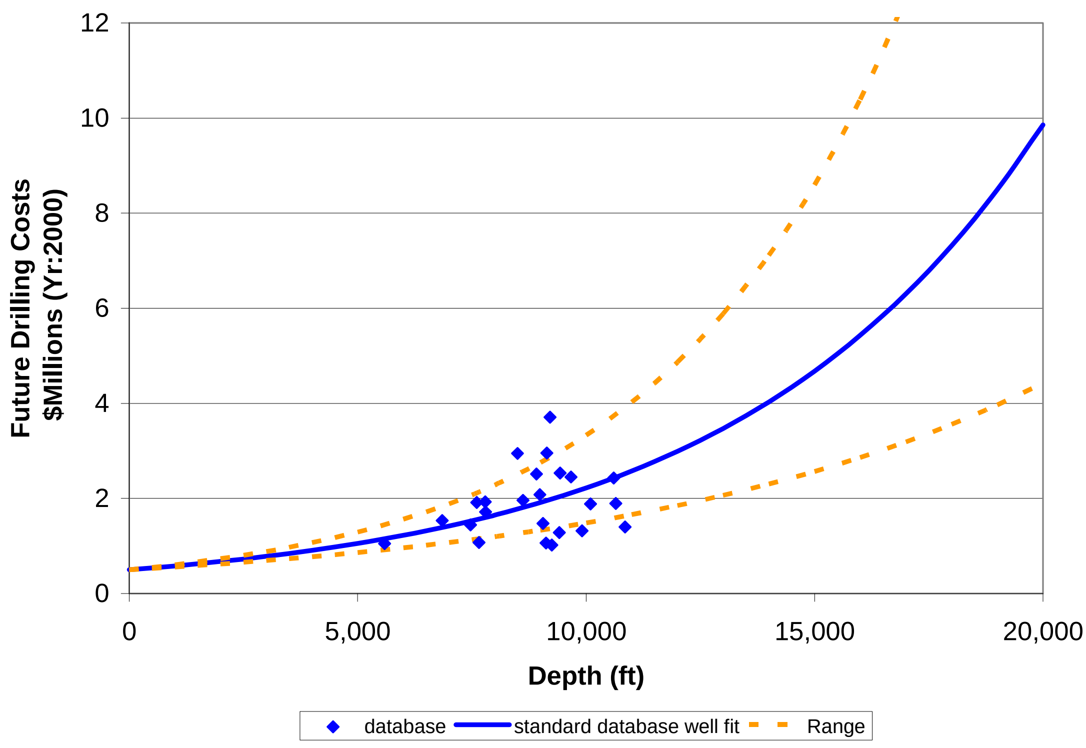


**Figure 5.2 Comparison of best fit data to recent geothermal wells**

**Approach and technical basis**

The well cost curves developed for GETEM combine what we know from actual geothermal wells drilled and from the application of the modeling methodology WellCost Lite. By itself, empirical analysis of data in the Sandia geothermal well costs database would not be adequate because of the limitations of the data. Any model requires validation. Thus it is only logical to use both the database and the model, WellCost Lite, to understand and predict geothermal well costs.

Not very many wells are drilled each year and records are available from only some geothermal fields. There are only 31 recent (since 1985) production/injection wells in the Sandia Geothermal well costs database. Costs are reported differently for each drilling program. Some wells are missing significant costs and others have excessive costs (e.g., some have no casing costs and others have excessive casing costs – it is not uncommon when drilling two wells to order both casings together and charge both to the first well). Costs can be missing from the reports, e.g., well testing is not uniformly reported. Examination of the data in the database shows that the 31 wells fall into a “bimodal” distribution. There are shallow large diameter wells that include titanium casing and deep multi-lateral wells. This inherent bimodal nature of the data leads to comparing apples and oranges. Careful sifting of the data can lead to meaningful comparisons (subtraction of the titanium casing cost, extracting the first leg costs, etc.), but analysis of these 31 wells alone is not enough. The data base also provides insight into real cost breakdowns, cost data helps us guide our research, provides a means to collect and safely store well cost data, allows us to analyze well cost data for actual drilling/trouble costs, provides factual data set to evaluate cost models, provides a means to evaluate drilling metrics. Clearly then, the need for understanding real cost data is well founded, however analysis of the data to meaningfully extrapolate cost trends needs to be supplemented with work using WellCost Lite.

In parallel to the development of GETEM, a well cost modeling methodology, WellCost Lite, has been developed and is being used to predict geothermal well costs. One challenge of developing any well cost model is validation. Without validation and site specific information, a well cost model may not sufficiently represent reality and be in error. The model is in essence self fulfilling – it produces the cost of what has been assumed. Often when modeling costs at a new location the time to drill can be off by 50% (anecdotal information on cost, depth, days to drill, diameter, etc. is often available in locations where more complete data is not in the database). Investigation has shown most of discrepancy (the 50%) is due to the assumptions made not the methodology. The rocks may have been softer, lost circulation may have been worse, wellbore integrity problems may have required an extra casing string, etc. Hence, WellCost Lite does not represent a stand alone tool; it must be constantly compared to information from actual drilling.

Analysis of data from the 1970’s has been a useful learning tool for how to understand recent geothermal well costs. In the 1970’s most geothermal wells have similar designs – diameters were mostly within one casing size, there weren’t multi-lateral completions, titanium casing was not being used, etc. Thus similarities and readily apparent well to well comparisons facilitated a more statistical approach to data analysis. Several useful questions that can be investigated using the data from the 1970’s include: 1) the appropriateness of a particular curve fit, 2) legitimacy of extrapolating outside the range of a curve fit, 3) the impact of location on curve fits, and 4) unresolved scatter in the data.

Appendix B-2 justifies using a “constrained” exponential fit to account for the dependence of well costs on depth. By “constrained” exponential, it is meant that other information (discussions with operator and WellCost Lite results) are used to assure the intercept (cost at zero depth) is reasonable.

Analysis of data in the 1970's (see Appendix B-3) shows that depth and field account for only some of the scatter shown on Figure 4.1, that is, there is scatter left over after the effect of depth and location are accounted for. Depth and location should be the most significant factors that affect geothermal drilling

Details about the scope of the reported costs are limited (except for drilling problems -- see list above), since in the 1970's design variations other than depth were minimal. There is insufficient information to distinguish between real drilling problems like lost circulation vs. unanticipated conditions and lack of experience in geothermal drilling. Thus, while residual scatter may be less today, a lesson learned from analyzing data from the 1970's is that one should expect scatter in well cost even after one accounts for design and location.

In the past geothermal well costs have been compared to oil & gas well costs (Carson and Lin, 1981). As a result, geothermal well costs have been estimated by scaling oil & gas drilling costs. Problems with this approach result from the scale factor being a function of depth. The scale factor has changed with time as geothermal drilling technologies have improved, and scaling oil & gas costs does not consider differences in geothermal vs. oil & gas well designs and formation (Mansure, 2005b). In geothermal drilling many issues that drive costs up occur near the surface; also drilling problems become less frequent with depth. On the other hand, deep oil and gas drilling targets formation that make drilling problems increase with depth, in particular overpressure, which can drive oil & gas drilling costs up by a factor of four (Smith, et. al., 1997 and Smith 1998). Table 5.1 compares deep geothermal vs. oil & gas drilling. These differences between geothermal and oil & gas drilling explain why shallow geothermal drilling is more expensive than oil & gas drilling. As the well depth approaches 20,000 feet, it is quite likely that geothermal drilling will be as inexpensive as, or less than, oil & gas drilling. Geothermal drilling costs proposed for GETEM have appropriately been derived from information on geothermal drilling, not oil & gas information.

| Geothermal (Basin & Range) | Oil & Gas formations |
|---|---|
| Normal to underpressured | Frequently overpressured |
| Frac gradient constant | Frequently frac gradient decreases |
| Long casing intervals possible | Frequently extra casings required |
| Lost circulation usually decreases with depth | Lost circulation frequently increases with depth |
| Moderate decrease in ROP with depth | Significant decrease in ROP with depth |
| Well control a function of temperature not depth | Well control increasingly difficult with depth |

**Table 5.1 Comparison of Deep Geothermal vs. Oil & Gas Drilling**

## Data, Correlations, and Algorithms

This material describes the current best inputs to GETEM-2005. Research in the area of actual cost of wells under various conditions is an important and active area

"Best" fit curves have been developed for predicting future geothermal drilling costs (Figure 5.2) using data from the well cost database (Mansure 2005a). Curve fits using data from the database were compared with WellCost Lite to constrain the fits and assure consistency. Figure 5.2 contains data for geothermal wells drilled within the U.S. and abroad since 1985. Records of the non-U.S. wells were carefully examined and it is believed their costs are representative of what similar wells in the U.S would have cost. Some processing of the data had to be done to produce Figure 5.2. For example, for wells with more that one leg, the cost reported is the estimated cost for the first leg. The actual fit is to recent data from harder rock geothermal sites (Geysers), not sedimentary rock geothermal sites (Salton Sea). The expression of the "average" line is given by:

Future Drilling Costs = $\$500\mathrm{k}e^{0.0001491 depth(ft)}$

in year 2000 dollars. In GETEM this curve has been changed to

Future Drilling Costs = $\$580\mathrm{k}e^{0.0001491 depth(ft)}$

in order to express well costs in current dollars (2004). Correcting to 2004 increases the cost ~16%, this is essentially the same as the 15% Geothermal Research Program cost reduction goal through 2010. Therefore, Figure 5.2 can also be interpreted as a reasonable projection for geothermal well costs in 2010, based on combining historical data and stated DOE goals.

While 1970's data shown on Figure 5.1 is from a wide variety of resources, the variability within a given resource is as much as 80% of the variability shown (see further discussion at "Limitations and Uncertainties," below). Thus, even in an individual resource, there is significant uncertainty in the drilling cost expected at any given depth. The range (dashed yellow lines on Figure 5.2) within which most geothermal costs can be expected to fall was established as follows. For the 1970's data, if one increases and decreases the exponential rate by ±27% of the average, one encompasses about 2/3 of the wells. Using the same ±27% for recent wells also encompass ~2/3 of the recent wells. Thus, ±27% determines a band within which 2/3 of the data fall independent of the data set (both 1970's and recent wells). The range bounding 2/3's of the recent well data on Figure 5.2 is given by the expressions

Low Future Drilling Costs = $\$500\mathrm{k}e^{0.0001088 depth(ft)}$, and

High Future Drilling Costs = $\$500\mathrm{k}e^{0.0001893 depth(ft)}$.

In GETEM these curves have been changed to

Low Future Drilling Costs = $\$580\mathrm{k}e^{0.0001088 depth(ft)}$, and

High Future Drilling Costs = $\$580\mathrm{k}e^{0.0001893 depth(ft)}$,
to express well costs in current dollars.

Figure 5.3 compares the "best" fit to WellCost Lite modeling and other geothermal well cost data.

For depths less than about 14,000 feet, WellCost Lite cost predictions are greater than the median line for recent wells. A couple of reasons may exist for this difference. Where as, the WellCost Lite estimates were for a specific geologic setting, the Northern Nevada Basin and Range, the curve fit is generic, including areas that may represent easier drilling. WellCost Lite estimates are full cost recovery (they include all costs), where as, the costs of many of the wells in the database may be incomplete, e.g., may not include testing, etc.

The green squares at 5,000 and 12,000 feet on Figure 5.2 are actual geothermal wells in the Basin and Range, with lithologies that should be representative of first generation EGS sites. These wells are not in the database (Sandia does not have actual well records from these sites), but sufficient limited information including, depth, diameter, and cost, are known such that these points are plotted with confidence. Note the good agreement between these wells and WellCost Lite estimates.

The WellCost Lite predictions on Figure 5.3 (red circles) fit the mean cost line fairly well below 14,000 feet. The assumptions behind the WellCost Lite calculations ("Main Assumptions" at the top of this Section) allow optimization of the casing design that reduce somewhat the increase in drilling costs with depth (no extra intermediate casing string is assumed). Below 14,000 ft, this undoubtedly helps bring the WellCost Lite estimates down to the median curve. Assuming no extra intermediate casing string is consistent with experience at Soultz (Roy Baria, personal communication) and makes sense based on the other assumptions, but it is premature to assume this will continue to apply below 20,000 ft. Actual casing designs and WellCost Lite studies would have to be done meaningfully estimate costs for depths below 20,000 ft.

The variation of WellCost Lite predictions at a given depth, for example 20,000 ft, reflects assumptions regarding drilling stratigraphy. The highest red dot at 20,000 feet is for an alternate casing design showing the impact of a non-optimal casing design.

The three bottom dots show the impact of increasing the rate of penetration (ROP) – from slow to normal to desirable. The closeness of the points shows that increasing ROP, while important, will not change the total well costs by a huge factor. This can be understood by realizing that for a 20,000 foot well, costs divide roughly into thirds: one third for casing and cement, one third for rock reduction and removal, and the last third for "other," such as testing. Thus, increasing ROP only targets one third of well costs.

The Soultz costs on Figure 5.3 (triangles) are from a personnel communication with Roy Baria, one of the lead scientists on the Soultz Hot Dry Rock project in France.

For any specific analysis (when location, drilling stratigraphy, casing requirements, etc. are known) the preferred cost prediction methodology would be to use WellCost and the User cost Curve Multiplier to input the actual drilling cost.

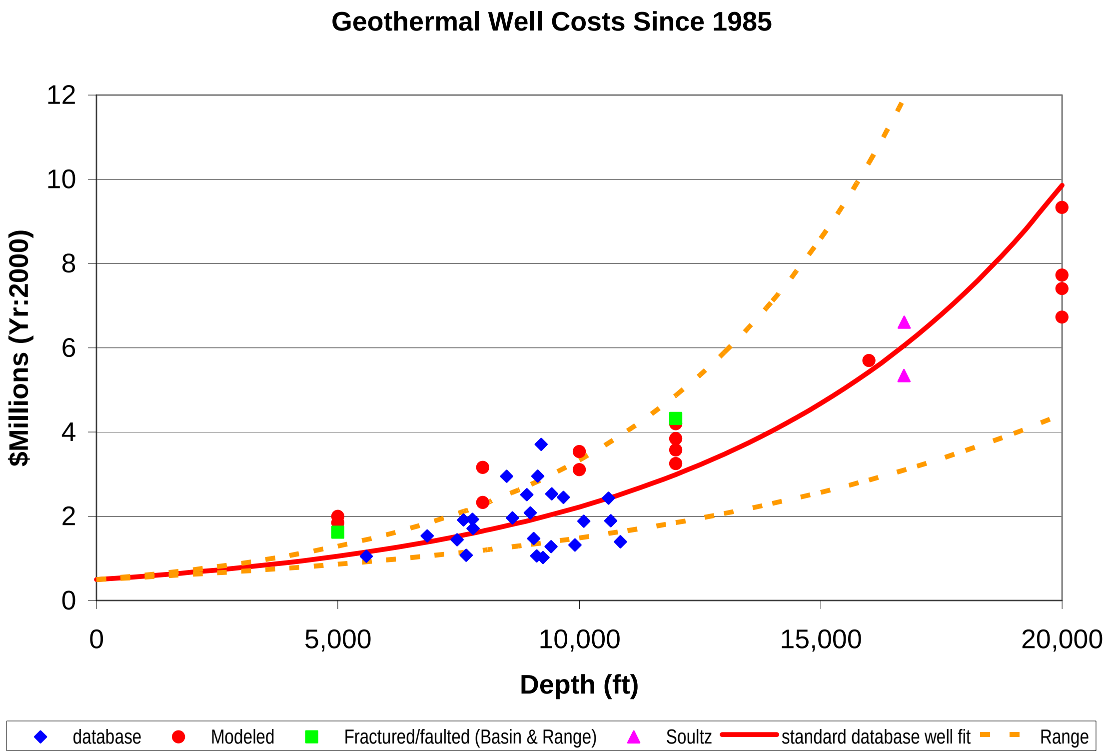


**Figure 5.3 Comparison of "best" fit predictions to WellCost Lite and other well cost data**

## Ranges of input data and correlations

One important purposes of GETEM is the estimation of LCOE (levelized cost of electricity) for future geothermal development. Future geothermal drilling, particularly EGS, will not be in the same locations and probably will be deeper than current geothermal development. Thus, it is necessary that GETEM allow inputs that extend beyond current experience. Estimates and extrapolation beyond our current knowledge base are necessary to both applying and using GETEM. This is particularly true of drilling. Currently geothermal drilling experience that has been incorporated into the drilling cost curves in GETEM is based on wells drilled less than 11,000 feet. It is quite likely that first generation EGS projects will require wells as deep as 20,000 feet. Hence, there is a need to make drilling cost estimates at depths greater than current experience.

The validity of fitting and extrapolation of well cost data to greater depths can be tested on the data for the 1970's, a larger (61 data points) more uniform diameter data set than the recent wells (24 data points) which includes both large and small diameters, as well as, single leg and multilateral wells. A comparison of linear and exponential fits (Figure 5.4) shows that a curved fit appears to more accurately represent the depth dependency of 1970's geothermal well costs.

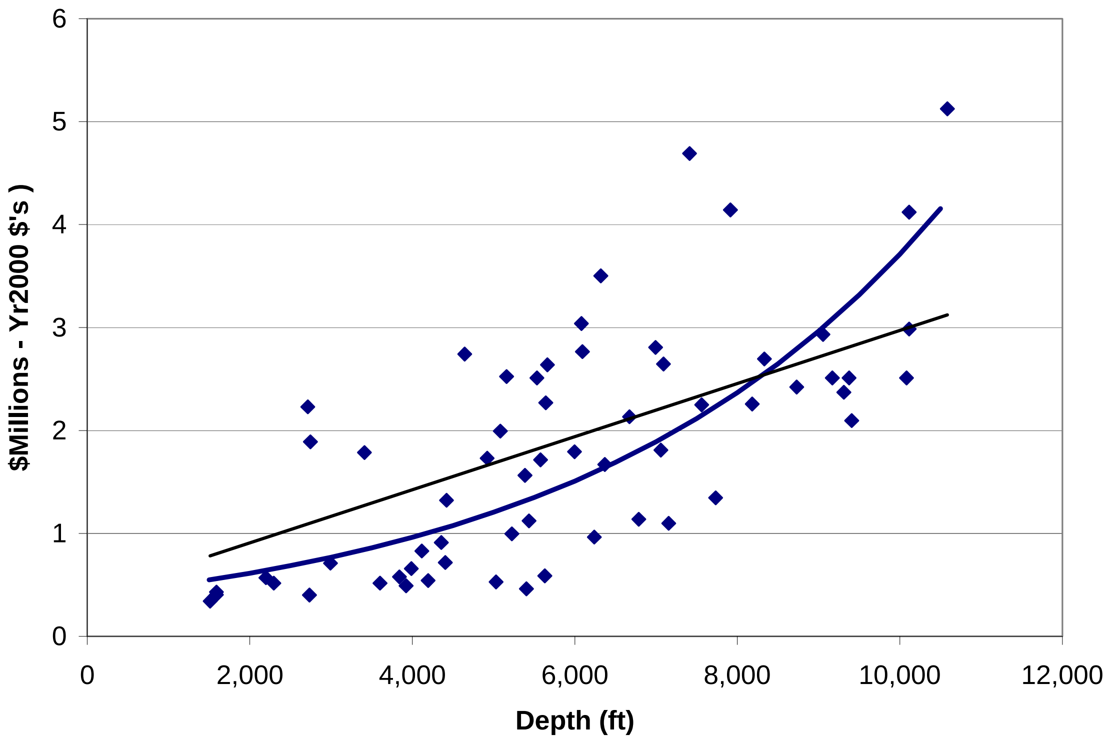


**Figure 5.4 Comparison of linear vs. exponential fits**

To address the question of what kind of curve is appropriate, one can divide the historical data into two sets: shallower and deeper than 6,000 feet (Figure 5.5). Separate constrained exponential fits (see Appendix B-2) lead to essentially the same mathematical expressions, that is, a fit to the data shallower than 6,000 feet extrapolated to 11,000 predicts the same cost as a fit to the data above 6,000 feet. Such an extrapolation would not be as good with a linear or polynomial fit.

Figure 5.5 suggests that using a constrained exponential fit may allow a drilling cost curve validated to a given depth to be extrapolated to twice the depth. Figure 5.3 shows that such an extrapolation is consistent with what one may predict using WellCost Lite.

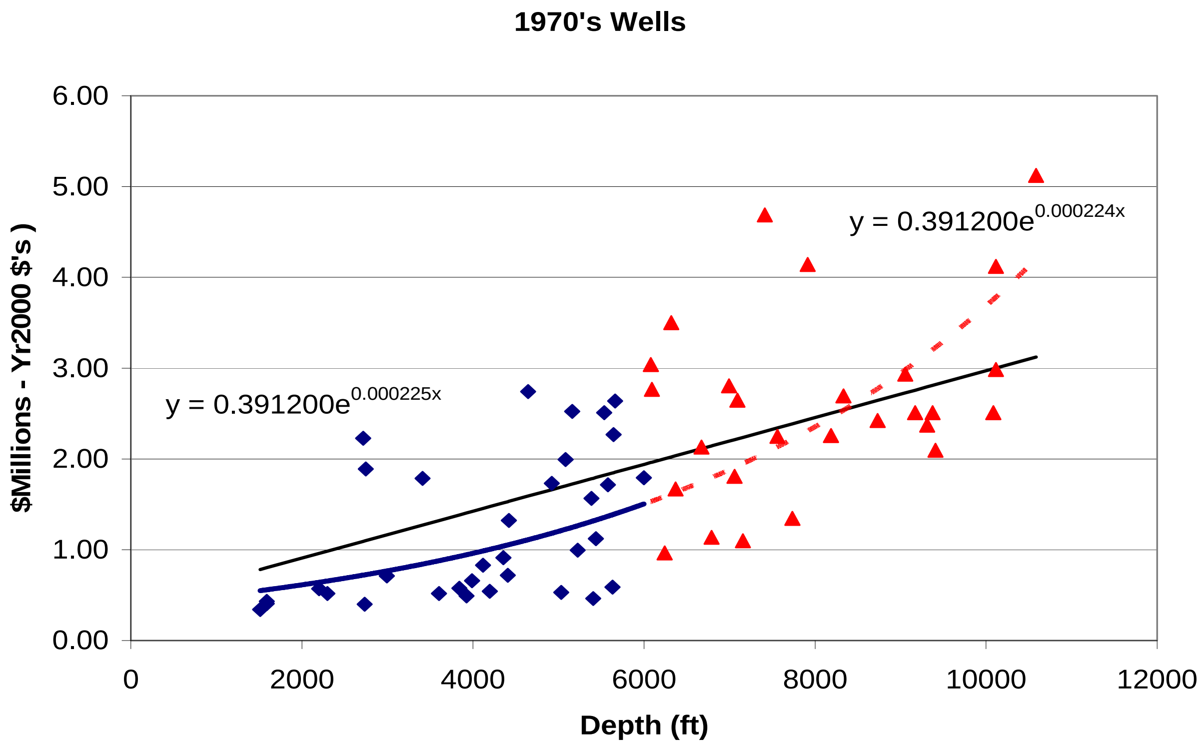


**Figure 5.5 Comparison of exponential fits below and above 6,000 feet**

## Limitations and Uncertainties

The main issue here is the importance of scatter in the well cost data and how that is incorporated into GETEM.

GETEM is a high level type of cost model. The nature of such a model precludes a certain amount of detail, and, rather, assumptions and simplifications are included in the model to prescribe “generalized costs”. This results in both limitations and uncertainties. Currently the major limitations of well costs in GETEM are those factors that effect drilling costs given is section 4.3.1 because only depth is an input to GETEM. Given that the other factors easily can change well costs by a factor of 2, here lies a significant limitation of GETEM.

Currently the only way to get around this limitation is to estimate well costs considering factor changes from the baseline assumptions listed in section 4.3.1 using WellCost Lite and then use the User Cost Multiplier to adjust the well cost to the desired value. Another potential limitation that needs to be investigated is that it is clear from Figure 5.1 that not all wells drilled to develop a particular resource will cost the same. GETEM does not accept a distribution of well costs. This begs the question: does using the median curve result in the same LCOE as distribution of well costs? A related issue is that the distribution of well costs shown on Figure 5.3 indicates that any project must have sufficient contingency funding to cover significant increases in well costs.

After depth the next most significant factor effecting well costs is believed to be location. Effects of location include both significant variations in prospect geology, and occasionally large differences in the cost of infrastructural services. For example in the latter case, drilling a well on Hawaii is much more expensive than drilling a similar wall in the Imperial Valley, California.

Figure 5.6 shows the effect of dividing the geothermal well data from the 1970's into separate sites or geothermal fields and curve fitting the data from each site. Each field is a separate color, for example, the brown dots are wells drilled in the same field and the brown curve is the curve fit for those same points.

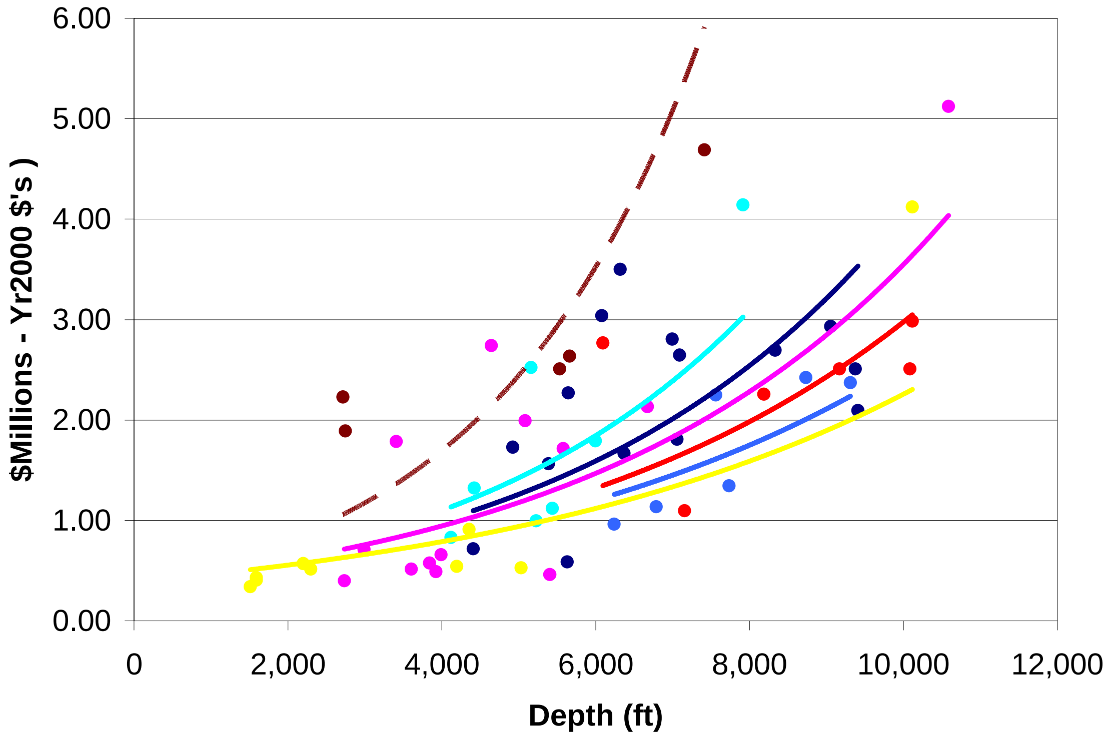


**Figure 5.6 Effect of location on fit to geothermal well costs**

Several conclusions can be made from the curves. First, at a given depth, for example 6,000 feet, there is as much as a factor of two or more variation in drilling costs from field to field. (at 6,000 feet the yellow line is just above one million, whereas, the brown curve is over three million). Thus, if location is unspecified, the well is generic rather than being drilled at a known location, there is considerable uncertainty in the drilling costs. A corollary of this observation is that in order to keep drilling costs from being excessive, it is important to choose a location that is favorable to drilling, e.g., according to the main assumptions for wells in this work.

Another observation form Figure 5.6 is that even after the wells are grouped into fields there is still considerable variation – not all the dots of a given color line up along a smooth line. In part this is because even for a given field there will be design variations in casing profile, materials, and trajectory, as well as, considerable variation in problems encountered. The reason for this is that even in a given field location certain factors, lithology in particular, are not constant. It is not uncommon for each well to be "in a different fault block." From a modeling perspective, before drilling there is seldom enough information to reduce cost uncertainty to a reasonable level (say, 20% or less).

The impacts of drilling cost uncertainties on LCOE can be studied using GETEM by selecting the low, median, or high cost curves.

**Suggested Improvements**

1. An input factor needs to be added to let the user set the success rate for production and infill well drilling to less than one, to accommodate the occasional dry hole at some prospects.

2. The GETEM development team needs to consider adding process and cost correlations that are directly sensitive to the main physical factors that affect costs, including perhaps, specific casing plans for wells with and without downhole pumps, drillability of the rock in the upper, middle, and lower thirds of the hole, for example. This has been done in previous DOE Geothermal Policy models, e.g. explicitly in GELCOM and implicitly for eight types of resources in IMGEO.

3. Explicit treatment of the time value of money in long duration exploration and confirmation programs needs to be added to the model. This will address part, but not all, of the policy concerns that arise by the large risks faced by industry in the initial discovery and opening of geothermal fields.

4. Going forward, the model, if it is to be much more useful for evaluating DOE geothermal policies, needs to be closely coupled to what are believed to be the best estimate of the physical characteristics of groups of identified and unidentified prospects in the continental U.S.

## 5.6. Surface Piping Systems **Mines, Entingh, Petty**

GETEM calculations of field costs include an "other" category that includes those elements of the well field development exclusive of the wells themselves. These costs include the production and injection pumps, and the surface piping between the well head and the selected conversion system. Section 5.7.1 describes how GETEM derives the cost and performance for the geothermal fluid pumping.

**Approach and technical basis**

GETEM does not currently calculate the cost of the surface piping. This cost is inputted by the model user as a cost per well. In lieu of attempting to calculate this cost, representative values were used during the initial model development (binary conversion system) to characterize this cost. These representative values were derived from EPRI's Next Generation Geothermal Power Plant (NGGPP) study (CE Holt Co, 1996). For binary plants, the cost of the surface piping system varied from $40K to $80K, while values for the flash plants varied from $45K up to ~$200K. A value of $100K per well was subsequently selected as being a representative cost for the initial studies, with the user having the option of changing as better cost information becomes available.

There is no performance calculation associated with the surface piping. One can account for any pressure drop in the geothermal fluid piping and conversion system by adjusting the injection pump pressure rise (see Section 5.7.2).

## Data, correlations, and algorithms

The total cost of the surface piping is the product of the inputted cost per well and the total number of the production and injection wells that are required. (Note that the model assumes fractional wells are possible.)

## Range and limits of input data and correlations

The cost of the surface piping is going to be strongly dependent upon the size of the plant, the number of wells required, and the well spacing. While some of the locations in the NGGPP study (CE Holt Co, 1996) had low costs per well for the surface piping, those costs are likely an artifact of the favorable generic well field spacing and configuration that was assumed, as well as the use of a large plant (50 MW) on lower temperature resources..

The estimated minimum input value for the surface piping is estimated to be ~$68K. This value is based upon material estimates obtained using a cost estimating software, ICARUS Process Evaluator (IPE) for 12-inch diameter, carbon steel pipe with a standard wt wall (~$45/ft, insulated). This lower limit estimate assumes an average well distance of 1,000 ft, an installation factor of 2 (installed cost is twice the material cost), and 1 production (insulated lines) well for every injection well. (Note that the assumption of 1 injection well per production well does not minimize the total piping system cost – it tends to minimize the cost per well because of the assumption that the injection wells would not be insulated.) If an 18-inch diameter pipe, with a XS wall (~$84/ft, insulated) is used with an average well distance of 2,500 ft and 2 production wells per injection well, the cost per well would increase to ~$365K per well. This could represent an upper limit for the input range (though there are likely instances where costs could exceed this value). It should be noted that the IPE estimates are based on early 2002 dollars, and that it is assumed that the cost of valves and fittings are included in the installation factor.

## Limitations and uncertainties

The discussion in the previous section on the input ranges reviews the potential variability in the cost of the surface piping system. As suggested by that discussion, a number of factors will affect this cost. The costs that are presented in the NGGPP report (CE Holt Co, 1996) were derived with wells distributed in a regular pattern, which was applied for all of the locations. An actual well field gathering and injection system will be based upon detailed engineering considerations, and will depend upon site specific conditions such as topography. In the NGGPP study, the costs of the gathering and injection system were less than 2% of the total project cost (and these costs were primarily associated with the geothermal pumps). This may be an artifact of the assumptions made regarding the distribution of wells and well spacing, and the well productivity (i.e. the number of wells). For instance, at some large well spacing the surface piping costs will be a significant contributor to the total cost.

However, it is improbable that in a commercial project that the surface piping system would become a major contributor to the cost of power. If it were becoming significant, steps would likely be taken to reduce the magnitude of these costs. Again, as indicated in the NGGPP study

(CE Holt Co, 1996), this is would be the subject of a site specific detailed engineering study to minimize this cost.

**Recommended model improvements**

The cost information generated with the IPE software could be used in conjunction with, the geothermal fluid temperature, the flow rate per well and the ratio of injection wells to production wells to generate a surface piping cost that is based upon an user inputted average distance from the conversion system to the well. (The use of the IPE cost estimates would require that they first be validated against industry experience.) It is possible that the user input could be eliminated if one imposed a generic gathering and injection system layout.

## 5.7. Reservoir Management

Reservoir management includes all cost aspects of operating the reservoir from the decision to pump the wells or flow them naturally to the placement of injectors to reduce the decline in temperature and pressure. GETEM includes three areas for cost calculation of reservoir management related costs: Downhole pumps, injection pump pressure, and reservoir drawdown and makeup operations.

Selecting inputs to the model in this area requires considerable knowledge about reservoir conditions, pump setting depths, etc.

### 5.7.1. Downhole Pumps

While some wells will self flow at high rates, particularly those with temperatures above about 200°C, lower temperature wells will likely need to be pumped to achieve the high rates needed for economic geothermal development. The GETEM code allows the user to calculate costs for pumping or not pumping the wells. If pumping is selected, either an electric submersible pump or a lineshaft pump can be selected. The flow rate under natural flow, and the rate with the wells either pumped with lineshaft or submersible pumps then needs to be input by the user as well.

The power required for the production pumps, if used, is not included in the determination of plant performance. Both the production pumping power and the injection pumping power are determined independent of the plant output and subtracted from the net plant output to determine the net project input. This net project power is used in the determination of the levelized cost of electricity

**Approach and technical basis**

Downhole pumps can be utilized to increase the flow produced from the production wells. By increasing the flow per well, the number of production wells required to meet the flow requirements for a given plant size is reduced. The pumps used have typically been line-shaft, however in recent years the use of submersible pumps has become more prevalent.

The GETEM binary conversion system model assumes and requires the use of downhole production pumps. The GETEM user sets the type of pump (lineshaft or submersible), the pump flow rate, the pump depth and the pump efficiency. With the flash-steam conversion system, the user has the option of using these pumps or having self-flowing wells.

GETEM uses the user-defined flow rate per well and the calculated total flow required to produce the specified plant output calculate the number of production wells required. For this reason, the GETEM user needs to be highly aware of the actual range of flow rates possible with and without pumping in geothermal systems. It is also necessary that the user have knowledge of the relationship between pumped flow rate and setting depth. The pump set depth and flow rate establish the parasitic power needed for production pumping. The deeper the pump is set or the higher the flow rate, the more energy required for pumping.

Currently, artificial lift methods for geothermal well production are limited to lineshaft pumps, where the pump motor on the surface turns a shaft that turns the downhole pump, and electric submersible pumps where the pump is turned by an electric motor in the well suspended from a cable carrying power to the motor. While the pump setting depth for lineshaft pumps is limited. Electric submersible pumps can be set at any depth. In addition, the well does not need to be straight. Because they can be set to deep depths, they can produce more fluid from each well since more drawdown can be accommodated.

It is probable that the use of downhole pumps will be critical to the viable development of power production from EGS reservoirs (unless the EGS conversion system uses flash-steam technologies). In particular it is likely that these applications will require the use of submersible pumps because the likely setting depths will exceed those possible with the line-shaft pumps.

## Data, correlations, and algorithms

The capital cost and power requirements for the production pumps are done in GETEM's sheets **5A.BI-Sys-1**, **6A.BI-Sys-2**, **8A.FL-Sys-1**, and **9A.FL-Sys-2**.

*Performance*: If the GETEM user inputs an additional drawdown factor, GETEM first determines the magnitude of the added drawdown and adds this value to the user inputted setting depth to determine the final pump depth. If there is no user input for additional drawdown (which is currently how the model is being used), the user inputted value for the setting depth is the depth used to determine the pumping power for the production well pumps. The total production pumping power is determined using the following equation.

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

In this correlation, the total flow is the total geothermal fluid flow to the plant; it is not an individual well flow. The pump efficiency is a user input.

*Costs*: The user inputs the installed cost of the production pumps ($ per pump). The O&M costs are based upon a assumed pump replacement interval and the cost for pump repair or replacement. There further discussion on these O&M costs in the discussion of the binary conversion system O&M costs in Section 3 of Appendix C.

Section 5.0 of Appendix C had additional discussion on the performance and cost correlations derived for the geothermal pumps and how these correlations are used in GETEM.

## Ranges of input data and correlations

The use of downhole pumps has been primarily associated with binary plants, though there have been instances where lower temperature flash plants have also used these pumps. Most of the pump usage has occurred at resources where the fluid temperatures are <175°C. Industry has been working to increase the upper temperature limits on these pumps (in particular the submersible pumps which have difficulty dissipating the heat from the motor at elevated resource temperatures), however it is not know whether an extended operating life is currently possible at temperatures above 175°C.

Line shaft pumps are currently limited to a setting depth of ~2,000 ft and flow rates of ~2,000 gpm. It is not known if these limits are imposed by the size of the pump that can be put in the well, or by the shaft horsepower (~1,250 hp). Submersible pumps are limited primarily by the size of the pump that can be put in the well (as determined by the well completion); if the casing is large enough to accommodate the required pump size these pumps are cable of higher flow rates and greater setting depths that a lineshaft pump.

GETEM does not have a reservoir productivity index or permeability or transmissivity as input variables, so the user must determine the flow possible from each lift option offline. If the user indicates that a pump will be used, they must select a pumping option based on their understanding of the type of resource they are modeling and the limitations of the technology for pumping. The calculation of the flow increase from setting the pump deeper or using an electric submersible must be done by the user based on their knowledge of the resource.

## Limitations and Uncertainties

The determination of pump performance is straight forward assuming that one knows the setting depth, flow rate and efficiency. There is some uncertainty in pump efficiency. The values obtained in discussions with industry vary between ~65% and 80%. The greater efficiency is used, however if the lower efficiency is correct the pumping power would increase by about one third.

The model currently assumes an operating life of 4 years for a lineshaft pump, and 3 years for a submersible pump. A lower operating life will increase the associated O&M cost.

GETEM does not limit the range of value for the pumped flow rate. Typical geothermal flow rates for natural flow are between 100,000 – 1,500,000 lb/hr. Pumped wells are likely to be operated at the maximum possible flow for the temperature and well construction, usually around 2000 gpm or greater unless the well completion can’t accommodate the pumps.

Another consideration for pumped *vs*. unpumped wells is the cost of the well itself. The current technology available for well pumps requires that casing of 13 3/8” diameter extend some distance past the pump set depth to accommodate the large pump diameter and reduce pressure drop. This is not linked in any way in GETEM, so the user must be aware of the issues for well cost. Since the well costs available to Sandia to develop their cost curves included very few pumped wells, the cost for shallow wells when pumps are used is likely to be higher than predicted by the well cost curves in GETEM. For this reason, the user cost multiplier can be used to adjust the well cost for the large required casing size when the wells are pumped. Extending large casing to a deeper depth may add up to 20% to the well cost.

### 5.7.2. Injection Pumps

GETEM assumes that all the geothermal fluid leaving the power plant is injected. It is also assumed that it may be necessary to utilize pumps for this injection. GETEM determines the amount of power required for injection based upon the total geothermal fluid flow and the user inputted injection pump pressure rise.

Generally speaking, geothermal injection is done at low pressures, but involves moving high volumes of fluid. (This is a site specific consideration. There are plants whose output in the summer was limited not by air-cooled condensers, but by their ability to inject fluid. Well head pressure was too high and flow had to be curtailed.)

The power required for the production pumps, if used, is not included in the determination of plant performance. Both the production pumping power and the injection pumping power are determined independent of the plant output and subtracted from the net plant output to determine the net project input. This net project power is used in the determination of the levelized cost of electricity.

## Approach and technical basis

Injection pumps are used to overcome the pressure in the portion of the reservoir taking the injected fluid. Ideally this pressure is sufficiently low that little if any injection pumping is required. Typically these pumps are located within the power plant. However in GETEM, their power requirement and cost are not included in either the performance or cost projections for the conversion system.

In the GETEM model, the user inputs a pressure rise across the injection pump that is sufficient to overcome the injection wellhead pressure. This inputted pressure rise also effectively accounts for the pressure losses through the surface components and piping. In order to provide a realistic value for this injection pressure, the GETEM user needs an understanding of the resource for the case being evaluated

GETEM determines the required injection pumping power based upon the pressure rise in the pump, the total geothermal fluid rate and a geothermal pump efficiency. The pump efficiency is a user input; GETEM calculates the total flow using the calculated plant performance and the user input for the plant size. The user inputted $/horsepower determines the installed pump cost using the total injection pumping power. GETEM does not have a correlation for the pump cost; like the injection pump pressure rise, it also requires determination external to GETEM.

## Data, correlations, and algorithms

The capital cost and pumping power for the injection pump are calculated in GETEM's sheets **5A.BI-Sys-1**, **6A.BI-Sys-2**, **8A.FL-Sys-1**, and **9A.FL-Sys-2**.

***Performance*****:** If the GETEM user inputs an additional drawdown factor, GETEM first determines the magnitude of the added drawdown and adds this value to the user inputted setting depth to determine the final pump depth. If there is no user input for additional drawdown (which is currently how the model is being used), the user inputted value for the setting depth is the depth used to determine the pumping power for the production well pumps. The total production pumping power is determined using the following equation.

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

In this correlation, the total flow is the total geothermal fluid flow to the plant; it is not an individual well flow. The pump efficiency is a user input.

The injection pumping power is calculated using the following equation:

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

Total flow in this equation is the total produced geothermal fluid flow; P is the user inputted injection pump pressure rise; rho is the fluid density (a nominal 62 lb/ft; the pump efficiency used is the same as that inputted for the production pumps.

***<u>Costs</u>*****:** The user inputs the installed cost of the production pumps ($ per pump). The cost for the injection pumps is also a user input as the installed cost per hp. The O&M costs are based upon a assumed pump replacement interval and the cost for pump repair or replacement. There further discussion on these O&M costs in the discussion of the binary conversion system O&M costs in Section 3 of Appendix C.

Section 5.0 of Appendix C had additional discussion on the performance and cost correlations derived for the geothermal pumps and how these correlations are used in GETEM.

## Ranges of input data and correlations

The value assigned to the pressure rise through the injection pump will vary significantly in existing geothermal applications. All facilities will have some pressure drop associated with the surface components and piping. The injection well pressure however will vary considerably.

For low permeability reservoirs with large distances between the injectors and the power plant, the injection pressure could be very high. However, the injection pressure can not exceed the fracture pressure for the reservoir or the fluid can migrate into zones that need to be isolated from the injection wells, either contaminating ground water or getting to the production wells to quickly and cooling them off. The fracture gradient for most geothermal reservoirs is about 0.6 psi/ft, so for a well with the last casing string cemented at 3000 ft, the injection pressure can not exceed 1800 psi. For EGS wells, where the reservoir has been stimulated, the created fractures will grow if the fracture pressure is exceeded. In either case, some safety factor to reduce the risk of exceeding the fracture pressure is usually used to limit the injection pressure.

GETEM’s calculation of pumping power uses the same pump efficiency as the production pumps. This value is likely conservative. The injection pump cost is based upon costs developed using the ICARUS Process Evaluator (IPE) for a typical injection pump size ~500 hp. It was assumed that if the injection pumping power is much larger than this, multiple pumps would be used.

If there is no injection pumping power, the user should input a value of “0” for the injection pump pressure rise.

## Limitations and uncertainties

There is considerable uncertainty in the pressure rise that the user assigns to the injection pump, primarily because of the uncertainty in the injection wellhead pressure. If this pressure is excessively high, it is probable that the number of injection wells will be increased. The threshold where additional wells are required would be site specific.

GETEM relies upon the user to properly account for pump setting depth. The pump setting depth will be a function of the flow rate and the reservoir properties. Low permeability reservoirs will require greater pump setting depths for a given flow rate. Higher flow rates will require increased setting depths for a given reservoir permeability. Setting depths and/or flow rates may also be limited by the well casing design. GETEM has no provisions for accounting for these various effects, and relies upon the user to correctly account for these effects in the model's input.

## 5.8. Reservoir Drawdown and Makeup Operations

As fluid is produced from the geothermal reservoir is produced, the pressure and temperature of the fluid can change with time. In binary projects, all of the water is injected, so the pressure tends to be supported in the reservoir. Instead, the temperature declines over time as the cooler injected water takes the heat from the rock and cools the reservoir off.

For a flash plant where water is commonly lost to evaporation in the cooling towers, the pressure and thus the flow rate declines with time. For dry steam resources, the amount of water in the reservoir is very low to start with so that declining pressure means that the steam may become superheated over time causing several complications in the operation of the plant. However, there are so few dry steam resources in the US, with only the Geysers likely to ever be produced, that this case is ignored in the GETEM economics.

For some flash steam plants, the reservoir may boil and become a two-phase reservoir as the pressure declines. This increases the enthalpy of the fluid reaching the plant, but the flow rate will still decline. The analysis of this situation is quite complicated, so it was simplified for this version of GETEM. Future versions might include the option of including increasing enthalpy with decreasing flow rate, or better yet might have a simplified reservoir simulator incorporated into the code.

GETEM includes routines and estimates of pressure and flow rate decline in flash systems, and enthalpy (heat content) decline for binary systems. The pressure and flow decline methods are described first.

As indicated above, the development of GETEM was initiated to support new directions in the ability of DOE Geothermal Technologies Program to measure and report its progress in work to improve geothermal power systems. The reservoir drawdown and makeup features are an important part of supporting the new directions.

### 5.8.1. Pressure Decline and Makeup Wells in Commercial Flash Systems

**<u>Approach and technical basis</u>**

For a flash plant where water is lost to evaporation, the pressure and, thus, the flow rate declines with time. For dry steam resources, the amount of water in the reservoir is very low to start with so that declining pressure means that the steam may become superheated over time causing several complications in the operation of the plant. However, there are so few dry steam resources in the US, with only the Geysers likely to ever be produced, that this case is ignored in the GETEM economics.

For some flash steam plants, the reservoir may boil and become two-phase as the pressure declines. This increases the enthalpy of the fluid reaching the plant, but the flow rate will still decline. The analysis of this situation is quite complicated, so it was simplified for this version of GETEM.

**<u>Data, correlation, and algorithms</u>**

For flash plants, it is assumed that some of the water is lost to evaporation and therefore the pressure in reservoir declines, dropping the flow rate using a harmonic decline curve.

$$q = q_i * (1 + Dt)$$

Where q is the flow rate at any time and $q_i$ is the initial flow rate. D is the decline factor and t is the time in years. GETEM calculates the loss of flow over time and then determines an average power output for the plant life based on this flow.

There is a linear relationship between pressure drop and flow rate in porous media, so this is a reasonable assumption. Of course, a flash plant might be on a reservoir that was fully supported by injecting added water, as is the case at Dixie Valley. In this case, the reservoir temperature might start to drop with time in a manner similar to the binary case.

GETEM estimates two direct effects of pressure drawdown, and the consequent reduction in .producer flow rate. First, a number of wells must be added to sustain the production flow. The discounted value of the size of this effect rises more or less linearly with the value of the flow decline, percent per year. Second, the discounted value of the loss of revenue (due to loss of power) reaches an asymptote of about eight percent when the value of the rate of flow decline reaches about 7 percent per year.

These impacts are graphed in Figure 5.7.

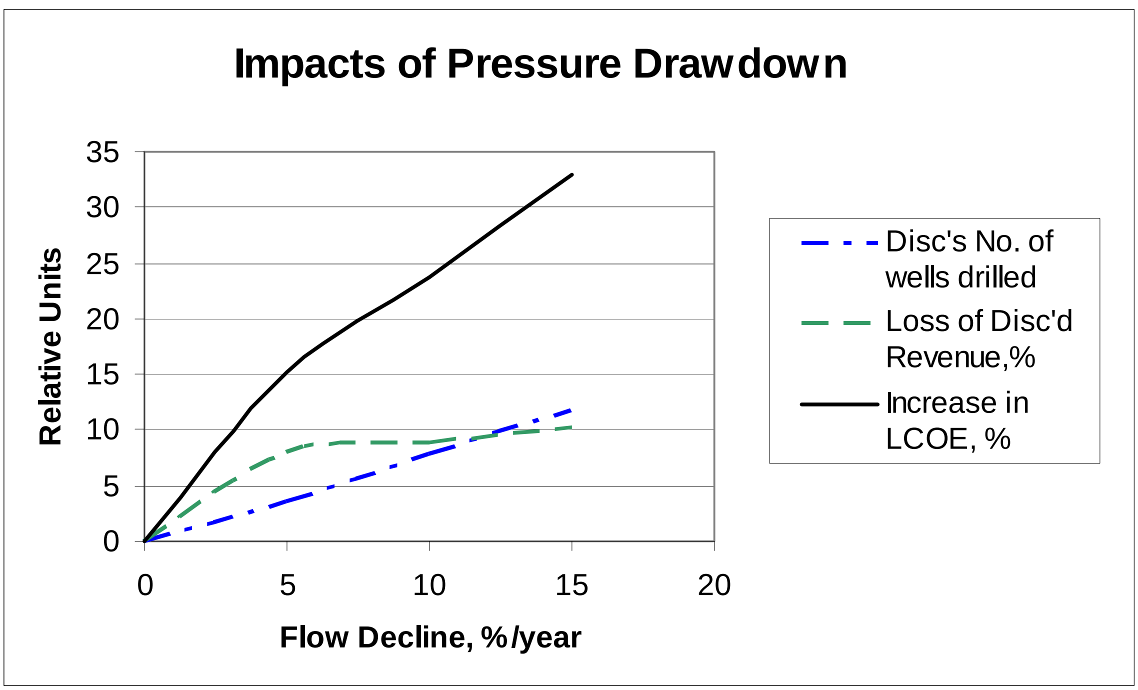


**Figure 5.7 Impacts of Pressure Drawdown**

As is well understood in the geothermal industry, the value of the increase in the LCOE (levelized cost of electricity from the project) is tolerable when the rate of flow decline is no more than 2 or

3 percent per year. But when the rate of flow decline exceeds perhaps 5% per year, then the relative increase in the cost of power (at the general conditions for the hydrothermal flash case shown here – reservoir at 200 deg C with 8,000 ft wells) exceeds 15 percent and becomes a major burden on the economics of the project.

**Ranges of Input and Data Correlations**

Figure 5.7 suggests that fairly high rates of pressure drawdown can be tolerated if the initial costs of electricity is low to begin with. But a rate higher than 10 percent per year starts to have fairly severe impacts on the overall cost of electricity. The impact is a combination of the costs of the additional makeup wells, and the loss in the discounted value of the revenue in the periods between additions of wells.

Note that we probably could have developed an algorithm that supplied yet additional wells, so that the revenue rarely dips below the desired initial value.

**Recommended model improvements**

Because enthalpy can increase in some reservoirs with flash plants as pressure declines, or because there might be cases where it would be possible to extend the plants useful life beyond the 10 degree C drop in temperature assumed for this version of GETEM, a more elaborate method for calculating plant output might be useful to GETEM. A simple reservoir model based on decline curve analysis could be used to determine the temperature and pressure over time.

### 5.8.2. Enthalpy Drawdown in Commercial Binary Systems

**Approach and technical basis**

In binary projects, all or most of the water is injected, so the pressure tends to be supported in the reservoir. Instead, the temperature declines over time as the cooler injected water leaches the heat from the rock and cools the reservoir off.

A means to estimate and study effects of enthalpy (fluid temperature) decline is needed in GETEM because this occurrence is common in some U.S. hydrothermal binary systems and can have significant cost impacts. S. Petty estimated, during the GETEM development colloquia, that in some such U.S. systems the total fluid volume in the reservoir is replaced (circulated through the reservoir) three or four times a year. This leads to inevitable cooling of the fluid at the wellhead over time.

**Data, Correlation, and Algorithms**

For the binary plants, it assumed that the temperature declines using the harmonic decline curve:

$$T = \quad T_i / (1 + Dt)$$

Where T is the temperature at any time and Ti is the initial temperature. D is the decline factor and t is the time in years. As the temperature drops the plant makes less power. The efficiency of the plant using the lower temperature fluid also drops, dropping the brine effectiveness calculated to convert the energy to electric power. This drop in temperature can be offset by increasing the flow to the plant, but this accelerates the drop in temperature. GETEM assumes that as the temperature drops, the output drops as well, until new wells are drilled to replace the heat depleted part of the reservoir. The same scenario applies to EGS reservoirs, where heat mining sweeps the heat from the rock over time and cools the produced fluid. As long as the reservoir lasts 30 years or more before dropping more than 10°C, GETEM calculates the average temperature over the life of the plant and then uses this to determine the output of the plant for the decline in temperature.

**Ranges of input data and correlations**

For Binary Systems, GETEM analyzes the drawdown of reservoir and wellhead temperature, as the reservoir is cooled by continuing circulation of fluid through it. In this case makeup is provided by adding entire new reservoirs.

If enthalpy decline is slow, then the only effect on system performance and costs is that the value of discounted revenue is decreased. No makeup wells are added. We used this approach because Mines, Petty, and Entingh had relatively little data and also conflicting opinions of the degree to which increased flow through the power plant primary heat exchanger could produce more power after one or two wells had been added. This question is worth some future study, but only as a second order effect after other larger issues are resolved (Entingh).

While the GETEM Team discussed real world cases where it appeared that one or two additional producers were drilled to apparently support the temperature to some degree, we decided that we simply did not understand some of the key factors that might be in play here, and so opted for the reasonably simple approach that we used.

The only recourse GETEM allows to combat severe enthalpy decline is to replace all of the productive reservoir (exclusive of exploration costs and the costs of unsuccessful confirmation wells). This comes into play mainly in the use of GETEM to study EGS systems in the near term, when reservoir lives are expected to be rather brief (see below). But we document the approach here because it is an intrinsic part of the Enthalpy Decline and Makeup routine.

Three criteria are used to determine if a new reservoir must be installed to replace the previous one:

IF the temperature drawdown has exceeded the limit shown in Figure 5.8,

OR the output of the core power plant has fallen below 50% of the design output,

AND it is not the last 5 years of the project life,

THEN replace the existing reservoir with a new one.

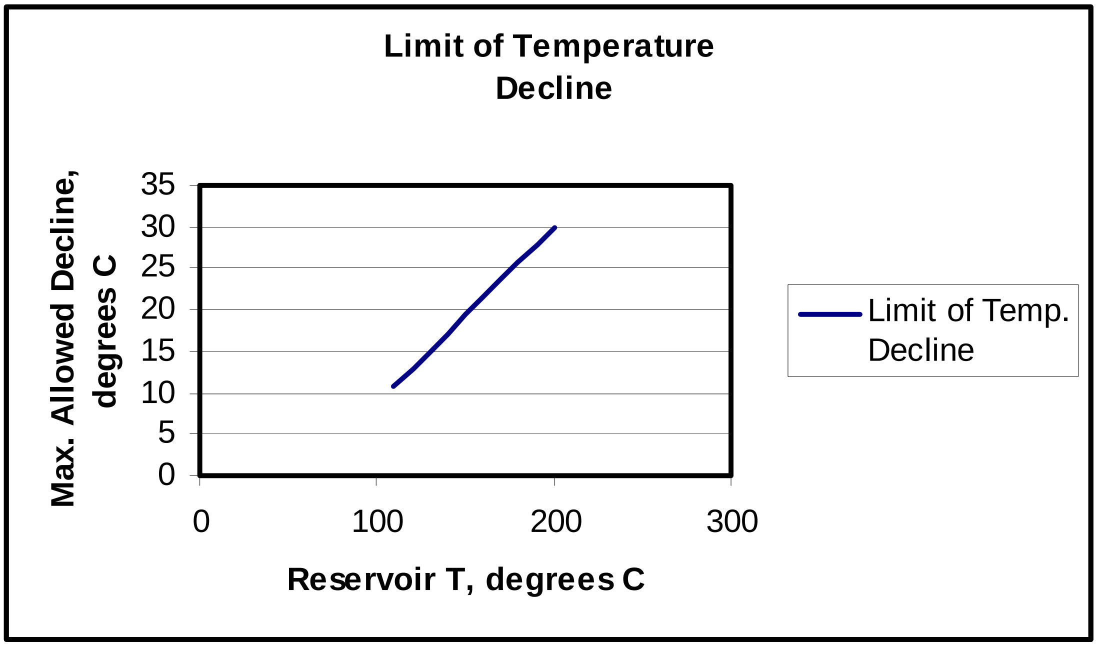


**Figure 5.8 Maximum Allowed Temperature Decline**

The data for the plot in Figure 5.8 come from the NGGPP analysis of the expected end of run temperatures for binary plants at various starting temperatures.

The equation for the plot in Figure 5.8 is**:**

**Delta.T.max = 0.21 * T.initial – 12.2,**

where all units are in degrees C.

The estimated output of the power plant as a function of temperature was simply drawn from the design output estimated by an earlier version of GETEM. This slightly overestimates the output at the lower temperatures, but that is of no great matter because we are simply looking for first order effects and interactions on this go around. The decline in Net Power, MWe, for a specific working case is shown in Figure 5.9.

## Limitations and uncertainties

What we have set up in GETEM is an initial approach to let us study some of the performance and cost impacts of enthalpy decline. We are likely to change some of the values used, but only once we establish a data-based approach toward understanding what has happened in U.S. commercial geothermal binary power systems.

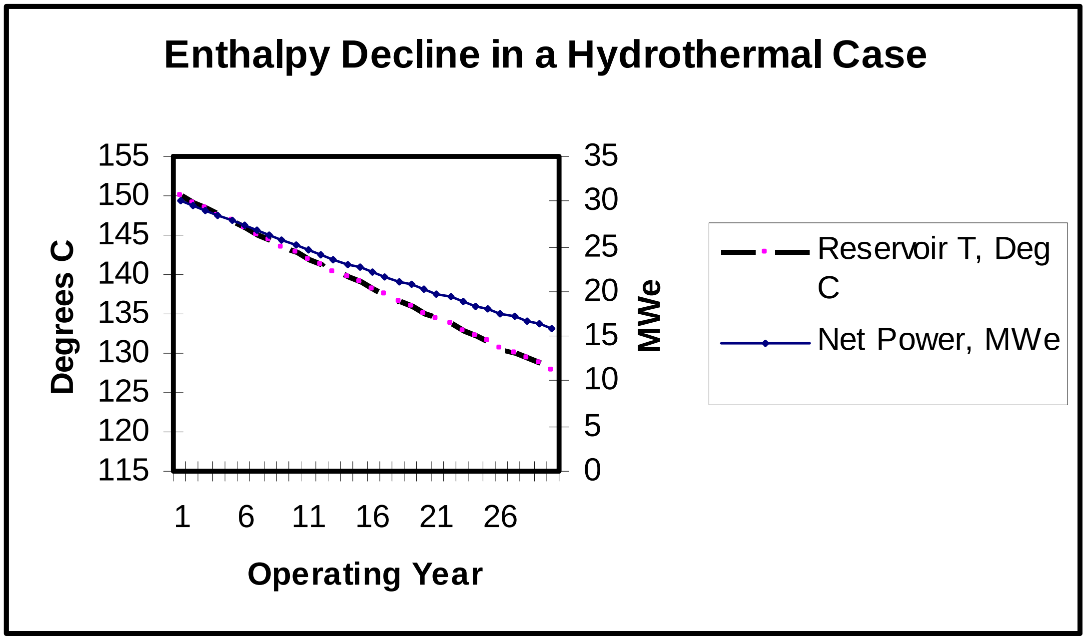


**Figure 5.9 Decline of Enthalpy and Power Output in a Hydrothermal Case**

### 5.8.3. Enthalpy Drawdown in Enhanced Geothermal Systems

It an inherent design feature of EGS systems that they "mine heat" from the reservoir rock. Thus decline in the temperature and enthalpy of the circulating fluid is expected and considered in the designs and analyses of EGS systems.

Enthalpy decline has been experienced as reality in the U.S. and World EGS / Hot Dry Rock (HDR) systems, and controlling the rate at which reservoirs cool is expected to remain a pointed target of EGS research for a considerable period. Therefore, GETEM had to include correlations where user-estimated high rates of enthalpy decline could lead to very short useful reservoir lifetimes, e.g., 5 years or even less.

**<u>Approach and technical basis</u>**

The theory and approach for cooling in EGS reservoirs, under binary conversion, is exactly the same as that for commercial binary systems, except that the rate of cooling (enthalpy decline) is greater in EGS.

To study both these types of cases, we modeled enthalpy decline using a harmonic decline function for the reservoir temperature over time. The rate of decline is set by a single user input. The binary power plant can operate, at continuously decreasing output until the temperature drops to a certain value.

Decline rates greater than 0.6% per year (an empirical value in the model) results in a drop in temperature of greater than 10°C by the end of 30 years. In such cases, GETEM assumes that the entire reservoir will be replaced to keep the plant running. The higher the decline rate, the more times the reservoir will be replaced. With current technology, long term testing suggests that at economic flow rates, the reservoir at Soultz will last about 6 years. Thus, the reservoir would need to be totally replaced 5 times during the life of the plant to maintain economic output.

## Data, correlations, and algorithms

These factors are the same as for the commercial air cooled binary case.

## Ranges of input data and correlations

The application of the Enthalpy Drawdown Correlations to EGS cases is somewhat more interesting than in case of a commercial binary system. Figure 5.10 show this operating in a possible EGS case.

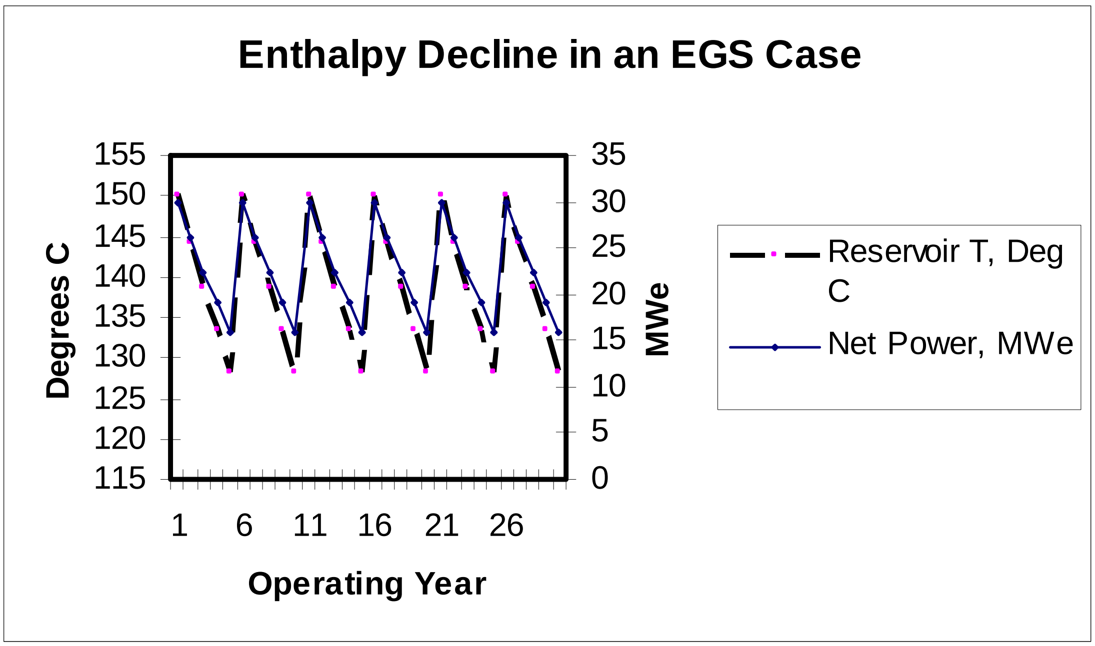


**Figure 5.10 Decline of Enthalpy and Power Output in an EGS Case**

Here the GETEM enthalpy drawdown rate parameter (percent per year) was set substantially higher than 0.6, perhaps to about 5.0. The reservoir then has a very short effective lifetime, and is replaced frequently during the 30 year duration of the power project. Here the effective lifetime was about 5 years.

## Limitations and uncertainties

Considerable theoretical research will be required to estimate what might be typical rates of enthalpy drawdown at proposed EGS reservoirs. This can probably be drawn from existing reservoir models.

### 5.8.4. Pressure Drawdown and Makeup in EGS Flash Steam Systems

In the case of flash plants, reservoir pressure and production flow rate are modeled as declining over time. It was not initially anticipated that flash plants might be used for EGS development.

However, continuing study suggests that for temperatures over 200°C flash plants are the best option even for EGS. Since the flash plant calculation assumes a decline in flow rate caused by a decline in pressure due to injecting only a portion of the produced fluid, the modeling of the temperature decline anticipated in an EGS system with a flash plant is not explicitly included. Doing that should be considered for future versions of the model.

In an EGS system it is likely that make-up water would be added to replace the water lost to evaporation in a flash system supporting reservoir pressure and that the temperature would therefore decline just as in the binary system.

In the current version of GETEM the cost for an EGS flash plant system can be simulated by looking at the total make-up wells drilled calculated by the model. The total number of makeup wells can be divided by the wells initially needed for the plant to see how many times the whole reservoir is replaced. The number of replacement reservoirs can be divided into the 30 project life to determine the reservoir life. This reservoir life can be compared to the reservoir life for the binary plant and the decline rate for the flash plant adjusted until they are the same.

**Recommended model improvements**

These recommendations are for the materials in Section 5.8 as a whole.

The general recommendation is that a new drawdown/makeup routine be devised that allows either or both of enthalpy decline and pressure decline. This would be applicable to both binary and flash steam systems, and to hydrothermal and EGS systems.

Future versions might include the option of including increasing enthalpy with decreasing flow rate, or perhaps better, might have a simplified reservoir simulator incorporated into the code. For EGS projects, such a model might allow the fracture length, height and spacing to be input to calculate the heat sweep efficiency and the temperature behavior of the reservoir with time.

## 5.9. Energy Conversion Systems

As discussed in Section 4.5, GETEM projects the performance and cost of two energy conversion systems, a flash-steam system and a binary system. The GETEM model's projections for a flash-steam plant are based upon the use of an evaporative heat rejection system. Projections for the binary plant are based upon the use of air-cooled condensers to sensibly reject heat to the ambient temperature. The GETEM correlations for both conversion system types are defined in terms of the net plant power, exclusive of the geothermal fluid pumping power (this net plant power is the user inputted plant size). The conversion system performance and the user inputted plant size are used to determine the total flow rate required. This total geothermal flow rate is used in subsequent calculations of the well field size and any geothermal fluid pumping power. Though is pumping power is not specifically accounted for in the plant calculations of performance and cost, GETEM accounts for the effect of this pumping on plant output in the projections of the levelized cost of electricity.

### 5.9.1. Air Cooled Binary System

**Approach and technical basis**

The air-cooled, binary conversion system will typically be used with lower temperature resources at locations lacking an adequate supply of surface or near-surface water for evaporative heat rejection system.

In order to characterize both cost and performance be characterized with minimal user input, the GETEM correlations for both are based upon the resource temperature. It is recognized that there are other factors that influence both cost and performance, however the scope of the initial development effort for GETEM effectively restricted the development of the cost and performance correlations to prior work on plant performance and cost. This other work generally does not provide sufficient information to readily allow correlations to be developed that included these other factors.

***Performance:*** Again, GETEM's indicator of binary plant performance is the net brine effectiveness, i.e., the net plant power produced, exclusive of the geothermal fluid pumping, per unit flow of fluid (w-h/lb, or w-h/kg,$_{gf}$). Although the performance of air-cooled binary plants is a function of a number of different parameters (some of which are identified in Section 1.1 of Appendix C.), the GETEM correlation performance is derived from only on the resource temperature, which has a significant influence on the brine effectiveness.

Development of the performance correlation was based upon prior work including the EPRI Next Generation Geothermal Power Plant (NGGPP) study (CE Holt Co, 1996), Pritchett's work on electrical power production from slim holes (Pritchett, 1998), and DiPippo's Geothermics paper on 2$^{nd}$ law analysis of low temperature binary plants, which included the performance of selected air-cooled plants (DiPippo, 2004) . In addition, prior work at INL on binary plant performance for low- to moderate-temperature resources was used (Mines, 2002, and Bliem and Mines, 1991).

See Section 1.1 of Appendix C for a more detailed discussion of the development of the correlation used to characterize the binary plant performance. The assumptions used in this development are identified in this section along with comparisons of the projected performance with the both performance of operating plants and those reported in the other studies.

***Cost:*** Plant costs (regardless of the type of conversion system) in GETEM are ultimately derived on the basis of the installed dollars per kW of net plant power produced (again, exclusive of the geothermal fluid pumping). EPRI's NGGPP study (CE Holt Co, 1996) provided the basis for the development of the plant costs. The plant costs reported in the NGGPP study were used to develop a correlation predicts the cost of a 50 MW,net plant as a function of the resource temperature.

The 50 MW plant cost that is derived at the inputted resource temperature provides the reference cost that is subsequently used to predict the cost of other plant sizes. An overall plant cost vs size scaling factor is applied to this 50 MW cost to derive the cost at the inputted plant size.

Section 1.2 in Appendix C provides detail on the derivation of the correlation that relates plant cost to resource temperature and the development of the overall plant cost vs size scaling factor. There is also discussion in Section 1.2 of Appendix C as to how the NGGPP costs were escalated to reflect current costs.

GETEM predicts the Operating and Maintenance (O&M) costs of the binary plant. These O&M costs are based upon postulated plant staffing requirements that increase with plant size, and upon a maintenance cost that is determined as a fraction of the capital cost of the conversion system. (Both this O&M capital cost fraction and the staffing level are GETEM user inputs). Section 3.1 of Appendix C has further discussion of the how the O&M cost projections are developed for the air-cooled binary plant.

## Data, correlations, and algorithms

The GETEM binary performance and capital cost calculations are done on sheet **7A.BI-Perf&Cost**. O&M cost calculations are done on sheet(s) **5B.BI-O&M-1** and **6B.BI-O&M-2**.

***Performance:*** Net brine effectiveness is calculated as a function of the inputted resource temperature using the following equation:

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

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

***Cost:*** The cost of a 50 MW plant is calculated as a function of the inputted resource temperature using the following equation(s):

$$\mathbf{Cost_{,50MW} = K_0 + K_1{*}T + K_2{*}\,T^2 + K_3{*}\,T^3}\text{, where}$$

$\mathbf{Cost_{,50MW}}$ is 50 MW plant cost in $/kW
**T** is fluid temperature, °C
$\mathbf{K_0}$ = 21520.78
$\mathbf{K_1}$ = -331.34
$\mathbf{K_2}$ = 1.854876
$\mathbf{K_3}$ = -0.003491132

This equation is used for resource temperatures up to 190°C. For T > 190°C, the following correlation is used:

$$\textbf{Cost,}_{\textbf{50MW}} = \textbf{Cost,}_{\textbf{50MW}}@190°\text{C} - 3.08*(\textbf{T} - 190)$$

This 50 MW,net plant cost ($/kW) is then scaled to the user inputted plant size using the following relationship. Note that the overall plant scaling factor is 0.8, and that plant size is inputted in MW,net. The costs that is determined is in $/kW,net.

$$\textbf{Cost} = [50{,}000 * \textbf{Cost,}_{\textbf{50MW}} * (\text{Inputted Plant Size} / 50)^{0.8}] / (\text{Inputted Plant Size} * 1{,}000)$$

This relationship is a derivation of the following equation for scaling cost (the reader maybe more familiar with this use of the scaling factor).

**Total Cost = Total Cost of 50 MW Plant * [(Inputted Plant Size / 50)$^{0.8}$]**,
where total costs are in dollars and plant size is in MW,net.

The correlations used to generate the binary conversion system O&M costs are provided in Appendix C, Section 3.1

## Ranges of input data and correlations

GETEM's binary conversion system model for cost and performance is limited to the use of sensible heat rejection with air-cooled condensers. The projections do not depict either cost or performance with evaporative heat rejection systems.

There is an increasing level of uncertainty in the overall plant cost vs size scaling factor for smaller plants. Though the specific plant size where the cost projections are no longer valid is not known, it is believed that the minimum size is >~5 MW.

At present it is believed that the amount of uncertainty in the model projections increases at temperatures below ~125°C and above ~200°C. The uncertainty increases at lower resource temperatures, because plant performance (and cost) at these temperatures will be increasingly sensitive to assumptions made relative to the design ambient temperature, working fluid selection, the heat exchanger pinch points, and the efficiencies of the rotating equipment (pumps and turbines). The uncertainty is greater for the higher temperature resources because they are generally considered the realm of the flash-steam conversion systems, and as a consequence, there is limited information available to use as a basis for projecting binary performance and cost at temperatures above ~200°C.

## Limitations and uncertainties

Though the work from several sources was used in developing GETEM's binary plant performance correlation, this development was largely accomplished using the work (Pritchett, 1998) done to assess power potential from slim-holes. This work was used because it used a uniform set of assumptions in predicting performance over a wide range of resource temperatures. One of the assumptions used in this study was that the condensing temperature was fixed at ~38°C. This condensing temperature is likely higher than what one would have if net output was optimized at a design ambient temperature of 10°C. It is also likely higher than the condensing temperatures used in the EPRI NGGPP study (CE Holt Co, 1996). As a consequence the performance projections in GETEM will likely be lower (by 5 to 10%) than would expect for the projected capital cost.

There is a direct correlation between plant performance and plant capital cost that is not reflected in the current GETEM model. For fixed resource and ambient temperatures, binary plant performance is a function of both the working fluid used and the size of the heat exchangers. There will be added cost when increasing performance, or conversely, decreasing cost would decrease performance. This linkage between plant performance and cost, and the magnitude of the “other” costs (capital and operating) will establish the economic optimum for a given plant size and resource condition. At present it is believed that the binary plant costs and performance projected by GETEM are reasonable for the identified resources, which are deeper than what have been commercially developed.

There are inherent limitations and uncertainty when using a single parameter (resource temperature) to characterize cost and performance. Though an analysis has not been done to quantify this uncertainty, it is believe that over a resource temperature range of 125° to 200°C, the performance correlation is within ±15 to 20%, and the cost projection is within ±25% (perhaps better stated, it is hoped that the projections are within this uncertainty range). This level of uncertainty exists in part because there is no linkage in GETEM between the plant’s cost and performance. Though the magnitude of this uncertainty may be considered high, it is believed that the predicted trends (or changes in cost or performance with temperature) are more representative and do not have the same level of uncertainty.

It is current industry practice to use either a modular design or to multiples of specific components in the plant design (i.e., multiple turbines in parallel). Though GETEM will predict the costs of larger plants, it is more probable that a larger binary plant would actually be consist of smaller plants that have a common geothermal fluid production and injection piping system. For example, a 60 MW plant would be more likely to be comprised of two 30 MW plants or three 20 MW plants operating in parallel, than a single 60 MW plant. Uncertainty as to how these larger plants would be configured increases the uncertainty in the overall cost vs size scaling factor used in GETEM.

It is believed that the binary plant costs reported in NGGPP reflect the use of multiples of certain components. If so, the cost *vs.* size scaling factor used in GETEM incorporates for the use of the multiple components. However, because details on the number of components and the individual component cost for the NGGPP study are not available, there is increased uncertainty regarding use of this data in generating GETEM’s cost *vs*. size scaling factor.

The GETEM cost correlation does not currently have any provision to account for inflationary increases in plant cost or for the impact of alternative materials on plant cost. The current year cost for the power plants is 2004, the year in which the initial the work was done to establish the cost correlation. As such the plant costs predicted by GETEM do not reflect the recent sharp increases in the cost of steel (the primary material of construction in binary geothermal plants).

See Section 1.4 of Appendix C for a more detailed discussion of the limitations associated with GETEM’s binary conversion system performance and cost correlations.

### 5.9.2. Flash Steam Systems

**Approach and technical basis**

The flash-steam conversion technology is typically used with the higher temperature hydrothermal resources. Because this conversion system produces a clean steam condensate, the development of GETEM's correlations to characterize these plants has assumed the use of an evaporative heat rejection system, with the steam condensate used as makeup for heat rejection.

The development of the correlations for the flash-steam conversion system had the same intent as the binary plant - both cost and performance were to be characterized using a minimum amount of user input. As with the binary plant, the resource temperature was considered the most important parameter affecting both cost and performance. (For the flash-steam system this resource temperature is the fluid temperature before any flashing occurs, either in the plant, or well.) In developing the cost and performance correlations it was subsequently decided that it would be necessary to account for a varying level of non-condensable gases (ncg's) in the geothermal fluid, and the ncg content was made an input parameter.

***Performance:*** Again the measure of flash plant performance that is predicted by GETEM, regardless of the type of conversion system, is derived as the net brine effectiveness of the power plant, i.e., the net plant power produced (exclusive of any geothermal fluid pumping) per unit flow of fluid (w-h/lb, or w-h/kg).

EPRI's NGGPP study (CE Holt Co, 1996) provided the basis for the initial efforts to develop a correlation for the flash plant performance. Difficulties were encountered in trying to use the reported results to predict performance as a function of the resource temperature only, and it was subsequently necessary to develop a generic method of predicting flash plant performance that accounted for a varying presence of non-condensable gases (ncg's). The NGGPP study (CE Holt Co, 1996) results were used to confirm that the generic method developed (a flash plant spreadsheet model) produced a reasonable match of the power produced by different NGGPP plants. The generic method was then used to optimize and characterize the flash plant output as a function of the resource temperature and the number of flashes used. This spreadsheet model was also used to quantify the effect of varying levels of ncg's on plant performance. The relationships derived were used to establish the correlations used by GETEM to predict plant performance (net brine effectiveness) as a function of the resource temperature, the number of flashes and the level of non-condensable gases.

Section 2.1 of Appendix C provides more detailed discussion regarding the development of the flash plant spreadsheet model, and the use of both results obtained using this model and the results reported in the NGGPP study to characterize the flash-steam conversion system performance.

***Cost:*** The flash plant costs (as well as binary plant costs) in GETEM are derived on the basis of the installed dollars per kW of net plant power produced.

As was the case with the binary plant, the NGGPP study (CE Holt Co, 1996) provided the basis for the development of the flash plant costs. The approach used in developing the flash plant cost correlations in GETEM deviated from that used for the binary plant. Primarily because of issues involved in trying to account for the effect of the ncg's on power output, it was necessary to initially derive the flash conversion system costs in GETEM by defining major plant equipment costs. The equipment costs are initially derived on the basis upon the gross plant output/performance, and then adjusted to a net plant output basis using the ratio of the gross to net brine effectiveness for the plant.

GETEM also estimates the cost for the ncg removal and hydrogen sulfide hydrogen sulfide ($H_2S$) abatement system. Correlations used in GETEM to predict these system costs were developed using the costs in the NGGPP study (CE Holt Co, 1996). An installation multiplier is then applied to the sum of the equipment costs and the sum of the system costs to obtain an installed plant cost. The installation multiplier is a user input to GETEM; a multiplier of 2.53 (taken from the NGGPP study (CE Holt Co, 1996)) is recommended.

The resulting installed plant cost is that of a 50 MW,net plant. GETEM projects the cost of flash-steam plants of differing sizes using the same approach as is used for the binary plant, though the overall cost *vs*. size scaling factor used for the flash plant is lower (0.75 vs 0.8).

Section 2.2 of Appendix C has a more detailed discussion of the development of the various cost correlations used in GETEM to predict the flash plant cost. This section also has discussion as to how the NGGPP report (CE Holt Co, 1996) costs were escalated to current dollars. Appendix C (Section 3.2) also has a discussion on the development of the O&M costs for the flash plant. The approach used to develop the O&M costs is similar to that used for the binary plants. It deviates in that the flash plant O&M costs also includes costs for chemical treatment. These chemical costs are based upon assumed dosage rates and the calculated flow rates for both the geothermal fluid and cooling water. At present, the dosage rates used and the costs of the chemicals used are effectively placeholders until representative information/data is obtained.

**<u>Data, correlations, and algorithms</u>**

The GETEM performance and capital cost calculations are done on sheet **10A.FL-Perf&Cost**. O&M cost calculations are done on sheet(s) **8B.FL-O&M-1** and **9B.FL-O&M-2**.

***<u>Performance:</u>*** The brine effectiveness for a dual flash cycle is calculated as a function of temperature using the following equation:

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

be is brine effectiveness, w-h/lb
T is fluid temperature, °F
$C_0$ = -1.4068479
$C_1$ = -0.01166551
$C_2$ = 0.000101009

The performance of a single flash plant is calculated as a function of temperature using the following equation:

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

be is brine effectiveness, w-h/lb
T is fluid temperature, °F
$C_0$ = 2.671814
$C_1$ = -0.02783
$C_2$ = 0.000104

These calculated brine effectiveness are the net values exclusive of the geothermal fluid pumping and the power required to remove the ncg's. The power to remove the ncg's is determined using the following equation:

$$\mathbf{power,\ ncg = (D * T + D_1) * PPM^{D2}}\text{, where}$$

power, ncg is the power to remove the ncg's/ w-h/lb,,

T is the geothermal fluid temperature, F,
PPM is the ncg content of the geothermal fluid, ppm,
D = 0.0000065
$D_1$= 0.0017
$D_2$= 0.66

The predicted power required to remove ncg's is the same for both the single and dual flash plants. This power requirement is subtracted from the calculated power for either the dual or single flash plants to establish the net brine effectiveness for the plant (exclusive of any geothermal fluid pumping). This net brine effectiveness is the plant performance parameter calculated by GETEM that is used in subsequent calculations to establish the total geothermal fluid flow rate required to support the user inputted plant size.

***Cost:*** In GETEM the cost of a 50 MW plant is determined by first calculating the cost of the individual major equipment items/categories listed below.

*Geothermal Fluid Handling Equipment*
*Turbine-Generator*
*Heat Rejection System (dependent upon user input for type of condenser)*
*Plant Auxiliary Equipment (including Fire and Air systems)*
*Other Equipment.*

GETEM also predicts the cost of the ncg removal system and the hydrogen sulfide removal system based upon the ncg and H2S levels in the geothermal fluid entering the plant. (The levels of both are user inputs to GETEM).

The individual correlations used to predict the cost of these systems and the major equipment items identified above are provided in Section 2.2 of Appendix C. This section of Appendix C also provides details on the correlations used by GETEM to determine an installed plant cost in $/kW, net from these system and equipment costs.

## Ranges of input data and correlations

Unless sub-atmospheric flashing is allowed, at lower resource temperatures flash plants will be at a significant performance disadvantage relative to the binary technology. The GETEM performance projections are derived from results using the flash plant model that was constrained by the assumption that the flash pressure is always above 1 atm (14.7 psia). Though the results may not depict the optimum performance that could be achieved if a sub-atmospheric flash were allowed, the constraint is consistent with industry practice.

GETEM assumes that the fluid delivered to the highest pressure flash vessel in the plant will be above the optimum flash pressure calculated for that resource pressure. This assumption may not be consistent with the operation of self-flowing wells where flashing occurs in the well bore. An operator will likely adjust the well head pressure such that the output per well (MW, electrical) is maximized. Though operation with a well head pressure below the optimum flash pressure will result in a performance penalty (on the basis of power per unit mass flow), the additional well flow that can be achieved at this lower pressure can offset the performance penalty.

The GETEM projections for the flash plant do not account for any temperature limit placed on the unflashed geothermal fluid leaving the plant. The imposition of a temperature limit would decrease the plant output projections. Limited discussions with plant operators suggest that they do not consider this temperature limit when establishing flash pressures; chemical inhibitors are added to the geothermal fluid to retard mineral precipitation until the fluid has been returned to the reservoir. It does not appear that this limit was imposed upon the flash plants in the NGGPP study (CE Holt Co, 1996). Though GETEM does not impose this temperature limit on the effluent geothermal, the costs associated with treating the fluid are largely unknown and are not adequately represented in the O&M costs,

It is expected that a commercial flash plant will be much closer in size to the 50 MW plant case studies in the NGGPP study than a commercial binary plant. As a consequence the issues associated with plant cost-size scaling factor will likely not be as much of an issue. However be cause of the limited amount of component cost data available as a function of size, there is still uncertainty in deriving costs for other plant sizes, especially smaller plants. Work with IPE suggested that turbine-generator scaling factors changed at about 10 MW. This is probably a reasonable lower limit for the GETEM plant cost projections also.

The predicted power required to remove the ncg gases is based upon the use of vacuum pumps for removal. The model performance correlation does not account for the use of steam ejectors for this removal.

**<u>Limitations and uncertainties</u>**

There are limitations and uncertainties in the GETEM projections of cost and performance that are inherent given the use of a limited number of parameters used in these characterizations. Although less effort was expended in developing the cost and performance correlations for the flash plant (compared to the binary plant), it is believed that the uncertainty associated with these plants is similar in magnitude to those expressed for the binary conversions system. Though the magnitude of uncertainty in both performance and cost projections maybe similar, it is believed that the uncertainty with the predicted trends with resource temperature is higher with the flash-steam plant. This is because of the effect of ncg's and the issues relative to the degree of flashing that might be allowed in self-flowing wells

As indicated for the binary conversion system, the recent volatility in the price of steel increases the uncertainty in the cost projections for the flash plant.

There is further discussion on the limitations and uncertainties associated with the flash-steam conversion system performance and cost correlations in Section 2.4 of Appendix C.

### 5.9.3. System Parasitics for Pumps

The system provides its own power for well downhole pumps and injection pumps. That material is covered in Sections 5.7.1 and 5.7.2 of this document and Section 5 of Appendix C.

### 5.9.4. System Parasitics for Environmental Abatement

The environmental abatement systems considered in GETEM are primarily associated with the flash-steam conversion system and the presence of non-condensable gases (specifically hydrogen sulfide, $H_2S$). Though other abatement systems maybe utilized in geothermal plants, they are primarily used to control corrosion or scaling processes and not to meet an environmental or regulatory requirement.

**Approach and technical basis**

GETEM accounts for the presence of hydrogen sulfide in the cost of the flash-steam conversion system. In the binary conversion system both the working fluid and the geothermal fluid systems are closed (no exposure to the ambient); as a consequence GETEM does not include any specific cost or performance penalty associated with any environmental or regulatory requirements.

The correlations used in GETEM to characterize the capital cost for the abatement of hydrogen sulfide based upon the information in the NGGPP study (CE Holt Co, 1996).

**Data, correlations, and algorithms**

The impact of hydrogen sulfide on capital cost is calculated in GETEM's sheet **10A.FL-Perf&Cost**. O&M cost calculations are done on sheet(s) **8B.FL-O&M-1** and **9B.FL-O&M-2**.

The hydrogen sulfide abatement system cost is based on the following correlation:

***$H_2S$ removal*: $\$/kW = 1135*(lb\ of\ H_2S/kW)^{0.59}$**

The lb of $_{H2S}$ per KW is based upon the $H_2S$ level in the geothermal fluid entering the plant and the calculated gross brine effectiveness for the flash plant. See Appendix C, Sections 2.1 and 2.2 for discussion on the development of this correlation.

**Ranges of input data and correlations**

The range of conditions for which the correlations might be valid is unknown.

**Limitations and Uncertainties**

It is believed that there is considerable uncertainty regarding both the cost and performance correlations, though the magnitude of the uncertainty is not known.

**Recommended model improvements**

The most critical thing here is to get much clearer statements from industry about the degree to which the performance and cost estimates made by the GETEM algorithms approach the realities of commercial geothermal power plants being built today.

## 5.10. Economics

**Approach and technical basis**

The basis of the economics calculations is to estimate the Levelized Cost of Power (LCOE) in units of U.S. Cents/kWh, using as inputs:

Project financial structure and cost of funds (equity and debt), and
The capital and O&M costs defined for all the components of the system,
Tax rates and tax incentives available to these projects.

The basic calculations are made using revenue requirements calculations (similar to those defined in the EPRI *Technical Assessment Guides* over the years, starting in 1978), rather than detailed cash flow analyses. Most of the economics considerations are listed here

a. Capital and O&M Costs

As derived in Section 5.2 through 5.9.
Expressed in year 2005 US$.
Status: the GETEM team still needs to verify the source years for all of the cost values.]
Cost indexes required [pending].
Cost of typical oil or gas well comparable to geothermal well
Drilling rig and equipment costs rose about 35% between March 2004 and December 2004 [per Dr. B.J. Livesay]
Cost of steel in power plants. This has varied quite a bit in 2003 and 2004, and might have a +/- 10% effect on the cost of the plants.

b. Project financial structure and assumptions:

Structure: IPP with corporate financing
General inflation rate: about 2.5% per year.
Project life: 30 years
Equity: Fraction and rate of return
Debt: Fraction and interest rate
General project insurance rate

c. Taxes and incentives considered:

Federal income tax
State income tax
Local property tax
5 year depreciation
Energy (investment) tax credit: 10% of capital costs

d. Taxes or incentives not considered [pending]:

State sales taxes on equipment
Intangible drilling expenses
Expensing of failed exploration costs
Allowance for depletion (percentage or cost)
Alternative minimum tax
The (new, 2005) Federal Production Tax Credit for geothermal systems.

Items (b.) and (c.) are mathematically merged into a Fixed Charge Rate that is multiplied against the project total capital cost to estimate the annual cost of capitalized equipment and services.

The estimate of the LCOE is done in "real," "constant dollar," terms, and is stated as the minimum wholesale price of power to the grid that will cover all project costs in the first year of operation (here assumed to be 2005). That price is then escalated by the estimate of the general rate of inflation (see above) in each of the following years of the project life.

This is the approach used in the EIA NEMS model, and lets the DOE Geothermal Program estimates remain synchronized with certain assumption there.

## Data, correlations, and algorithms

The only explicit specific factor used in GETEM-2005, of all those above, is the "Fixed Charge Rate" (FCR). The FCR is applied by multiplying it times the summed Capital Costs of the project to find, as the result, the annual payment that has to be made (normally from project annual revenues) to cover all payments to debt, equity (dividends or retained earnings), Federal and State income taxes, and local property taxes and insurance. The FCR used in GETEM-2005 was taken from the value used in the EIA NEMS runs for the Annual Energy Outlook 2005 report. It was provided to Entingh by Frances Wood of On Location, Inc., Vienna, VA.

This FCR for 2005 is assumed to represent: a period of relatively low cost of funds (debt and equity), with about 30 percent of the capital in equity. It includes the effect of the conventional Federal 10% investment tax credit for geothermal power systems. It does not include the effect of the recently enacted, albeit time-limited, Federal Production Tax Credit provided for in the Energy Policy Act of 2005. Entingh believes, but has not yet verified that the PTC might be somewhat more than 1 cent/kWh (over a 30 year project life) for financial entities that absorb its value during the first 10 calendar years of geothermal project.

## Ranges of input data and correlations

As of this time, all parameters are fixed. This should be changed in the future.

## Limitations and Uncertainties

It is likely, as it usually turns out upon examination, that the FCR used by EIA in NEMS is 2 to 5 points lower than the FCR that many firms use in screening geothermal projects. This is in part because EIA assumes a larger firm with more financial strength than is the case in the U.S. for most firms that are actively attempting to develop new small geothermal power projects.

Two other important aspects of geothermal power projects deserve more study and perhaps explicit consideration in the GETEM work:

a. The fact that many projects have very long exploration and permitting lead times. This is true for example at the Glass Mountain / Medicine Lake sites in northern California. Work may have been going on there for more than 20 years, and we simply have not yet accounted for the potentially large carrying costs of such projects. However in many instances, such projects change hands, and many of the carrying costs disappear in written off sunk costs of the seller.

b. Details of the impacts of severe geothermal brine chemistries on project costs. For example, the GETEM Team today would hardly know where to begin to estimate such Capital and O&M Costs related to the development at the Salton Sea KGRA, especially for new projects emerging there.

## **Recommended model improvements**

In future years substantial additional work needs to be conducted by the Geothermal Program Analysis Team to reestablish the specific linkages between all detailed financial and tax assumptions, and the various specific tax incentives for geothermal into the FCR and additional factors used by GETEM to estimate the LCOE.

# 6. REFERENCES AND NOTES


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# 7. GLOSSARY

**BE** – Brine Effectiveness. The energy extracted from geothermal fluid by a specific energy conversion device. The meaning of BE can be energy that is the gross output of a generator or that is net of various auxiliary devices.

**C –** Degrees of Celsius temperature scale

**COTR** – Contracting Officer's Technical Representative. An agent of the U.S. Government who makes decisions about the technical direction of research projects.

**DOE** – U.S. Department of Energy

**EERE –** Energy Efficiency and Renewable Energy. The Office of DOE responsible for research and development in the areas of energy use and conservation, and renewable energy.

**EGS –** Enhanced Geothermal System(s). Future technology that is expected to generate economic energy from geothermal resources that are not commercial now. Advances in well construction, power plants, and ability to manipulate permeability in reservoirs are all expected to be necessary for EGS to work at many sites.

**EIA –** Energy Information Administration. A federal agency housed within the DOE that is responsible for making the Government's estimates about current and future uses of various sources of energy.

**EPRI –** Electric Power Research Institute. Until about 10 years ago, EPRI was the research arm of the U.S. electric public utility firms. It is now more independent.

**FCR** – Fixed charge rate. A financial term (value on the order of 0.09 to 0.14) that calculates the annual amount that must be paid to account for all charges of a project that are related to capital expenses. Its scope includes more than just amortization of the capital costs, e.g., it includes income taxes.

**ft** – Foot or feet

**GELCOM** – A geothermal project cost screening model developed for use by DOE in the late 1970s. From MITRE Corporation, McLean, VA.

**GEOCOST** – A geothermal project cost screening model developed for use by DOE in the late 1970s. From Battle Pacific Northwest Laboratory, Richland, WA.

**GES** – The Geothermal Electricity Submodule of the EIA National Energy Modeling System. This too is a geothermal project cost screening model. It is in current (2006) use at EIA.

**GETEM** – Geothermal Electric Technology Evaluation Model. The name of the model that is documented in this report. The initial versions and documentation of GETEM were developed by DOE contract researchers during 2004 – 2006.

**gpm –** **G**allons per minute. A measure of flow rate.

**GPRA** – Government Performance and Results Act of 1993. This Federal law requires that all federal programs be managed through a process of setting and tracking measurable goals and objectives. Recently, emphasis of GPRA implementation within DOE requires that the progress of programs such as the Geothermal Technologies Program be measured on an annual basis.

**GRC** – Geothermal Resources Council. The main geothermal interest and education association in the U.S. Its members are drawn from industry, universities, and governments.

**GTP –** Geothermal Technologies Program. GTP is the geothermal research program of the Department of Energy, and is one of the programs of EERE.

**$H_2S$ –** Hydrogen sulfide

**HDR** – Hot Dry Rock. Geothermal rock that contains little permeability or fluid (water).

**HQ –** Headquarters of the U.S. Department of Energy in Washington, D.C.

**hp** – Horsepower. A measure of power, i.e., rate of production of or consumption of energy.

**HTEL** – Geothermal HydroThermal ELectric power systems. An informal acronym used in this report to distinguish between hydrothermal and other potential commercial forms of geothermal power systems. e.g., EGS.

**ICARUS** – Process economic evaluation software, product of Aspen Technology, Inc. This has been used by the Idaho National Laboratory (INL) to study performance and cost of geothermal power conversion systems (i.e., power plants).

**IMGEO** – Impacts of R&D on the cost of Geothermal electricity. A U.S. geothermal cost of power model developed by three of the authors of this report, in 1987 and following. The purpose of IMGEO, like that of GETEM, was to help the DOE GTP understand some of the likely impacts of components of the Geothermal R&D Program.

**INL –** Idaho National Laboratory. One of the National Laboratories of the Department of Energy.

**INEEL -** Idaho National Engineering and Environmental Laboratory. An earlier name and acronym for INL.

**IPE –** ICARUS Process Evaluator. See “ICARUS,” above.

**KGRA** – Known Geothermal Resource Area. An area in the U.S. designated by the U.S. Geological Survey as likely to contain commercial-grade deposits of geothermal energy.

**kW –** Kilowatt. A unit of or measure of power. In this report, kW usually refers to electrical power.

**kWh –** **K**ilowatt-hour. A measure of energy, usually electricity, produced or used.

**LBNL** – Lawrence Berkeley National Laboratory

**LCOE** – Levelized cost of electricity. Sometimes, Levelized cost of energy.

**LLNL** – Lawrence Livermore National Laboratory

**MARKAL** – Market Allocation Model. MARKAL is a computer-driven, dynamic optimization model that uses upwards of 10,000 equations and constraints to foster strategic energy planning. By integrating energy, environmental, and economic factors, the MARKAL model provides energy system solutions to support national planning and policy decisions. It is often used by the U.S. DOE and EIA to study energy use in periods after 2025.

**MARKAL-GPRA** – The version of MARKAL used by contractors for the EERE in making assessments of EERE research programs under the regulations and requirements of Government Performance and Results Act .

**MITRE** – MITRE Corporation, an occasional contractor to the Department of Energy.

**MW –** **M**egawatt. One thousand kilowatts. In this report, MW almost always stands for MWe, megawatt electric. See MWe below.

**MWe –** **M**egawatt electric. In this report, MWe is a rating of the power output of an electric power plant. In many policy studies, MWe specifically refers to the reliable <u>summer</u> output of a power plant or system.

**MYP** – Multi-Year Plan. A plan for a specific DOE R&D program, or group of such programs.

**MYPP** – Multi-Year Program Plan. Means the same thing as Multi-Year Plan.

**NCGs** – Noncondensable gases. Gases other than steam that collect in the heat rejection portions of power generation systems.

**NEMS** – National Energy Modeling System. A complex dynamic model that has been created, maintained, and used by the Energy Information Administration to estimate energy usage in the U.S. from current year through 2025. (See MARKAL.) NEMS includes consideration of renewable energy supply industries, including geothermal.

**NEMS-GES** – The Geothermal Electricity Submodule in NEMS.

**NEMS-GPRA** – National Energy Modeling System – Government Performance and Results Act. This is a special version of NEMS that is used by EERE to estimate the future benefits of energy R&D programs under the conditions specified by the implementation of the GPRA law.

**NGGPP –** The "Next Generation Geothermal Power Plant" research study and report prepared by the CE Holt Company (now Bibb and Associates), Pasadena, CA, 1993 - 1995. The study was managed by EPRI (see above) for the Geothermal Technologies Program of the Department of Energy.

**NREL** – National Renewable Energy Laboratory

**O&M** – Operating and Maintenance. Usually related to the annual cost to operate and maintain a machine, system, or operation.

**OMB –** Office of Management and Budget

**PNL -** Pacific Northwest National Laboratory, Richland, WA. One of the National Laboratories of the Department of Energy.

**PNWL** – Pacific Northwest National Laboratory. An earlier name and acronym of PNL

**psi –** Pounds per square inch. A measure of pressure.

**PTC** – Production tax credit. An allowance against Federal income taxes that is afforded for some kinds of renewable energy, for certain periods of time.

**RD&D** – Research, Development, and Deployment.

**R&D** – Research and development

**ROP –** Rate of penetration. Rate, usually expressed as ft per hour, of how fast a drilling operation makes hole.

**TC** – Technology Characterization.. An analysis for the GTP and EERE of the cost and performance of a current renewable energy technology and projections of how much the technology can be improved by R&D and other means during the next 40 to 40 years.

**TIOs** – Technology improvement opportunities. Estimates of the degree to which sets of R&D projects are likely to be able to improve the performance and or cost of an energy system, during a defined period.

**TIPs** – Technology improvement potentials. Essentially the same as TIOs.

**USGS** – United States Geological Survey. The branch of the U.S. Department of Interior that is responsible for "understanding the geology" of the United States, and the economic potential of its fuels and minerals.