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CONTRACTOR REPORT

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Impact of R & D on Cost of Geothermal Power

Documentation of Model Version 2.09

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IM-GEO

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ABSTRACT

IM-GEO is an analysis used to estimate the impact of technology improvements on the relative cost of hydrothermal power. The analysis is available in a tutorial program for use on personal computers. It is designed for use by R & D program managers to evaluate R & D options. Only the potential impact of technologies is considered with all economic factors being held constant. This analysis has one unique feature. The economic impact of reducing risk by improving reservoir characterization is included using a strategy currently employed by financial institutions.

This report describes the basis of the calculations, documents the code, and describes the operational procedures. Application of the code to study potential cost reductions due to R & D success will be done by R & D managers to evaluate and direct their own programs.

IMPACT OF R & D ON GEOTHERMAL POWER

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IMPACT OF R & D COST OF GEOTHERMAL POWER

1.0 Executive Summary

A menu driven program for IBM-PC compatible microcomputers has been developed for use by program managers as one tool to evaluate the impact of various technology developments on the cost of hydrothermal power. This program considers the impact of general areas of technology improvement. All economic variables are fixed since only technology issues are considered.

Hydrothermal resources are divided into geologic regions because the geology determines the costs in many of the areas of possible technology improvement. These regions are consistent with the USGS defined resource areas. Individual hydrothermal resources were then considered within these regions on the basis of the possibility of near term (within ten years) economic development. Thus only moderate to high temperature resources were included in this study.

Possible areas of technology improvement were related to GTD programs. The impact of the following program areas was considered:

Reservoir Engineering (Reservoir Identification,
Reservoir Confirmation, Reservoir Management
in model.)

Hard Rock Penetration (Drilling in model)

Conversion Technology (Power Plant in model)

Each GTD program element or project can be evaluated using this program for potential impact on the relative cost of geothermal power.

A unique feature of this model is the inclusion of reservoir risk in the analysis as a quantifiable cost element. Previous studies have had difficulty evaluating the impact of technology improvements in the area of resource definition, description and long term behavior prediction. It is clear that such activities as well testing, numerical simulation and geochemical modeling should have an impact on the relative cost of power. Improving our understanding of geothermal systems should in the long run lower development costs. However, this has been difficult to quantify in a simple, easy to evaluate way. This program calculates the cost of a development using best and worst case estimates for relevant physical factors. The difference between these costs is considered the cost of the risk associated with the project. Technology improvements which reduce the difference between the best and worst cases reduce the risk and thus reduce the relative cost of power.

1.1 Scope of Work

This report and the model include the following:

a) Description of the model and documentation of its general strategy and algorithms.

b) Documentation of the baseline cost estimates used on the model. These are for electricity production systems at a number of promising hydrothermal regions in the U.S.

c) Descriptions of many aspects of current U.S. geothermal development practice, and explanations of how these are accounted for in the model.

d) Examples of how a few hypothetical R & D achievements could be entered as data to the model to estimate the impacts of those achievements on the cost of geothermal power.

The model and report do not provide estimates of:

a) The degree to which the modeled geothermal energy production and conversion subsystems appear to be susceptible to improvement through continued R & D.

b) The size of anticipated research achievements (magnitude of technology improvement) expected from the geothermal R & D program of the U.S. Department of Energy.

c) How cost reductions fostered through R & D would affect resource availability or market penetration.

d) Any aspects of power production technology costs from geopressured, hot dry rock, or magma energy resources.

It is possible to use the model to accomplish a. and b. using input from the geothermal community, R & D managers and further effort by the present team. Additional work on the model would be necessary to accomplish c. and d.

1.2 General Capabilities of Model

The model estimates the cost of geothermal electric energy by estimating the costs of major subsystems. Subsystem costs are based on and are sensitive to: a) the physical characteristics of specific geothermal reservoirs and b) the performance and costs of the engineering and technology needed to convert geothermal fluid to electricity.

The model allows R & D managers to enter alternative numerical estimates for component costs or for reservoir parameters. Such alternative estimates are assumed to reflect improvements in the technology that could result from R & D on the technology. The model then calculates the relative cost of geothermal power for improvements. The estimation of the anticipated size of such "R & D Achievements" is expected to be done by R & D managers, who are familiar with the technology and with the technical directions and intensity of DOE and other R & D programs for geothermal energy technology improvement.

An important and novel feature of the model is that it estimates costs related to financial risks due to major uncer-

tainties of predicted reservoir performance. This "risk analysis" feature mimics the way that a commercial banker evaluates such risks.

The importance of the risk analysis feature is that it provides a means by which R & D managers can estimate the impacts of improvement in reservoir testing, analysis and prediction techniques upon the cost of geothermal power. This feature appears not to have been incorporated into earlier efforts to estimate the impacts of R & D on the cost of U.S. geothermal electricity.

1.3 Power Plant Performance and Costs

The estimates of geothermal power plant performance and cost used in this model are relatively crude approximations.

Late in the project, it was determined that power plant data that had been initially selected for use in the model were based on a range of plant inlet conditions too narrow to accommodate the range of conditions encountered in some of the "high risk" site characteristics. Accordingly a brief survey was made of a number of earlier reports of plant performance and cost. The costs then used in the model were drawn from what appeared to be some dominant trends in those data, as described in Sections 13 and 14 of Appendix A.

However, there was a considerable degree of scatter in the data that were available. Thus we believe that the estimates of power plant performance and cost are likely to include uncertainties on the order of $\pm 25\%$. The estimates of plant performance and cost and the way in which those are optimized relative to the cost of the geothermal fluid supply should be reviewed and improved in future updates of this model.

2.0 BACKGROUND, PURPOSE AND SCOPE

In evaluating the impact of R & D on the cost of power produced by conventional methods and on newer renewable technologies such as solar or wind power generation there is an obvious cause and effect relationship between improvement in technology and reduction of cost. If a less expensive process for producing photovoltaic cells, for instance, is developed, the cost of producing power with those cells is reduced. If a more reliable bearing for a wind generator is designed, electricity produced by wind will be less expensive. In geothermal energy production, however, much of the cost of power production is related to the behavior of a natural resource over time.

It is relatively easy to calculate the reduction in cost of geothermal power from the development of a more efficient binary power plant, or improved drilling technologies. Impacts of technological improvements in these areas are included in this analysis under R & D achievements for wells and for plants. However it is not so obvious how the cost of power is reduced when an improvement in pressure or flowrate measurement equipment is made or a better method for modeling the long term behavior of

a reservoir is found. The cost of well testing or reservoir modeling may in fact go up if these new methods are used, making the apparent cost of power higher.

Reservoir engineering is aimed at using information about the geothermal reservoir collected prior to production to describe the field for plant design and predict the long term behavior of the field. It is clear that improved reservoir engineering techniques should provide a more accurate estimate of the conditions to be expected at the time of initial start up of the power plant and predict better the conditions for operation of the plant at 10 to 30 years. This should in turn affect the calculation of the price per kilowatt needed to make development of the resource economic and the investors and lenders estimates of the financial risks involved in development of the resource.

Since reservoir engineering is not an exact science, the reservoir engineer usually develops a most reasonable case scenario to describe the reservoir and looks at what the worst case for the reservoir would be. In predicting the long term behavior of the field the same principal is used. The engineers designing the wellfield and the power plant generally design for the worst case conditions. If the first six wells have temperatures ranging from 450 degrees F to 475 degrees F, the engineers may estimate the fluid requirements for the power plant based on the lower temperature even though it is most probable that the fluid temperature from all wells in the field may average out to 465 degrees F.

Technology improvements in reservoir engineering should result in less discrepancy between the most reasonable case and the worst case estimates for the field. These technology improvements reduce the risk associated with production of geothermal power. Risk must have a cost, but how that cost should be calculated is not obvious.

Bankers and insurers of geothermal projects have had to grapple with this issue. One major bank solved the problem by requiring geothermal operators to borrow the difference between the cost of a geothermal power project based on the most likely estimate of reservoir parameters and long term behavior and the worst case estimate. Using this approach allows assignment of a cost to reservoir risk. Improvements in reservoir technology reduce the difference between the most likely case and the worst case estimates and thus reduce the cost of risk associated with geothermal power projects. Potential impacts of improved reservoir engineering are included under R & D Achievements, Reservoir and Risks, Reservoir.

2.1 Purpose

Other DOE efforts have been directed toward analyzing the relative improvement in the cost of geothermal power due to research efforts. A list of these previous studies is included in Appendix H.

This effort draws from these previous studies. Since technology has improved since the completion of these previous

studies, costs and practices have needed to be updated to make this effort current.

The Meridian Corporation models GEO.BAS and BUSBAR, which give the engineering costs and busbar costs for flash or binary systems, seemed the best starting point for the calculation of the improvement in geothermal power cost. The models were updated using current exploration, testing and drilling practice and recent power plant cost. A team of individuals familiar with the day to day workings of the geothermal business collected costs and reviewed basic procedures used for geothermal development.

The study relied thoroughly on interviews of industry experts. There are too few operating geothermal plants outside the Geysers for statistics collected on geothermal projects to be meaningful. Determining industry practice must therefore be and was done by consulting with those practicing in the geothermal industry. For this reason the numbers used to represent a generic well cost or the description of a representative reservoir in a region may not be the average reservoir or well in that region, but should be close to what experienced geothermal field developers would view as typical and economic.

The purpose of this report is to describe the function of the model and give examples of its use to estimate the impact of R & D technology on the cost of geothermal power. The model is menu driven and allows input of baseline and improved costs and best estimate and worst case reservoir parameters by the user. These inputs correspond to improvements in reservoir and power plant technology resulting from research and development. The resulting output shows the percentage change in the cost of power resulting from either reducing the reservoir risk or reducing the cost of some aspect of the power production cycle.

R & D in geothermal is aimed at improving technology by reducing the cost, increasing the efficiency, or reducing the risk of a contributing factor in the cost of power production. For instance, research could develop a new drill bit which would increase the rate of penetration during drilling of geothermal wells thus reducing the cost of well completion. Using an algorithm which calculates the cost of geothermal wells from some key input factors such as depth, penetration rate and amount of lost circulation and the time it takes to deal with lost circulation, the improvement in cost expected from the new drill bit can be used to calculate the expected reduction in well cost. The model then proceeds to calculate a change in cost of power associated with this technology enhancement.

The model is intended for use by R & D managers who define the goals of their research projects and understand the areas of impact of improvements in technology.

2.2 Scope

The model targets five areas with present day potential for hydrothermal power production. Only areas where economic power from hydrothermal sources can be expected in the near future were

used for this study. Hot dry rock, geopressured geothermal and magma energy were not addressed. The five areas were determined using data from the U.S. Geological Survey and correspond to the U.S.G.S. geothermal regions as follows:

THIS STUDY	U.S.G.S. REGION
Imperial Valley	Salton Trough
Basin and Range	Basin and Range
Cascades	Cascades
Geysers	Pacific Border (Not included in this study.)
Young Volcanics	Alaska, Hawaii, Valles Caldera Sierra Nevada (Coso, Long Valley)

The regions were chosen for their similarity in overall geology and resource characteristics. One of the areas of variability which determines the cost of a geothermal project is difference in geology between different reservoirs. Dividing the possible areas of geothermal development in the U.S. into regions with roughly the same geology allows for variation in exploration and resource development strategy of basic drilling cost without increasing the complexity of the program input data.

For each of these regions two generic projects were defined, a binary and a flash plant project. Data from existing development and selected potential developments in each region were used to determine the characteristics of the generic project. Criteria for the inclusion of a project in this study were: 1) the potential for economic geothermal electric development over the next ten years and 2) the likelihood of reduction of project cost by new technologies which are probable within the next ten years. The Geysers was removed from this study since this dry steam resource is unique and has been commercially exploited for many years.

Baseline data for these generic projects were determined from an actual project deemed "typical" for the region. Other U.S.G.S. regions were reserved for a later phase of study as being unlikely to yield economic quantities of electric power in the near future. The Young Volcanics category is a hold-all for resources in various U.S.G.S. regions other than the Cascades which are associated with recent volcanic features and can be expected to produce at very high temperatures.

Major cost accounts were then identified which contribute to the end cost of geothermal power. Current costs for actual projects were investigated to update earlier work on the cost of geothermal power. The major cost accounts were then broken down into sub-accounts for the purpose of determining present costs. These sub-accounts also reflect potential areas of possible R & D.

An existing model for calculating the cost of geothermal

power was then selected. This model included algorithms for calculating the cost of power plants and production systems given information on the nature of the resource. The model was updated to take into account the changes in the drilling industry and in other areas which have occurred. An algorithm for calculating the cost of geothermal wells given certain characteristics of the reservoir was then developed and used to calculate the baseline well costs. Add-on costs for the possibility of trouble during drilling in the area of lost circulation, cementing and other troubles related to the nature of the geothermal resource were included. A method for taking into account long term field behavior with respect to production decline was added. The current version of the model does not, however, take heat depletion of the reservoir into account. Complex modeling of production and injection practices would be necessary to determine heat sweep accurately. A simple temperature decline model from actual and projected data would be possible although of dubious accuracy, but time was not available to add this to the model for this version.

Model updates take into account current exploration, reservoir testing, drilling and power plant design costs and practice as of January, 1986. Costs used in this analysis thus reflect the current status of the drilling and service companies due to the downturn in the oil and gas industries.

Throughout the task of validating the model by assessing current costs and in developing the costing strategies the study relied thoroughly on interview of industry experts. There are not enough geothermal power generation projects operational other than those in the Geysers to use a statistical approach to determining costs and development strategies. Therefore, people familiar with geothermal development were chosen to evaluate and update the model and benchmark the costs. These "experts" used their own knowledge of geothermal development and relied on their contacts in the business for backup and for information not available to them.

The model is demonstrated using some hypothetical R & D achievements including: 1) improvement in wells, 2) improvement in down hole pumps, 3) improvement in reservoir identification/-engineering, 4) improvements in power plants, 5) the above four achievements combined, and 6) combined achievements at lower levels of achievement (see Section 5.0).

Using the model the impact of current DOE R & D programs on the cost of power produced using geothermal energy can be estimated. Such estimates are not included in this report. In order to make these estimates, input from R & D managers of ongoing DOE research projects is needed. Using this input, the project team can determine the possible improvement in risk or cost. The model can then be used to calculate relative improvement in cost of power.

Reducing the cost of geothermal power production is only one goal of R & D. Making currently uneconomic resources available for development is equally important. Although this model can be modified to determine how much power can be made available by

cost reductions resulting from R & D, this study does not undertake that task.

In addition, large quantities of energy are now untapped from hot dry rock, geopressured geothermal and magma energy sources. The reservoir assessment, drilling and power conversion technologies for these sources are sufficiently different from that used for hydrothermal sources that considerable programming would be needed to change the model to accommodate these resources. However, this could be accomplished using the basic strategies of the model.

3.0 GEOTHERMAL TECHNOLOGY BASELINE

This section describes the major cost items included in the model. Also defined here are the reservoir baseline data used to define the five regions used for the study.

It is important to understand how current industry practice relates to current technology. A problem important to the industry may have been solved by research, but industry may not be using the latest technology in actual practice. This study uses current industry practice as the basis for cost estimates and costing algorithms. Current practice used to define costs will therefore be described in this section. However, current technology which could improve practice will be mentioned where it exists and the method used to estimate the risk reduction resulting from its use will be described if possible.

The cost of power production in a typical geothermal electrical development project can be divided into 5 sub-systems:

- 1) Reservoir Identification - Project selection activities including geophysics, geochemistry, geologic mapping and analysis, gradient well drilling, stratigraphic test well drilling and drilling of wildcat wells.
- 2) Reservoir Confirmation - Drilling of confirmation wells, well testing, geophysical logging, production logging, reservoir analysis and prediction of reservoir behavior through modeling.
- 3) Reservoir management - Strategies for management of the resource including pumping, injection, well workovers, redrilling of wells, adding supplemental wells and well spacing.
- 4) Well Drilling - Drilling and completion of production and injection wells.
- 5) Power plant and gathering system - Piping, separators, fluid treatment, environmental protection equipment, turbine generators, pumps, binary cycle equipment.

3.1 Major Cost Items and Their Interactions

The costs of each of these subsystems are interrelated in

ways that are not always obvious. It is clear that the brine requirements for the power plant determine the number of wells needed in the fields. The lower the energy content of the fluid, the more wells will be needed to supply the plant. The lower the average flow rate from each well the larger the number of wells needed. The greater the drawdown in each well, the less fluid each well will produce. The cost of the well field is determined by the cost of each well and by the number of wells needed. In this way the risk associated with predicting the flow rate of each well impacts the cost of the well field.

For this model as many cost items as possible were tied to the resource characteristics which govern them. Thus the cost of reservoir confirmation is tied to the temperature, total dissolved solids and depth of the resource. The cost of the power plant is tied to the resource temperature, amount of dissolved solids and the amount of H_2S . If the wells are pumped, parasitic pumping load will reduce the net electrical output of the plant. Since well cost is almost entirely dependent on geology, a separate well costing algorithm was developed outside of the model for calculating the well cost. Well costs and add-ons are entered for each region and then varied using risk factors such as the fraction of wells requiring redrill.

Each reservoir characteristic is entered as a "most reasonable estimate" from available data and as a "worst case" estimate. The assumption is made that these values are determined during the reservoir identification and confirmation phases and are used in the design of the power plant. The difference between the cost of the project for the best estimate values and the worst case values determines the premium charged for reservoir risk.

Changing the "Risk Factors" in the model reduces the estimation errors in site characteristics such as temperature, flow rate or rate of decline. This reduces the spread between the best and worst case estimates.

For example, it might be determined during identification and confirmation drilling that the average well in the reservoir will produce 450,000 lbs per hour of 475°F fluid. The error in estimating the flowrate is as high as $\pm 40\%$ so the value could be as low as 270,000 lbs per hour. The number of wells needed for the plant might be determined from the most reasonable estimate of 450,000 lbs per hour to be 10. However, the banker would make the developer borrow the money to drill 40% more or 14 wells. The difference between the cost of 10 wells and 14 wells is added on to the cost of the plant and is attributable to the uncertainty of the methods used to measure and estimate the well flow. A technology improvement in flow rate measurement would reduce this risk cost.

Since several of the site characteristics have a risk value, the model calculates the cost premium associated with all of these worst case estimates at once. Some of the reservoir parameters are tied to several cost items and the effect of the use of the worst case estimate ripples throughout the project cost. The fact is that all of the worst case estimates coming

true at once is extremely unlikely. However, the power plant and well field designer must plan and design for the contingency that they may. The financial planner for the project must raise enough money to cover all of these contingencies along with the usual construction contingency included as part of standard engineering practice.

The other side of the premium added to the project for the effect of reservoir risk is the possibility that the field will be better than the most reasonable estimate. Fewer wells may be needed; the average temperature of the fluid may be hotter. Yet the field developer can not count on this possibility. He must still borrow or in some other way come up with enough money to finance the worst case scenario. He may end up with a power plant that is overdesigned and more costly than he actually needs. Thus if technology could be improved and the spread between the worst case and the most reasonable estimate improved, the cost of the projects would go down.

It is assumed for this model that no project can have 100% certainty of success. The worst case estimate therefore only gets us to a 95% confidence. The remaining 5% chance of failure is insured against by the purchase of reservoir insurance. The cost of this insurance is included in the total power price.

There is a possibility that the interaction of the various cost parameters and their associated risks can multiply costs beyond what would be reasonable due to multiple interactions. Where possible this has been avoided in the coding of the model. However, the interactions of the elements are not always obvious. For this reason, actual plant, well and field costs were estimated using real project data and information from developers. These estimates were used as a basis for comparison to prevent the model from producing unrealistic answers.

3.2 Reservoir Baseline Data

Reservoir baseline data provides a description of the reservoir at the time of plant start up. The values are the most probable estimates of such characteristics as flow rate from each well, reservoir fluid temperature, wellhead pressure, fluid chemistry and so forth.

3.2.1 Regions Selected

For each region a typical project was determined with what is assumed to be average characteristics. For instance, in the Imperial Valley region the project is assumed to be somewhere near the Salton Sea, but the wells are deeper than the average well in current Salton Sea projects and the brine is more concentrated to account for the characteristics of the resources at Brawley and Westmorland. Thus it should not be assumed that the reservoir parameters used for this study represent any actual project. They are those which might represent the average project in the region.

For the young volcanic region, many of the projects in this region may be in remote areas such as Alaska or Hawaii where

services and equipment can only be obtained at premium. Other projects will be in the mainland U.S. To accomodate the large difference in cost between these isolated projects and their counterparts in more accessible areas, two "typical" high temperature young volcanic projects were used, one in a remote location such as Hawaii and the other in the more accessible Coso, California area.

The baseline data assumed for each region is listed in Appendix D. This data was obtained from USGS Circular 790, the BPA study of geothermal potential in the Cascades, material published in the GRC Bulletin and in the transactions of the GRC and by personal communication with developers. Where data was received by personal communication, it has been averaged in with publicly available data to preserve the confidentiality of the sources.

3.2.2 Energy

The total enthalpy in the region is used by the model to weight the average power price. Thus a region containing a larger amount of potential energy would weigh more heavily in the average power price. The values were taken from USGS Circular 790 except for the Cascades values. At the time that data for Circular 790 was compiled, little exploration had been done in the Cascades. Total enthalpy in a reservoir for Circular 790 was largely based on surface manifestations. Deep cold ground water circulation caused by high rainfall in the Cascades obscures most potential surface manifestations. Cascades values were therefore taken from the BPA study which used other criteria for estimating total energy in a reservoir.

Only reservoirs with possible temperatures above 125 degrees C were considered since lower temperature resources are not likely to be economic for power generation for some time. (A study of power availability should be done to take these and other resources not used for this study into account). Since Circular 790 does not break down the resources it lists by physiographic province, geothermal areas listed were assigned to one of the regions used for this study on the basis of geology. Some resources did not fit into any of the regions and have been left out of this study. Most of these, however, were of very low temperature and would not have fit the study criteria.

The exploration strategy assumes that an area of some size characteristic of each region is explored as a unit. This strategy will be described in more detail in section 3.4. The variable titled "Energy in SubArea" in Appendix D, page D-3, allows alteration of this modular exploration area. Increasing the energy in the exploration unit would mean that exploration costs are shared by a larger number of power plants so that the total cost of exploration allocated to a individual plant would be smaller.

3.2.3 Temperature

Reservoir temperatures for this study are taken from typical projects already developed in the regions used. Thus the

temperature of 475°F used for the Imperial Valley region is not meant to be the average or mean temperature for all possible high temperature resources in the Imperial Valley, but a "typical" temperature representative of projects either currently under development or abandoned. A typical temperature was selected because in many cases a range of temperatures may be present in a given resource area, but some high temperature fluids may be too high in dissolved solids or may present other problems for exploitation. For example, it is highly likely that 700 degrees F fluids exist in the Kilauea East Rift Zone in Hawaii. However, it is not likely that these will be exploited without mixing with cooler fluids from reservoirs above due to the difficulty in controlling such high temperature, high pressure fluids.

Although the reservoir temperature is important to the design of the power plant, it is the enthalpy of the fluid delivered at the wellhead that determines the amount of power the plant will produce. Very little data on produced enthalpy is currently available. As a result, some other way of determining the fluid requirement for the power plant was needed. In addition, the drawdown associated with flow of the fluid in the reservoir determines the wellhead pressure. Even a very high temperature fluid with a high enthalpy may have to be produced at a low wellhead pressure due to low permeability of the reservoir. Low wellhead pressure will require a lower pressure, larger turbine. This is the case in Hawaii. For this reason the fluid requirement for flash power plants was tied to the wellhead temperature. Future versions of the model may use both reservoir requirements.

The values for reservoir temperature were taken from both reservoirs with operating power plants and those which are still in the exploration or confirmation phase. Proprietary data was provided by several operators for both reservoir and wellhead temperature. Where no test data was available, such as for the large number of resources in the Cascades, data from the USGS and from estimates made by those exploring the Cascades were used.

3.2.4 Chemistry

Fluid chemistry is an important factor in determining the cost of geothermal power conversion. Proprietary data from operating plants and from resources being tested was used to determine a representative range of values for several important aspects of fluid chemistry including: total dissolved solids, total non-condensable gases, hydrogen sulfide and carbon dioxide.

All of this data is currently estimated and available as input for each region. However, only total dissolved solids and hydrogen sulfide are currently tied to power conversion costs. Total dissolved solids are used to determine the need for brine stabilization equipment, in the drilling cost estimates and for the cost of testing. Hydrogen sulfide is used to determine the need for H₂S abatement.

There are other aspects of the cost of power conversion which are tied to chemical factors. The cost of plant and field maintenance is linked to the corrosive effects of the fluid. In

a general way, corrosiveness can be determined from the levels of dissolved solids, H_2S , and CO_2 . Well workovers are more costly if high levels of calcium carbonate are present as is the case in much of the Basin and Range. H_2S corrosion requires the use of more expensive metals for well casing and production piping. Pumps may need special maintenance if the fluid is corrosive. At present these factors are accounted for by inputting higher workover cost values where corrosion or scale are expected.

3.2.5 Depth

The average depth of wells drilled in an area clearly impacts the cost of wells drilled in the area and the cost of maintenance of those wells. Well depths are a factor of geology and can vary greatly from reservoir to reservoir in a region. Depths were therefore selected for each region based largely on data from existing field developments unless these developments did not seem to represent the majority of future developments anticipated in the region. Such is the case in the Cascades where exploration for binary resources has been to fairly shallow depths although it is not anticipated that future resources will occur at less than 3000 feet.

The depth to the resource is used to calculate the well cost and the pump set depth for calculation of pumping cost. However, well base costs are calculated outside this program using a detailed algorithm described in Section 3.6.2 and used as inputs to the model. Pump set depth is calculated as a step function with wells deeper than 1000 which are pumped using a pump set depth of 1000 feet. This is due to the current use of line shaft pumps exclusively in the industry. Changing the resource depth without changing the well cost and pumping cost will not effect the total power cost.

3.2.6 Flow Rate

Flow rate is one of the factors difficult to estimate; particularly for reservoirs which have not yet been developed. Yet flow rate is tied to many cost factors including: production piping diameter, number of wells, pumping costs and power plant sizing. It was therefore necessary to project data from fields already produced or tested onto future developments. The highest values for flow rate for a region were not used. Very high rate wells have been drilled in the Imperial Valley for instance, but many reservoirs have been tested with more moderate rates.

It was decided that for this modeling effort average rate wells would be assumed to dominate future developments to make estimates more conservative, even though high rate wells are likely to be drilled at many prospects. In fact, at one resource in the Salton Sea, the developer estimated the average flow rate for the wells conservatively, but the bank experts made even more conservative estimates. The wells produced at much higher rates than either estimate requiring fewer wells and an overall lower plant cost. Unfortunately, without more knowledge it is not possible to project flow rate accurately. This must of necessity increase the cost of geothermal development. The cost of this lack of information is reflected in the model in the size of the

risk value associated with flow rate estimates.

Flow rate changes with time represent a large uncertainty for both the developer and the financing agency. Reservoirs are generally operated at a constant pressure and flow rate is allowed to decrease during the drawdown, both around the well and in the reservoir as a whole. In order to represent the decrease in flow rate in a producing reservoir, a simple exponential decline was assumed. Although data does not exist (except at Lardarello and the Geysers), to determine the shape of long term decline curves, an exponential decline is logical. This type of decline represents the drainage of a reservoir of limited extent. It is clearly a conservative approach to estimating flow rate behavior with time. A very limited resource can be represented by a rapid decline rate while a resource with some or a large amount of recharge can be represented by a smaller rate of decline. This does not account for the possibility of catastrophic reservoir failure. Such a possibility is assumed to be small for the purpose of this model, no greater than 5%, and is insured against by requiring the cost of reservoir insurance to be added to the field cost.

The shape of the curve determines the points during exploitation that replacement wells will be needed and therefore has an effect on the cost of power. It is possible in the future to link this model with numerical models which predict more complex long-term behavior of flow rate with time in the reservoir. However, this is a more complex programming effort and was not justified for this version of the model.

3.3 Reservoir Identification

The exploration of resources varies widely from one geologic setting to another and from one developer to another. Geothermal resources can sometimes be easily identified by surface manifestations such as hot springs and fumeroles. If no surface expression is obvious, exploration methods such as geologic mapping, geophysics, remote sensing, fluid and soil chemistry and temperature gradient measurement have been used with varying degrees of success to locate resources at depth.

An "expert interview" approach was used to develop the strategy for identifying an economic reservoir. Geologists and reservoir engineers working in the regions defined for this model were consulted to determine how they would explore an area and what probability of success their strategy would have. The numbers used for calculating exploration costs may not be the numerical average of all exploration costs, but come close to actual amounts spent.

3.3.1 Industry practice vs. current technology

Geothermal energy exploration is in the same state that petroleum exploration was when developers started to explore beyond areas with oil seeps and obvious domes. The Cascades are a good example of this situation. Heat is clearly present in the Cascades, an area of active volcanism. However, the high rain fall and igneous rocks make many commonly used methods of

geothermal exploration inappropriate. In this area, it may be necessary to drill many stratigraphic, deep test holes to find reservoirs which will be economic to produce.

Because geothermal exploration is in its early stages, developers use their own style of exploration which may or may not take advantage of the most current technology. Current practice was used for the purpose of estimating the cost of exploration. It can be argued that there are better exploration strategies or that more exploration would yield better data and ensure more successes. However, real exploration success ratios are linked with these exploration costs, so it seems reasonable to use actual exploration methods.

In order to determine the cost of exploration, developers actively exploring in each area were asked about their exploration programs. This information was generalized into three categories of expenditure: geology and geophysical survey work, temperature gradient hole drilling, and drilling of one exploration well of production size. In each category, where there was a conflict between strategies developed as part of DOE studies and industry practice, the cost for exploration using standard industry methods was used. For example, although larger numbers of exploration wells are needed to define a moderate temperature resource, lower profit margins on such resources have driven developers to cut costs on exploration. This is reflected in an increased spread between best and worst case values for these resources due to the increased risk and shows up in the calculation on risk.

An example of the net effect of this modeling decision is that it shows the "Cascades" plants as: a) producing relatively expensive power at high risk, but b) being most amenable to reduction of risk through improvements of reservoir identification and confirmation technology.

3.3.2 Exploration strategy assumed for this model

Previous studies have shown various success rates for the drilling of geothermal wildcat wells, defined as wells drilled far from other successful geothermal wells. One such study showed that between 1 and 2 geothermal wells out of 10 drilled as a total wildcat is successful. Wildcat success should be affected by the efficacy of the exploration strategy employed. Thus research could change the success of wildcat drilling. For this reason the wildcat success ratio is an input variable. The baseline and risk values for wildcat success are shown in Appendix D.

The overall regions were divided into exploration units of a size related to the geology of the region and used as an input variable. Thus if 10,000 MWe of power could be developed from a region and an average exploration unit would identify 500 MWe of power then 20 units could be developed in that region with potentially ten 50 MWe power plants on each unit. Each exploration unit in a region would have the same amount of money spent to identify it as economic. Thus the exploration budget for each unit would be shared by the total number of power plants

constructed in the unit.

The code allows the exploration budget to be expended for each unit up to the completion of a deep production diameter test well, a wildcat well. Of these wildcats only a fraction will be successful so the cost of exploring the unsuccessful unit is also spread out among the power plants constructed on the successfully explored unit. It was assumed that geology for each large region was similar enough for exploration strategies to be the same throughout the region, keeping the average cost to explore each unit constant over the region. Cost of exploration varied only from region to region. The model applies the entire cost of exploration for each failed exploration attempt. No possibility of partial expenditure for exploration was included. The time allowance for the exploration of each unit was 6 months.

A successful wildcat well does not guarantee a successful power plant. Some areas will have the exploration budget expended on them and then go on through the confirmation phase only to fail. The model adds in the cost of exploring these areas with successful wildcats which do not have a confirmed reservoir to the total exploration cost.

3.3.3. Costing algorithm

Exploration costs include overhead using an average multiplier of 2.25 on manpower. Costs for exploring in the various regions were estimated using data from developers actively working in each region. However, there was a large difference in the strategies employed even in the same region by different developers. For instance one developer in the Basin and Range region felt that drilling of temperature gradient holes yielded the most information while another relied heavily on geochemistry from hot springs. However, the average budget for exploration did not differ greatly from developer to developer for resources of similar temperature. There was a cut-off for moderate temperature resources at shallower depths. For this type of resource the developers expended far less on gradient holes and relied more on existing data, expending much less overall on these projects than was spent on deeper, hotter resources. For this reason depth was made a variable for exploration cost. For deep resources, i.e. those greater than 3000 feet a deep geology surcharge was added. This could include the cost of doing geophysical surveys or drilling a stratigraphic core hole.

In order to calculate an average exploration cost for each region, data on strategies and budgets was examined and broken down into the three categories mentioned above: 1. Geology, geophysical and geochemical survey work, 2. Temperature gradient holes, and 3. Exploration wells. Included in the first category are all activities not related to well drilling including literature searches, chemical sampling of springs and wells, mapping, study of aerial photos, interpretation of existing data, geophysical data collection and interpretation and soil chemistry. Appendix D gives a listing of the input data finally assumed by region. Detailed exploration strategies are not included here since budgets seemed more constant than strategy.

3.4 RESERVOIR CONFIRMATION

After the drilling of a successful wildcat well it is assumed that steps are taken to confirm whether an economic reservoir is present. This confirmation phase includes the drilling of further production diameter wells of which some fraction will be successful, testing of the wells during drilling and production testing and interpretation of the data collected during tests including geology, geochemistry, geophysics and reservoir engineering.

3.4.1 Industry practice vs. current technology

During the confirmation phase, as during exploration, industry practice may differ from what current research has shown to be most effective in confirming a reservoir. Although long term testing of wells with careful sampling of fluid and non-condensable gases is recommended by many DOE studies, not all developers test wells for longer than a few days and few make rigorous measurements of fluid chemistry. Where a conflict arose between industry practice and current technology, again the cost of actual practice was used.

The largest area of variability in practice seems to be in use of numerical simulation for data interpretation. Although it seems reasonable to use numerical simulation techniques to predict the long term behavior of a resource, many developers do not do so, particularly for smaller projects and moderate temperature resources. In many cases numerical simulation is undertaken not by the developer, but as research by a university or national laboratory funded by DOE. Although some developers routinely use numerical simulation others never do. In this case, unlike all other cases of conflict between industry practice and current technology, it was decided to include some cost for numerical simulation in the confirmation phase even though this may not be standard practice. The model uses a system of multipliers for determining the change in cost for various aspects of power production. If a zero cost for simulation is used then no multiplier can increase this cost to show improvement in technology.

3.4.2 Confirmation strategy assumed for this model

Included in the cost of confirming a reservoir are not only the cost of drilling wells and testing them, but the cost of those wells which fail to produce economic amounts of energy. To account for this cost a fraction of the wells drilled during the confirmation phase were assumed to be dry holes. Of these dry holes a certain number can be used as injection wells, while some are totally useless. For this model an "expert interview" approach was again used to determine the confirmation strategy. By examining both successful and failed projects and talking to reservoir engineers practicing in geothermal now, it was decided that during confirmation four good producers are drilled with 1.5 injectors and .5 dry holes. After the drilling and testing of these six wells the developer is ready to go to the bank or other financial source for further financing for the construction of a

power plant. This is not statistically accurate data, but probably comes close to actual statistical probabilities of success and failure.

No amount of testing and well drilling can guarantee that the resource will be economic to operate for the 30 year life of most power plants. This model assumes that the best that can be done is a 95% certainty. The cost of reservoir insurance is included in the field cost. This in part insures against a catastrophic reservoir failure that could not be foreseen using testing methods. The remaining risks are accounted for in the add-on cost of additional wells, testing and so forth which would be required to bring the confidence up to this 95% level as seen by a typical lending institution.

In addition to dry holes and injection wells an allowance for redrilling a fraction of the production wells was made. Since most geothermal reservoirs are drilled into fractured rock, redrilling non-productive wells by side tracking can often yield results. The redrill fraction is input as a variable. A simple equation also calculates the number of spare producers as a fraction of the total number of production wells. The number of spares is always one or more.

Some sites will be identified and go through the confirmation process only to turn out to be uneconomic at the end of this phase. The probability of successful confirmation is input as a variable and can be changed to reflect improvements in exploration technology. The baseline success ratio was set at sites in all of the regions and was determined by discussion with developers and from personal knowledge. Actual statistics were not used since early demonstration projects and projects started and stopped for reasons other than the economics of that particular project bias the small sample available. The Geysers would tend to dominate any overview of the success of identified geothermal resources.

Another aspect of reservoir confirmation is the success rate of drilling after a reservoir has been identified. The success of drilling is not only higher after initial identification of the resource, but differs from area to area depending on the geology. For this reason, the success rate for confirmation drilling was input as a variable for each region. Appendix D shows the values used. These were again determined using expert knowledge from those involved in drilling in each region. In areas where little exploration has so far been done such as the Cascades, opinion can only be conjecture and will need updating as more information is available.

Geothermal wells can be dry holes by virtue of either low temperature or flow rate. Neither problem precludes their use as injectors. For this reason a fraction of the dry holes are passed on as injectors and are not totally written off. If there are insufficient injectors from the dry holes, separate injectors are then costed. Geothermal injectors must generally be drilled to the same depth as producers or sometimes deeper and are therefore at least as costly as producers. The retaining of some dry holes as injectors is current practice and reflects a realistic

economic approach.

Some producers may show promise, but be just under the flow or temperature needed for economic production. Other producers experience downhole problems. In each case the developer may need to redrill a fraction of the producers completed. A redrill fraction was estimated for all regions and an add on redrill cost developed. This is discussed in more detail in the drilling section.

3.5 Reservoir Management

Following confirmation of the reservoir it is assumed that financing is obtained and the remaining necessary production wells drilled. As soon as this phase is entered it is necessary to begin managing the use of the resource. Reservoir management involves determining the spacing of wells and whether they will be pumped or allowed to freeflow. Some estimates of the rate that new wells will need to be drilled is made and the cost of maintaining the wells and the wellfield is estimated. Fluid injection may present special problems such as the need for well cleanout or chemical fluid treatment. These are all reservoir management decisions and they have a large impact on the cost and operation of the power plant.

3.5.1 Reservoir pressure decline

One of the greatest areas of uncertainty is the rate of pressure decline of the well field. As fluid is produced for power generation the pressure in the field will decline. The rate at which this occurs depends on whether there is a source of hot fluid to recharge the reservoir, on how fast this recharge fluid can reach the produced zone and on how much fluid was stored in the reservoir initially.

The petroleum industry uses data from fields similar to a new field to determine the decline rate, often by the use of decline curves or by numerical simulation of the field. Decline curves and material balances are simple methods which rely on knowledge of the long term behavior of existing produced fields to prove their validity. There are too few geothermal fields which have been produced for a long period of time and none which have been depleted. We don't know how geothermal reservoirs will behave in the long run. Numerical simulation of existing fields can be matched against what little production data is available, but there can be no way to prove whether the simulation is a valid model of the field until the field approaches depletion.

Because of this enormous uncertainty, any approach used to project field pressure behavior is in the realm of conjecture. Decline curves allow for a great deal of flexibility with a relatively simple computational scheme. For this model an exponential decline was assumed because this is a conservative shape of curve and fits the assumption that there is a limit to the resource. Other curves may fit some resources better, but at this time the data is not available to tell one way or another which type of decline curve fits which reservoir. Data from the

Geysers are available, but the Geysers is one of the few vapor dominated resources in the world and Geysers data is not relevant to the hydrothermal systems considered here.

Decline rates were therefore estimated using either test data, production data where available, a material balance approach where enough data was available for this or conjecture. In some cases such as the Imperial Valley, production has continued for long enough for the data to be very useful in determining the possible decline rate, but this data is proprietary. However, rumors and hints have escaped concerning field behavior that can be used for educated guesses. Combined with test data, an expert opinion can be formed. In the case of Hawaii a small scale pilot plant provides useful data, but may not be applicable to a large scale development. In the Basin and Range only limited test data are available. The Cascades have little useful reservoir data. The decline rates estimated are shown in Appendix D.

Since this is an area of high risk, that risk is reflected in the large variations in decline rates. Some regions have so much risk, that very large decline rates are possible, reflecting the possibility of catastrophic reservoir failure.

No attempt was made for this phase to account for reservoir heat depletion. A useful model has been developed by Stanford University and could be coupled with this program as some time. A decline curve approach to heat sweep is also possible, but the rate of decline for hydrothermal resources is very dependent on the injection strategy chosen and on the geology of an individual reservoir. A first approach to heat depletion will probably use a temperature decline curve developed from numerical simulation results.

3.5.2 Well Workover

Along with regular wellhead maintenance, wells may routinely need to be cleaned out or worked over in some other way. Corrosion, scale and injection well clogging are the usual reasons for well workover. The cost is therefore dependent on fluid chemistry. For this model, however, a regional cost and time to workover was determined and can be seen in Appendix D.

3.5.3 Pumps and pumping costs

For most binary power plants the very high flow rates needed for economic power production justify the cost of pumping the wells. The cost of the pump is input as a variable and can be changed to show a change in cost a pump improved by research. The flow rate which could be expected from the well can also be changed using the improved pump. In the case of pumped wells improvements in pumping ability should be tied to the flow rate for each well by a productivity curve. However, this level of detail was not attempted for this version of the model.

The cost of pumping was calculated as a parasitic power loss to avoid the vagaries of power purchase price vs. power sale price. This assumes that power consumed in pumping is generated

by the plant itself and therefore reduces the net power output of the plant.

Currently, only lineshaft pumps are considered reliable enough for geothermal use. The limit on set depth for lineshaft pumps is either 1200 or 1000 feet according to who you talk to. For this study an arbitrary set depth of 1000 feet was used for all wells deeper than 1000 feet. For shallow wells a set depth of $2/3$ of the well depth was used. Calculation of a set depth would allow determination of the benefits of downhole submersible pumps. A simple modification would allow this calculation and should be included in the next version of the model.

3.6 DRILLING AND COMPLETION

The cost of drilling geothermal wells has long been recognized to be higher than that for oil and gas. Separating out the reasons for this increase in cost should enable us to estimate the cost of drilling geothermal wells in a given geologic setting.

3.6.1 Current Practice v. Current Technology

A number of differences in the tools and operations in geothermal drilling and completion make it more expensive than its oil and gas cousin. The four major items or troubles that contribute to the increased cost of geothermal drilling over oil and gas are 1) high temperature, 2) lost circulation, 3) corrosion and 4) hard formation. There are many things done in geothermal to cope with these differences which increase the cost.

Temperature - Temperature has both a direct and indirect influence on the cost of drilling and completion. Mud, casing design, cement placement and strength, the cementing procedure used and instrumentation all are more costly due to high temperature. Not only do these items cost more in order to withstand the higher temperatures, but the failure rate increases in the operations involving these items due to the temperature. The cost to fix failures is always higher than the cost to prevent them, making geothermal even more expensive.

Lost Circulation - In a geothermal reservoir lost circulation is almost essential. The high permeabilities needed to give the large production rates necessary for economic geothermal energy mean that geothermal reservoirs are in highly fractured or very porous rocks. In these rocks drilling fluid can be lost at a tremendous rate.

If the temperatures in the well are not yet high enough for a productive well, then lost circulation means difficulties. In the oil and gas business it is always necessary to stop lost circulation because of the possibility of a high pressure blowout. Hydrothermal reservoirs are usually at hydrostatic or sub-hydrostatic pressure. Blowouts result from a loss of the pressure that keeps the high temperature fluid from boiling. As a result, if temperatures are not yet hot enough for the fluid to

flash into steam, a blowout is less likely. Control equipment can be used that will reduce the likelihood of a dangerous blowout. Therefore if lost circulation can not be stopped by ordinary methods the well can be drilled ahead blind until a casing point can be reached and the loss zone permanently shut off. However, lost circulation control always takes time, and time takes money.

Lost circulation combined with corrosive fluids and high temperatures can result in more difficult completions and in casing failures. Lost circulation plays a very important role in preventing complete cement jobs. Often the loss zone must be plugged before cementing to prevent unsupported casing or fluid getting trapped behind the casing. Corrosive fluids trapped behind the casing can reduce the casing life. Expansion of trapped fluids as they are heated during well flow can cause casing collapse.

Corrosion - Corrosive fluids cause another set of problems which can increase the cost of geothermal wells. Corrosion in oil and gas wells can be a problem, but the high temperatures and complex chemistry of geothermal fluids vastly increase the cost of the solution to the corrosion problem in geothermal wells. Four elements all present in geothermal contribute to the degree of corrosion problems: corrosive materials, oxygen, moisture and high temperature. More expensive casing and drillstring materials, oxygen scavengers, H₂S abatement equipment and fluid disposal problems during drilling are all related to corrosion. All contribute to the increased cost of geothermal wells.

Hard rock penetration - A sizable portion of geothermal wells are drilled in metamorphic and igneous rocks. These rocks tend to be harder and more abrasive than the sedimentary rocks encountered in oil and gas drilling. Rate of penetration is lower and bit life is shorter, leading to increased drilling time. Because little oil and gas drilling is done in very hard rock, there is little equipment available from industry to improve the situation and little incentive for industry to develop equipment which would solve the problem.

In addition to slowing drilling time hard rocks make directional drilling more difficult. Turning the hole and controlling direction in highly fractured hard rock take more time and therefore more money.

The regions selected for this study were grouped to have common geologic properties. This facilitates design of a "generic" geothermal well for each region for the binary and flash systems which will have similar properties with respect to the trouble areas discussed above.

A previous unpublished study by Sandia analyzed in some detail the operations, time and costs for drilling of such generic geothermal wells. The wells analyzed were trouble free. The cost of various troubles was added separately to this base well cost. The design of the well could then be optimized to reduce cost by changing the rate of penetration or other time factors in the cost of the well.

For the present study the well costs are handled in the same way. The wells are meant to be representative wells for the power plant in a given region. But the cost may not apply to any particular well actually drilled in that region. The well cost can be changed to reflect improvements in technology by changes in the cost table and performance tables used to calculate the base and add on costs. The new well cost can then be entered into the program as a variable.

3.6.2 Base well cost

The well costs were calculated in two steps independently of the model code. The first step was to determine what a typical well might cost in each of the regions without the cost of troubles such as lost circulation, cementing problems, etc. Time consumed in drilling through hard rock is accounted for using rates of penetration estimated for different rock types. Rapid bit wear due to hard, abrasive formations is included through use of expected bit life for the environment anticipated for the region.

For the purpose of this study drilling was considered finished when the total depth had been reached, the last liner or casing string cemented and the wellhead in place. Tubing needed for pumping was considered to be run with a workover rig and was included in the pump cost.

The approach to calculating the well cost involves input from the geologist, the production plan and the drilling engineer. The steps in the calculation are:

1) Determine the temperature profile.

From the geologic information a generalized temperature profile is estimated which is representative of the region. Higher temperature results in increases in the mud cost, problems in cementing, logging cost and other increases. The profile is then referred to for estimating costs which are affected by temperature.

2) Make a table of the ROP/bit life.

The classification of rate of penetration and bit life range from 1 to 10 with 1 being the easiest to drill and 10 being the hardest. The values are an integration of discussions with geothermal operators, geologists, bit users and review of well records. Although hardness is not always correlated directly with bit life, hardness is a good approximation of abrasiveness which determines bit life.

3) Determine the ROP map for the well.

The geologist and the drilling engineer make a drilling classification profile for each well using the table of ROP and bit life. This map is assumed to be consistent with the geology and drilling conditions anticipated on average over the entire region. The bit life is simplified and is considered to only

depend on hardness, not temperature or abrasiveness.

4) Select the standard and oversize casing program.

Past casing design used the size series 20" - 13 3/8" - 9 5/8" - 7". current practice has in a number of cases gone to use of 22" - 16" - 11 3/4" - 8 5/8" and 6". In a four element casing string the larger program can handle a 30% increase in flow. For this model both designs were used. If the production expected from a typical well is 500,000 lb/hr or below the 20" program is used. If the flow rate is above 500,000 lb/hr the 22" design is used.

Casing set points and the use of liner strings are decided from the temperature profile, lost circulation map, a borehole stability map and information on possible water inflow as well as by consulting standard practice for existing wells.

5) Determine the cost of casing and transportation.

The cost for the casing is determined from price sheets from commonly used suppliers of new casing. Transportation is calculated from the mill to the west coast. No attempt was made to optimize transportation cost by assuming delivery directly from Japan to a place like Hawaii, for instance.

The cost of downhole casing equipment such as the casing shoe, is costed as 200 extra feet of casing of that size. Where a liner hanger or polished bore is used, the cost is estimated as 300 extra feet of that size casing.

This step results in a table of casing costs for each well.

6) Make a table of the running times for casing.

A table of running times for the common casing sizes was determined from interviews of drilling engineers. The estimate is in hours per 1000 feet of casing to be run.

7) Make a table of running times for logs.

Using the estimates from the Sandia generic wells study, times for running logs were calculated from the casing program. The estimate included time to condition mud, rig up for logging, log and rig down the equipment. The cost for logging paid to the service company is included in the well confirmation cost.

At the end of each interval that logs will be run, the time estimate and day rate are used to determine the cost to set up and run the log. This cost is included in the well cost.

8) Make a table of the cost of cementing.

Again from the Sandia generic well work and current practice, an estimate of the time to cement the casing and liner is made. Added to this are the cost of the cement and the cementing service charge. The cement cost is calculated for the different size casings which need cementing, for the type of cement needed

for the appropriate temperature and for the depth.

The time estimate for cementing includes rig up and rig down, the cementing time and time waiting for cement to set.

The well costs are estimated over three phases: initiation, intervals 1 through N and completion. Total cost for each phase is calculated using information from the above tables where applicable and then the total cost is added up.

3.6.2.1 Initiation

Site cost - The site cost is determined from past experience in site construction. The site expenses attempt to take into account the possible well location and type of terrain that can be expected.

Geothermal locations are often in remote areas or difficult terrain. The size of the location may depend on the availability of land, the well spacing and the fluid production rate expected from each well. If a very large fluid flow is expected, a larger site may be needed to construct pits for fluid storage during testing. Concern for lost circulation alone justifies the use of larger reserve pits. In many fields the desire to reduce piping cost has resulted in drilling of clustered wells from pads. This level of detail was not included in this version of the model.

Cellar - The cellar is estimated to cost \$10,000 for all sites.

Conductor - A table was constructed to estimate the correct cost for the conductor pipe. The cost depends on depth, diameter of the conductor and the hardness of the soil. The cost varies from \$20,000 to \$55,000.

Mobilization/Demobilization - The mobilization cost is the move on/move off expense that is a part of the contract with the drilling rig. This amount varies with the distance of the location from available rigs, the availability of rigs and size of the rig. For this study the mobilization cost was set at 10 times the rig day rate. This is in general a fair approximation of the mobilization charge over variable conditions.

3.6.2.2 Interval 1 through N

Interval costs were calculated for each casing interval. The costs are computed from the time of drilling out of the shoe to the next string of casing or liner has been run and fixed into place. The following grid shows the numbers to be calculated for each interval that is drilled. Items included in the interval cost are 1) bits and tools, 2) logging time, 3) casing, 4) cementing and 5) mud cost. The following chart shows the costs to be calculated for each interval drilled.

	Time	Variable	ODC
	----	-----	----
Drilling	1	2	
Bits and Tools			3
Mud			4
Logging	5	6	
Casing	7	8	9
Cement	10	11	12

- 1) Drilling time is determined from the footage to drill, ROP table and estimated number of trips calculated from bit life.
- 2) The variable cost for drilling time is computed by multiplying the hourly rig expense times the hours to drill the interval. The hourly rig expense includes the rig rate plus other services and fuel.
- 3) Bits and tools are estimated for the hole using the expected bit life determined from the map of formation hardness. The expense for these items is calculated from the number of trips times the cost of replacing the bit and parts of the bottom hole assembly. Again the table of rock hardness is used to assess the amount of bottom hole assembly which will need replacing.
- 4) The mud cost for the interval is computed based on the amount of mud lost during the drilling of the interval, the additional amount of mud needed to accomodate the additional hole and an hourly rate that reflects the cost of maintaining the mud system. The hourly rate is adjusted for the temperature of the hole.
- 5) The logging time is estimated from the table that reflects the amount of time to prepare the mud, rig up, log and rig down. The table is an estimate of that time as a function of depth.
- 6) The variable cost for logging is determined by multiplying the time to log by the hourly rig expense.
- 7) Casing time is estimated from the table that gives the rig up/ rig down plus running time. The running time is estimated from the table on running times.
- 8) The variable cost for casing is computed by multiplying the casing time by the hourly rig expense.
- 9) The direct cost for casing is computed from the casing or liner to be run in the interval, the cost per 100 feet of the casing, plus additional amounts for the downhole equipment and the hanger where appropriate. The casing costs are obtained from the table of casing costs using the casing program established for each well.
- 10) The time to cement is determined from the table for cement operations including the time for the cement to set.

- 11) The cementing variable cost is computed from the cementing time and the hourly rig expense.
- 12) The direct cost for cementing is taken from the cementing table.

3.6.2.3 Completion

Completion costs are estimated from the cost of the wellhead and the time for the operations. The completion time for the drilling rig is estimated at 3 days.

Completion activities include well cleanout, installation of the wellhead, test activities with the rig on the hole and other activities related to preparation of the well for production which require the rig.

After each component cost is calculated the total well cost is determined by summing the elements.

3.6.3 Add on costs

Three major cost centers for difficulties which add cost to geothermal wells were established by the Sandia generic well study: 1) lost circulation, 2) depth risk; and 3) cementing problems. All other possible difficulties were grouped together as other problems.

3.6.3.1 Lost Circulation

Lost circulation expense was calculated in two steps:

- 1) Make a table of the lost circulation severity.

Lost circulation classes are estimated ranging from 1 to 7 based on both the time lost and the amount of money spent to solve the problem. The classes were defined with small enough differences between classes to prevent enormous changes in well cost when applied over the entire length of an interval.

- 2) Determine the lost circulation map for the well.

A lost circulation classification for each 1000 feet was then assigned. On average one such class event will occur for that 1000 feet of hole. Where less than a full 1000 foot section is drilled a fractional portion of expense and time was calculated.

The reasonableness of this result was then tested against some known experiences. The time and money spent on lost circulation for actual wells was found to agree well with the regional wells used for this study.

3.6.3.2 Depth Risk

In the drilling of any well for the production of oil, gas or geothermal there is an uncertainty about the depth at which the production is to be found. Failure to find production at the

expected depth will result in one of three decisions: 1) abandon the well and move on to another location, 2) deepen the well, and 3) plug back and side track.

The possibility of abandonment is covered by the dry hole fraction. A certain percentage of wells are not economic for any purpose. Some can be turned into injection wells if they will receive sufficient fluid and that fluid will not interfere with producing wells.

The cost to deepen the well is estimated from the daily cost and time to drill for deepening a fixed amount. An average deepening of 500 feet was selected for this study. Using the knowledge of general geology for a region and interviews with operators the fraction of wells requiring deepening was chosen. For this version of the model these values are fixed, but easily could be input as variables. Because these values are fixed, the only way to show the impact of improved near wellbore fracture detection, for instance, would be to reduce the base well cost or the dry hole or redrill fraction.

The third possible action to be taken when production is inadequate at the depth expected is to plug back and side track a new leg. The cost to side track was calculated for several different well situations and found to average 22% of the base well cost without trouble. The fraction of wells to be redrilled is a variable subject to risk. Best and worst case estimates for the redrill fraction are input. Improvements in exploration techniques, downhole logging, drilling technology and completion technology can be reflected by reducing the worst case value for the redrill fraction.

3.6.3.3 Cementing Problems

The cost of cementing problems was estimated similarly to the cost of lost circulation.

- 1) Make a table of cementing trouble severity.

This table is similar to the table of lost circulation severity described above. Five classifications of cementing difficulty were made ranging from a small amount of time and money to fix the problem to the most severe of five days and \$250,000.

- 2) Make a map of the cementing troubles.

Using the well casing program a map of the well showing number of incidents of cementing trouble of a chosen degree of severity was made. The time for fixing the problem was then multiplied by the daily rig expense and the cost to fix the problem added for each interval. The total for the well was then added up.

3.6.3.4 Other Problems

All other problems such as tools lost in the hole, drill pipe wear, deviation control problems and mud system difficulties

were lumped together. An overall estimate was made that these problems total 3% of the well cost.

3.7 POWER PLANT SELECTION AND DESIGN

The IM-GEO model uses a power plant costing approach developed by EG&G Idaho for a previous cost of power study. In order to determine if this approach matched current plant costs, costs for representative plants in each of the regions were examined. Where available actual plant costs were used. In other areas a set of inputs such as those used by the model were given to a power plant engineer and a first cut cost estimate was made of the cost of the plant.

3.7.1 Power Plant Exclusive of Brine Stabilization and Environmental Controls

The largest area of variability in the cost of the plant itself is the brine effectiveness. This is dependent on the fluid enthalpy for which little data is available. However, temperature relates in a relative way to fluid enthalpy and was therefore used as the input factor for plant fluid requirement. Plant fluid requirements then determine the size of the turbine and condenser and drive the cost.

Other variables such as the availability of cooling water, the ambient temperature and the degree of plant automation have less effect on the total cost of the plant than does the brine effectiveness. However, the choice of materials for the turbine and piping may have a large impact on cost and are strongly influenced by the fluid chemistry. For this version of the model fluid chemistry only affects the need for brine stabilization equipment and for environmental controls. Other areas affected by fluid chemistry were neglected for this phase.

For each region a binary technology power plant and a dual flash power plant were costed. The power plant efficiency is a variable and can be input to show the impact of power conversion technology. For binary plants the cost of the heat exchanger was included as a separate item to allow for ease in tying the fluid chemistry to the cost of the binary power plant.

3.7.2 Field Piping Cost

For this study the cost of the field piping system was estimated as a separate cost. To determine piping costs, the assumption was made that phase separation would occur at the plant and a single pipe would carry two phase fluid to the plant. In some cases wellhead separation may be feasible, but in most areas the need for water treatment and environmental controls precludes this option. The length of piping was then determined using an input well spacing which was again determined using actual data and expert opinion. A piping layout based on uniform branching pipes from a central plant with injectors on the outermost ring was used to calculate pipe length. The piping size was based on the flow rate fraction in each pipe section.

3.7.3 Brine Stabilization and Environmental Controls

A large cost area for any power plant using geothermal fluids is the need to contend with corrosive or scaling water. The cost of stabilizing brine and removing or neutralizing scale and corrosion problems was calculated as an add on cost based on the total dissolved solids content. A step function was used. If TDS was higher than 10,000 ppm then stabilization was needed and the cost added on. It was assumed that a flash crystalizer would be used and the cost calculated on that basis.

The cost of environmental controls is determined in general by the amount of H_2S in the noncondensable gases. This again was calculated as a cost add on using a Stretford type abatement system for the base cost. Clearly other types of environmental controls and costs may be necessary for different geothermal fluids. Future versions of the model could tie aspects of fluid chemistry into the cost of environmental controls.

3.8 ECONOMIC ANALYSIS

It would be unrealistic to pretend that inflation, taxes and the cost of money are not factors in the cost of geothermal power plants. However, it is always a problem what assumptions to make when including these factors in calculating the cost of geothermal power. Putting power on line takes time and that time costs money. A power generation method which can get power on line quickly has an advantage over one that is slow.

These factors are included in this study using input values shown in Appendix A, on page 1-14. They can be varied to reflect currently accepted ideas for future values.

4.0 HOW THE MODEL WORKS

This section presents a brief overview of how IM-GEO works. Details are presented in the appendixes.

4.1 Data Elements

The major data elements of IM-GEO are as follows.

A. Data Base of Site Characteristics

The data file "SITEDATO.DAT" contains data on physical and cost characteristics of about 35 aspects of eight U.S. liquid-dominated hydrothermal electric regions. About 20 of those characteristics are used in the computations.

About a dozen of those characteristics have "estimation errors" associated with them. Those characteristics can be used in the costing calculations as either a "Best Case" or "Worst Case" value.

B. Sensitivity Factors

These are entered by the user. They are inferred to be "achievements of R&D that alter technology performance or cost". Some of the sensitivity factors, "RISK factors" alter the current values of the "estimation errors" described immediately above. Others, "R&D Achievements", impact upon selected cost or performance terms in the costing code that are not covered by "RISK factors".

To avoid a possible confusion, you should note that "RISK factors" are just as much achievements of R&D as are "R&D Achievements" factors. The two names are used in IM-GEO to distinguish between two sets of R&D achievements that are calculated somewhat differently.

C. Parameters Embedded in Costing Code

Many technology performance and cost parameters and their values are embedded directly in the costing code. These cannot be changed without rewriting and compiling the code.

D. Financial Factors

Microeconomic factors that support translation of capital and O&M values to Mills/KWh are contained in the data file "BUSFNFACT.GEO".

4.2 General Flow of Computation

The general flow computation is shown in Figure 4-1.

There are four steps.

1. User edits/alters sensitivity factors.
2. Computations occur.
 - a. A first pass through the costing code estimates the "Best Case" cost of power.
 - b. The second pass estimates the "Worst Case" cost of power.
 - c. The difference between the two cases is assigned to "Financial Risk" sub-account.
3. User views one or more Reports available after computations are done. Both Multi-Region and Single-Region/Site reports are available.
4. User decides to print one or more Reports.

The "Base Case", which assumes R&D Achievements are zero, can be altered at any time to reflect accomplished improvements in the baseline technologies.

The control structure of IM-GEO, represented in Figure 4-2 ensures that every results screen or Report generated will reflect the effects of all sensitivity factors that are active at the time the report is generated.

The presentations available are described in detail in Appendix C.

FIGURE 4 - 1
OVERVIEW OF IM-GEO CALCULATIONS

Note (a):
Physical RISK factors are mostly related to uncertainties of reservoir characteristics.

Note (b):
Financial RISK is the difference in cost between two cost estimates for the project, one based on "Best Case" and the other based on "Worst Case" estimates of the site and technology physical or cost characteristics.

FIGURE 4 - 2
OVERVIEW OF CONTROL STRUCTURE OF IM-GEO

4.3 A Few General Matters

4.3.1 Power-On-Line (POL) Temporal Relationships

All costs are reflected to a POL date of January 1, 1986. Construction time is 3 years. Plant life is set at 30 years.

The duration of the identification stage (Account 2) is a calculated value, and depends on the Probability of Success of Identification; with a typical value of 6 to 7 years. The duration of the confirmation stage (Account 3) is set at 3 years.

The costs for Accounts 1 and 2 are estimated at early 1986 levels, and escalated to the POL date at a fixed Discount Rate. This accounts for the rate of return effects due to lags between expenditures in those phases and the POL date, but also results in a slight overestimation of their effects on the cost of power because all costs are estimated at 1986 levels.

The costs of the supplemental field equipment needed to deal with reservoir pressure and well flow rate declines appears in appropriate O&M accounts for Wells, Gathering equipment, etc.

4.3.2 WEIGHTS for Cost of Power Totals

Weights [I] "Regional Potential" and [L] "Program Relevance" both depend on the Site Data variable 1., "Energy in Region, MW*30Y". This variable has risk associated with it, whose impact is changeable at Screen [Y,E], line A. These weights, and the general weighted sums, are recalculated after the value of item [Y,E], line A is changed.

Weight [L], "Program Relevance" depends upon the Base Case cost of power as well as upon the "Energy in Region, MW*30Y". The dependence is as follows:

a) The weight is the product of the "Energy in Region" and a Utility function derived from the Region's Base Case cost of power.

b) The Utility function is:

1. If the cost of power is less than or equal to 80 Mills/KWh, then
 $U = (\text{Cost of Power})/80$. Thus, U would be 1.0 at 80 Mills/KWh, and 0.5 at 40 Mills/KWh.
2. If the cost of power is greater than 80 Mills/KWh, then
 $U = 80/(\text{Cost of Power})$. Thus, U would be 0.5 at 160 Mills/KWh, 0.25 at 160 Mills/KWh, etc.

This Utility function is intended to reflect the Program's interest in conducting R&D that will most benefit potential power plants that are at or near the competitive economic margin.

4.3.3 Non-Linearities in Results

R&D managers who use this model should note, above all, that the impacts of R&D achievements upon the cost of power are, in general, not linear.

In general, when two sets of R&D achievements are combined, the resulting impact on the cost of power will be less than the sum of the impacts of each set of achievements acting alone.

For example, consider these results from a single plant case, using an earlier version of IM-GEO.

Case	Sensitivity Factors		Saving in Cost of Power, Percent
	Cost per Well	Plant Efficiency	
1.	0.7	1.0	10.0
2.	1.0	1.2	8.5
3.	0.7	1.2	17.4

In this case, the combined savings are less than the sum of the "parts" because a more efficient plant requires fewer wells to serve it. Thus the savings due to well cost reduction are applied to fewer wells in Case 3 than in Case 1.

This is not a "problem" in a technical sense, although it can often seem like a problem in the "psychological" sense. It simply means the IMGEO costing codes take into account many of the major ways in which different physical factors and technology performance coefficients interact to result in a final cost of power from a specific project.

This effect does mean that the best representation of the impacts upon the cost of power expected to result from the efforts of the R&D Program as a whole should be entered by merging all anticipated R&D Achievements into a single set of Achievements, and then running the program. See the section on "Merging Multiple Sets of R&D Achievements".

It also means that the estimate of the final impact of any single achievement will be represented best against a "background" of the integrated set of achievements. This means, for example that the impact of the 30 % reduction in the cost of wells in the example above would be best represented by the value $17.4 - 8.5 = 8.9$ percent, rather than the 10 percent found by entering the well cost achievement alone. Thus, final claims regarding the overall impact of single R&D programs should be estimated by subtracting those achievements from the more global set of achievements of the R&D Program as a whole.

4.3.4 Merging Multiple Sets of R&D Achievements

When two or more independent sets of anticipated R&D Achievements are to be merged into a common set of R&D Program Achievements, then some of their anticipated R&D Achievements are likely to overlap, in terms of IM-GEO sensitivity factors. For example, both changes in well drilling procedure and in materials for casings could reduce the overall cost of the casing portion of the well costs.

Such overlaps must be resolved in reasonable ways by analysts who are familiar with the technology as a whole. Ideally that resolution should be done by the R&D Program managers. It is to be anticipated, however, that technical inputs and assessments from researchers or other analysts will be required to complete such a process.

If such a process is not done, then the R&D Program as a whole remains open to possible charges of "double counting" the impacts of selected achievements.

4.3.5 Error Messages

The IM-GEO code is protected from many but not all possible user errors in data inputs. Division by zero can be attempted under certain circumstances. For example if the user sets a power plant efficiency multiplier to 0, then a "Division by Zero" message will occur, and the program will terminate. Your work will be lost, and you'll have to start over.

5.0 EXAMPLES OF ANALYSES

In this section we present a few preliminary examples of how changes in sensitivity factors affect the cost of power results. The examples shown in this section are drawn from Version 2.08 of the model, and are not accurate for R&D impact analysis purposes.

The "R&D Achievements" were selected by an analyst with no deep understanding of the current Geothermal R&D program, and therefore should not be construed as reflecting anything real.

The cases and results summarized in the table below. The following pages present detailed inputs and outputs for each case.

Preliminary Results from Draft IM-GEO Code	
Not for Citation or Publication	
Aspect of R&D Program	Impact on Cost of Power, Percent
1. IMPROVEMENTS IN WELLS	- 7.1
2. IMPROVEMENTS IN DOWN HOLE PUMPS	- 1.5
3. IMPROVEMENTS IN RESERVOIR IDENTIFICATION/ ENGINEERING	- 20.2
4. IMPROVEMENTS IN POWER PLANTS	- 7.3
5. ABOVE FOUR ACHIEVEMENTS COMBINED	- 29.1
6. COMBINED ACHIEVEMENTS, AT LOWER LEVELS OF ACHIEVEMENT	- 17.0

5.1 IMPROVEMENTS IN WELLS

GEOHERMAL COST OF POWER ESTIMATE RUN: 02-24-1987 - 00:50:23
Multi-Region Weighted Averaged Data WEIGHTS = Regional Capacity

[From IMGEO Model] ACCOUNT	1986 TECHNOL. ***** % OF COST	***** NEW TECHNOLOGY SYSTEM *****		
		% OF 1986 TECHNOLOGY ELECT. COST	% COST CHANGE FROM 1986	% OF NEW TECH. TOTAL ELECT. COST
TOTAL :	100.0	92.9	- 7.1	100.0
RISK FRACTION :	27.3	25.2	- 7.8	27.1
1. Identify Reservoir	7.1	5.7	- 19.6	6.1
2. Confirm Reservoir	7.1	6.2	- 13.3	6.6
3. Wells	31.3	26.7	- 14.5	28.8
4. Downhole Pumps	3.5	3.5	- 0.0	3.7
5. Gathering Equip.	8.5	8.5	- 0.0	9.2
***** RESULTS NOT VALID FOR CITATION *****				
6. Power Plant	30.8	30.8	- 0.0	33.2
7. Heat Exchangers	5.4	5.4	- 0.0	5.8
8. Brine Stabilizing	1.4	1.4	- 0.0	1.6
9. Environmental	2.0	2.0	- 0.0	2.1
10. Insurance	2.9	2.7	- 6.7	2.9

IM-GEO: SENSITIVITY FACTORS IN EFFECT 02-24-1987 - 00:50:23

R&D Achvmt: TOTAL Cost, Avg. Well	[Nom.=1.0]: 0.90
R&D Achvmt: Well Prblms, Lost Circul	[Nom.=1.0]: 0.50
R&D Achvmt: Well Prblms, Cementing	[Nom.=1.0]: 0.40
R&D Achvmt: Well Prblms, Other	[Nom.=1.0]: 0.80

5.2 IMPROVEMENTS IN DOWN HOLE PUMPS

GEOHERMAL COST OF POWER ESTIMATE RUN: 02-24-1987 - 00:52:26
Multi-Region Weighted Averaged Data WEIGHTS = Regional Capacity

[From IMGEO Model] ACCOUNT	1986 TECHNOL. ***** % OF COST	***** NEW TECHNOLOGY SYSTEM *****		
		% OF 1986 TECHNOLOGY ELECT. COST	% COST CHANGE FROM 1986	% OF NEW TECH. TOTAL ELECT. COST
TOTAL :	100.0	98.5	- 1.5	100.0
RISK FRACTION :	27.3	26.9	- 1.6	27.3
1. Identify Reservoir	7.1	7.1	- 0.0	7.2
2. Confirm Reservoir	7.1	7.1	- 0.0	7.2
3. Wells	31.3	31.3	- 0.0	31.7
4. Downhole Pumps	3.5	2.0	- 41.5	2.1
5. Gathering Equip.	8.5	8.5	- 0.0	8.6
***** RESULTS NOT VALID FOR CITATION *****				
6. Power Plant	30.8	30.8	- 0.0	31.3
7. Heat Exchangers	5.4	5.4	- 0.0	5.5
8. Brine Stabilizing	1.4	1.4	- 0.0	1.5
9. Environmental	2.0	2.0	- 0.0	2.0
10. Insurance	2.9	2.9	- 0.3	2.9

IM-GEO: SENSITIVITY FACTORS IN EFFECT 02-24-1987 - 00:52:26

R&D Achvmt: Cap.Cost, Deep Well Pump [Nom.=1.0]: 0.80
R&D Achvmt: O&M Cost, Deep Well Pump [Nom.=1.0]: 0.50

5.3 IMPROVEMENTS IN RESERVOIR IDENTIFICATION/ ENGINEERING

GEOHERMAL COST OF POWER ESTIMATE RUN: 02-24-1987 - 01:10:58
Multi-Region Weighted Averaged Data WEIGHTS = Regional Capacity

[From IMGEO Model]		1986 TECHNOL. *****	***** NEW TECHNOLOGY SYSTEM *****		
ACCOUNT	% OF COST	% OF 1986 TECHNOLOGY ELECT. COST	% COST CHANGE FROM 1986	% OF NEW TECH. TOTAL ELECT. COST	
TOTAL :	100.0	79.8	- 20.2	100.0	
RISK FRACTION :	27.3	15.6	- 42.8	19.6	
1. Identify Reservoir	7.1	3.3	- 53.5	4.1	
2. Confirm Reservoir	7.1	7.1	- 0.0	8.9	
3. Wells	31.3	22.5	- 28.2	29.2	
4. Downhole Pumps	3.5	2.4	- 32.2	3.0	
5. Gathering Equip.	8.5	5.9	- 30.7	7.4	
***** RESULTS NOT VALID FOR CITATION *****					
6. Power Plant	30.8	28.0	- 9.0	35.1	
7. Heat Exchangers	5.4	4.9	- 10.1	6.1	
8. Brine Stabilizing	1.4	1.4	- 0.0	1.8	
9. Environmental	2.0	2.0	- 0.0	2.5	
10. Insurance	2.9	2.3	- 19.1	2.9	

IM-GEO: SENSITIVITY FACTORS IN EFFECT 02-24-1987 - 01:10:58

R&D Achvmt: Wildcat Success Ratio [Nom.=1.0]: 1.50
R&D Achvmt: Dry Holes / Producer [Nom.=1.0]: 0.60
R&D Achvmt: Flow Rate, Producer [Nom.=1.0]: 1.20

RISK: Wellhead Temperature, F [Nom.=1.0] : 0.60
RISK: Prod. Well Flow, Klb/hr [Nom.=1.0] : 0.60
RISK: Flow for Decline, Klb/hr [Nom.=1.0] : 0.60
RISK: Decline Coeff., 1/Years [Nom.=1.0] : 0.60

5.4 IMPROVEMENTS IN POWER PLANTS

GEOHERMAL COST OF POWER ESTIMATE RUN: 02-24-1987 - 01:13:16
Multi-Region Weighted Averaged Data WEIGHTS = Regional Capacity

[From IMGEO Model] ACCOUNT	1986 TECHNOL. ***** % OF COST	***** NEW TECHNOLOGY SYSTEM *****		
		% OF 1986 TECHNOLOGY ELECT. COST	% COST CHANGE FROM 1986	% OF NEW TECH. TOTAL ELECT. COST
TOTAL :	100.0	92.7	- 7.3	100.0
RISK FRACTION :	27.3	23.1	- 15.3	24.9
1. Identify Reservoir	7.1	6.9	- 6	7.5
2. Confirm Reservoir	7.1	7.1	- 0.0	7.7
3. Wells	31.3	26.6	- 15.1	28.6
4. Downhole Pumps	3.5	2.7	- 21.3	2.9
5. Gathering Equip.	8.5	6.6	- 22.0	7.2
***** RESULTS NOT VALID FOR CITATION *****				
6. Power Plant	30.8	30.6	- 0.6	33.0
7. Heat Exchangers	5.4	6.0	11.0	6.5
8. Brine Stabilizing	1.4	1.4	- 0.0	1.6
9. Environmental	2.0	2.0	- 0.0	2.1
10. Insurance	2.9	2.7	- 7.5	2.9

IM-GEO: SENSITIVITY FACTORS IN EFFECT 02-24-1987 - 01:13:16

R&D Achvmt: Efficiency, FLASH Plant [Nom.=1.0]: 1.05
R&D Achvmt: Efficiency, BINARY Plant [Nom.=1.0]: 1.20
R&D Achvmt: Cap. Cost, BINARY Plant [Nom.=1.0]: 1.05
R&D Achvmt: Cap. Cost, Heat Exchange [Nom.=1.0]: 1.30
R&D Achvmt: O&M Cost, Heat Exchange [Nom.=1.0]: 0.90

5.5 ABOVE FOUR ACHIEVEMENTS COMBINED

GEOHERMAL COST OF POWER ESTIMATE RUN: 02-24-1987 - 01:16:16
Multi-Region Weighted Averaged Data WEIGHTS = Regional Capacity

[From IMGEO Model]		1986 TECHNOL. ***** % OF COST	***** NEW TECHNOLOGY SYSTEM ***** % OF 1986 TECHNOLOGY ELECT. COST	% COST CHANGE FROM 1986	% OF NEW TECH. TOTAL ELECT. COST
ACCOUNT					
TOTAL :		100.0	70.9	- 29.1	100.0
RISK FRACTION :		27.3	13.1	- 52.0	18.5
1. Identify Reservoir		7.1	2.6	- 62.5	3.7
2. Confirm Reservoir		7.1	6.2	- 12.7	8.8
3. Wells		31.3	17.0	- 45.8	23.9
4. Downhole Pumps		3.5	1.1	- 67.9	1.6
5. Gathering Equip.		8.5	4.8	- 43.6	6.8
***** RESULTS NOT VALID FOR CITATION *****					
6. Power Plant		30.8	28.1	- 8.7	39.7
7. Heat Exchangers		5.4	5.5	- 1.2	7.8
8. Brine Stabilizing		1.4	1.4	- 0.0	2.0
9. Environmental		2.0	2.0	- 0.0	2.8
10. Insurance		2.9	2.1	- 26.8	3.0

IM-GEO: SENSITIVITY FACTORS IN EFFECT 02-24-1987 - 01:16:16

R&D Achvmt: Wildcat Success Ratio	[Nom.=1.0]:	1.50
R&D Achvmt: TOTAL Cost, Avg. Well	[Nom.=1.0]:	0.90
R&D Achvmt: Dry Holes / Producer	[Nom.=1.0]:	0.60
R&D Achvmt: Flow Rate, Producer	[Nom.=1.0]:	1.20
R&D Achvmt: Efficiency, FLASH Plant	[Nom.=1.0]:	1.05
R&D Achvmt: Efficiency, BINARY Plant	[Nom.=1.0]:	1.20
R&D Achvmt: Cap. Cost, BINARY Plant	[Nom.=1.0]:	1.05
R&D Achvmt: Cap.Cost, Deep Well Pump	[Nom.=1.0]:	0.80
R&D Achvmt: O&M Cost, Deep Well Pump	[Nom.=1.0]:	0.50
R&D Achvmt: Cap. Cost, Heat Exchange	[Nom.=1.0]:	1.30
R&D Achvmt: O&M Cost, Heat Exchange	[Nom.=1.0]:	0.90
R&D Achvmt: Well Prblms, Lost Circul	[Nom.=1.0]:	0.50
R&D Achvmt: Well Prblms, Cementing	[Nom.=1.0]:	0.50
R&D Achvmt: Well Prblms, Other	[Nom.=1.0]:	0.80
RISK: Wellhead Temperature, F	[Nom.=1.0]	: 0.60
RISK: Prod. Well Flow, Klb/hr	[Nom.=1.0]	: 0.60
RISK: Flow for Decline, Klb/hr	[Nom.=1.0]	: 0.60
RISK: Decline Coeff., 1/Years	[Nom.=1.0]	: 0.60

5.6 COMBINED ACHIEVEMENTS, AT LOWER LEVELS

The achievements used in section 5.5 were each reduced slightly, to show the impacts that might occur from an overall-lower set of achievements.

GEOHERMAL COST OF POWER ESTIMATE RUN: 02-24-1987 - 01:20:47
Multi-Region Weighted Averaged Data WEIGHTS = Regional Capacity

[From IMGEO Model]	1986	***** NEW TECHNOLOGY SYSTEM *****		
	TECHNOL. ***** % OF COST	% OF 1986 TECHNOLOGY ELECT. COST	% COST CHANGE FROM 1986	% OF NEW TECH. TOTAL ELECT. COST
TOTAL :	100.0	83.0	- 17.0	100.0
RISK FRACTION :	27.3	18.3	- 32.9	22.1
1. Identify Reservoir	7.1	4.5	- 36.6	5.4
2. Confirm Reservoir	7.1	6.7	- 5.9	8.1
3. Wells	31.3	22.6	- 27.9	27.2
4. Downhole Pumps	3.5	2.1	- 40.7	2.5
5. Gathering Equip.	8.5	6.1	- 28.1	7.4
***** RESULTS NOT VALID FOR CITATION *****				
6. Power Plant	30.8	29.6	- 3.9	35.7
7. Heat Exchangers	5.4	5.6	2.8	6.7
8. Brine Stabilizing	1.4	1.4	- 0.0	1.7
9. Environmental	2.0	2.0	- 0.0	2.4
10. Insurance	2.9	2.4	- 15.5	3.0

IM-GEO: SENSITIVITY FACTORS IN EFFECT 02-24-1987 - 01:20:47

R&D Achvmt: Wildcat Success Ratio	[Nom.=1.0]:	1.20
R&D Achvmt: TOTAL Cost, Avg. Well	[Nom.=1.0]:	0.95
R&D Achvmt: Dry Holes / Producer	[Nom.=1.0]:	0.80
R&D Achvmt: Flow Rate, Producer	[Nom.=1.0]:	1.10
R&D Achvmt: Efficiency, FLASH Plant	[Nom.=1.0]:	1.02
R&D Achvmt: Efficiency, BINARY Plant	[Nom.=1.0]:	1.10
R&D Achvmt: Cap. Cost, BINARY Plant	[Nom.=1.0]:	1.05
R&D Achvmt: Cap.Cost, Deep Well Pump	[Nom.=1.0]:	0.90
R&D Achvmt: O&M Cost, Deep Well Pump	[Nom.=1.0]:	0.80
R&D Achvmt: Cap. Cost, Heat Exchange	[Nom.=1.0]:	1.20
R&D Achvmt: O&M Cost, Heat Exchange	[Nom.=1.0]:	0.95
R&D Achvmt: Well Prblms, Lost Circul	[Nom.=1.0]:	0.80
R&D Achvmt: Well Prblms, Cementing	[Nom.=1.0]:	0.80
R&D Achvmt: Well Prblms, Other	[Nom.=1.0]:	0.90

RISK: Wellhead Temperature, F	[Nom.=1.0]	: 0.80
RISK: Prod. Well Flow, Klb/hr	[Nom.=1.0]	: 0.80
RISK: Flow for Decline, Klb/hr	[Nom.=1.0]	: 0.80
RISK: Decline Coeff., 1/Years	[Nom.=1.0]	: 0.80

6.0 RECOMMENDATIONS

These areas for continuation and improvement of this work remain: 1) extend this model to allow calculation of increase in resource availability due to technology improvement, 2) extend the level of detail of this model, and 3) produce similar models for hot dry rock, geopressured and magma energy systems.

6.1 Resource Availability

The present model shows the percentage reduction in cost of power due to technology achievements for 6 regions with the potential for near term geothermal power development. Using updated information from the USGS on resource size and temperature, the model could be programmed to also show how this cost reduction brings more resources into economic availability. This would largely involve careful input on resource size and characteristics and a cut off for an economic price of power, perhaps on a regional basis.

6.2 Extend Level of Detail

At several points in the discussion of the model statements are included which indicate where interactions between variables were neglected or fixed inputs were used where variables would be more appropriate. In any programming effort decisions are made about the level of detail to be included which are controlled by the availability of time and money. The more variables allowed as input the more complex the task of operating the model.

Future versions of the model could increase the complexity of the model and increase the number of interactions programmed into the code. The areas where this would be of most benefit include:

1. Extend power plant interactions between plant cost and fluid chemistry including total dissolved solids, non-condensable gases and perhaps specific dissolved chemical species.
2. Increase the detail in the code dealing with pumping power to include calculation of increased well productivity from increased set depth. This would involve programming in productivity curves for the representative wells for each region and would be fairly complex. However, the current version would require the user to calculate the increased well flow from increasing the pump set depth and input a new well flow.
3. The current model version does not consider reservoir heat depletion. This is a complex issue and would not be easy to program in accurately. A simplistic model of heat depletion using a decline curve approach could be used until the model could be combined with a reservoir model such as that developed by Paul Kruger of Stanford.
4. Linking the code with a reservoir model would allow for more accurate estimation of the effect of fluid depletion and pressure drawdown in the reservoir.

5. At present the model uses a simple algorithm to calculate testing costs for each well during each phase of development. It would be fairly easy to make some of the inputs to this testing algorithm input variables so that the effect of longer testing or more costly testing on the cost of power could be calculated. Since well testing is an area which is likely to reduce reservoir risk, this would make the model reflect cost increases associated with that risk reduction more easily. This is also true of the cost of well logging which is programmed in as a function dependent on depth and temperature. The only way to change the cost in the current version of the model is to change this function. This improvement would allow the calculation of the impact of specific technology improvements in the area of reservoir testing and instrumentation. Because we know the amount of measurement error resulting from use of inaccurate test procedures and instrumentation, it is easy to determine the risk reduction from improvements of this type.
6. The model does not account for long term changes in reservoir chemistry. This is a complex problem for which no simple solution seems adequate. However, recent work in this area has indicated that CO_2 in the reservoir may decrease with time. Wells in Hawaii have increased in salinity with continued production. Consideration of these results may lead to the possibility of modeling these effects.
7. Include the well costing algorithm as part of the model. This would allow calculation of changes in the well cost within the model and would enable the R & D manager to see the impact of very detailed technology improvements in the area of Hard Rock Penetration.

6.3 Extend Model to Include Non-Hydrothermal Resources

In order to extend this work to include these resources, substantial modification would need to be made to the code. Each of these energy sources uses some modification of a standard power conversion cycle to exploit the heat of a fluid. However, the well cost, exploration cost and reservoir management techniques would be very different. Each energy type would have to be considered separately using a systems analysis approach to determine the cost of development.

There have been efforts to model the cost of Hot Dry Rock geothermal energy. Certainly for the power conversion technology these will form a good basis. For other aspects of the Hot Dry Rock conversion process, such as well cost and reservoir management, new approaches to these sections would have to be made. Progress on the Hot Dry Rock Project indicates that the fractures produced at depth for heat exchange with the reservoir are different from those anticipated. New ideas for well completion strategies are being generated. A user selected multiple scenario approach to well construction might be useful.

Well cost and power generation from fluid heat for geopressured geothermal could probably be calculated using the existing code. However, other aspects of energy conversion, such as use of fluid mechanical energy and separation and sale of petroleum fluids would have to be added. Again a multiple scenario approach could be used here.

For magma energy extraction use of multiple scenarios for the well completion might be essential. Since a system analysis has been done at least in part by Sandia, this information could be incorporated into the model reducing the time and effort needed for coding. Exploration and reservoir confirmation strategies would need to be determined and new sections coded for the model.

The large potential of these three energy conversion technologies more than merits the effort that would be required to include them in the cost of power model so that the impact of R & D could be calculated.

6.4 Case Studies

Two case studies would make the use of this model clearer to the R&D managers for whom it is intended. The first would show the impact of using currently available technology in all areas of geothermal development that presently do not take advantage of these technologies. The second would show the maximum possible improvement in technology and reduction in risk.

This version of the model has been benchmarked using costs determined from standard industry practice. Some technology improvements are not taken advantage of by industry for many reasons. As an example of how the model can be used and to show the benefit of technology transfer, a case study of the cost improvement possible by using currently available technologies could be done.

Because this model does not have all the possible interactions between reservoir factors and their associated costs directly programmed into the code, a case study showing the maximum reasonable improvement in technology and its associated risk reduction would prevent unreasonable expectations for cost drilling, exploration, power conversion technology and other aspects of geothermal development could be consulted to provide input for this case study. A cost reduction for best possible achievable research goals would also show up any difficulties in the model and point out areas of improvement.

APPENDIX A
TECHNOLOGY BASELINES

TECHNOLOGY BASELINES

A.1 General Note on Technical Factors

This appendix is a guide to many of the major technical and costing relationships that are built into the computer code of this model. We intend these comments to be instructive rather than definitive.

The definitive description of any and all of these factors is the listing of the IM-GEO code. The code includes lengthy documentation to ensure that interested technical reviewers will have little difficulty in determining what was done where.

The project team had to make many decisions about which factors were most important for depicting current practice in U.S. geothermal development projects. These decisions are not sacred. We hope that as review occurs a body of suggestions and contributions will allow for further improvement of the model. As guidelines for these suggestions two comments follow:

- * The baseline technologies represented should reflect U.S. industry practice as of January, 1986.
- * The anticipated improvements in technology should represent those that seem achievable by modest investments in R & D (shared by D.O.E. and industry) within the next 5 to 10 years.

A.2 Costing Basis

All cost estimates reflect our best understandings of industry practices and costs as of January 1, 1986. All elementary costs are loaded with relevant supervisory and overhead costs.

A.3 Power Plant and Field Design

This is the critical relationship in every design for a geothermal power development project. The brine flow requirement of the plant, divided by the anticipated flow from the average production well, determines how many wells are required at plant start up.

Ideally, the plant brine flow requirement should be a continuous function of the brine flow required by the plant, sensitive to the work available from the brine (at estimated temperature, pressure, dissolved solids, and non-condensable gases), and the average flow per production well. We have not achieved much clarity here and there is room for improvement.

The data available to us within the schedule and budget for the project allowed us to get up the following relationships:

Flash Plants:

- 1) The flow into and from the plant is taken from point estimates in the site data base. These flows are

subject to some small adjustments in the code.

- 2) The power plant cost is a simple function of the temperature of the brine at the wellhead.

Binary Plants:

- 1) Flow requirements are estimated from a simple model of the net brine effectiveness at the wellhead temperature. The plant flow requirements in the site data base are not used.
- 2) The power plant cost is modeled as related most directly to the rate of brine flow through the plant. Brine temperature has a modest effect on this cost relationship.

A.4 Brine stabilization

The need for brine stabilization equipment depends on the total dissolved solids contained in the fluid. This is programmed into the code as a step function. Fluids with greater than 10,000 ppm are assumed to require stabilization while those with less do not. The cost assumed is that of a flash crystalizer system.

A.5 Environmental Control

The only environmental control programmed into this version of the model is H₂S abatement. The cost of a Stretford type abatement is added to the base plant cost when the H₂S content of the fluid is above 50 ppm for flash type plants. For binary plants the H₂S level is not considered. In addition to adding to the plant capital cost, high H₂S also adds to the O & M cost. Both cost additions are scaled to the amount of H₂S in the fluid as a multiplier of the plant capital cost for the base O & M cost.

A.6 Well Costs

Well costs are calculated early in the model because wells are an essential part of Identification, Confirmation, and Reservoir Management operations. Well costs are divided into base costs and add-on costs as described in section 3.7.

The actual cost of the wells is calculated using a series of tables and maps discussed in section 3.7. This is done externally to the model. Thus impacts of technology on the cost of the well are shown by the cost multiplier. This multiplier affects the entire well cost including add-ons.

A.7 Extension, Redrill, and Dry Hole Relationships

The relationships among these cost add-ons to the base well cost are roughly as follows:

A, B, D, and E are entered or coded values. C is calculated.

A = 0.25 X Dry Hole Fraction

B = 0.20, fixed value

C = 1 - A - B - D

D = Redrill Fraction

E = 0.75 X Dry Hole Fraction

A.8 Well Flow Testing Costs

Testing Costs are estimated based on 3-day, 10-day or 21-day flow tests. Testing costs are then added to well costs to form a final cost for each of four categories of wells:

- Wildcat Wells
- Wells drilled during the reservoir confirmation phase
- Production wells drilled during field development phase
- Injection and Dry Holes

The cost of logging is included here and is calculated from an equation using depth and temperature as variables.

A.9 Identification Operations

Geological, geophysical and geochemical aspects of exploration are calculated for the region as a whole. The cost of exploration is dependent on the anticipated depth of the

resource. A premium cost is added for wells deeper than 3000 feet. This could include the cost of geophysical exploration such as seismology or a cored small diameter test hole. It was found from the cost estimates that the cost of whatever was done to explore for deeper resources was about \$100,000.

The cost of gradient wells was emphasized by several developers as one of the most important cost aspects of exploration. This cost was apportioned for every wildcat well drilled and is therefore affected by the sensitivity parameter "Wildcat Success Ratio" since this will increase or decrease the number of wildcat wells drilled.

Wildcat wells are assumed to cost the same as any other production well. Successful wells are included in the pool of available producers.

The amount of developable electrical power in each region is an input variable and can be found in the table of input data. Each region is divided into areas of a size which can be affected by an input variable. These areas are further divided into 50 MW units.

The sensitivity parameter "Probability of Success of Confirmation" affects the costs accumulated here in the following manner" A fraction of the reservoirs that appear to be "identified" will fail to support power production after a "confirmation" attempt has ensued. Therefore, the "Identification" cost for each reservoir that successfully supports power production is calculated to include additional identification costs in proportion to the probability of failure of the unit "Confirmation" effort.

A.10 Confirmation Operations

Confirmation activity is assumed to take three years to drill and test six wells. Of these it is assumed that four will be good producers, 1.5 will make good injectors and .5 will be dry holes not useful for anything. At conclusion of the confirmation phase the developer is assumed ready to seek project financing. For a field developer who anticipates someone else, perhaps a utility, will build the power plant, he is ready to seek the builder of the plant.

It is assumed that the developer has a .95 certainty of achieving 30 years of power production if the full cost of developing the site is available. The additional .05 of uncertainty is covered by the cost of reservoir insurance. The risk of failure does not change from one site to another, only the cost of the development. Thus a site with a very high risk at the end of drilling and testing six wells will cost a great deal, perhaps a prohibitively large amount. This should be remembered when risk reduction factors are chosen.

Testing cost for wells drilled during confirmation and identification phases are more expensive than those for infill drilling.

The probability of success of confirmation affects costs that show up in both the confirmation and identification phases. The reason is that any failed confirmation effort implies that some amount of exploration had been incurred to achieve a "go" status on the attempt to confirm. Both of these efforts move into the "sunk cost" column when the confirmation effort fails, yet are reflected in the relevant accounts for the cost of power at a successful project. In IM-GEO the "identification" costs occasioned by the confirmation failure are added to the Identification account, while the direct costs of the failed confirmation effort are added into the Confirmation account.

A.11 Field Decline Factors

The effect of pressure decline in the reservoir is modeled explicitly to find the number and temporal pattern of supplemental production wells needed. Annual payments to cover the capital and O & M costs of the supplemental wells and their piping are added to the Well and Gathering O & M accounts.

The estimated decline coefficient for each site includes provision for the drawdown effects of production from multiple plants on each reservoir. However, it should be remembered that the decline coefficients are estimated using the most elementary of methods and may not apply to any actual reservoir. An exponential decline is used although other equations might model an individual reservoir better.

Because of the curve fitting technique used to estimate the decline coefficient and define the exponential curve, there are two initial flow rates used as input data. One is the average initial flow rate per well used for purposes of estimating the number of wells in the field. The other is the initial flow for the purpose of the decline curve. If the risk for one of these values adjusted to show a technology improvement than the other must be adjusted by an equal percentage.

A.12 Well Life Due to Plugging or Corrosion

Many geothermal R & D impact models have set a single value for the life of a production well that incorporated both drawdown and other well loss effects. The current model breaks these two effects apart. The drawdown effect is modeled explicitly by the decline curve, while the other problems which limit well life are handled by estimating the time between mechanical workovers on the well and the average amount of a typical workover. These factors are both influenced by the fluid chemistry so that changes in the risk values for fluid chemistry factors should effect the well life and cost of workovers. These interactions are not programmed into the model.

There is no simple well life parameter in this program. The need for added wells as the pressure in the field decreases and the need for replacing wells due to mechanical failure is handled separately.

A.13 Field Piping

The gathering system for producer wells is modeled as a diamond-shaped rectilinear array with the plant in the center. There is a full run of pipe from each production well to the plant. The pattern is as follows, with the number, [n], in each square showing the number of "separation" units between the well and the plant:

This pattern is a reasonable compromise between the case where the field is narrower in one dimension than the other, and a case where pads and multiwell manifolds are used to reduce certain drilling and piping costs.

This pattern moreover has the quite useful computational property of requiring a total pipe length that scales in a fractal manner with the total number of producer wells required. The fractal dimension is roughly 1.5. This is especially useful in computing the additional pipe required for supplemental production wells.

Injection piping costs assume that injection wells are located outside of the production field, at 6 separation units from the plant. The piping costs assume that groups of 4 injection wells are fed from the same pipe. Thus injection wells are modeled as lying to one or two sides of the field, rather than being arrayed in a circular radial pattern.

A.14 Supplemental Production Wells

The requirement for supplemental production wells is driven entirely by the estimate of the pressure decline in the reservoir. This is modeled explicitly as an exponential flow-rate decline coefficient applied to the initial production wells and any required supplemental wells.

There is no provision (in Version 3.00 and earlier) for temperature decline in the reservoir during the reservoir life. Thus, the model is similar to a tea kettle whose bottom is kept at a constant temperature and to which no fluid is added as the initial fluid convects out of the spout.

There is no provision for supplemental injection wells.

The costs for drilling and O&M of supplemental production wells are added to the O&M accounts for production and injection wells. Costs associated with

the gathering pipes for supplemental production wells are added to the O&M accounts for the gathering system. These accumulation are per previous practice in similar models. (Future modellers take note: It would be more illuminating if such costs were shown in a separate account.)

A.15 Down Hole Pumps

Down hole pumps are assumed only for binary power plants. The primary objective is to prevent flashing in the wellbore. A secondary objective is to increase the flowrate from low-temperature wells. Neither of these requirements/relationships is modeled explicitly.

The power required per pump varies with the well depth (setting depth). The model could be enhanced if the relationship between pumping power and resource temperature shown in Figure 8.18 of the "Sourcebook" were updated and incorporated into the code.

The costs for pumps are for contemporary line shaft pumps. Comparable costs for electric downhole pumps, should these ensue from R&D, can be entered quite directly. However, advantages that might accrue from electric downhole pumps with respect to being able to set those deeper than line shaft pumps (currently limited to about 1000 feet) would have to be analyzed quite carefully for relevant sensitivity entry points into IMGEO, especially with respect to average flow per production well, and the relationship between reservoir and well head fluid enthalpy.

A.16 Flash Plant Flow and Costs

Flash plant brine flow requirement rates vary greatly with the saturation conditions ("steam quality") of the well head brine. The quality factor for each site is implicit in the Site data base, by comparison of factors "Required Flow into Plant" and "Flow from Plant". Flow rates for flash plants are based explicitly on those values in the Site data base.

Future versions of this model would benefit greatly if this relationship were linked more explicitly to measurable characteristics of the reservoir.

The capital cost of flash plants is estimated from two linear equations that break at 390 degrees F. The equations were derived from a review of previous studies and the costs provided by S. Unitt in December 1986. The results of the equations are quite consistent across the following studies, when stated costs were escalated to January 1986 using the GNP Implicit Price Deflator: The GELCOM model from the MITRE Corp, 1976; The BPA Pacific Northwest Geothermal Study, 1984; and S. Unitt's costs, 1986. Flash plant cost values from the INEL/Technecon studies, estimated in 1979 - 1980 were significantly higher than those aforementioned. The overall pattern suggests that flash plant costs have not changed much in a decade.

A.17 Binary Plant Flow and Costs

The estimated brine flow requirement for binary plants was found to vary considerably across the small number of studies available. The problem

appears to arise from the very active R&D into the properties of working fluids during the last decade, with relatively few studies offering explicitly detailed assumptions. The problem is compounded in that some studies report net or gross brine effectiveness values that only sometimes include explicit provision for powering deep well pumps that feed the plant.

Sundry data points from the BPA Pacific Northwest Geothermal Study, S. Unitt's data, the INEL / Technicon studies, and the EPRI well-head generator studies (1984-86) were compare graphically. Crude functions for net and gross brine effectiveness across a wide temperature range were apparent, and adopted. Various adjustments, as documented in the code, to account for the net power requirement in the field for down hole pumps.

Binary power plant cost-estimate data were even more sparse than those for flow requirements. This problem is exacerbated in the current study because two of the sites use relatively cool brines, especially in the "risky" conditions. It was noted that available costs tend to scale fairly well with the brine flow requirement, provided that a minor secondary adjustment is made for temperature beyond that implicit in the flow requirement dependence on temperature.

Thus users of this model are cautioned that flow rates may be off as much as +/- 30 percent, especially at the lower temperatures. Additional uncertainty prevails with respect to plant cost estimates. The sponsors of this study have been notified orally of this state of uncertainty.

A.18 Microeconomics and Financial Assumptions

Busbar costs are calculated on a revenue requirements basis, following the recommendations of the EPRI Technical Assessment Guides of 1978 (algorithms) and 1982 (certain costing factors). Tax requirements reflect the Federal Tax act of 1986 provisions for geothermal energy projects, with a 10 percent special investment tax credit assumed; these assumptions should be adequate for plants that go on line in late 1987 through 1989.

Field and plant cost of capital (required rates of return) are assumed to be the same, to keep matters relatively simple.

The final results are expressed as levelized in January 1986 constant dollars, with values given as mills per kilowatt hour. That value is close to the first year cost at that date, and should be multiplied by the effect of general inflation (assumed to be 4 percent per year) to find the cost value in following years.

Various factors from the EPRI-TAG methodology for busbar costing are embodied in the the file BUSFNCT.GEO, used by IM-GEO. The assumptions behind those factors are as follows:

SOURCE: MERIDIAN Corporation, Fairfax, VA
VERSION: BUSIMGEO.BAS Program
RUN DATE: 03-12-1987 11:20 a.m.
CASE: SET IM-GEO FACTORS, AS-BUILT, NO AFDC
POL DATE: 1986 All Values in Current Dollars: 1986

ASSUMPTIONS:

AFDC: Not included in capital cost estimates.

Capital and O&M Cost Basis Year: 1986.0

Years to Construct: 3

General Inflation Rate: 0.04 Fuel Inflation Rate: 0.04

Book Life: 30 Tax Life: 5

Debt Fraction: 0.50 Debt Rate: 0.11

Common Fraction: 0.50 Common Rate: 0.15

Derived Discount Rate: 0.13

Income Tax (0.34 + 0.02): 0.36

Investment Tax Credit: 0.10 'Geothermal Property

Property Tax & Insurance: 0.02

Accounting Method: Flow Through

Accelerated Depreciation: Double Declining Balance

Capacity, Net MWe: 50

Average Capacity Factor: .85

Average Annual Energy, kWh: 372,300,000.

(Report is continued on the next page.)

----- LEVELIZED ANNUAL FIXED CHARGE RATES, Percent -----

• Weighted Cost of Capital	13.00
* Sinking Fund Depreciation	0.34
* Retirement Dispersion Allowance	0.56
* Income Tax (Federal and State)	3.43
* Accelerated Depreciation	-3.40
* Investment Tax Credit	-1.84
* Property Tax and Insurance	2.00

Total 14.09

----- LEVELIZED BUSBAR COSTS -----

Charge and Units	Value	Levelizing Factor	BUSBAR COST mills/kWh
Capital Cost, \$1000s	106150.8	0.14087	40.2
Fixed O&M, \$/kW per year	10	1.413805	1.9
Variable O&M, mills/kWh	10	1.413805	14.1
Fuel, mills/kWh	10	1.413805	14.1
Total:			70.3

At certain places in the costing code the term "unacost" occurs. This is a technical term to describe an annual payment required to amortize a lump sum present value over N years, where N is usually (but not always) the book life of the power plant. This term is used in code lines where unusual streams of payments, e.g. for supplemental production wells, need to be converted to an equivalent level O&M charge during each year of the plant life.

APPENDIX B

MODEL GENERAL OPTIONS AND MENUS

MODEL GENERAL OPTIONS AND MENUS

This section describes the major messages and menus that you will see on the screen. Reports (results of calculations), which also appear on the screen, are described elsewhere.

1.0 Start Up Messages

IM-GEO loads some data files and calculates the Base Case results for the eight regions when it begins operation. Messages about the progress of those operations appears on the screen:

```
WELCOME TO IM-GEO.          ( Setting up Base Case )

WAIT:  LOADING PHYSICAL DATA FOR REGIONS
WAIT:  ADJUSTING WORST CASE DATA
WAIT:  LOADING BASE CASE VALUES
WAIT:  CALCULATING 8 REGIONS:
      (A count message appears as Region is calculated.)
WAIT:  FILLING BASE CASE VALUES
```

Once the Base Case is initialized, the IM-GEO identification screen appears, showing the source, Version number, and date of the program:

```
                IM-GEO

VERSION 3.00      [IMGE0300]      16 Mar. 1987

IMPACTS OF R&D ON COST OF GEOTHERMAL POWER

      Prepared By Meridian Corporation
      Falls Church, Virginia

      Under Contract to Sandia Corporation
      Albuquerque, New Mexico
      Contract No. 02-1947

      Project Team:

      Dan Entingh,  Bill Livesay,  Susan Petty,
      Richard Traeger,  Stanley Unitt

PRESS ANY KEY TO START OPERATION ----->
```

A beep sounds after this display appears on the screen. Press any key, and you will see the "Start-Up and Quit" Menu.

2.0 Menu [Z], "START-UP and QUIT"

IM-GEO-[Z]	START-UP and QUIT MENU
A. HELP:	What You Can / Should Do Here
F. SET:	BASE CASE to Current Data
G. RESET:	BASE CASE to Original Defaults
R. CHANGE:	Where REPORTS are sent: NOW = PRINTER
Y. GO TO:	OPERATIONS Menu
Q. QUIT to DOS	

ENTER SELECTION =====>

At all menus that look like this, boxed with an ENTER SELECTION ==> prompt, just press the letter you want, and the indicated action will occur. You can use either upper or lower case entries.

If you get your working parameters all fouled up, come back to this menu and press [G]. That will set everything back to the original startup values.

Option [F] here lets you set up an alternative Base Case. To do that, you would edit R&D Achievements from Menu [Y] to establish different geothermal technology parameters than those in the Default Base Case. Then come back to this menu and select [F]. That will establish the costs of power resulting from your technology selections as the Base Case for all further reports, until you select [Z,G] here.

Option [R] lets you divert "printed" Reports to a disk file. You can integrate results in that file into publishable reports. When the file output channel is active, the menu section looks like this:

R. CHANGE: Where REPORTS are sent: NOW = File: IMGEOU.TXT
--

The contents of the file IMGEOU.TXT are emptied each time the program is restarted or if Option [G] is selected.

You can exit IM-GEO only from option [Q] at this menu.

Pressing [Y] at the [Z] menu sends you to the OPERATIONS Menu. It is from the OPERATIONS menu that you will do almost all of your work with IMGEO.

3.0 Menu [Y], OPERATIONS

This is the master menu.

IM-GEO-[Y] OPERATIONS MENU	
A. HELP: Editing Options	K. HELP: Report Options
B. EDIT: R&D Achvmnts, RESERVOIR	L. SHOW: R&D Achievements
C. EDIT: R&D Achvmnts, WELLS	M. SHOW: 1-Site Current Costs
D. EDIT: R&D Achvmnts, PLANTS	N. SHOW: 1-Site Base Case Costs
E. EDIT: RISKS, RESERVOIR	O. PRINT 1-Site Technical Details
F. EDIT: RISKS, WELLS & FLOW	P. ****
G. EDIT: RISKS, UNIT COSTS	Q. SHOW: Multi-Reg., Costs X Region
H. EDIT: Regional WEIGHTS	R. PRINT Multi-Reg., FINE GRAIN Rpt
I. ****	S. ****
J. EDIT: Financial Factors	T. EJECT Page (After <Prt.Scr>)

U. SELECT: Single Analysis Site, NOW = 1	
V. RUN: Single-Site Cost of Power Analysis	

W. RUN: Multi-Region Analysis, (ACCOUNTS X PERCENT Report)	

Z. GO TO: START-UP / QUIT MENU	

ENTER SELECTION ----->

This is the menu where you will spend most of your time. It allows you to:

- 0 Edit Sensitivity Data, via Options [B] through [J].
- 0 View and print a list of all of those factors whose current value differs from 1.0, via Option [L].
- 0 Alter the weights that each Region carries in the Multi-Region result weighted-average totals; Option [H]. Option [H] contains an option to print the resulting weights.
- 0 View (SHOW to console screen) and print reports from the various calculations; [M] - [R]
- 0 Eject page from printer [T]. This is for when you may have performed a DOS <Shift-Prt Scr> to print the console results. For example, you might want to do that when one or more of the editing screens [B] through [G], or [I] is active.
- 0 Perform multi-site or single site calculations; [U] - [W].

The most important thing for you to note here is that the results that IM-GEO shows to screen or paper always reflect accurately the current

settings of the Base Case cost of power, the R&D Achievements, Risk Impacts, and Regional Weights. The computer program contains logical interlocks which ensure that no results are presented to you until the appropriate recalculations, based on the current settings of R&D achievements, occur.

In general, each request for a calculation or a report will be followed by the presentation of those results on the screen. At that point, you are usually given an option [P] to send the results to your printer.

Details of R&D Achievement Editing Options are given in section 3.6.

Details of the Regional Weight Option are described in section 3.5.

Details of the Reports are described in Appendix C.

4.0 [Y,U], Select Site for Single-Site Reports

Option [U] at the Y-OPERATIONS menu lets you change the "Single Site" for which calculations are made in Single-Site modes:

SELECT SINGLE SITE FROM ONE OF THE FOLLOWING:

1. Imperial Valley - Flash
2. Imperial Valley - Binary
3. Basin & Range - Flash
4. Basin & Range - Binary
5. Cascades - Flash
6. Cascades - Binary
7. Young Volcanics - Flash 1
8. Young Volcanics - Flash 2

CURRENT SITE # IS: 1

SELECT SITE NUMBER [1 - 8], <Enter> : 1

Here you will have to press the <Enter> key after you type the number of the site you wish to have active as the "Single Site".

5.0 [Y,H], EDIT Regional Weights

All Multi-Region cost of power estimates are based on weighted averages of costs estimated for eight (8) separate regions. Four different weighting methods have been programmed.

The Weights in force are selected from the following menu, which appears if you press [H] at Menu [Y]:

IM-GEO-[Y,H] Select Regional Weights for Totals	
Re-weighted results appear quickly, since individual regional power costs do not have to be recomputed.	
A. HELP: What You Can / Should Do Here	
CURRENT SELECTION: Regional Capacity	
I. Weight = Regional Capacity [= DEFAULT]	
J. Weight = Equal for all Regions	
K. Weight = User's Numerical Values	
L. Weight = Relevance to R&D Program	
S. SHOW/PRINT Value of Current Weights	
Z. CONTINUE	

ENTER SELECTION =====>

[K] brings up a screen that helps you enter any weights you wish.

See the technical discussion sections of this manual for explanations of the meanings of options [I] and [L] here.

6.0 [Y,B-J], Edit R&D Achievements and Risks

Options [B] - [G] and [I] - [J] of the [Y]-OPERATIONS Menu let you enter the anticipated Achievements of the Research and Development Program. Here we describe the actions of the following subset of the OPERATIONS menu:

IM-GEO-[Y]		OPERATIONS MENU	
A.		K.	
B. EDIT: R&D Achvmnts, RESERVOIR		L.	
C. EDIT: R&D Achvmnts, WELLS		M.	
D. EDIT: R&D Achvmnts, PLANTS		N.	
E. EDIT: RISKS, RESERVOIR		O.	
F. EDIT: RISKS, WELLS & FLOW		P.	
G. EDIT: RISKS, UNIT COSTS		Q.	
H.		R.	
I.		S.	
J. EDIT: Financial Factors		T.	

Some R&D Achievements are in the form of improvements in equipment cost or efficiency, [B], [C], [D].

Other R&D Achievements are in the form of reduction of reservoir and drilling uncertainties, [E], [F], [G].

[J] allows access to a few minor financial factors.

Each of these options brings up an "Editing Screen". The specific screens are shown below.

Each editing screen presents a list of factors, each keyed to a letter. You are prompted to press the letter for the factor you want to edit. Then you are further prompted to enter the new value for the factor.

You can continue to select and change factors in this manner, until you press [Z]. Pressing [Z] returns you to Menu [Y].

The following subsections present the editing screens, current as of IMGEO Version 2.08 of 20 February 1987. These screens may be somewhat different in later versions.

6.1 [Y,B], Edit R&D Achievements for RESERVOIR

EDITING: R&D Achievements for RESEVOIR:

A. R&D Achvmt: Wildcat Success Ratio	[Nom.=1.0] / NOW = 1
B. R&D Achvmt: Testing Costs, Identify	[Nom.=1.0] / NOW = 1
C. R&D Achvmt: Confirm. Success Ratio	[Nom.=1.0] / NOW = 1
D. R&D Achvmt: Testing Costs, Confirm	[Nom.=1.0] / NOW = 1
E. R&D Achvmt: Dry Holes / Producer	[Nom.=1.0] / NOW = 1
F. R&D Achvmt: Flow Rate, Producer	[Nom.=1.0] / NOW = 1
G. R&D Achvmt: Flow Rate, Injector	[Nom.=1.0] / NOW = 1
H. R&D Achvmt: Testing Costs, Producer	[Nom.=1.0] / NOW = 1
I. R&D Achvmt: Test Costs, Inj. or Dry	[Nom.=1.0] / NOW = 1

ENTER x of Data Item to Change, or Z to CONTINUE:

Simply press the "x" letter of the factor you wish to change. You will then be prompted to enter a new value, and then press <Enter>. When you have changed all of the factors you wish, press [Z] to return to Menu [Y].

Consult pages F-1 and F-36 for details on how these factors and those from the next two screens are connected into the geothermal power plant costing routines.

6.2 [Y,C], Edit R&D Achievements for WELLS

EDITING: R&D Achievements for WELLS:

A. R&D Achvmt: Producer Redrill Fract.	[Nom.=1.0] / NOW = 1
B. R&D Achvmt: Well Prblms, Lost Circul	[Nom.=1.0] / NOW = 1
C. R&D Achvmt: Well Prblms, Cementing	[Nom.=1.0] / NOW = 1
D. R&D Achvmt: Well Prblms, Other	[Nom.=1.0] / NOW = 1
E. R&D Achvmt: TOTAL Cost, Avg. Well	[Nom.=1.0] / NOW = 1
F. R&D Achvmt: Cap.Cost, Deep Well Pump	[Nom.=1.0] / NOW = 1
G. R&D Achvmt: O&M Cost, Deep Well Pump	[Nom.=1.0] / NOW = 1
H. R&D Achvmt: Cap.Cost, Gathering Sys.	[Nom.=1.0] / NOW = 1
I. R&D Achvmt: O&M Cost, Gathering Sys.	[Nom.=1.0] / NOW = 1
J. R&D Achvmt: Workover Interval, Prod.	[Nom.=1.0] / NOW = 1
K. R&D Achvmt: Cost per Workover, Prod.	[Nom.=1.0] / NOW = 1
L. R&D Achvmt: Workover Interval, Injc.	[Nom.=1.0] / NOW = 1
M. R&D Achvmt: Cost per Workover, Injc.	[Nom.=1.0] / NOW = 1

ENTER x of Data Item to Change, or Z to CONTINUE:

6.3 [Y,D], Edit R&D Achievements for PLANTS

EDITING: R&D Achievements for PLANTS:

A. R&D Achvmt: Years Between Plants [Nom.=1.0] / NOW = 1
B. R&D Achvmt: Efficiency, FLASH Plant [Nom.=1.0] / NOW = 1
C. R&D Achvmt: Cap. Cost, FLASH Plant [Nom.=1.0] / NOW = 1
D. R&D Achvmt: O&M Cost, FLASH Plant [Nom.=1.0] / NOW = 1
E. R&D Achvmt: Efficiency, BINARY Plant [Nom.=1.0] / NOW = 1
F. R&D Achvmt: Cap. Cost, BINARY Plant [Nom.=1.0] / NOW = 1
G. R&D Achvmt: O&M Cost, BINARY Plant [Nom.=1.0] / NOW = 1
H. R&D Achvmt: Cap. Cost, Heat Exchange [Nom.=1.0] / NOW = 1
I. R&D Achvmt: O&M Cost, Heat Exchange [Nom.=1.0] / NOW = 1
J. R&D Achvmt: Cap. Cost, Brine Stabil. [Nom.=1.0] / NOW = 1
K. R&D Achvmt: O&M Cost, Brine Stabil. [Nom.=1.0] / NOW = 1
L. R&D Achvmt: Cap. Cost, H2S Treatment [Nom.=1.0] / NOW = 1
M. R&D Achvmt: O&M Cost, H2S Treatment [Nom.=1.0] / NOW = 1

ENTER x of Data Item to Change, or Z to CONTINUE:

Note, for editing screen "[Y,D], Edit R&D Achievements for PLANTS", that the Binary Plant factors [E] and [F]:

F. R&D Achvmt: Cap. Cost, BINARY Plant
G. R&D Achvmt: O&M Cost, BINARY Plant.

operate completely independently of factors:

H. R&D Achvmt: Cap. Cost, Heat Exchange
I. R&D Achvmt: O&M Cost, Heat Exchange

This independence was set into IMGEO so that effects expected from radically different heat exchanger concepts could be entered fairly explicitly.

If you want to alter Binary plant costs in simple ways, you should enter the same Capital cost Achievement level for factors [F] and [H]. Similarly, if you change the Binary O&M cost factors, enter the same cost Achievement level for factors [G] and [I].

The case for Flash plants is similar. For simple changes, enter the same achievement levels for each factor in the following triplets:

C. R&D Achvmt: Cap. Cost, FLASH Plant
J. R&D Achvmt: Cap. Cost, Brine Stabil.
L. R&D Achvmt: Cap. Cost, H2S Treatment

D. R&D Achvmt: O&M Cost, FLASH Plant
K. R&D Achvmt: O&M Cost, Brine Stabil.
M. R&D Achvmt: O&M Cost, H2S Treatment

6.4 [Y,E], Edit RISK Factors for RESERVOIR

EDITING: Estimation Errors for RESERVOIR:

A. RISK: Energy in Region, MW*30Y [Nom.=1.0] / NOW = 1
B. 0
C. 0
D. 0
E. RISK: Reservior Satur. Temp, F [Nom.=1.0] / NOW = 1
F. 0
G. RISK: Wellhead Temperature, F [Nom.=1.0] / NOW = 1
H. 0
I. 0
J. 0
K. RISK: H2S, PPM [Nom.=1.0] / NOW = 1
L. RISK: Tot. Dis. Solids, PPK [Nom.=1.0] / NOW = 1

ENTER x of Data Item to Change, or Z to CONTINUE:

Editing "RISks": The comments here apply to this editing screen as well as to those for "[Y,F], Edit RISK Factors for WELLS & FLOW", and "[Y,G], Edit RISK Factors for UNIT COSTS".

Some of the Site Data factors have "Bad Case" offset values associated with them. For example, a Well Head Temperature of 450 degrees F., might have an offset of -30 degrees F. The 450 degree value is the estimate of the most likely well head temperature for the modeled prospect in the Region. The value $450 - 30 = 420$ degrees F. represents a typical worst case value for the temperature. That is, the reservoir engineer has said, "I think it will be 450 degrees, but I don't want to promise you that it will really be any better than 420 degrees."

With factor [G]. "RISK: Wellhead Temperature, F" set equal to the default value of 1.0, the "RISKY" cost of the current plant will be costed assuming a well-head temperature of $450 - (1.0 \times 30) = 420$ F. If factor [G] is set to 0.4, then the "RISKY" cost will assume a temperature of $450 - (0.4 \times 30) = 438$ F.

The RISK values in the "Site Data" data-base thus are generally to be viewed as errors of estimation that reservoir analysts typically make in 1986. The RISK factors that you establish here are interpreted as accomplishments of R&D that will help reservoir analysts reduce the magnitude of errors of estimation.

These menus have a "spotty" look because not all of the Site Data factors have risk values set against them. The presentation selected here is intended to help you cross-correlate these three screens to the information in the Site Data file.

The values of the offsets are Region-specific.

6.5 [Y,F], Edit RISK Factors for WELLS & FLOW

EDITING: Estimation Errors for WELLS & FLOW:

- A. 0
- B. 0
- C. RISK: Producer Redrill Fraction [Nom.=1.0] / NOW = 1
- D. RISK: Dry Holes per Producer [Nom.=1.0] / NOW = 1
- E. RISK: Yrs Btwn. Workover, PRODU [Nom.=1.0] / NOW = 1
- F. RISK: Yrs Btwn. Workover, INJCT [Nom.=1.0] / NOW = 1
- G. 0
- H. 0
- I. RISK: Prod. Well Flow, Klb/hr [Nom.=1.0] / NOW = 1
- J. RISK: Inject. Well Flow Klb/hr [Nom.=1.0] / NOW = 1
- K. RISK: Flow for Decline, Klb/hr [Nom.=1.0] / NOW = 1
- L. RISK: Decline Coeff., 1/Years [Nom.=1.0] / NOW = 1
- M. 0
- N. 0

ENTER x of Data Item to Change, or Z to CONTINUE:

See the note in section 3.6.4 for the description of the meaning of these factors.

6.6 [Y,G], Edit RISK Factors for UNIT COSTS

EDITING: Estimation Errors for UNIT COSTS:

- A. 0
- B. 0
- C. RISK: Well Cost, Extension, \$M [Nom.=1.0] / NOW = 1
- D. 0
- E. 0
- F. 0
- G. 0
- H. 0

ENTER x of Data Item to Change, or Z to CONTINUE:

Here RISK Factor [C] represents the an estimate of the average non-optimized cost risk associated with drilling and completing an "incident-free" well.

See the technical discussion sections for the detailed explanation.

6.7 [Y,J], Edit Financial Factors

EDITING: Financial Factor Data Values :

A. Royalty Rate	Default: .10	/ CURRENT Value = .1
B. Severance Tax	Default: .04	/ CURRENT Value = .04
C. Percent Depletion Allowance	Default: .15	/ CURRENT Value = .15
D. Intangible Fract. of Well Cost	Default: .75	/ CURRENT Value = .75

ENTER x of Data Item to Change, or Z to CONTINUE:

This screen lets you edit a few geothermal-specific financial factors. They are included only because they were available as local values in the older model from which IMGEO was developed.

These factors are described in discussions of "Financial Factors" in the more technical sections of this report.

APPENDIX C

DETAILS OF MODEL REPORTING OPTIONS

DETAILS OF MODEL REPORTING OPTIONS

This section provides examples of the major reports that issue from IM-GEO's calculations and presentations. They are presented here without comment on the reasonability of the R&D Achievements used to produce the reports, or the possible implications of the example results.

You might note that the reports indicate which method of weighted averaging is in effect, for those reports which include weighted averages.

1.0 Sensitivity Factors in Effect for These Example Reports

The report immediately below results from Option [Y,L], "Show R&D Achievements". The factors shown there were in effect when producing the example calculations and Reports shown in this section.

IM-GEO: SENSITIVITY FACTORS IN EFFECT 03-16-1987 - 15:14:04

R&D Achvmt: Well Prblms, Lost Circul	[Nom.=1.0]:	0.70
R&D Achvmt: TOTAL Cost, Avg. Well	[Nom.=1.0]:	0.85
R&D Achvmt: Efficiency, FLASH Plant	[Nom.=1.0]:	1.05
R&D Achvmt: Efficiency, BINARY Plant	[Nom.=1.0]:	1.20
R&D Achvmt: Cap. Cost, Heat Exchange	[Nom.=1.0]:	1.30
R&D Achvmt: O&M Cost, Heat Exchange	[Nom.=1.0]:	1.20

RISK: Wellhead Temperature, F	[Nom.=1.0]	:	0.70
RISK: Prod. Well Flow, Klb/hr	[Nom.=1.0]	:	0.50
RISK: Inject. Well Flow, Klb/hr	[Nom.=1.0]	:	0.50
RISK: Decline Coeff., 1/Years	[Nom.=1.0]	:	0.70

Regional Weights = Regional Capacity

2.0 Multi-Site Results Reports

Each of these reports is either printable after it appears on the screen, or is printed directly without being shown on the screen.

2.1 The Main Multi-Site Results Report, ACCOUNTS X PERCENT

The report from [Y,W]: "RUN: Multi-Region Analysis (ACCOUNTS X PERCENT) Report", is the main report of IM-GEO. Example:

GEOHERMAL COST OF POWER ESTIMATE		RUN: 03-16-1987 - 15:14:04		
Multi-Region Weighted Averaged Data		WEIGHTS = Regional Capacity		
[From IMGEO Model]		1986	***** NEW TECHNOLOGY SYSTEM *****	
		TECHNOL.	% OF 1986	% COST
		*****	TECHNOLOGY	CHANGE
ACCOUNT	% OF COST	ELECT. COST	FROM 1986	% OF NEW
				TECH. TOTAL
				ELECT. COST
TOTAL :	100.0	76.8	- 23.2	100.0
RISK FRACTION :	32.2	18.0	- 44.1	23.5
1. Identify Reservoir	5.6	4.7	- 16.6	6.1
2. Confirm Reservoir	6.4	5.4	- 14.7	7.1
3. Wells	33.5	21.1	- 37.2	27.4
4. Downhole Pumps	1.4	0.9	- 32.2	1.2
5. Gathering Equip.	5.7	3.8	- 33.1	4.9
6. Power Plant	33.7	28.2	- 16.1	36.8
7. Heat Exchangers	4.1	3.8	- 7.7	5.0
8. Brine Stabilizing	2.0	2.0	- 0.0	2.6
9. Environmental	4.4	4.4	- 0.0	5.7
10. Insurance	3.2	2.4	- 25.2	3.1

The sensitivity factors in effect are printed at the bottom.

This report reflects three aspects of the cost impacts of R&D changes:

1. Column 2, "% OF 1986 TECHNOLOGY ELECT. COST", shows that the weighted average cost of the New Technology system is 76.8 percent of the 1986 cost. It also shows New Technology subsystem costs expressed as fractions of the 1986 total cost. This gives a clear indication of those subsystems in which the greatest dollar cost changes have occurred.
2. Column 3, "% COST CHANGE FROM 1986", shows percentage changes in costs. High percentage changes could be especially relevant for the Identify Reservoir and Confirm Reservoir subsystems (project phases). These might reduce the overall risk to the private sector with regard to identification and confirmation activities, even if other aspects of the cost of power do not change much.
3. Column 4, "% OF NEW TECH. TOTAL ELECT. COST", shows the percentage distribution of total costs across the elements of the New Technology

system. Under this particular set of R&D Achievements, the power plant accounts (6, 7, 8, and 9) would make up a substantially greater percentage of the total system cost than they did with 1986 technology.

You should note that "RISK Fraction" here and in all other IMGEO reports is an independently estimated fraction of the Cost of Power, and is not a specific account that is summed to get the Total Cost. The Total Cost is explicitly the sum of Accounts 1 through 10.

Also note the time stamp on this report and others. The time shown there is the time at which any of the R&D Achievement or Regional Weighting factors was edited. That time is then "stamped" on any report you generate, until you edit the factors again. This time stamp will help you identify which printed reports are tied to a specific set of R&D Achievements, especially when you are running many analyses on the same day.

Although it is not shown here, this report (and a few others) will always have the values of the currently active R&D Achievements printed out beneath it. That ensures that a given set of R&D Achievements and their impacts on the cost of power are always kept together.

If the results from the main Multi-Region Report look like those immediately below, then you are seeing the report for the Base Case. That is, all R&D Achievements were set = 1.0 before the Multi-Region calculation was run. Notice that all of the "Percent Cost Change from 1986" values are zero.

GEOHERMAL COST OF POWER ESTIMATE RUN: 03-16-1987 - 14:58:18
Multi-Region Weighted Averaged Data WEIGHTS = Regional Capacity

[From IMGEO Model] ACCOUNT	1986 TECHNOL. ***** % OF COST	***** NEW TECHNOLOGY SYSTEM *****		
		% OF 1986 TECHNOLOGY ELECT. COST	% COST CHANGE FROM 1986	% OF NEW TECH. TOTAL ELECT. COST
TOTAL :	100.0	100.0	- 0.0	100.0
RISK FRACTION :	32.2	32.2	- 0.0	32.2
1. Identify Reservoir	5.6	5.6	- 0.0	5.6
2. Confirm Reservoir	6.4	6.4	- 0.0	6.4
3. Wells	33.5	33.5	- 0.0	33.5
4. Downhole Pumps	1.4	1.4	- 0.0	1.4
5. Gathering Equip.	5.7	5.7	- 0.0	5.7
6. Power Plant	33.7	33.7	- 0.0	33.7
7. Heat Exchangers	4.1	4.1	- 0.0	4.1
8. Brine Stabilizing	2.0	2.0	- 0.0	2.0
9. Environmental	4.4	4.4	- 0.0	4.4
10. Insurance	3.2	3.2	- 0.0	3.2

IM-GEO: SENSITIVITY FACTORS IN EFFECT 03-16-1987 - 14:58:18
All Sensitivity Factors = 1.0
Regional Weights = Regional Capacity

2.2 Multi-Site Report, Costs X Region

The report from [Y,Q]: "SHOW: Multi-Reg., Costs X Region" is shown here. This lets you set the major cost estimates and cost of power (mills/KWh) estimates for each of the eight Regions. Example:

GEOHERMAL COST OF POWER ESTIMATE 03-16-1987 - 15:14:04
WEIGHTS = Regional Capacity

REGION	CAP. COST, \$M	O&M COST, \$M/Y	CAP., MILLS /KWH	O&M, MILLS /KWH	TOTAL, MILLS /KWH	TOTAL, % CHANGE FROM BASE
1. IV-FL	153.3	7.0	39.0	19.5	58.5	-12.1
2. IV-BI	168.7	3.2	43.6	8.9	52.5	-26.5
3. BR-FL	123.5	2.5	30.0	7.0	37.0	-14.6
4. BR-BI	267.7	3.8	64.5	10.7	75.2	-22.7
5. CS-FL	267.7	3.8	64.5	10.7	75.2	-22.7
6. CS-BI	312.5	6.3	83.4	17.2	100.6	-29.0
7. YV-F1	223.3	12.3	53.6	34.9	88.5	-29.9
8. YV-F2	123.5	4.8	31.3	13.2	44.5	-10.3
WEIGHTED:	204.4	6.3	51.7	17.5	69.2	-23.2

The sensitivity factors in effect are printed at the bottom.

As you might expect, the same set of R&D Achievements has different effects on different regions. Usually, but not always, the sites with relatively high Base Case cost of power will show the highest absolute and percentage changes in the New Technology cost of power.

For general interest, the Base Case version of this report is shown below. If you see that all the "Percent Changes" here are zero, then you are looking at a "Base Case" Report.

GEOHERMAL COST OF POWER ESTIMATE 03-16-1987 - 14:58:18
WEIGHTS = Regional Capacity

REGION	CAP. COST, \$M	O&M COST, \$M/Y	CAP., MILLS /KWH	O&M, MILLS /KWH	TOTAL, MILLS /KWH	TOTAL, % CHANGE FROM BASE
1. IV-FL	179.8	7.7	45.2	21.4	66.5	0.0
2. IV-BI	234.9	4.0	60.3	11.0	71.3	0.0
3. BR-FL	148.9	2.5	36.3	7.0	43.3	0.0
4. BR-BI	398.5	10.7	104.4	30.0	134.4	0.0
5. CS-FL	355.8	4.4	85.0	12.2	97.3	0.0
6. CS-BI	448.3	8.4	118.6	23.0	141.6	0.0
7. YV-F1	271.0	21.6	64.4	61.8	126.3	0.0
8. YV-F2	144.8	4.9	36.3	13.3	49.6	0.0
WEIGHTED:	266.7	8.2	67.0	23.1	90.1	0.0

2.3 Multi-Site Report, Costs X Regions X Accounts

The [Y,R] "FINE GRAIN" report shows the Mills/KWh totals for the Accounts for each Region. Base Case results are at the top, and current case (New Technology) costs are at the bottom.

This is the most useful report for making quick comparisons of impacts on R&D at the different modelled regions.

GEOHERMAL COST OF POWER 03-16-1987 - 15:14:04
IM-GEO: ACCOUNTS-BY-SITE COST DATA

BASE CASE VALUES, MILLS/KWH

	IV-FL	IV-BI	BR-FL	BR-BI	CS-FL	CS-BI	YV-F1	YV-F2
EXPLR	4.2	4.2	4.8	3.1	7.3	3.7	8.2	3.9
CNFRM	5.4	4.4	5.4	3.0	8.7	3.3	8.9	4.4
WELLS	19.3	15.2	11.2	38.1	47.5	26.8	71.1	9.2
PUMPS	0.0	2.0	0.0	5.8	0.0	5.6	0.0	0.0
GATHR	3.6	5.4	2.5	8.3	6.0	7.2	6.9	2.8
PLANT	19.8	30.1	18.0	57.4	23.9	72.1	18.0	18.0
HTXCH	0.0	7.2	0.0	13.7	0.0	17.3	0.0	0.0
STABL	4.8	0.0	0.0	0.0	0.0	0.0	2.3	2.3
ENVIR	7.6	0.0	0.0	0.0	0.0	0.0	8.3	7.6
INSUR	1.8	2.6	1.4	5.0	3.8	5.6	2.6	1.4
TOTAL	66.5	71.3	43.3	134.4	97.3	141.6	126.3	49.6
RISK	20.9	18.7	8.7	42.2	33.2	36.0	57.0	15.7

CURRENT CASE VALUES, MILLS/KWH

	IV-FL	IV-BI	BR-FL	BR-BI	CS-FL	CS-BI	YV-F1	YV-F2
EXPLR	3.5	3.6	4.1	2.5	6.2	2.9	6.9	3.3
CNFRM	4.7	3.8	4.7	2.6	7.3	2.8	7.6	3.8
WELLS	14.3	8.6	7.9	19.5	32.1	15.2	40.2	6.8
PUMPS	0.0	1.4	0.0	3.9	0.0	3.8	0.0	0.0
GATHR	2.8	3.3	2.0	4.6	4.7	4.3	3.5	2.3
PLANT	19.3	22.9	17.3	41.8	22.2	51.9	17.7	17.2
HTXCH	0.0	7.0	0.0	12.7	0.0	15.8	0.0	0.0
STABL	4.8	0.0	0.0	0.0	0.0	0.0	2.3	2.3
ENVIR	7.6	0.0	0.0	0.0	0.0	0.0	8.3	7.6
INSUR	1.5	1.8	1.1	3.3	2.8	3.9	2.1	1.2
TOTAL	58.5	52.5	37.0	90.9	75.2	100.6	88.5	44.5
RISK	16.0	8.7	4.5	16.7	20.2	15.6	26.3	13.0

3.0 Results from Single-Site Analyses

The single site analyzed for these reports is that selected at Option [Y,U]. When you select that option, you are shown a list of the sites, and asked for your selection.

3.1 Report from "RUN: Single-Site Cost of Power Analysis"

The report from [Y,V], "RUN: Single-Site Cost of Power Analysis" is shown below. You should note that the format here is the same as the Main Multi-Site (ACCOUNTS X PERCENT) Report. But the results are for the current single site.

GEOHERMAL COST OF POWER ESTIMATE RUN: 03-16-1987 - 15:14:04
Region : 2 Imperial Valley - Binary

[From IMGEO Model] ACCOUNT	1986 TECHNOL. ***** % OF COST	***** NEW TECHNOLOGY SYSTEM *****		
		% OF 1986 TECHNOLOGY ELECT. COST	% COST CHANGE FROM 1986	% OF NEW TECH. TOTAL ELECT. COST
TOTAL :	100.0	73.5	- 26.5	100.0
RISK FRACTION :	26.2	12.2	- 53.5	16.6
1. Identify Reservoir	5.9	5.0	- 16.0	6.8
2. Confirm Reservoir	6.2	5.4	- 13.2	7.3
3. Wells	21.4	12.1	- 43.5	16.4
4. Downhole Pumps	2.9	2.0	- 31.1	2.7
5. Gathering Equip.	7.6	4.7	- 38.5	6.4
6. Power Plant	42.3	32.2	- 23.9	43.7
7. Heat Exchangers	10.1	9.8	- 3.2	13.3
8. Brine Stabilizing	0.0	0.0	- 0.0	0.0
9. Environmental	0.0	0.0	- 0.0	0.0
10. Insurance	3.7	2.5	- 31.1	3.4

The sensitivity factors in effect are printed at the bottom.

You get to this report by using Option [Y,V], "RUN: Single-Site Cost of Power Analysis".

If the third column, "% COST CHANGE FROM 1986", is all zeros, you would be looking at the Base Case version of this report.

3.2 Single-Site Current Costs Report

The report from [Y,M], "SHOW: One-Site Current Costs" is shown below. This format is different from any of the Multi-Site reports. Here you can see, for each of the major accounts, Capital Cost, O&M Cost/Year, and Mills/KWh values for the capital components and Total.

GEOHERMAL COST OF POWER ESTIMATE RUN: 03-16-1987 - 15:14:04
Current Case Costs: Imperial Valley - Binary

[From IMGEO Model]	----- Million \$ -----		----- Mills/KWhour -----	
	Capital Cost, \$	O&M Cost, \$/Yr	Capital Part of System	Total Busbar Cost
ACCOUNT				
TOTAL :	168.7	3.2	43.6	52.5
RISK FRACTION :	28.6	0.5	7.3	8.7
1. Identify Reservoir	17.9	0.0	3.6	3.6
2. Confirm Reservoir	17.3	0.0	3.8	3.8
3. Wells	29.5	0.7	6.7	8.6
4. Downhole Pumps	1.7	0.3	0.5	1.4
5. Gathering Equip.	9.5	0.2	2.7	3.3
6. Power Plant	68.2	1.3	19.4	22.9
7. Heat Exchangers	18.2	0.7	5.2	7.0
8. Brine Stabilizing	0.0	0.0	0.0	0.0
9. Environmental	0.0	0.0	0.0	0.0
10. Insurance	6.4	0.0	1.8	1.8

The sensitivity factors in effect are printed at the bottom.

3.3 Single-Site Base Case Costs Report

The report from [Y,N], "SHOW: One-Site Base Case Costs" is shown here. The format is the same as that of the One-Site Current Costs report.

GEOTHERMAL COST OF POWER ESTIMATE RUN: 03-16-1987 - 15:14:04
Base Case Costs: Imperial Valley - Binary

[From IMGEO Model] ACCOUNT	----- Million \$ -----		----- Mills/KWhour -----	
	Capital Cost, \$	O&M Cost, \$/Yr	Capital Part of System	Total Busbar Cost
TOTAL :	234.9	4.0	60.3	71.3
RISK FRACTION :	64.2	0.9	16.2	18.7
1. Identify Reservoir	21.3	0.0	4.2	4.2
2. Confirm Reservoir	19.9	0.0	4.4	4.4
3. Wells	58.2	0.7	13.2	15.2
4. Downhole Pumps	2.5	0.5	0.7	2.0
5. Gathering Equip.	15.8	0.4	4.5	5.4
6. Power Plant	89.7	1.7	25.5	30.1
7. Heat Exchangers	18.4	0.7	5.2	7.2
8. Brine Stabilizing	0.0	0.0	0.0	0.0
9. Environmental	0.0	0.0	0.0	0.0
10. Insurance	9.2	0.0	2.6	2.6

An indication is shown that all sensitivity factors in effect are nominal.

3.4 Single-Site Technical Factors Report

This report shows intermediate calculation values. Its purpose is solely for checking on the reasonableness of certain intermediate results.

Results from this report should not be cited as "performance values" or "cost estimates" for any particular site or region.

Some of the values shown here do not appear when Binary Plants or Deep Well pumps are not used for the specific region.

***** SITE DETAILS ----- Page 1

03-16-1987 - 15:14:04

Region analyzed: 2 Imperial Valley - Binary

***** PROJECT MAJOR PARAMETERS *****

[S27] Plant Type 1=BIN 2=FLA 3=STEAM	1
Plant net size, MWE	50
Plant Final GROSS Power estimate, MW	74.17367
[S7] Well-Head Temperature, Deg-F	336
[S12] Brine Contam. Index = BCI	0
Flow Into Plant required, 10 ⁶ lb/hr	7.320121
Flow From Plant, to Injectors, 10 ⁶ lb/hr	7.320121
[S28] Down Hole Pumps 1 = YES	1

***** WELL PARAMETERS AND COSTS *****

[S13] Well Depth, K-Feet = DEEP	9
[S21] Producer Well Flow, 10 ⁶ lb/Hour	.515
Injectors / producer	.6
Spare wells/ producer	.1
[S15]*[R6] Prod. redrill fract. add-on cost	.15
Dry Holes / Active Producer	.2
No. of Producer Wells (at plant start)	15
Producers plus spares	17
Injectors required	9
Total Number of Initial Wells	30
Base cost (no risk) of bare well	.8126
Fraction of wells to be extended	.75
Fraction to be redrilled	.15
Cost to Extend bare well	5.259376E-02
Cost to Redrill bare well	2.011185E-02
Adjust: Per Well Cost Multiplier	.85
Well cost, w/incidents, no tests	.9423407
Cost of 3-Day Well Test	.04
Cost of 10-Day Well Test	.061
Cost of 21-Day Well Test	.1375
Test Cost for Wildcat, Inj., Dry	.182033
Test Cost for Confirmation Producers	.319533
Test Cost for Phase 3 Producers	.203033
Total Cost per Wildcat Well	1.124374
Total Cost per Confirmation Well	1.261874
Total Cost per Producer Well in Phase 3	1.145374
Total Cost per Injector or Dry Well	1.124374
Capcost of all initial wells (in Phase 3)	29.49145

***** SITE DETAILS ----- Page 2

03-16-1987 - 15:14:04

Region analyzed: 2 Imperial Valley - Binary

***** IDENTIFY, CONFIRM RESERVOIR *****

[S3]*[R1] P(success). Identification	.2
No. of Ident. units	5
Cost, Geol. and Geophysics, Regional	.05
Cost, Therm. Grad. Holes/ Wildcat,	.005
# 50 MWe Power Plants/Area (per GROSS MWe)	3.370468
UNIT Identific. Cost, not P.V.'d	5.696868
Years between plants, 4 = nominal	4
Duration of Identific. period, years	6.7
Total Regional Production Life, Yrs.	43.48187
Cap recov fact. for I.D. over plants	.1609883
TOTAL Identific. Cost, V'd, Per Plant	4.546623
[S4]*R3], Prob. of Conf/Unit	.6
No. of Confirm. Units	.6666666
[R4] Unit Cost, Confirmation	7.571242
Duration of confirmation, years.	3
Total confirm \$, P.V., All alloc'd to 1 plant	17.31182
OK Producers after CONFIRM	4
OK Injectors after CONFIRM	1.5

***** SUPPLEMENTAL WELLS *****

[S24] Flow Rate Decline Coefficient.	.0282
Per [S19] Adjusted Decline Coefficient.	.0282
[S23] ' Initial flow rate, for Decline Calcs	.798
[S21] ' Minimum flow per initial well	.515
No. of suppl. prod.s added over LIFE years	8.00001
Discounted No. of supplemental wells.	.633004
Sum of Disc'd O&M Units for suppl. wells.	1.636164
Cap. Cost Part of Supplm., Final Unacost	.1223586
O&M Part of Supplm., INCOMPLETE CALC. *****	.2182817

***** DEEP WELL PUMPS *****

Deep Pumps, No. to purchase at start	17
No. of Pumps on line (active) at start	15
Per pump horsepower (1000s)	.6
FINAL, Net to D.W. PUMPS, MW	6.7113
Deep Pumps, Cap. Cost & Installation, \$M	.1
Deep Pumps, Total capital cost, \$M	1.7
O&M per active pump per year.	.02
Deep Pumps, Total O&M, \$M/yr	.3128105

***** SITE DETAILS ----- Page 3

03-16-1987 - 15:14:04

Region analyzed: 2 Imperial Valley - Binary

***** GATHERING SYSTEM DETAILS *****

[S14] Sep. betw'n producer wells, Ft.	2600
Length of prod. pipe, rectang. field, Ft	87890.09
Production gath. cost cap. total, M\$	4.734505
Cost of pipe for four average injectors, M\$	2.057781
Capcost of injector gathering, \$M	4.810008
Field Surface Equipment, Total Cap., \$M	9.544512
TOTAL Field, Cap, \$M (Includes Phase 3 Wells)	45.28259
Length of pipe for supplm. gathering, feet	155534.6
Gathering for supplm. producers, \$M,	.2802799
Gath for supplm. prod, as \$M/yr	3.739232E-02
F1: Field staff annual cost, \$M/yr	.456
F2: Initial PROD and INJ wells annual cost	.075
F3: Gathering Pipes and valves annual cost	.1908902
F5: Supplm. wells, Capital portion, unacost	.1223586
F6: Supplm. wells, O&M portion, unacost	6.821303E-04
F7: Supplm. wells Gath. capital, unacost	3.739232E-02
F8: Supplm. Wells Gath. O&M, unacost	5.605598E-03

***** POWER PLANT FACTORS *****

----- BINARY SIZING DETAILS -----

Binary net brine effectiveness 'Wh/LB, NET	6.035786
Added Gross to Make 1 More MWe net out.	.2380316
FITTED, Net to D.W. PUMPS, MW	3.299534
ADJUSTED GROSS Brine Effectiveness	8.444039
Aux Power, W/O D.W. Pumps (Prim. loop & cool)	15.86487

----- END, BINARY SIZING DETAILS -----

Power Plant Capital cost, \$M	82.20496
Plant O&M, \$M/Year, w/o Proper. Tax & Insur.	1.890714
Brine Stabil., Cap. \$M	.00001
Brine Stabil., O&M, \$M/yr	.00001
[S11] H2S, ppm	50
H2S Equip, \$M	.00001
H2S O&M, \$M/yr	.00001

***** FINANCIAL FACTORS *****

Power plant book life, Years	30
Capital Recovery factor	.1334106
Discount Rate, Plant and General	.13
ECON: (Field VLAFCR)/(Plant VLAFCR)	1
ECON: (Field DISC)/(Plant DISC)	1
Discount Rate for Field Equipment	.13
Income tax rate (Federal + State)	.36
Adj. all costs for ROYR, SEVR, (INTXR)*DEPL	.914

***** FINAL COST FACTORS *****

Field Total cap, Reduced re tax credits	21.52876
Capital cost to be insured, \$M	127.1334

APPENDIX D

IM-GEO DATA FILES

IM-GEO SITE DATA FILE

The following pages depict the contents of the file "SITEDAT0.DAT", the main file of site characteristics.

Not all of the data lines (numbered) are used in the IMGEO code. This file was compiled during a group effort to develop the model, with the understanding that some factors would be more important than others.

The explanation of the major lines is as follows, using variable 1 as an example:

```
1., "YES", "YES", "Energy in Region, MW*30Y "  
5750, 1041, 3060, 1751, 4559, 51490., 3250, 3250, 4000  
-750, -41, -1500, -751, -1559, -48490., -750, -750, -1500
```

The first line of numbers represents the "Best Case" value for each Region. The second line of numbers represents the amount by which the "Best Case" value is amended to find the "Worst Case" value. Note that the sign of the second line is always in the direction of making the project less less efficient or more expensive.

The first "YES" means that the variable is used somewhere in the costing code. The second "YES" means that the variable has "risk" associated with it. IM-GEO senses these logical flags to determine if this variable can be edited by one of the three "risk" editing screens. Both flags must be "YES" if editing is to be allowed by the user.

"Imperial Valley - Flash ", "Imperial Valley - Binary "
 "Basin & Range - Flash ", "Basin & Range - Binary "
 "Cascades - Flash ", "Cascades - Binary "
 "Young Volcanics - Flash 1", "Young Volcanics - Flash 2"
 "Dry Steam"
 "IV-FL", "IV-BI", "BR-FL", "BR-BI"
 "CS-FL", "CS-BI", "YV-F1", "YV-F2", "GY-DS"
 1., "YES", "YES", "Energy in Region, MW*30Y "
 5750, 1041, 3060, 1751, 4559, 51490., 3250, 3250, 4000
 -750, -41, -1500, -751, -1559, -48490., -750, -750, -1500
 2., "YES", "NO", "Energy in SubArea, MW*30Y"
 500, 250, 250, 250, 500, 250, 250, 250, 500
 0, 0, 0, 0, 0, 0, 0, 0, 0
 3., "YES", "NO", "Wildcat Success Rate "
 .20, .20, .20, .20, .20, .20, .20, .20, .20
 0, 0, 0, 0, 0, 0, 0, 0, 0
 4., "YES", "NO", "Confirmation Success Rate"
 .60, .60, .60, .60, .60, .60, .60, .60, .60
 0, 0, 0, 0, 0, 0, 0, 0, 0
 5., "YES", "YES", "Reservoir Satur. Temp, F "
 525, 360, 450, 300, 425, 280, 600, 550, 375
 -25, -20, -50, -20, -50, -10, -25, -75, -3
 6., "NO", "NO", "Resv. Temp at 10 Years, F"
 548, 358, 448, 298, 423, 278, 590, 520, 370
 -10, -10, -10, -10, -10, -10, -10, -10, -10
 7., "YES", "YES", "Wellhead Temperature, F "
 375, 350, 400, 288, 375, 270, 385, 406, 347
 -20, -20, -25, -10, -65, -10, -10, -31, -2
 8., "NO", "NO", "Wellhead Pressure., PSIA "
 380, 500, 225, 500, 225, 500, 166, 235, 100
 -38, -50, -23, -50, -23, -50, -17, -24, -10
 9., "NO", "NO", "Wellhead Enthalpy, BTU/lb"
 419, 340, 375, 280, 366, 260, 900, 370, 1100
 -42, -34, -38, -28, -37, -26, -90, -37, -110
 10., "NO", "NO", "Non-Cond. Gases, PPM "
 5000, 1000, 1000, 2000, 1000, 1000, 2000, 1000, 10000
 15000, 5000, 5000, 8000, 1000, 1000, 700, 200, 10000
 11., "YES", "YES", "H2S, PPM "
 50, 0, 10, 0, 0, 0, 1500, 50, 2000
 50, 50, 50, 200, 25, 25, 500, 75, 2500
 12., "YES", "YES", "Tot. Dis. Solids, PPK "
 250, 5, 1.5, 1.2, 1.0, 0.5, 15, 10, 0
 125, 1, 1.0, 1.3, 1.5, 0.5, 20, 5, 0
 13., "YES", "NO", "Well Depth, 1000 Feet "
 6, 9, 8, 3, 10, 3, 6, 5, 10
 0, 0, 0, 0, 0, 0, 0, 0, 0
 14., "NO", "NO", "Wellhead Separat., Ft "
 2600, 2600, 2600, 1000, 2600, 1000, 1320, 2600, 2600
 0, 0, 0, 0, 0, 0, 0, 0, 0
 15., "YES", "YES", "Producer Redrill Fraction"
 .15, .10, .33, .20, .35, .20, .35, .20, .35
 .05, .05, .07, .05, .10, .05, .10, .05, .10
 16., "YES", "YES", "Dry Holes per Producer "
 .17, .17, .25, .17, .17, .17, .20, .14, .14
 .03, .03, .08, .03, .33, .08, .13, .06, .06

17.,	"YES",	"YES",	"Yrs Btwn. Workover, PRODU"						
	2.0,	10.,	15.,	3.,	10.,	10.,	7.,	10.,	15.
	-1.5,	-2.,	-5.,	-2.,	-2.,	-1.,	-2.,	-3.,	-5.
18.,	"YES",	"YES",	"Yrs Btwn. Workover, INJCT"						
	2.0,	10.,	15.,	3.,	10.,	10.,	7.,	10.,	15.
	-1.5,	-2.,	-5.,	-2.,	-2.,	-1.,	-2.,	-3.,	-5.
19.,	"NO",	"NO",	"N-Plant Drawd'n Effect "						
	0,	0,	0,	0,	0,	0,	0,	0,	0
	0,	0,	0,	0,	0,	0,	0,	0,	0
20.,	"NO",	"NO",	"NOT IN CURRENT USE "						
	10,	10,	10,	10,	10,	10,	10,	10,	10
	5,	5,	5,	5,	5,	5,	5,	5,	5
21.,	"YES",	"YES",	"Prod. Well Flow, Klb/hr "						
	450,	580,	750,	400,	350,	500,	70,	550,	100
	-100,	-130,	-250,	-50,	-100,	-50,	-5,	-100,	-25
22.,	"YES",	"YES",	"Inject. Well Flow, Klb/hr "						
	1350,	1160,	2250,	1200,	700,	1500,	210,	2200,	900
	-450,	-580,	-750,	-800,	-175,	-500,	-70,	-550,	-00
23.,	"YES",	"YES",	"Flow for Decline, Klb/hr "						
	720,	928,	1200,	640,	560,	800,	112,	880,	160
	-100,	-130,	-250,	-50,	-100,	-50,	-5,	-100,	-25
24.,	"YES",	"YES",	"Decline Coeff., 1/Years "						
	.002,	.024,	.020,	.027,	.020,	.010,	.036,	.020,	.012
	.008,	.006,	.015,	.011,	.025,	.010,	.064,	.010,	.008
25.,	"YES",	"NO",	"Flow into Plant, Klb/hr "						
	5450,	7140,	6600,	10500,	6850,	20000,	1250,	6655,	850
	0,	0,	0,	0,	0,	0,	0,	0,	0
26.,	"YES",	"NO",	"Flow from Plant, Klb/hr "						
	4250,	7140,	5400,	10500,	5650,	20000,	590,	5460,	50
	0,	0,	0,	0,	0,	0,	0,	0,	0
27.,	"YES",	"NO",	"Plant: 1=Bin 2=Fla 3=Stm "						
	2,	1,	2,	1,	2,	1,	2,	2,	3
	0,	0,	0,	0,	0,	0,	0,	0,	0
28.,	"YES",	"NO",	"Downhole Pump: 0=No/1=Yes"						
	0,	1,	0,	1,	0,	1,	0,	0,	0
	0,	0,	0,	0,	0,	0,	0,	0,	0
29.,	"NO",	"NO",	"Brine Stability 1=POOR "						
	1,	0,	0,	0,	0,	0,	1,	1,	0
	0,	0,	0,	0,	0,	0,	0,	0,	0
30.,	"NO",	"NO",	"Wellhead Layout 1=Pads "						
	1,	1,	1,	0,	1,	0,	0,	1,	1
	0,	0,	0,	0,	0,	0,	0,	0,	0
31.,	"NO",	"NO",	"Identification Cost, \$M "						
	1.,	1.,	1.,	1.,	1.,	1.,	1.,	1.,	1.
	0,	0,	0,	0,	0,	0,	0,	0,	0
32.,	"NO",	"NO",	"Confirmation Cost, \$M "						
	1.,	1.,	1.,	1.,	1.,	1.,	1.,	1.,	1.
	0,	0,	0,	0,	0,	0,	0,	0,	0
33.,	"YES",	"YES",	"Well Cost, Extension, \$M "						
	1.123,	0.956,	1.217,	0.556,	2.032,	0.576,	2.038,	0.906,	1.155
	0.112,	0.110,	0.171,	0.062,	0.144,	0.032,	0.179,	0.102,	0.127
34.,	"YES",	"NO",	"Well Lost Circ. Probs., M\$"						
	0.149,	0.053,	0.097,	0.048,	0.253,	0.088,	0.219,	0.120,	0.100
	.0,	.0,	.0,	.0,	.0,	.0,	.0,	.0,	.0

35., "YES", "NO", "Well Cementing Probs., M\$"

 0.067,0.001,0.040,0.001,0.107,0.027,0.191,0.086,0.100

 .0, .0, .0, .0, .0, .0, .0, .0, .0

 36., "YES", "NO", "Well Other Problems, M\$ "

 0.034,0.029,0.036,0.017,0.061,0.017,0.061,0.027,0.035

 .0, .0, .0, .0, .0, .0, .0, .0, .0

 37., "YES", "NO", "Workover Cost, \$M, PRODU "

 .055, .025, .025, .025, .025, .025, .055, .025, .050

 .0, .0, .0, .0, .0, .0, .0, .0, .0

 38., "YES", "NO", "Workover Cost, \$M, INJECT "

 .055, .025, .025, .025, .025, .025, .055, .025, .050

 .0, .0, .0, .0, .0, .0, .0, .0, .0

IM-GEO FINANCIAL FACTS FILE

The contents of "BUSFNCT.GEO" are presented here only as a matter of record. If you need to change the contents of these files, please contact Dan Entingh, Meridian Corporation, Falls Church, Virginia, (703) 998-0922, for guidance and assistance.

1986	1986	1986	3	
.85	.9747237	1.089035	.1408685	
1.413805	1.413805	1	1	1
30	.13	.04		

Financial Factors:

Generated by: BUSIMGEO.BAS
Used by: IMGEOonn.EXE

CASE Title: SET IM-GEO FACTORS, AS-BUILT, NO AFDC
Run Date: 03-12-1987
AFDC (1=yes): 0
Overnight = 0, As Built = 1: 1

APPENDIX E

INSTALLATION and START UP

INSTALLATION and START UP

1.0 Required Files

You can run IM-GEO directly from the distribution diskette, or copy it to your hard disk.

The distribution diskette for IM-GEO Version 3.00, dated 16 March 1985 contains the following files:

IMGEO300.EXE	128764	3-16-87	11:02a	Executable IM-GEO Program
HWEIGHT.HLP	1024	3-15-87	11:57p	HELP File
HTOPMENU.HLP	1024	3-14-87	7:30p	HELP File
HEDIT.HLP	1152	3-15-87	8:56p	HELP File
HSHOW.HLP	1152	3-15-87	8:58p	HELP File
BUSFNCT.GEO	427	3-12-87	11:22a	Financial Factors
DATATEST.BAS	2176	3-04-87	12:53p	For Testing Edited SITEDATO.DAT
SITEDATO.MAS	6656	3-16-87	11:52a	"Official" SITEDATO.DAT File
SITEDATO.DAT	6656	3-16-87	11:52a	Site Data Base read by IM-GEO
IMGEO300.BAS	88388	3-16-87	10:42a	Source Code (in QUICK BASIC 2.0)
IMGEOUT.TXT	1	3-16-87	1:21p	File for IM-GEO Report Outputs

All of these files except DATATEST.BAS, SITEDATO.MAS, IMGEO300.BAS, and IMGEOUT.TXT must be on the same default disk drive (diskette or hard disk) from which you execute IMGEO300.

2.0 Starting the Program

To start IM-GEO, type:

D> IMGEO300 and press the <Enter> key.

("D>", here, indicates the DOS system prompt on your screen.) The program loads in about 20 seconds from diskette, and then uses about 25 more seconds (on an XT) to read files and initialize data. (Things are substantially faster if you use a hard disk or an AT computer.)

You will hear a beep when the program is ready for you to use.

NOTES:

1. Pressing the <Ctrl-Break> key combination will stop this program. You can also exit this program by selecting Option Q from the [Z] MENU.

2. The file IMGEO300.BAS on the distribution diskette is the Source code for IM-GEO in QUICK BASIC 2.0. The programming conventions are similar to those for IBM BASICA and MicroSoft GW-BASIC, but are sufficiently different that IM-GEO.BAS will not run as a BASICA program.

3. Any documentation files on the distribution diskette are WordStar (TM) files.

APPENDIX F

IM-GEO PROGRAM SOURCE CODE

IM-GEO PROGRAM SOURCE CODE

The IM-GEO program source code is presented here. The code consists of seven conceptual sections. Each section contains one or more routines or subroutines.

- * ZINIT - Initializes arrays, displays program identification screen.
- * ZENG - The main costing routines. These are controlled by processes located in sections ZMENU and ZCTRL.
- * ZMENU - Presents options to User, and controls much of the logic of program flow to ensure that results conform to the current values of sensitivity parameters.
- * ZCTRL - Executes lower level control for single-site and multi-site calculations.
- * ZEDIT - Enables editing of sensitivity parameters.
- * ZLOAD - Loads Site Data and other factors. Resets Base Case values.
- * ZOUTS - Creates major screen and printed report outputs.
- * ZMISC - Creates other screen and report outputs.

Note that program control at start up begins with ZINIT, and jumps from there to the top of section ZMENU.

ZENG, the "costing engine", is presented early in the following pages because it contains the code for most of the technical relationships among reservoir physical characteristics, sensitivity factors, and the equations for performance and cost of technology. This section starts on page F-6.

The programmed list of "non-risk" R&D Achievements is on page F-36. That list will help you tie the factors on Editing Menus [Y,A], [Y,B], and [Y,C] to specific lines in the ZENG costing codes. Note that the sequence of these factors on the editing screens is controlled by the vectors REV(i).

In some places in the ZENG code you will find features that are blocked off by comment-controlling apostrophes. These reflect places where useful additional features could easily be added to the code later.


```

' *** ZINIT
'
' Last Edited      14 March 87

'PROGRAM NAME:      "IMGEO300.EXE"

'PURPOSE:           CALCULATE IMPACTS OF RESEARCH AND DEVELOPMENT ON
'                   COST OF GEOTHERMAL ELECTRIC POWER

'Version:           3.00      16 March 1987
'Author:            Daniel J. Entingh, Meridian Corporation, Falls Church, VA
'Language:          QUICKBASIC 2.0, Microsoft (CR)

'PROGRAM HISTORY:
'(from GEO.BAS) Copyright, Daniel J. Entingh, April 25, 1984
'Use permitted by Meridian Corporation, Falls Church VA 5/84
'Use permitted by U.S. Department of Energy 5/84
'Revised: GEO.BAS V1.1 5/85 Added constant $ costs to displays.
'Revised: IM-GEO.EXE 12/86 V1.08 Adds Menus, Editors, Risk Calcs.
'Use Permitted Sandia Corporation, 12/86
'Revised: IM-GEO.EXE Jan & Feb 87, Version 2.xxx:
'      Extensive revisions of costing codes per technical inputs
'      from Bill Livesay, Susan Petty, Stanley Unitt
'Revised: Version 3.00, 13-16 March 1987
'      Prepared By Meridian Corporation, Falls Church, Virginia
'      as final deliverable under Contract No. 02-1947 from
'      Sandia Corporation, Albuquerque, New Mexico.
'      Meridian Corporation Project No. 275.

'Copyright, Meridian Corporation, 1986, 1987
' NOTICE: LICENSE TO USE AND DISTRIBUTE HEREBY
'          GRANTED TO SANDIA CORPORATION, 16 March 1987

' *****  INITIALIZATION ROUTINES  *****
'
OPTION BASE 1      'Least subscript = 1 on all arrays.
DIM MTB$(18), MV(18), MM$(18)
'
DIM RADRISK$(50), RADRISK(50) 'R&D, Estimation Errors
DIM RADACH$(60), RADACH(60)  'R&D, Other Achievements
DIM REV(60)                  'R&D Ach. Editing Vectors
'
DIM SITENAMES$(10)           'Region Names
DIM SITESHORT$(10)           'Region Short Name Stubs
DIM SITEUSES$(40)            '"YES" if Datum is active
DIM SITERISK$(40)            '"YES" if Risk offset is active
DIM SITEDATA$(40)            'Physical Data Categ. Names
DIM SITEDATA(2,40,10)        'Physical Data, by Categ./Region
'   SITEDATA(1,I,J) = Best Case values
'   SITEDATA(2,I,J) = Worst Case values. These are
'   compounded in *** SUBR: ADJUST.WORST.DATA
'   from SITEDATA(1,I,J), SITERISK(I,J) and RADRISK(I)

```

```

DIM SITERISK(40,10)      'Measurement/Risk Data
DIM RESULTS(2,10,12,5)  'MAIN RESULTS MATRIX
'  RESULTS(I,J,K,L)
'    I: 1 = Base Case, 2 = Current Case
'    J: Vectors for 10 Regions. 8 active on 16 Jan 87.
'    K: Accounts for Project Elements
'        11 = Total
'        12 = Portion Due to Risk.
'    L: Calculation Subtotals
'        1 = Capital Cost, $ Million
'        2 = O&M, $ Million/Year
'        3 = Capital, mills/kwh, Constant Dollars
'        4 = O&M, " "
'        5 = Total, " "
'
DIM ACCOUNT$(12)        'Cost Account Names
DIM WEIGHT(8)           'Result weights for Regions
DIM WEIGHT.USER(8)      'User's weights, Editable
DIM RESCAPADJ (12)      'Results, Adjusted Capital Costs
'    (Used only in Costing Engine)
DIM PICOST(5)           'Cost Totals from Engine outer loop
DIM RESMUL(2,12)        'Results: 8-Site Weighted Avgs, 12 Accounts
'    1 = Base Case, 2 = Current Case
DIM RSUM(20)            'Sums for intermediate results.
DIM WCOSTL(2,5)         'Results: 8-Site Weighted:
'    (See L in RESULTS(I,J,K,L) for the 5 cost categories)
DIM SHOWOUT(12,4)      'Results for SUBR: SHOW.MAIN

'Miscellaneous Initiation Steps:
'
'Print-time control codes:
CHANNEL1$ = "PRINTER"
CHANNEL2$ = "File: IMGOUT.TXT"
CHANNEL$ = CHANNEL1$
PSWITCH$ = "P"

'First site for single site analysis:
JSITE = 1
'User's weights for regions:
FOR I=1 TO 8:WEIGHT.USER(I)=1: NEXT I
' Data not edited yet:
EDFLAG$="NO" : EDFLAG2$="NO"
' Initialization completed.

```

' Begin Operation:

```
WELCOMES$ = "WELCOME TO IM-GEO.          ( Setting up Base Case )"
GOSUB sub1BASELOAD      'LOAD Base Case Site Data
WELCOMES$ = ""          'No longer appropriate.
PRINT CHR$(7);          'Beep tells user that program is ready.
```

' Program Identification Screen:

```
CLS : PRINT
PRINT "                      IM-GEO                      "
PRINT
PRINT "          VERSION 3.00          [IMGEO300]          16 Mar. 1987"
PRINT
PRINT "          IMPACTS OF R&D ON COST OF GEOTHERMAL POWER"
PRINT
PRINT "          Prepared By Meridian Corporation"
PRINT "          Falls Church, Virginia"
PRINT
PRINT "          Under Contract to Sandia Corporation"
PRINT "          Albuquerque, New Mexico"
PRINT "          Contract No. 02-1947  "
PRINT
PRINT "          Project Team: "
PRINT
PRINT "          Dan Entingh,  Bill Livesay,  Susan Petty,"
PRINT "          Richard Traeger,  Stanley Unitt"
PRINT: PRINT:
PRINT "          PRESS ANY KEY TO START OPERATION -----> "
GOSUB INLETTER 'Get response
```

```
TTIMES$ = TIMES$ 'Initial Static Time for Reports
GOTO TOPMENU      'Start at TOPMENU (MAIN MENU)
```

' NOTE: EXIT to SYSTEM is at TOPMENU subroutine in ZMENU Section

' ***** End of "Initialize" Section *****

```

'*** ZENGN
/
'***** COSTING CALCULATION ROUTINES FOR ONE PROJECT *****
/
'Author:      Daniel J. Entingh, Meridian Corporation
/              Falls Church, VA 22041      March 1987
/
' Last edited:      15 March 1987

CALC.A.SITE :
/
'*** SUBR: Calculation: One Reservoir
/ Used for single and multi-site cases.
/
' Data Setups, Not affected by RISK:
FEXCS = RADACH(2)      ' [R02] Identification Unit Cost
FWLCS = RADACH(5)      ' [R05] Unit cost of avg. Well
PTYPE = SITEDATA(1,27,JSITE) ' [S27] Plant Type
DPUMP = SITEDATA(1,28,JSITE) ' [S28] Down Hole Pumps
' Power Plant Cost Multiplier:
FPTCS = 1
IF SITEDATA(1,27,JSITE) = 1 THEN FPTCS = RADACH(17) 'Binary
IF SITEDATA(1,27,JSITE) = 2 THEN FPTCS = RADACH(16) 'Flash
' Power plant efficiency multiplier:
FPTEF = 1
IF SITEDATA(1,27,JSITE) = 1 THEN FPTEF = RADACH(15) 'Binary
IF SITEDATA(1,27,JSITE) = 2 THEN FPTEF = RADACH(14) 'Flash
/
' Cost adjustments from Jan 1 1980 to Jan 1 1986:
ESC1WELL = 0.940      'SERIES 7, DONE 2 Jan 86 dje
ESC1GENRL = 1.425      'GNP IMPLICIT DEFL., DONE 2 Jan 86 dje
/
'***** Factor Value Set:
WSPR = 0.1 'Spare wells/ producer. BJJ/SP/DJE
/
'***** NO VARIABLE IN NEW SET, YET, 15 Feb 87:
KROK = 1 'MED-HARD ROCK [NOT USED]
POUT = 50. '50 MWE
/
' Income tax rate: .34 Federal + .02 State:
INTXR = 0.36 'July 1 1987 and following
/
' Capital Recovery Factor. For uses in Engine.
' (Spreads PV at P.O.L. date over 30 Year as a unacost:)
' DISC = Discount Rate, from BUSFNCT.GEO Financial Factors file.
' FBL = Project Book Life, " ".
LIFE = FBL 'Nominal = 30 years
D = (1 + DISC)^LIFE
CAPRECOV = (DISC*D)/(D - 1)
/
'*** END OF ENGINE FACTOR SET-UP SECTION *****

```

```

'
' Two passes here calculate and save cost of "non-risky" and
' "risk-loaded" project.
'
' Pass 1 = No Risk:
ZRI = 1 ' Uses BEST CASE data for site.
'
BASECOP = 100' Avoid Div/Zero
'
GOSUB ENGINE.CORE ' Calculate cost w/o risk
BASECOP = BUSBAR ' Cost w/o Risk, in mills/kwh
' Save account totals:
FOR I=1 TO 5 : PICOST(I)=RESULTS(2,JSITE,11,I) : NEXT I
'
' Pass 2 = With Risk:
ZRI = 2 ' Uses WORST CASE data for site.
'
GOSUB ENGINE.CORE ' Calculate cost with risk.
ZRISK = BUSBAR - BASECOP 'RISK Cost, in mills/kwh
BASECOP = BUSBAR '16 Jan, OLD/ May be needed ?????
' Save Presentation totals:
' Total, Incl. Risk is in: RESULTS(2,JSITE,11,I)
FOR I = 1 TO 5 ' Risk amounts:
RESULTS(2,JSITE,12,I) = RESULTS(2,JSITE,11,I) - PICOST(I)
NEXT I
'**** NEW <--> OLD Correspondence:
' RESULTS(2,JSITE,11,5) = BASECOP '*** Total, W/RISK, m/kwh
' RESULTS(2,JSITE,12,5) = ZRISK '*** Risk, m/kwh
'*****
'For OLD Display Header: For GOSUB RESULT1 ****
COSTPOW = 100*BUSBAR/BASECOP 'Relative, percent points
COSTRISK = 100*ZRISK/BASECOP 'Relative, percent points
RETURN
'
'*** END SUBR: OUTER CALCULATION ENGINE, one site

ENGINE.CORE :
'
'*** SUBR: ONE PASS SIZES, COSTS, AND PRICES
'
'Dual value (ZRI: 1=No Risk 2=Risk-Loaded) Data Factors set here:
'[ 5] Reservoir Sat. Temperature, Deg-F
ZZTRES = SITEDATA(ZRI,5,JSITE)

'[ 7] For TEMP: Well-Head Temperature, Deg-F
ZZT = SITEDATA(ZRI,7,JSITE)
TEMP = ZZT
'[12] For TDS, Total Dissolved Solids,
' and BCI: Brine Contam. Index:

```

```

TDS = SITEDATA(ZRI,12,JSITE)
' Per Holt 1987 apparent cut points:
  IF TDS > 10. THEN ZZB = 1 ELSE ZZB = 0.
  IF TDS > 100. THEN ZZB = 2
  BCI = ZZB
''' Note INEL/Technicon 1980 lower cut point was:
''' IF TDS > 2. THEN ZZB = 1

'[13] For DEEP: Well Depth, K-Feet
ZZD = SITEDATA(ZRI,13,JSITE) : DEEP = ZZD
'[15] For WRED: Redrilling incidence fraction
WRED = SITEDATA(ZRI,15,JSITE) * RADACH(6)
'[16] For WDRY: Dry wells/producer
WDRY = SITEDATA(ZRI,16,JSITE) * RADACH(7)

'[21] For FLOW: Producer Flow, 10^6 lb/Hour
'Data start as 1000 lb/Hour:
ZZF = SITEDATA(ZRI,21,JSITE)*RADACH(8)/1000.
FLOW = ZZF

'Programmer's note: Correspondences of variable names:
' ZZB = BCI : ZZD = DEEP : ZZF = FLOW : ZZT = TEMP
' Not used in Vers 3.00: ZZW = WLIF
,
'***** Other NEW Data Setups should go here:

'The costing steps start here:

PLANT.SIZE:
' Set gross plant size to meet aux. requirements.
,
IF PTYPE = 2 THEN GOTO FLASH.SIZE
,
BINARY.SIZE : ' PTYPE = 1
,
'1. GROSS WITHOUT PUMPS, FROM PUMP3.BAS, DJE, 6 FEB
'1.1 FIND FLOW AND GROSS FROM NET POWER AT TEMP, DEG-F
NETBE = -14.64212 + (0.06154139)*(ZZT) 'WH/LB, NET
TFLOWINO = 50/NETBE 'M-LB/HR
GROBE = (1.450921E-05)*(ZZT^2.281921) 'WH/LB, GROSS
GROSSO = TFLOWINO*GROBE 'MW, SHADOW
'1.2 SUBTRACT FITTED PUMP POWER, USING "KBIN" FORMULA:
' KBIN + 1 = Added Gross to Make 1 More MWe net out.
KBIN = 3.243886 - .5167263*LOG(ZZT)
PUMPF = GROSSO*(1-KBIN) - 50 'FIT, NET TO D.W. PUMPS
'1.3 SET BARE-AUX => 15 MW (Primary loop & cooling).
BARE.AUX = GROSSO - 50 - (1+KBIN)*PUMPF
IF BARE.AUX < 15 THEN BARE.AUX = 15 ' MW
' Gross Power net of Field Auxilliary Power Needs:
GROSS1 = 50 + BARE.AUX 'GROSS W/O PUMPING
GROSSO = GROSS1 + (1+KBIN)*PUMPF ' ADJUSTED SHADOW GROSS
' FACTOR FOR CALC'ING GROSS POWER:
GROBE1 = GROSSO/TFLOWINO ' ADJUSTED GROSS B.E.

```

```

''' *****
''' Adjust for POUT:
''' GROSS1 = GROSS1*POUT/50
,
' Convergence loop below sets binary gross power and
' plant inlet/outlet flow requirements, adjusted
' To fit Auxilliary power requirements.
' Starting Guesses:
  GROSS = 1.3*POUT ' Mw
' WNUM = # of Primary Producer Wells and Pumps at Start :
  WNUM = GROSS/15
,
BINARY.SIZE2 : ' Top of conv. loop.
' Previous Gross for conv. test:
  GROSSTEST = GROSS
'2. Add Pump Power from previous producer well count:
,
'1000 Horsepower per pump; depends on well depth:
IF ZZD > 1. THEN PER.PUMP = 0.6 ELSE PER.PUMP = 0.4
PUMP.POWER = 0.7457*PER.PUMP*WNUM '@ 1000HP = 0.7457 MW
GROSS = GROSS1 + (1+KBIN)*PUMP.POWER
' FPTEF = Plant Efficiency Multiplier [R15]
TFLOWIN = GROSS/(GROBE1*FPTEF)'Flow required
' ZZF = Flow per producer, initialized above:
,
WNUM = INT(TFLOWIN/ZZF) + 1 ' No. of PRODUCERS needed. ***
' Convergence test:
IF ABS(GROSS - GROSSTEST) > 1.0 THEN GOTO BINARY.SIZE2
' Test met:
GOTO BASEWELLCOST
'**** End of binary sizing. ****
,
FLASH.SIZE : ' PTYPE = 2
,
GROSS1 = 52.5 'Net + 2.5 MW Internal
'Add Brine stablization power requirement:
GROSS = GROSS1 + 3*ZZB - 0.5*ZZB*(ZZB-1) 'Unitt
'Flash Flow Requirement:
' OLD: Specific energy: Net Whr/lb brine:
' OLD: SPE = (-16.9+.0614*ZZT+2.344*PTYPE-.534*ZZB)*FPTEF
' OLD: TFLOW = POUT/SPE'Plant flow, 10^6 Lb/hr
'FPTEF = Adjust per Plant Efficiency Multiplier [R14]
TFLOWIN = SITEDATA(ZRI,25,JSITE)/(1000*FPTEF)
TFLOWIN = TFLOWIN*GROSS/52.5 ' Adj, for Gross.
,
WNUM = INT(TFLOWIN/ZZF) + 1 ' No. of PRODUCERS needed. ***
GOTO BASEWELLCOST
'*** End of Flash sizing. ****

```

BASEWELLCOST :

```

'*** WCPW: Well Cost, per well, $ Millions
' Livesay Estimates, February 87:
' Base cost part of bare well:
WCBASE = SITEDATA(1,33,JSITE)
' Extension add-on, full cost:
WCEXTEND = SITEDATA(ZRI,33,JSITE) - WCBASE 'Still "RISKED"
WCPW = WCBASE 'Base cost, "Non-Optimized"
      + SITEDATA(ZRI,34,JSITE)*RADACH(30) - 'Lost circulation Problems
      + SITEDATA(ZRI,35,JSITE)*RADACH(31) - 'Cementing Problems
      + SITEDATA(ZRI,36,JSITE)*RADACH(32) - 'Other Problems
WCPW = WCPW * FWLCS 'Adjust by Well Cost Multiplier.
' Set ups for adding Extension and Redrill Costs to the
' base price of the wells:
WCBASE = WCBASE * FWLCS 'Adjusted, For use below.
WCEXTEND = WCEXTEND * FWLCS ' " " " "
PR.EXTEND = 1 - .2 - .25*WDRY 'Fraction of wells to be extended.
PR.REDRILL = WRED 'Fraction to be redrilled.
MODAL.FR = 0.75 'Fraction of full cost of operation that is
               expended in modal (expected) case.
'Cost to Extend:
CST.EXTEND = (MODAL.FR)*(PR.EXTEND)*(WCEXTEND)
'Cost to Redrill (Cost to redrill is 22% of well base cost.)
CST.REDRILL = (MODAL.FR)*(PR.REDRILL)*(.22)*(WCBASE)
' Adjust WCPW to reflect Extension and Redrill Costs:
WCPW = WCPW + CST.EXTEND + CST.REDRILL
' WCPW = Fully loaded well cost, sans testing costs.
' SET UP COSTS OF TESTING:
' TESTING COST = INITIAL + DAYS*($/DAY) ; $ Million
' 3 Day Test:
IF TDS < 100
  THEN TEST.3D = .025 + 5 * .003 -
  ELSE TEST.3D = .035 + 5 * .005 -
' 10 Day Test:
IF TDS < 100
  THEN TEST.10D = .025 + 12 * .003 -
  ELSE TEST.10D = .035 + 12 * .005 -
' 21 Day Test:
IF TDS < 100
  THEN TEST.21D = .050 + 25 * .0035 -
  ELSE TEST.21D = .100 + 25 * .0060 -
' Logging:
IF ZZTRES < 400
  THEN TEST.LOG = (2.53 + ZZD*10.667)/1000 -
  ELSE TEST.LOG = (5.33 + ZZD* 6.667)/1000 -
' Analysis of All Tests:
TEST.ANSIS = 0.0435

```



```

' Combos of tests needed:
TEST0 = TEST.LOG + TEST.ANSIS ' All wells
TEST1 = TEST0 + TEST.3D ' For WC.GENL
TEST2 = TEST1 + TEST.21D ' For WC.CONF
TEST3 = TEST0 + TEST.10D ' Development Producers
'
'
WC.WILD = WCPW + TEST1 *RADACH(2) ' WILDCAT WELL
WC.CONF = WCPW + TEST2 *RADACH(4) ' PRODUCER IN PHASE 2, CONFIRMATION
WC.PROD = WCPW + TEST3 *RADACH(33) ' PRODUCER IN PHASE 3, DEVELOPMENT
WC.GENL = WCPW + TEST1 *RADACH(35) ' INJECTOR OR DRY WELL
'
'*** End: Well Capital Cost

'*** SUBSYSTEM Costing Modules LINE1 - LINE9 Start Here.

LINE1 : ' IDENTIFY RESERVOIR
'
' EXPL = Exploration Cost, $ Millions, Jan 1980
'
' ** IDENTIFICATION UNIT COST
'
' Unit of Identification Consists of:
' 1. Geological and Geophysical Survey Work, Per Region
' 2. Gradient Wells, per Wildcat sited
' 3. Wildcat Wells, per Wildcat Success Ratio, to achieve one
' successful well, used later as Observation Well.
'
' Unit costs depend on depth of prospect:
IF ZZD > 3000 THEN GOTO ID.UC.1
' Shallower system costs:
UCOST1 = 0.050 ' $M, Geology and Geophysics, Regional
UCOST2 = 0.005 ' $M, Therm. Gradient Holes/ Wildcat
GOTO ID.UC.2
ID.UC.1:
' Deeper system costs:
UCOST1 = 0.200 - ' $M, Geology and Geophysics, Regional
+ 0.100 - ' $M, "Deep Geology"
UCOST2 = 0.010 ' $M, Therm. Gradient Holes/ Wildcat
ID.UC.2:
' Adjust non-well costs vis R&D factor:
UCOST1 = UCOST1 * RADACH(2)
UCOST2 = UCOST2 * RADACH(2)
' Probability of wildcat success:
UPROB = SITEDATA(1,3,JSITE)*RADACH(1) '[S3],[R1]
IF UPROB > 1 THEN UPROB = 1 'Protect
IF UPROB < .1 THEN UPROB = .1
' Number of Wildcat Wells to get one good one :
N.IDENT = 1/UPROB
'
' TOTAL Identification UNIT Cost (not present valued):
UCOST.ID = UCOST1 + N.IDENT*(UCOST2 + WC.WILD) ' $M

```

' The next probability, UPROB1, reflects the probability that
 ' a confirmation effort will fail. The identification effort spent
 ' to preceed that failed confirmation effort is added here.
 ' Some additional time for failed portion is added here.

UPROB1 = SITEDATA(1,4,JSITE)*RADACH(3) '[R3]

IF UPROB1 >= 1 THEN UPROB1 = 1 ' Protect

IF UPROB1 < .1 THEN UPROB1 = .1

' Total Identification cost (not present valued):

EXPL = UCOST.ID/UPROB1 'I.D. Work, Includes extra
 ' exploration for unsuccessful confirmation.

' Spread Exploration over a number of 50 MWe Plants:

P.PER.SITE = SITEDATA(ZRI,2,JSITE)/GROSS '[S2]

' Duration of exploration unit:

DUR.EXPL = 2.0 'Geological, geophys. surveys.
 + 0.5 /UPROB 'Per wildcat attempt
 + 3.0 * (1-UPROB1) 'Failed confirmation work
 + 1.0 'Permitting re confirmation

' Spread over all P.PER.SITE plants, as unacost:

BTWN.PLANTS = 4*RADACH(34) '4 years between plants, nominal.

AREA.LIFE = BTWN.PLANTS*(P.PER.SITE)

D = (1+DISC)^AREA.LIFE

EXPLRECOV = (DISC*D)/(D - 1) ' Unacost factor for each year.

E = (1+DISC)^BTWN.PLANTS

PAYMENTS = (E - 1)/(DISC*E) 'P.V. factor for BTWN.PLANTS number
 ' of payments required for each plant.

EXPL = EXPL * EXPLRECOV * PAYMENTS

AREA.LIFE = AREA.LIFE + LIFE 'Total Production Life, Yrs.

RESULTS(2,JSITE,1,1) = EXPL/CAP

' NOTE: RESULTS(2,JSITE,1,1) is escalated to P.O.L.
 ' year at end of Section LINE2.)

RESULTS(2,JSITE,1,2) = .000001 'OM

' Count of OK Production Wells so far:

' GOOD.PRODS = 0 'Assumes no good producers from Ident. Phase.

LINE2 : ' CONFIRM RESERVOIR

'** CONFIRMATION UNIT COST

' Unit of Confirmation consists of activity over 3 years to
 ' drill and test the following:

GOOD.PRODS = 4 ' Production wells

GOOD.INJS = 1.5 ' Injection wells

DRY.COUNT = 0.5 ' Dry Holes

' All of this results in a reservoir for which developer is ready
 ' to go to bank for loan. Certainty of achieving 30 years of
 ' power production is assumed to be 0.95.

DUR.CONF = 3 ' Years, Total duration

```

' Total cost (not present valued), $M:
UCOST.CF = GOOD.PRODS * (WC.CONF) - 'Producers
          + GOOD.INJS * (WC.CONF) - 'Injectors
          + DRY.COUNT * (WC.CONF) - 'Dry Holes
' All of 1 Unit of CONF is allocated to a single plant.
' In addition, UPROB1, from above, is used to add an amount of
' confirmation effort (at a different prospect) that is assumed
' to fail. Its costs are then spread over all plants at
' this prospect.
'
' Number of failed Confirmation Units:
N.CONF = (1 - UPROB1)/UPROB1
' Distribute those N.CONF units of CONF over P.PER.SITE plants
' Raw total of confirmation costs:
CONF = (1 + N.CONF*EXPLRECOV*PAYMENTS)*UCOST.CF
' Escalate confirmation cost to plant start up:
' YCN = years of construction, from above, 3 years nominal,
' YCN/2 avoids double count from AFDC adjustments later:
CONF = CONF * ((1 + DISC)^(DUR.CONF + YCN/2))

RESULTS(2,JSITE,2,1) = CONF 'CAP
RESULTS(2,JSITE,2,2) = 0.00001 'OM
' And, escalate cost of EXPL:
C = RESULTS(2,JSITE,1,1)
' YCN = years of construction, from above, 3 years nominal,
' YCN/2 avoids double count from AFDC adjustments later:
C = C * ((1 + DISC)^(DUR.EXPL + DUR.CONF + YCN/2))
RESULTS(2,JSITE,1,1) = C
'

LINE3 :      ' PRODUCTION AND INJECTION WELLS
'
' Calculate required number of Wells:
' Flow into plant:
' NOTE: TFLOWIN was calculated in plant sizing routine, above.
TFLOW = TFLOWIN 'For old displays
'
' Flow from plant:
' Note: Relationship to SITEDATA for flash is not highly
'       and should be remodelled from data with a broader
'       temperature range, and perhaps a more explicit code for
'       expected steam quality of the brine.
IF PTYPE = 1
  THEN TFLOWOUT = TFLOWIN ' Binary Plant, must balance
  ELSE TFLOWOUT = TFLOWIN*SITEDATA(ZRI,26,JSITE)/SITEDATA(ZRI,25,JSITE)
' "Else" clause reflects steam quality at wellhead, for flash plant
'
' WIJN variable is new, 19 Jan 87
WIJN = INT(TFLOWOUT/(SITEDATA(ZRI,22,JSITE)/1000)) + 1
WIJN = WIJN*RADACH(9) ' [R9]
WINJ = WIJN/WNUM 'Ratio, Inj/Producer
' Total Number of Wells & Total Well Cost:
WSPR = INT(WNUM*WSPR) + 1 ' Spare Producers
WPDY = INT((WNUM)*WDRY) + 1 ' Dry "Producers"

```

```

'Total Number of Initial Wells:
WCNT = WNUM + WIJN + WSPR + WPDY
' Capital cost of all initial wells, including testing:
' GOOD.PRODS and GOOD.INJS are paid for previously:
T1 = (WNUM + WSPR - GOOD.PRODS) * (WC.PROD*(1+WRED) + 0)
' Injector tests are included in producer test costs.
T2 = (WIJN - GOOD.INJS) * WC.GENL
T3 = (WPDY - DRY.COUNT) * WC.GENL
WCTL = T1 + T2 + T3 'CAP COST, WELLS
''' Escalate to P.O.L date, for 3 year construction lag:
''' This is turned off because AFDC is added below:
''' WCTL = WCTL*((1+DISC)^(1.5))

' Calculate No. and Discounted No. of Supplemental Wells:
'
' 1. Factor to adjust decline coefficient to multiplant interference
'    effect. As parameter CPIF [S19] increases from 0 to 1, the
'    impact of drawdown interference from all other plants on same
'    prospect increases, by an algorithm here that increases the
'    one-plant flow decline coefficient via a power function of the
'    supportable number of plants.
' NOTE: This feature is not used in Version 3.00 or earlier.
' (13 March 87)
'
DRWDN = SITEDATA(ZRI,24,JSITE) ' Decline Coefficient.
CPIF = SITEDATA(ZRI,19,JSITE) ' Adjustment factor
''' CPIF = 0 in SITE DATA BASE of 12 March 87.
PPSITE = (P.PER.SITE)^0.7 'From LINE1 calcs., fractal
DRWDN2 = DRWDN*(1 + CPIF*(PPSITE-1))
'
' 2. Supplemental wells to compensate for pressure decline:
DECLINE :
'DISC ' Discount Factor, from above. (FINFACT)
'LIFE ' Life of Plant, Yrs., from above. (FINFACT)
'DRWDN2 ' Decline Coefficient, adjusted for N Plants
VSTART = SITEDATA(ZRI,23,JSITE) ' Initial flow rate
VNEEDED = SITEDATA(ZRI,21,JSITE) ' Min. flow per initial well
NWO = WNUM ' No. of producers at start
NW1 = 0.00001 'Result: No. of wells added over LIFE years
NWD = 0.00001 'Result: Discounted No. of wells added.
SNWOAM = 0 'Result: Sum of Disc'td O&M Units for these wells.
FOR IYR = 1 TO LIFE ' In years.
  NW = 0 ' # of new wells needed this year.
  S1 = 0 'Disc'td O&M units added, this year.
  FLOW0 = VSTART*EXP(-IYR*DRWDN2) ' Flow, start of Yr.
DECLINE1 :
  FLOWQ = FLOW0*(NWO+NW1)/NWO ' Test Flow
  IF FLOWQ > VNEEDED THEN GOTO DECLINE2
'Loop: Add new wells this year:
  NW = NW + 1 : NW1 = NW1 + 1 : GOTO DECLINE1
DECLINE2 :
  IF NW = 0 THEN GOTO DECLINE3
'Accumulate Present Value of No. of new wells:
  NWD = NWD + NW/((1+DISC)^(IYR-1))

```

```

'Accumulate O&M Units due to this year:
  S = 0
  FOR K = IYR TO LIFE: S=S + 1/((1+DISC)^(LIFE-IYR)): NEXT K
' Then, discount to P.O.L. year, and total:
  SNWOAM = SNWOAM + S*NW/((1+DISC)^IYR)
DECLINE3 :
  NEXT IYR
' Convert Present Values to Annual Unit O&M costs:
WDECLOM1 = NWD * (WC.PROD*(1+WRED)*(1+WSPR) + TEST.WELL) * CAPRECOV
' WDECLOM1, the Capital Part, is FULLY costed here.
WDECLOM2 = SNWOAM * CAPRECOV 'O&M Part. MUST be multiplied
' by annual O&M cost per well to get final $M/year value.
' Both WDECLOM1 and WDECLOM2 are added into Field O&M, below.
,
'*** End of Supplemental Well Costs.

' Final Result: Well cap cost:
  RESULTS(2,JSITE,3,1) = WCTL 'CAP
' Wells O&M Costs are below, under LINE5:

LINE4: 'DEEP WELL PUMPS
,
' * Deep Pump Cost and O&M
IF DPUMP = 0 THEN DPTL=.00001 : DPOM=.00001 : GOTO PUMPENDED
,
'OLD: DPC = ZZP*(.2068-.1681*LOG(ZZF)) 'EG&G, mega$/well
' Pump Capital and Installation, $M :
' Depends on depth of well:
IF ZZD > 1. THEN DPC = 0.100 ELSE DPC = 0.075
DPC = DPC*RADACH(20) 'R20]
PNUM = WNUM + INT(WNUM*WSPR) + 1 '# of pumps to purchase
DPTL = DPC*PNUM'total capital cost, $M
' OLD: DPTL = DPTL * ESC1GENRL 'To 1986.0

'PUMP O&M:
'OLD: DPM = .05724+.02348*LOG(ZZF) 'mega$/yr/WELL mechanical
'OLD: DPM = DPM * ESC1WELL 'To 1986.0
DPM = 0.020 'Per active pump per year.
DPM = DPM*RADACH(21) 'R21]
D1 = (DPM)*WNUM ' Initial pumps
D2 = NWD*DPC*CAPRECOV 'Capital, supplemental wells
D3 = WDECLOM2*DPM 'O&M, suppl.
DPOM = D1 + D2 + D3 'Total pump O&M, mega$/yr
,
PUMPENDED:
,
RESULTS(2,JSITE,4,1) = DPTL 'CAP
RESULTS(2,JSITE,4,2) = DPOM 'OM
'*** End of Pump Calculations
,

```

LINE5 : ' GATHERING SYSTEM

'
'*** Field Surface Equipment Capital costs: \$/kWe net
'
' 1. Initial Gathering System Cost:
' 1.A. Producer Wells:
' NOTE: Feb 87: No provision is made for pipe cost saving due
' to having a # of producers on a single pad. All wells are
' assumed to be drilled vertically, not directionally.
' Separation between producers wells, in feet:
SEPAR = SITEDATA(ZRI,14,JSITE) ' [14]
WPRODSUM = INT(WNUM*(1+WSPR)) + 1 ' Producers plus spares
' Total length of pipe, rectangular field,
' one full run for each well:
NFEET = (WPRODSUM^(1.48))*(0.51039)*SEPAR ' 2 Feb 87 DJE
' 1986 Cost is then \$50.00 per foot,
' Plus \$20,000 for control valve on each well:
CPRDGDATH = (50.*NFEET + 20000.*WPRODSUM)/(10^6) ' M\$
CPRDGDATH = CPRDGDATH*RADACH(28) ' R[28]
' 1.B. Injector Wells:
' Assumes four wells per pipe run, with injectors heads
' set at 6 times SEPAR distance from plant.
COSTPER4 = 6*SEPAR*50.*SQRT(4*(SITEDATA(ZRI,22,JSITE)/500))
COSTPER4 = COSTPER4/(10^6)
' Total, and add \$20K per well for valve:
CINJGATH = COSTPER4*(WIJN/4) + 0.020*WIJN
CINJGATH = CINJGATH*RADACH(28) ' R[28]

' Field surface equipment total cost:
SPTL = CPRDGDATH + CINJGATH
'''SPTL=SPTL/FPTEF 'Adjust: Plant efficiency multiplier
'
TTL = EXPL+WCTL+DPTL+SPTL ' TOTAL Field, cap, mega\$
'
RESULTS(2,JSITE,5,1) = SPTL 'Capital, Gathering Sys.

' 2. Gathering System Cost for Decline Producers :
' NOTE: It is assumed that initial injectors will
' same total flow rate through life of plant. 2 Feb.
' 2.A. Capital Portion of Added gathering:
' Pipe run, based on increment to original piping:
A = (WPRODSUM + NW1)^(1.480)
A = A*(0.51039)
NFEET2 = A*SEPAR 'Did not compile as one line
CPRDGDATH1 = (50.*(NFEET2 - NFEET) + 20000.*NW1)/(10^6) ' M\$
IF NW1 < 1 THEN NFEET2 = 0 : CPRDGDATH2 = 0
CPRDGDATH1 = CPRDGDATH1*RADACH(28) ' [R28]
' Discount to POL year:
CPRDGDATH2 = CPRDGDATH1 * (NWD/NW1) ' \$M
' Apply unacost to treat as an annual cost:
CPRDGDATH3 = CPRDGDATH2 * CAPRECOV ' \$M/year
' Added to Well O&M Costs, Later
'

' 3. Miscellaneous Field O&M Costs, mega\$/year
 ' From INEL 1980 Analysis: mega\$/year, revised 2 Feb 87
 BBB = ZZB^2 - ZZB + 2 ' (0,1,2) maps to (2,2,4)
 F1 = .320 * ESC1GENRL ' Field staff
 ' NOTE: NO R&D impact on Field Staff cost.
 ' OLD: F2 = 0.01 * BBB * WCTL ' Initial PROD and INJ wells.
 ' Unit annual costs for reworking initial wells:
 PROD.REWORK = SITEDATA(ZRI,37,JSITE)*RADACH(11) / -
 SITEDATA(ZRI,17,JSITE)*RADACH(10) -
 INJ.REWORK = SITEDATA(ZRI,38,JSITE)*RADACH(13) / -
 SITEDATA(ZRI,18,JSITE)*RADACH(12)
 F2 = WNUM*PROD.REWORK + WIJN*INJ.REWORK ' Total Rework
 F3 = 0.01 * BBB * SPTL ' Gathering Pipes and valves.
 F3 = F3 * RADACH(29)
 ' ' F4 from OLD model: 2 Feb:
 ' ' F4 = ZZB*(ZZB-1)*.0075*(TTL-EXPL) ' Schilling, Solid Waste
 ' For supplemental wells needed due to pressure decline:
 ' (All R&D impacts for F5 and F6 are via factors from above)
 F5 = WDECLOM1 ' Capital portion, unacost
 ' OLD: F6 = WDECLOM2*(0.01*BBB*WCPW)
 F6 = WDECLOM2*PROD.REWORK ' O&M portion, unacost
 ' For Gathering Cap. & O&M for supplemental wells:
 F7 = CPROD GATH3 ' Supplm. Wells Gathering Cap., unacost
 ' R&D Ach. on F7 is via CPROD GATH1, above.
 F8 = 0.01*BBB*CPROD GATH2 ' Supplm. Gathering O&M
 F8 = F8 * RADACH(29) ' [R29]
 ' Note: [R28] also affects F8.
 ' ,
 ' Old summation, for Reports (DPOM=Pump O&M) :
 FOAM = F1+F2+F3 +F5+F6+F7+F8 + DPOM ' + F4 ??
 ' O&M Cost totals:
 RESULTS(2,JSITE,3,2) = F1+F2+F5+F6 ' O&M, WELLS
 RESULTS(2,JSITE,5,2) = F3+F7+F8 ' O&M, GATHERING + F4 ??

LINE6 : ' PLANT

'*** Electric Plant Capital Costs: Mega\$

IF PTYPE = 2 THEN GOTO FLASH.PLANT.COST

BINARY.PLANT.COST:

' NOTE: Changed markedly on 15 March 87, DJE:
 ' Based on Input Flow Requirement and Temperature, as best
 ' way to match Unitt Dec. 86 cost estimates:
 ' COST.PER.FLOW units = \$Million per Million Lb/Hr:
 COST.PER.FLOW = 2.83 + 0.025*ZZT
 PPC = TFLOWIN * COST.PER.FLOW ' \$M, 1986.0
 ' ' SET BELOW: PPC = PPC*FPTCS ' Plant Cost Mult. [R17]
 ' ' PPC = PPC*((POUT/50)^.7) ' Scale to net size
 ' Scale to BCI per Technecon Heber Analysis, 1983:
 B=ZZB
 P1=EXP(7.7103- (.001968-B*(B+1)*.000006)*ZZT+6.456001E-02*B)
 PPC = PPC*P1/EXP(7.7103-.001968*ZZT)
 ' End of Binary Plant Costing.

GOTO PLANT.OM

FLASH.PLANT.COST :

'Flash Plant Capital Cost, Per KW net:

' From 5 Feb 87 curve fits, DJE:

IF ZZT <= 390 THEN P = 3357 - 6.4286*ZZT

' Above is OK down to 350 DEG-F.

IF ZZT > 390 AND ZZT < 550 THEN P = 972 - 0.3125*ZZT

IF ZZT >= 550 THEN P = 800

'Scale to size:

PPC = ((POUT/50)^{.7})*(P/1000)*POUT '\$ Million

'''SET BELOW: PPC = PPC*FPTCS 'Plant Cost Multiplier [R16]

' Scale to BCI per INEL 1980: (OFF 8 FEB 87)

' Assumed not needed, since clarifier cost is explicit below.

' P1=EXP(7.2281-(.001045+.000271*ZZB)*ZZT+.183*ZZB)

' PPC = PPC*P1/EXP(7.2281-.001045*ZZT)

'End of Flash Capital Cost

PLANT.OM:

' \$M/Year, 'Not including Property Tax & Insurance

IF PTYPE = 1 THEN POAM = 0.023*PPC 'Unitt's IV-B

IF PTYPE = 2 THEN POAM = 1.7 'Unitt, bare Flash

'OLD Plant, O&M, Blair et al.'82, adjusted for plant size:

'OLD BO = ((POUT/100)^{.7})*(.891+(1-PTYPE)*.063)

'OLD BO = BO * ESC1GENRL 'To 1986.0

'OLD SPE = (-16.9+.0614*ZZT+2.344*PTYPE-.534*ZZB)*FPTEF

'OLD P = ZZB*(ZZB-1)*(9.288001E-02*POUT/SPE+.00224*POUT)

'OLD P = P * ESC1GENRL 'To 1986.0

'OLD BO = (BO + P + .02*PPC/FPTCS)*FPTCS 'Plant cost multiplier

'OLD POAM = 1.25*BO 'Not including Property Tax & Insurance

PLANT.RESULT1 :

IF PTYPE = 2 THEN GOTO PLANT.RESULT2

'BINARY FINAL COSTS:

RESULTS(2,JSITE,6,1) = 0.83*PPC *RADACH(17) 'PLANT CAP

RESULTS(2,JSITE,6,2) = 0.70*POAM*RADACH(23) 'PLANT O&M

RESULTS(2,JSITE,7,1) = 0.17*PPC *RADACH(24) 'HEAT EXCH, CAP

RESULTS(2,JSITE,7,2) = 0.30*POAM*RADACH(25) 'HEAT EXCH, O&M

GOTO PLANT.RESULT3

PLANT.RESULT2 :

'FLASH FINAL COSTS:

RESULTS(2,JSITE,6,1) = PPC *RADACH(16) 'PLANT CAP

RESULTS(2,JSITE,6,2) = POAM*RADACH(22) 'PLANT O&M

'(LINE7) : ' HEAT EXCHANGERS:

RESULTS(2,JSITE,7,1) = .00001 'HEAT EXCH, CAP

RESULTS(2,JSITE,7,2) = .00001 'HEAT EXCH, O&M

PLANT.RESULT3:

' For Site Technical Report:

PPC = PPC * FPTCS 'Cost multiplier

*** End of Base Plant Costing

LINE8 : ' BRINE STABILIZATION

' At 13 March 87, covers only cost of crystallizer-clarifier.

BSCAP=.00001 : BSOAM=.00001 'Nil

IF PTYPE = 2 AND ZZB = 1 THEN BSCAP = 6.6

IF PTYPE = 2 AND ZZB = 2 THEN BSCAP = 14.0

IF PTYPE = 2 THEN BSOAM = 0.15*ZZB

BSCAP = BSCAP * RADACH(26) '[R26]

BSOAM = BSOAM * RADACH(18) '[R18]

RESULTS(2,JSITE,8,1) = BSCAP 'CAP

RESULTS(2,JSITE,8,2) = BSOAM 'OM

LINE9 : ' ENVIRONMENTAL CONTROL

' At 13 March 87, covers only cost of H2S control.

ENVCAP=0.00001 : ENVOAM=0.00001 'Nil

HSULF = (SITEDATA(ZRI,11,JSITE)) 'ppm

IF HSULF > 70 AND PTYPE = 2 THEN ENVCAP = 6.0 ' \$M

IF HSULF > 500 AND PTYPE = 2 THEN ENVCAP = 8.3 ' \$M

IF HSULF > 70 AND PTYPE = 2 THEN ENVOAM = 2.2 ' \$M/yr

ENVCAP = ENVCAP*RADACH(27) '[R27]

ENVOAM = ENVOAM*RADACH(19) '[R19]

RESULTS(2,JSITE,9,1) = ENVCAP 'CAP

RESULTS(2,JSITE,9,2) = ENVOAM 'OM

'LINE10: ' RESERVOIR INSURANCE

'16 Jan 87, Rough estimate:

'Insurance set at 5 percent of post-confirmation Cap. Cost:

ZINSUR = 0

FOR I = 3 TO 9

ZINSUR = ZINSUR + RESULTS(2,JSITE,I,1)

NEXT I

RESULTS(2,JSITE,10,1) = 0.05 * ZINSUR 'CAP

RESULTS(2,JSITE,10,2) = .00001 'OM

'LINE12: ' CONTINGENT RISK

RESULTS(2,JSITE,12,1) = .00001 'CAP

RESULTS(2,JSITE,12,2) = .00001 'OM

***** FINANCIAL ADJUSTMENTS, AS COST CHANGES:

*** ADJUST FIELD COSTS:

' Set Capital Costs into RESCAPADJ(12), which
' keeps RESULTS(1,J,K,1) as capital cost estimates.
FOR I=1 TO 12:RESCAPADJ(1)=RESULTS(2,JSITE,I,1):NEXT I

*** NOTE: Hand Calculate PTOF,DTOF from 2 BUSIMGOE.BAS runs.

' Version 3.00: Same economics for plant and field:

PTOF=1.000 '(Field VLAFCR)/(Plant VLAFCR)

DTOF=1.000 '(Field DISC)/(Plant DISC)

FLAFCR=PTOF*VLAFCR : FISC=DTOF*DISC 'Field Rates

*** Expense INTANGIBLE % of wells

' LINE1 - IDENTIFY:

' Entire cost assumed intangible and expensed:

RESCAPADJ(1) = RESCAPADJ(1) * (1 - (1.0)*INTXR)

' LINE2 - CONFIRM:

' Large additional fraction is intangible:

RESCAPADJ(2) = RESCAPADJ(2) * (1 - INTXR*(FINT +.3)/1.3)

' LINE3 - FIELD DEVELOPMENT WELLS:

' The nominal fraction of well costs is intangible:

RESCAPADJ(3) = RESCAPADJ(3) - WCTL*FINT*INTXR

*** LEVELIZED COSTING CALCULATIONS:

***** ROYALTIES, ETC

' SEVFAC "Severance Factor" is used to adjust all costs to

' reflect positive effects of royalty rate, resource severance

' tax, and negative effect of resource depletion allowance tax

' saving on the final cost of power.

SEVFAC=1/(1 - ROYR - SEVR + (INTXR)*DEPL)

RMILLS = 1000*COSTADJ/(8.76*POUT*FLVLCF)

'SET UP FACTORS FOR MILLS/KWH, LEVELIZED IN CONSTANT DOLLARS

' NOTE: "Constant \$" cost is January 1986 cost. This must be

' multiplied by the assumed general rate of inflation to

' get the sales cost in each succeeding year.

MFCP = FABC*FAFRD*YOAM*FLAFCR*RMILLS*SEVFAC/GLVL

MPCP = FABC*FAFRD*ZOAM*VLAFCR*RMILLS/GLVL

MFOM = YOAM*FLVL*RMILLS*SEVFAC/GLVL

MPOM = ZOAM*GLVL*RMILLS/GLVL

```

'CONVERT Capital and O&M Costs to mills/kwh
,
' CAPITAL ACCOUNTS:
FOR I = 1 TO 3
  RESULTS(2,JSITE,I,3) = MFCP * RESCAPADJ(I)
NEXT I
FOR I = 4 TO 10
  RESULTS(2,JSITE,I,3) = MPCP * RESCAPADJ(I)
NEXT I
' O&M ACCOUNTS:
' Deep Pump O&M, per Field Equipment Factor:
FOR I = 1 TO 4
  RESULTS(2,JSITE,I,4) = MFOM * RESULTS(2,JSITE,I,2) : NEXT I
FOR I = 5 TO 10
  RESULTS(2,JSITE,I,4) = MPOM * RESULTS(2,JSITE,I,2) : NEXT I
,
'Find Account Subtotals: Cap + O&M, mills/kwh:
FOR I = 1 TO 10
  RESULTS(2,JSITE,I,5) = RESULTS(2,JSITE,I,3)+RESULTS(2,JSITE,I,4)
NEXT I
,
' RISK (LINE12) IS ZERO DURING THESE SUMMATIONS
,
LINE11:      'COST TOTALS
,
' And, Bottom Line Totals, $, $/Yr, 3 X Mills/kwh :
FOR I = 1 TO 5 : ZZXR = 0
  FOR J=1 TO 10
    ZZXR = ZZXR + RESULTS(2,JSITE,J,I)
  NEXT J      : RESULTS(2,JSITE,11,I) = ZZXR
NEXT I
,
'AND FINAL BUSBAR COST:
,
BUSBAR = RESULTS(2,JSITE,11,5)
,
RETURN
'*** END SUBR:   ENGINE.CORE   ***

'***** END OF SUB-FILE: CALCULATION ENGINE *****

```

```

'*** ZMENU
/
'**** MENUS SECTION ****

' LAST EDITED      14 March 1987

TOPMENU :
/
'*** ENTRY POINT and INTIATION for TOP MENUS: *****
AXPS = "-----"
BXPS = " "
MLITS = AXPS+AXPS+"--" : MLIMS = "|" + AXPS+AXPS+"|"
MLIBS = "|" + BXPS+BXPS+"|"
CLS '***** TOP MENU *****
PRINT MLITS
PRINT "| IM-GEO-[Z]      START-UP and QUIT MENU      |"
PRINT MLIMS
PRINT "|      A. HELP:   What You Can / Should Do Here      |"
PRINT "|      B. SELECT: Report Contents                      |"
PRINT "|      C. SHOW:   Files/Print Control STATUS           |"
PRINT MLIMS
PRINT MLIBS
PRINT "|      F. SET:    BASE CASE to Current Data           |"
PRINT "|      G. RESET:  BASE CASE to Original Defaults        |"
PRINT MLIBS
PRINT MLIMS
PRINT "|      R. CHANGE: Where REPORTS are sent:              |"
PRINT "|                  NOW = "; CHANNEL$ ; "                |"
PRINT MLIMS
PRINT MLIBS
PRINT "|      Y. GO TO:  OPERATIONS Menu                      |"
PRINT MLIBS
PRINT MLIMS
PRINT "|      Q. QUIT to DOS                                  |"
PRINT MLITS
PRINT "ENTER SELECTION =====> ";
TOPMENU1 : GOSUB INLETTER: IF ANS$ = "" THEN GOTO TOPMENU1
/
IF ANS$="A" THEN HELP$ = "HTOPMENU.HLP" : GOSUB SUBHELP
'IF ANS$="B" THEN GOSUB SUBREPCON ' 7 Dec 86
'IF ANS$="C" THEN GOSUB MENSTATUS
IF ANS$="F" THEN GOSUB CALC.MULTI.SITES : 'Get C.O.P. Values
                GOSUB MAKE.BASE.CASE ' - 'Load values
IF ANS$="G" THEN GOSUB subIBASELOAD ' Reset ALL
IF ANS$="Y" THEN GOTO MENUEDIT ' 8 DEC.
'***** THE EXIT Point *****
IF ANS$="Q" THEN CLS : SYSTEM
IF ANS$="R" THEN
    IF PSWITCH$ = "p"
        THEN PSWITCH$ = "F" ELSE PSWITCH$ = "P"
IF PSWITCH$ = "P"
    THEN CHANNEL$ = CHANNEL1$ ELSE CHANNEL$ = CHANNEL2$
GOTO TOPMENU ' No valid option selected.
'*** END: MENU: START-UP = "TOPMENU"

```

MENUEEDIT :

' EDFLAG\$="NO" & EDFLAG2\$="NO" ' Set in INIT & elsewhere.

CLS

M2LTS = STRING\$(72,"-")

M2LMS = "|" + STRING\$(70,"-")+ "|"

M2LBS = "|" + STRING\$(70,"-")+ "|"

PRINT M2LTS

PRINT "| IM-GEO-[Y] OPERATI";

PRINT "ONS MENU |"

PRINT M2LMS

PRINT "| A. HELP: Editing Options ";

PRINT " K. HELP: Report Options |"

PRINT "| B. EDIT: R&D Achvmnts, RESERVOIR";

PRINT " L. SHOW: R&D Achievements |"

PRINT "| C. EDIT: R&D Achvmnts, WELLS ";

PRINT " M. SHOW: 1-Site Current Costs |"

PRINT "| D. EDIT: R&D Achvmnts, PLANTS ";

PRINT " N. SHOW: 1-Site Base Case Costs |"

PRINT "| E. EDIT: RISKS, RESERVOIR ";

PRINT " O. PRINT 1-Site Technical Details |"

PRINT "| F. EDIT: RISKS, WELLS & FLOW ";

PRINT " P. **** |"

PRINT "| G. EDIT: RISKS, UNIT COSTS ";

PRINT " Q. SHOW: Multi-Reg., Costs X Region |"

PRINT "| H. EDIT: Regional WEIGHTS ";

PRINT " R. PRINT Multi-Reg., FINE GRAIN Rpt |"

PRINT "| I. **** ";

PRINT " S. **** |"

PRINT "| J. EDIT: Financial Factors ";

PRINT " T. EJECT Page (After <Prt.Scr>) |"

PRINT M2LMS

PRINT "| U. SELECT: Single Analysis Site, NOW = ";

PRINT STR\$(JSITE); "|"

PRINT "| V. RUN: Single-Site Cost of ";

PRINT "Power Analysis |"

PRINT M2LMS

PRINT "| W. RUN: Multi-Region Analysis";

PRINT ", (ACCOUNTS X PERCENT Report) |"

PRINT M2LMS

PRINT "| Z. GO TO: START-UP / QUIT MENU ";

PRINT " |"

PRINT M2LTS

PRINT "ENTER SELECTION -----> ";

```

MENUEDIT1 :
  GOSUB INLETTER: IF ANS$ = "" THEN GOTO MENUEDIT1
  'OPERATIONS Action List:
  '''Set static TTIMES$ if editing of factors occurs:
  '''IF 0 <> INSTR("BCDEFGHM",ANS$) THEN TTIMES$ = TIMES

  SAV$ = ANS$ ' To restore selection after *** SUBR: changes.
  IF ANS$="A" THEN HELP$ = "HEDIT.HLP" : GOSUB SUBHELP
  IF ANS$="K" THEN HELP$ = "HSHOW.HLP" : GOSUB SUBHELP
  IF ANS$="B" THEN GOSUB EDIT.ACH.FIELD
  IF ANS$="C" THEN GOSUB EDIT.ACH.WELLS
  IF ANS$="D" THEN GOSUB EDIT.ACH.PLANT
  IF ANS$="E" THEN GOSUB EDIT.RISK.RESVOIR
  IF ANS$="F" THEN GOSUB EDIT.RISK.WELLS
  IF ANS$="G" THEN GOSUB EDIT.RISK.COSTS
  'Fix up risk factors:
  IF (0 <> INSTR("EFG",SAV$)) AND EDFLAG$="YES" THEN _
    GOSUB ADJUST.WORST.DATA
  IF ANS$="J" THEN GOSUB EDFIN
  IF ANS$="L" THEN GOSUB RADACH.SCRN
  IF ANS$="T" THEN LPRINT CHR$(12); : ANS$ = "ZAP" 'Ej. page
  '
  IF LEN(ANS$) > 1 THEN GOTO MENUEDIT 'Done with above, ZAP.
  'Unresolved effects for both Single and Multiple cases:
  IF EDFLAG$ = "YES" THEN EDFLAG2$ = "YES"
  'If no unresolved changes, don't mess about:
  IF EDFLAG$ <> "YES" AND EDFLAG2$ <> "YES" THEN GOTO MENUEDIT3
  'Recalc for single-site reports:
  IF 0 <> INSTR("MNOV",SAV$) AND EDFLAG$ = "YES" THEN _
    GOSUB SUBENGINE
  'Recalc for multi-site reports:
  IF 0 <> INSTR("QRW",SAV$) AND EDFLAG2$ = "YES" THEN _
    GOSUB CALC.MULTI.SITES : EDFLAG2$ = "NO"
  EDFLAG$ = "NO" ' Everything is fixed for single case.
  ANS$ = SAV$ ' Restore user's option selection.

MENUEDIT3 :
  IF ANS$="H" THEN GOSUB MENUWEIGHTS
  IF ANS$="M" THEN IXCOST=2:GOSUB COSTS.OUT 'Current 1 site
  IF ANS$="N" THEN IXCOST=1:GOSUB COSTS.OUT 'Base 1 site
  IF ANS$="O" THEN GOSUB SUBENGINE : 'Intermed. Data = JSITE
    GOSUB SITE.TECH.FACS '1-Site Technical
  IF ANS$="Q" THEN GOSUB REGIONS.SCR 'Costs, Multi-Site
  IF ANS$="R" THEN GOSUB COSTS.LIST: 'Costs, Sites X Accounts
  '
  IF ANS$="U" THEN GOSUB PICK.ONE.SITE :
    IF EDFLAG2$ = "YES" THEN GOSUB SUBENGINE
  '
  IF ANS$="V" THEN GOSUB SUBGENCOP 'Run/Show 1 Prospect
  IF ANS$="W" THEN GOSUB RUN.MULTI 'Run Multi-Site
  IF ANS$="Z" THEN ANS$ = "ZAP" : GOTO TOPMENU
  GOTO MENUEDIT ' NO GOOD RESPONSE

```

```

SUBHELP :
'*** SUBR: Writes simple HELP to screen.
CLS : axb$ = "*****"
print axb$ + " HELP " + axb$ : OPEN HELPS FOR INPUT AS #3
HELP.YOU2 : IF EOF(3) THEN GOTO HELP.YOU4
LINE INPUT#3, B$ : IF LEFT$(B$,3)="$$$" THEN GOTO HELP.YOU4
PRINT B$ : GOTO HELP.YOU2 ' Next Line
HELP.YOU4 : PRINT
PRINT "*****> PRESS ANY KEY ";
PRINT "to CONTINUE <*****"
GOSUB INLETTER : CLOSE #3 : ANS$ ="ZAP" : RETURN
'*** END SUBR: Give HELP *****

```

MENUWEIGHTS :

```

CLS : PRINT MLITS
PRINT "| IM-GEO-[Y,H] Select Regional Weights for Totals |"
PRINT MLIMS
PRINT "| Re-weighted results appear quickly, since individual |"
PRINT "| regional power costs do not have to be recomputed. |"
PRINT MLIBS
PRINT "| A. HELP: What You Can / Should Do Here |"
PRINT MLIMS
PRINT MLIBS
PRINT "| CURRENT SELECTION: "; WEIGHT$ ; " |"
PRINT MLIBS
PRINT MLIMS
PRINT "| I. Weight = Regional Capacity [ = DEFAULT ] |"
PRINT "| J. Weight = Equal for all Regions |"
PRINT "| K. Weight = User's Numerical Values |"
PRINT "| L. Weight = Relevance to R&D Program |"
PRINT MLIBS
PRINT "| S. SHOW/PRINT Value of Current Weights |"
PRINT MLIMS
PRINT "| Z. CONTINUE |"
PRINT MLITS
PRINT "ENTER SELECTION -----> ";
MENUWEIGHTS1 :
GOSUB INLETTER: IF ANS$ = "" THEN GOTO MENUWEIGHTS1
IF ANS$="I" THEN GOSUB WEIGHT.CAPACITY : GOTO MENUWEIGHTS3
IF ANS$="J" THEN GOSUB WEIGHT.UNITY : GOTO MENUWEIGHTS3
IF ANS$="K" THEN GOSUB WEIGHT.USER : GOTO MENUWEIGHTS3
IF ANS$="L" THEN GOSUB WEIGHT.RELEVANCE : GOTO MENUWEIGHTS3
GOTO MENUWEIGHTS9 'Skip display
MENUWEIGHTS3 : 'Show newly weighed results:
GOSUB WAY.SUMS : TTIMES = TIMES : GOSUB SHOW.MULTI
MENUWEIGHTS9 :
IF ANS$="A" THEN HELPS = "HWEIGHT.HLP" : GOSUB SUBHELP
IF ANS$="S" THEN GOSUB WEIGHTS.SHOW
IF ANS$="Z" THEN ANS$="ZAP" : RETURN
GOTO MENUWEIGHTS ' No valid option selected.
'*** END: MENU: Set Regional Weights 10 Feb 87

```

'*** END SECTION: ZMENUS ***

```

'*** ZCTRL
'
'***** CONTROL OF MAJOR CALCULATIONS *****

' Last Edited      21 Feb 87

SUBGENCOP :
'
'*** SUBR: ' Calculate One Plant Case, Show/Print
'   CLS
'   GOSUB subENGINE
'   GOSUB 9CONSOLE1      'Show/Print Results
'   ANS$ = "ZAP" : RETURN 'to CALLER
'*** END SUBR: SUBGENCOP *****

SUBENGINE :
'
'*** SUBR: SINGLE SITE CALC VERSION
'Direct call to here will calculate, not Show/Print.
'Is called from 4 or 5 places: 21 Feb 87.
'JSITE = [1-8] (Site # to Do). Must be set above.
'   CLS
'   PRINT WELCOMES : PRINT
'   : PRINT "WAIT: RECALCULATING SINGLE SITE No. : "; JSITE
'   GOSUB CALC.A.SITE
'   RETURN
'*** END SUBR: SINGLE SITE CALC VERSION

'***** CONTROL CALC-ENGINE FOR MULTI-CASE USES *****

RUN.MULTI :
'
'*** SUBR: Calc and Show Multi-Site Case
'   GOSUB CALC.MULTI.SITES 'Calc. 8 Sites
'   GOSUB SHOW.MULTI      'Display the results
'   RETURN
'*** END SUBR: Calc and Show Multi-Site Case

SHOW.MULTI :
'
'*** SUBR: Show Multi-Site Case
'   GOSUB LOAD.OUT.MULTI   'Load Output Array
SHOW.MULTI1 :
'   GOSUB SHOW.ACCOUNTS ' TO SCREEN
'   GOSUB SHOW.CHOICE   ' USER RESPONSE
'   IF ANS$ <> "ZAP" THEN GOTO SHOW.MULTI1 'RESHOW
'   RETURN
'*** END SUBR: Show Multi-Site Case

```


CALC.MULTI.SITES :

```
'
'*** SUBR: Calculate and Show MultiSite Case
CLS : PRINT WELCOMES : PRINT
PRINT "WAIT: CALCULATING 8 REGIONS: " : PRINT
TEMPSITE = JSITE      'Save User's Selection
FOR IXSITE = 1 TO 8
  PRINT "      REGION:"; IXSITE
  JSITE = IXSITE : GOSUB CALC.A.SITE ' ENGINE. Do one of 8.
NEXT IXSITE
GOSUB WAY.SUMS      'Reset Weighted Averages
JSITE = TEMPSITE    'Restore User's Selection, Data:
IF JSITE <> 8 THEN GOSUB SUBENGINE
RETURN
'*** END SUBR: Calculate MultiSite Case
```

LOAD.OUT.MULTI:

```
'
'*** SUBR: Out-Load Multi-Site Results:
B$ = "Multi-Region Weighted Averaged Data "
CASETITLE$ = B$ + "WEIGHTS = " + WEIGHTS$
ZREPORT$ = "A"      'No-cost report
' Move 8-case results to SHOWOUT(12,4):
FOR I = 1 TO 12
  ' Base Case Percents:
  SHOWOUT(I,1) = 100*(RESMUL(1,I)/RESMUL(1,11))
  ' Current/Base Totals:
  SHOWOUT(I,2) = 100*(RESMUL(2,I)/RESMUL(1,11))
  ' Current, Change from Base:
  SHOWOUT(I,3) = 100*((RESMUL(2,I)/RESMUL(1,I)) - 1)
  ' Current Case Percents:
  SHOWOUT(I,4) = 100*RESMUL(2,I)/RESMUL(2,11)
NEXT I      ' Ready to display
RETURN
'*** END SUBR: Load-Out Multi-Site Case
```

WAY.SUMS :

```
'
'*** SUBR: Make Weighted Averages:
'12 Accounts, weighted and normalized:
FOR K = 1 TO 12 : B = 0 : C = 0 'Base & Current cases
  FOR J = 1 TO 8
    B = B + RESULTS(1,J,K,5)*WEIGHT(J)
    C = C + RESULTS(2,J,K,5)*WEIGHT(J)
  NEXT J : RESMUL(1,K)=B/WAYSUM : RESMUL(2,K)=C/WAYSUM
NEXT K
'5 Cost Values, weighted and normalized:
FOR I = 1 TO 2 : FOR L = 1 TO 5 : A = 0
  FOR J = 1 TO 8
    A = A + RESULTS(I,J,11,L)*WEIGHT(J)
  NEXT J
  WCOLSTL(I,L) = A/WAYSUM
NEXT L : NEXT I
RETURN
'*** END SUBR: Make Weighted Averages
```

```

'*** FOUR WEIGHT SETTING ROUTINES *****
,
WEIGHT.CAPACITY :
,
'*** SUBR: Weight = Region's gross potential
EDFLAG$ = "YES"
TTIME$ = TIME$ 'Set time stamp.
WEIGHT.CAPACITY.EX : '<-- For automatic use, w/o top flags.
CLS : WAYSUM = 0
FOR J = 1 TO 8
' RISK SET HERE, 20 Feb. Per S.P. & D.J.E.
  WEIGHT(J) = SITEDATA(2,1,J)
  WAYSUM = WAYSUM + WEIGHT(J)
NEXT J
WEIGHT$ = "Regional Capacity"
ZWAYZ = 1 : ANS$ = "ZAP" : RETURN
'*** END SUBR: WEIGHT.CAPACITY
,
WEIGHT.UNITY :
,
'*** SUBR: All weights set to 1.0
CLS: FOR I = 1 TO 8 : WEIGHT(I) = 1 : NEXT I
  WAYSUM = 8
WEIGHT$ = "Equal for all Regions"
ZWAYZ = 2 : EDFLAG$ = "YES" : TTIME$ = TIME$ 'Set time stamp.
ANS$ = "ZAP" : RETURN
'*** END SUBR: WEIGHT.UNITY
,
WEIGHT.USER :
,
'*** SUBR: Weights entered by user.
' Restore Users Earlier Weights : ARE IN WEIGHT.USER
' Let User edit the weights (using DATA)
CLS
MNAME$ = " WEIGHT for Region's Contribution to Totals"
MSIZE = 8
FOR I = 1 TO 8
  MV(I) = WEIGHT.USER(I)
  IF MV(I) < .00001 THEN MV(I) = 0 'Hide protection
  MMS(I) = "WEIGHT of " + SITENAME$(I) 'Region name
NEXT I
GOSUB SUBDATA 'Time stamp, EDFLAG$ are there.
'And store results:
WAYSUM = 0
FOR I = 1 TO 8
  IF MV(I) <= 0 THEN MV(I) = .000001 'Protection
  WEIGHT.USER(I) = MV(I) 'User's Weights
  WEIGHT(I) = WEIGHT.USER(I) 'Active Weights = User's
  WAYSUM = WAYSUM + WEIGHT(I) 'Active sum
NEXT I
WEIGHT$ = "User's Numerical Values"
TTIME$ = TIME$ 'User may be just checking, and keeping
this selection.
ZWAYZ = 3 : ANS$ = "ZAP" : RETURN
'*** END SUBR: WEIGHT.USER

```

```

,
WEIGHT.RELEVANCE :
,
'*** SUBR: Weighted by Resource and C.O.P. utility
,
' The utility function here assumes that the program's interest
' in a region decreases on either side of an assumed competitive
' cost of power of 80 mills/KWh. C.O.P. used is from Base Case.
,
EDFLAG$ = "YES"
TTIME$ = TIME$ 'Set time stamp.
WEIGHT.RELEVANCE.EX : '<-- For automatic use, w/o top flags.
CLS
FOR J = 1 TO 8
  COP = RESULTS(1,J,11,5) 'Mills/KWh Total, Base Case
  MWE = SITEDATA(2,1,J) 'Resource potential, Risk Loaded
  ' COP utility curve:
  IF COP <= 80 THEN U = COP/80 ELSE U = 80/COP
  WEIGHT(J) = MWE*U/1000
NEXT J
WAYSUM=0
FOR I=1 TO 8:WAYSUM=WAYSUM+WEIGHT(I) : NEXT I
WEIGHT$ = "Relevance to R&D Program "
ZWAYZ = 4
ANS$ = "ZAP" : RETURN
'*** END SUBR: WEIGHT.RELEVANCE
,
'*** END OF THE WEIGHT SETTING ROUTINES *****

MAKE.BASE.CASE :
,
'*** SUBR: Fill base case from current case, all Regions:
CLS : PRINT WELCOMES : PRINT
PRINT "WAIT: FILLING BASE CASE VALUES"
FOR J = 1 TO 10
  FOR K = 1 TO 12
    FOR L = 1 TO 5
      RESULTS(1,J,K,L) = RESULTS(2,J,K,L)
      IF RESULTS(1,J,K,L)=0 THEN
        RESULTS(1,J,K,L)=.000001 '** Prevent Div by Zero
      IF RESULTS(2,J,K,L)=0 THEN
        RESULTS(2,J,K,L)=.000001 '** Prevent Div by Zero
    NEXT L
  NEXT K
NEXT J
RETURN
' *** END SUBR: MAKE.BASE.CASE

'*** END OF ZCTRL PORTION OF CODE ***

```

```

'*** ZEDIT
,
'*** EDIT MAJOR FACTORS *****

' Last Edited: 13 March 87

PICK.ONE.SITE :
,
'For Single-Site Analysis:
CLS :
PRINT "SELECT SINGLE SITE FROM ONE OF THE FOLLOWING: "
PRINT : PRINT
FOR I = 1 TO 8
  PRINT USING "#####. "; I;
  PRINT SITENAME$(I)
NEXT I
LOCATE 14,8 : PRINT "CURRENT SITE # IS: "; JSITE
LOCATE 16,8
INPUT "SELECT SITE NUMBER [1 - 8], <Enter> : ", ZNSITE
ZNSITE = INT(ZNSITE)
IF (ZNSITE < 1) OR (ZNSITE > 8) THEN GOTO PICK.ONE.SITE
JSITE = ZNSITE
ANS$="ZAP" : RETURN
'*** END SUBR: PICK.ONE.SITE

EDIT.ACH.FIELD :
'***SUBR: Edit R&D Achievements, Reservoir *****
'Variables: REV(I) = 1 - 9
CLS : MNAME$=" R&D Achievements for RESEVOIR"
MSIZE=9
FOR I = 1 TO MSIZE
  MV(I)=RADACH(REV(I)):MM$(I)=RADACH$(REV(I))
NEXT I
GOSUB subDATACH 'Data Changer, then Outload:
FOR I = 1 TO MSIZE : RADACH(REV(I)) = MV(I) : NEXT I
ANS$="ZAP" : RETURN
'*** END SUBR: EDIT.ACH.FIELD ***

EDIT.ACH.WELLS :
'***SUBR: Edit R&D Ach.s, WELLS *****
'Variables: REV(I) = 10 - 22
CLS : MNAME$=" R&D Achievements for WELLS"
MSIZE=13
FOR I = 1 TO MSIZE
  MV(I)=RADACH(REV(I+9)):MM$(I)=RADACH$(REV(I+9))
NEXT I
GOSUB subDATACH
FOR I = 1 TO MSIZE : RADACH(REV(I+9)) = MV(I) : NEXT I
ANS$="ZAP" : RETURN
'*** END SUBR: EDIT.ACH.WELLS ***

```

```

EDIT.ACH.PLANT :
'***SUBR: Edit R&D Ach.s, PLANTS *****
'Variables: REV(I) = 23 - 35
CLS : MNAME$=" R&D Achievements for PLANTS"
MSIZE=13
FOR I=1 TO MSIZE
  MV(I)=RADACH(REV(I+22)):MM$(I)=RADACH$(REV(I+22)):NEXT I
GOSUB subDATAACH
  FOR I = 1 TO MSIZE : RADACH(REV(I+22)) = MV(I) : NEXT I
ANS$="ZAP" : RETURN
'*** END SUBR: EDIT.ACH.PLANT ***

```

```

EDIT.RISK.RESVOIR :
'
'***SUBR: Edit Estimation Errors, RESERVOIR *****
'Variables: 1 - 12
CLS : MNAME$=" Estimation Errors for RESERVOIR"
MSIZE=12
FOR I=1 TO MSIZE
  MV(I)=RADRISK(I) : MM$(I)=RADRISK$(I):NEXT I
SAVPOT = RADRISK(1) 'Re Weight Resetting
GOSUB subDATAACH
  FOR I = 1 TO MSIZE : RADRISK(I) = MV(I) : NEXT I
'Reset weights under certain conditions:
IF SAVPOT = RADRISK(1) THEN GOTO EDIT.RISK.RESV9 'OK
IF ZWAYZ = 2 OR ZWAYZ = 3 THEN GOTO EDIT.RISK.RESV9 'OK
'Reset Weights, and recalculate all:
IF ZWAYZ = 1 THEN GOSUB WEIGHT.CAPACITY
IF ZWAYZ = 4 THEN GOSUB WEIGHT.RELEVANCE
GOSUB ADJUST.WORST.DATA '': GOSUB CALC.MULTI.SITES
EDFLAG$ = "NO" : EDFLAG2$ = "NO"
EDIT.RISK.RESV9 :
ANS$="ZAP" : RETURN
'*** END SUBR: EDIT.RISK.RESVOIR ***

```

```

EDIT.RISK.WELLS :
'***SUBR: Edit Estimation Errors, WELLS & FLOW *****
'Variables: 13 - 26
CLS : MNAME$=" Estimation Errors for WELLS & FLOW"
MSIZE=14
FOR I=1 TO MSIZE
  MV(I)=RADRISK(I+12) : MM$(I)=RADRISK$(I+12):NEXT I
GOSUB subDATAACH
FOR I = 1 TO MSIZE : RADRISK(I+12) = MV(I) : NEXT I
ANS$="ZAP" : RETURN
'*** END SUBR: EDIT.RISK.WELLS ***

```

```

'Programming Note: 18 Jan 87
' Variables RADRISK(27-30) are not edited. They are integer
' values that select aspects of technology for each region.
' These variables can be changed only by editing the site
' data file "SITEDATO.SIT" or other versions of site
' data files.

```

```

EDIT.RISK.COSTS :
'***SUBR: Edit Estimation Errors, UNIT COSTS *****
'Variables: 31-38
CLS : MNAME$=" Estimation Errors for UNIT COSTS"
MSIZE=8
FOR I=1 TO MSIZE
MV(I)=RADRISK(I+30) : MM$(I)=RADRISK$(I+30):NEXT I
GOSUB subDATACh
FOR I = 1 TO MSIZE : RADRISK(I+30) = MV(I) : NEXT I
ANS$="ZAP" : RETURN
'*** END SUBR: EDIT.RISK.COSTS ***

'Programming Note:
' The following OLD Editors were moved to
' file: ZHOLD on 19 Feb 87:
'EDPROSP: '***SUBR: EDIT Base Case G.T. Prospect
'EDLOGI : '***SUBR: EDIT Reservoir LOGICAL Data
'EDRISK : '***SUBR: EDIT RESERVOIR RISK FACTORS
'EDRAND : '***SUBR: EDIT MAJOR IMPACT MULTIPLIERS

EDFIN :
'
'***SUBR: EDFIN: EDIT Financial Factors *****
MNAME$=" Financial Factor Data Values "
MSIZE=4
MM$(1) = O$ : MM$(2) = P$ : MM$(3) = Q$ : MM$(4)=R$
MV(1)=ROYR : MV(2)=SEVR : MV(3)=DEPL : MV(4)=FINT
GOSUB subDATACh 'DATACh = Data Changer
'Reload new data values:
ROYR=MV(1) : SEVR =MV(2) : DEPL=MV(3) : FINT=MV(4)
ANS$="ZAP" : RETURN
'*** END SUBR: EDFIN ***

'***** DATA AND TABLE EDITING SUBROUTINES:

INLETTER : ' ** SUBR **
' Get/Clean Up 1-char ALPHA Input
' Accepts one key press. Returns:
' - ANS$ = A-Z or ""
' - ANS = 1-26 or 0
INLETTER1: ANS$ = INKEY$
IF ANS$ = "" THEN GOTO INLETTER1
ANS = ASC(ANS$): IF ANS > 90 THEN ANS=ANS-32
ANS$ = CHR$(ANS) : ANS = ANS - 64
IF (ANS < 1) OR (ANS > 26) THEN ANS$="": ANS=0
RETURN
'*** END SUBR: INLETTER **

```

```

subDATACH:
'*** SUBR: DATACH: GENERAL DATA CHANGING HANDLER ***
' Edits by changing absolute value.
' Calling:
'     MSIZE = Number of data elements (rows)
'     MM$(i) = i-th Data element name
'     MV(i) = i-th Data element numerical value
'     MNAME$ = Menu Title
'
BLANK$ = STRING$(79," ")
'Print MENU Title and (n = MSIZE) Options:
subDATACH1 : CLS : LOCATE 1,1
PRINT "EDITING: " + MNAME$ ":" : PRINT: PRINT
FOR I = 1 TO MSIZE
PRINT CHR$(64+I) + ". " + MM$(I);
IF MM$(I) <> ""
THEN PRINT " / NOW = "; MV(I) _
ELSE PRINT MV(I)
NEXT I
subDATACH2 : LOCATE 20,1,1 ' Response PROMPT
PRINT "ENTER      x of Data Item to Change, or Z to CONTINUE: ";
subDATACH3 :
GOSUB INLETTER : IF ANS$ = "" THEN GOTO SUBDATACH3
IF ANS$ = "Z" THEN GOTO SUBDATACH9 'Done, get out.
IF ANS <= MSIZE THEN GOTO SUBDATACH5 'Is OK
'Reminder re Options:
LOCATE 20,1 : PRINT BLANK$ : PRINT BLANK$ : LOCATE 21,1
PRINT "Selection "; ANS$;" is not on Menu. Select again."
GOTO subDATACH2
'Enter new datum value:
subDATACH5 :
LOCATE 20,1 : PRINT BLANK$ : PRINT BLANK$
EDFLAG$ = "YES" 'Set flag to show editing occurred
TTIME$ = TIME$ 'Set time stamp.
LOCATE 22,1 : PRINT "EDITING: "; ANS$; ". " + MM$(ANS);
PRINT " / NOW = "; MV(ANS)
LOCATE 23,1: INPUT "ENTER NEW VALUE = ", NEWVAL
MV(ANS) = NEWVAL 'New value to Menu Variable
GOTO subDATACH1
subDATACH9 : CLS : RETURN
' *** END SUBR: DATA CHANGING HANDLER ***

' *** END OF DATA EDITORS SECTION ***

```

```

' *** ZLOAD
'
' *** LOAD INITIAL DATA FACTORS *****

' Last Edited      14 March 87

sublBASELOAD :
'
' ** SUBR: Load BASE CASE
' Load Multi-Site Data:
GOSUB LOAD.SITE.DATA      'LOAD Regional Case Data
GOSUB LOADFIN            'Read Financial Factors BUSFNCT.GEO:
' Note: Next two, LOAD.RAD.FACTS & ADJUST.WORST.DATA,
' MUST be after LOAD.SITE.DATA, because they use
' Title Strings or Data from there.
' Open and close report scroll file to empty it:
OPEN "IMGEOUT.TXT" FOR OUTPUT AS #2 : CLOSE #2
GOSUB LOAD.RAD.FACTS
GOSUB ADJUST.WORST.DATA   'MUST be after LOAD.RAD.FACTS
GOSUB WEIGHT.CAPACITY.EX 'Avoid a div.by.zero.
'
CLS : PRINT WELCOMES : PRINT
PRINT "WAIT: LOADING BASE CASE VALUES"
'
GOSUB LOADBASE           'LOAD: BASE CASE parameter values.
GOSUB LOAD.ACCOUNTS      'Load Account TITLES for SHOW.MAIN>
GOSUB CALC.MULTI.SITES   'Set C.O.P. Values
GOSUB MAKE.BASE.CASE     'Set base case values.
GOSUB WEIGHT.CAPACITY.EX 'Default Weights
GOSUB WAY.SUMS           'Weighted results for displays
ANS$ ="ZAP" : RETURN
'*** END SUBR: sublBASELOAD ****

LOADBASE :
'
' *** SUBR: Initialize Physical/Econ Factor Data
' *** Values in [...] are Default Values = "Base Case"
' Note: 18 Feb 87: This was old routine for loading factors and
' stubs for 1 site model. Complete copy of the original can be
' found in "ZOLD0". A few remnants are kept here for
' initialization purposes:
' *** Local Financial Factors: (Probably Used)
ROYR = .1      :O$="Royalty Rate           Default: .10 "
SEVR = .04     :P$="Severance Tax          Default: .04 "
DEPL = .15     :Q$="Percent Depletion Allowance Default: .15 "
FINT = .75     :R$="Intangible Fract. of Well Cost Default: .75 "
'
' *** R&D DETAILED IMPACT MULTIPLIERS:
' Note: None of these are used, as of 4 March 87:
RIDET(1)=1.
RETURN
'***END SUBR: *****

```


LOADFIN:

```
'**SUBR: Read Financial Factors:
OPEN "I", #1, "BUSFNCT.GEO"
INPUT #1, YCB, YPL, YRP, YCN
INPUT #1, FLVLCF, FABC, FAFRD, VLAFCR
INPUT #1, GLVL, FLVL, COSTADJ, ZOAM, YOAM
INPUT #1, FBL, DISC, FIFL
CLOSE #1
RETURN
'*** END SUBR: Read Fin. Factors ***
```

LOAD.SITE.DATA:

```
'**SUBR: Load Multi-Site Base Case Data
CLS : PRINT WELCOMES : PRINT
PRINT "WAIT: LOADING PHYSICAL DATA FOR REGIONS"
'Open Site Data File:
OPEN "SITEDATO.DAT" FOR INPUT AS #1
'Read Regional Titles:
FOR I = 1 TO 9 : INPUT #1, SITENAMES(I) : NEXT I
FOR I = 1 TO 9 : INPUT #1, SITESHORT$(I) : NEXT I
'Read Site Data Names and Values:
FOR I = 1 TO 38
    INPUT #1, DUMMY
    INPUT #1, SITEUSES(I)
    INPUT #1, SITERISKS(I)
    INPUT #1, SITEDATAS(I)
    ' SETS OF DATA
    ' Item Number, Dump
    ' Data Item Used? YES/NO
    ' Risk Offset Used? YES/NO
    ' DATA ITEM HEADER
' Sites physical characteristics data line:
FOR J = 1 TO 9 : INPUT #1, SITEDATA(I,I,J) : NEXT J
' Sites risk add-ons data line:
FOR J = 1 TO 9 : INPUT #1, SITERISK(I,J) : NEXT J
NEXT I
CLOSE #1 : RETURN
'***END SUBR: Load Multi-Site Base Case Data
```

LOAD.RAD.FACTS :

```
'*** SUBR: Load R&D Titles and Factors
'NOTE: Must occur only after first call to LOAD.SITE.DATA,
'       because this uses Title Strings from there.
' 1. Make RADRISK$ Title Strings from SITEDATAS(I):
FOR I = 1 TO 38
    IF SITEUSES(I) <> "YES" THEN RISKS$="" : GOTO ZLRF4
    IF SITERISKS(I) <> "YES" THEN RISKS$="" : GOTO ZLRF4
'ELSE: Title from SITEDATO file.
    RISKS$= "RISK: "+ SITEDATAS(I) +" [Nom.=1.0]"
ZLRF4 :
    RADRISK$(I) = RISKS$
    IF RISKS$="" THEN RADRISK(I)=0 ELSE RADRISK(I)=1.0
NEXT I
```

2. Set RADACH Titles, then Values:

PROGRAMMING NOTE: R&D Achievement Editing Vectors.

Vectors are established here to allow programmer to set different orders and groupings when the R&D achievements are being edited by the user. The reverse vectors, RACH(i) are calculated automatically below. Groupings are set and operated upon at the relevant Editing Screens.

CRITICAL: Use# MUST = Subscript of RADACH\$(i) --.

EDITING VECTOR:		Edit# /	Use#
RADACH\$(1)	= "Wildcat Success Ratio "	: REV(1)	= 1
RADACH\$(2)	= "Testing Costs, Identify "	: REV(2)	= 2
RADACH\$(3)	= "Confirm. Success Ratio "	: REV(3)	= 3
RADACH\$(4)	= "Testing Costs, Confirm "	: REV(4)	= 4
RADACH\$(7)	= "Dry Holes / Producer "	: REV(5)	= 7
RADACH\$(8)	= "Flow Rate, Producer "	: REV(6)	= 8
RADACH\$(9)	= "Flow Rate, Injector "	: REV(7)	= 9
RADACH\$(33)	= "Testing Costs, Producer "	: REV(8)	= 33
RADACH\$(35)	= "Test Costs, Inj. or Dry "	: REV(9)	= 35

RADACH\$(6)	= "Producer Redrill Fract. "	: REV(10)	= 6
RADACH\$(30)	= "Well Prblms, Lost Circul "	: REV(11)	= 30
RADACH\$(31)	= "Well Prblms, Cementing "	: REV(12)	= 31
RADACH\$(32)	= "Well Prblms, Other "	: REV(13)	= 32
RADACH\$(5)	= "TOTAL Cost, Avg. Well "	: REV(14)	= 5
RADACH\$(20)	= "Cap.Cost, Deep Well Pump "	: REV(15)	= 20
RADACH\$(21)	= "O&M Cost, Deep Well Pump "	: REV(16)	= 21
RADACH\$(28)	= "Cap.Cost, Gathering Sys. "	: REV(17)	= 28
RADACH\$(29)	= "O&M Cost, Gathering Sys. "	: REV(18)	= 29
RADACH\$(10)	= "Workover Interval, Prod. "	: REV(19)	= 10
RADACH\$(11)	= "Cost per Workover, Prod. "	: REV(20)	= 11
RADACH\$(12)	= "Workover Interval, Injc. "	: REV(21)	= 12
RADACH\$(13)	= "Cost per Workover, Injc. "	: REV(22)	= 13

RADACH\$(34)	= "Years Between Plants "	: REV(23)	= 34
RADACH\$(14)	= "Efficiency, FLASH Plant "	: REV(24)	= 14
RADACH\$(16)	= "Cap. Cost, FLASH Plant "	: REV(25)	= 16
RADACH\$(22)	= "O&M Cost, FLASH Plant "	: REV(26)	= 22
RADACH\$(15)	= "Efficiency, BINARY Plant "	: REV(27)	= 15
RADACH\$(17)	= "Cap. Cost, BINARY Plant "	: REV(28)	= 17
RADACH\$(23)	= "O&M Cost, BINARY Plant "	: REV(29)	= 23
RADACH\$(24)	= "Cap. Cost, Heat Exchange "	: REV(30)	= 24
RADACH\$(25)	= "O&M Cost, Heat Exchange "	: REV(31)	= 25
RADACH\$(26)	= "Cap. Cost, Brine Stabil. "	: REV(32)	= 26
RADACH\$(18)	= "O&M Cost, Brine Stabil. "	: REV(33)	= 18
RADACH\$(27)	= "Cap. Cost, H2S Treatment "	: REV(34)	= 27
RADACH\$(19)	= "O&M Cost, H2S Treatment "	: REV(35)	= 19

```

' Set nominal value and String:
FOR I = 1 TO 35
  RADACH(I) = 1.0 'Nominal R&D Achievements
' & Augment these Strings:
  RADACH$(I) = "R&D Achvmt: "+ RADACH(I)+" [Nom.=1.0]"
NEXT I
'
' Set Null Strings (For Later, and NULL Editing)
FOR I = 36 TO 40 'DIM IS 60
  REV(I) = I
  RADACH(I) = 1.0
  RADACH$(I) = "R&D Achvmt: EMPTY SLOT"
NEXT I
RETURN
'***END SUBR: Load R&D Achievement Strings & Values

```

LOAD.ACCOUNTS :

```

'*** SUBR: LOAD ACCOUNT STUBS
ACCOUNT$(1) = "Identify Reservoir "
ACCOUNT$(2) = "Confirm Reservoir "
ACCOUNT$(3) = "Wells "
ACCOUNT$(4) = "Downhole Pumps "
ACCOUNT$(5) = "Gathering Equip. "
ACCOUNT$(6) = "Power Plant "
ACCOUNT$(7) = "Heat Exchangers "
ACCOUNT$(8) = "Brine Stabilizing "
ACCOUNT$(9) = "Environmental "
ACCOUNT$(10) = "Insurance "
ACCOUNT$(11) = " TOTAL : "
ACCOUNT$(12) = " RISK FRACTION : "
RETURN
'*** END SUBR: LOAD ACCOUNTS

```

ADJUST.WORST.DATA :

```

' Make SITEDATA(2,I,J) to reflect worst case values:
CLS : PRINT WELCOMES : PRINT
PRINT "WAIT: ADJUSTING WORST CASE DATA"
FOR I = 1 TO 40 : FOR J = 1 TO 10
  SITEDATA(2,I,J) =
    SITEDATA(1,I,J)+ RADRISK(I)*SITERISK(I,J)
NEXT J : NEXT I
RETURN
'***END SUBR: ADJUST.WORST.DATA

```

'***** END OF ZLOAD PORTION OF CODE *****

```

'*** ZOUTS
,
'***** DISPLAY AND REPORTS SECTION *****

' Last Edited    21 Feb 87

'***** DISPLAY RESULTS TO CONSOLE *****

9CONSOLE1:
,
' ** SUBR: SHOW-A: 1-CASE RESULTS TO CONSOLE:
CLS
GOSUB LOAD.OUT.1      ' STANDARD RESULTS
GOSUB SHOW.ACCOUNTS   ' TO SCREEN
GOSUB SHOW.CHOICE     ' USER RESPONSE
IF ANS$ <> "ZAP" THEN GOTO 9CONSOLE1 'RESHOW
RETURN
'*** END SUBR: Show One Case To Console

COSTS.OUT :
,
' *** SUBR: COSTS.OUT
' Single-site 4-column cost report.
CLS: GOSUB LOAD.OUT.COSTS :
' IXCOST = 1: Base Case      = 2: Current Case
IF IXCOST=1 THEN CASETITLE$ = "
Base Case Costs: " + SITENAME$(JSITE)
IF IXCOST=2 THEN CASETITLE$ = "
Current Case Costs: " + SITENAME$(JSITE)
GOSUB SHOW.ACCOUNTS   ' TO SCREEN
GOSUB SHOW.CHOICE     ' USER RESPONSE
IF ANS$ <> "ZAP" THEN GOTO COSTS.OUT 'RESHOW
CASETITLE$ = "" 'Eradicate it.
RETURN
'*** END SUBR: Costs Out to Console

SHOW.ACCOUNTS :
,
' *** SUBR: Main Output to Screen:
WIDTH "SCRN:", 255
OPEN "SCRN:" FOR OUTPUT AS #2 : CLS
GOSUB SHOW.MAIN1 '12 Accounts, % of Base, Risk
CLOSE #2          'Release #2.
RETURN
' *** END Show main to Screen. *****

REGIONS.SCR :
,
'*** SUBR: Regional Results to Screen.
WIDTH "SCRN:", 255
OPEN "SCRN:" FOR OUTPUT AS #2      'Open Console for Output.
CLS : GOSUB REGIONALS : CLOSE #2   'Show results
PRINT
PRINT TAB(8); "ENTER: P = PRINT Results, Z = Continue ----> ";

```

```

REGIONS.SCR1 : GOSUB INLETTER
  IF ANS$ = "P" THEN GOSUB REGIONS.PRN : GOTO REGIONS.SCR
  IF ANS$ = "Z" THEN ANS$ = "ZAP" : RETURN 'EXIT
GOTO REGIONS.SCR1
'*** END SUBR: REGIONS TO SCREEN

SHOW.CHOICE:
,
'*** SUBR: Get User Prompt Re Print:
PRINT TAB(8); "ENTER: P = PRINT Results, Z = Continue > ";
SHOW.CHOICE1: GOSUB INLETTER
  IF ANS$ = "P" THEN GOSUB PRINT.MAIN.RES : CLS : RETURN 'RESHOW
  IF ANS$ = "Z" THEN ANS$ = "ZAP" : RETURN 'EXIT
GOTO SHOW.CHOICE1
'*** END SUBR: SHOW.CHOICE ***

'*****PRINTER OUTPUT ROUTINES *****

PRINT.MAIN.RES :
,
'*** SUBR: SHOW.OUT Results to PRINTER
GOSUB ZOPEN.PRINTER 'Open as #2
GOSUB SHOW.MAIN1 'Percentage of Base, Risk Points
PRINT #2, " "
GOSUB RADACH.OUT
GOSUB ZCLOSE.PRINTER 'Close #2.
ANS$ = "ZAP" : RETURN
'*** END SUBR: Show Main to Printer *****

REGIONS.PRN :
,
'*** SUBR: Regional Results to PRINTER
GOSUB ZOPEN.PRINTER
GOSUB REGIONALS
PRINT #2, " "
GOSUB RADACH.OUT
GOSUB ZCLOSE.PRINTER
ANS$ = "ZAP" : RETURN
'*** END SUBR: REGIONS, TO PRINTER

'***** ROUTINES FOR DEVICE #2 OUTPUT *****
,
' PROGRAMMING NOTE:
' These routines send results to any device that has been
' previously opened as device #2.
' As of 14 Feb 87 they are used only for SCRN: and LPT1:.

SHOW.MAIN1 :
,
' *** SUBR: Master Display for the 12 Accounts
' For Screen or Printer:

```

```

GOSUB SHOW.STUB1
IF ZREPORT$ = "A" THEN GOSUB SHOW.STUB2 'No cost
IF ZREPORT$ = "B" THEN GOSUB SHOW.STUB3 '1-Site 4-col cost
GOSUB SHOW.RESULT1
RETURN ' *** END MAIN Part of OUTPUT SUBR *****

SHOW.STUB1 :
,
PRINT #2, TAB(8); "GEOTHERMAL COST OF POWER ESTIMATE : " ;
PRINT #2, "      RUN: "; DATE$; " - "; TIME$
'Case Title String, if Defined:
IF CASETITLES <> "" THEN PRINT #2, TAB(8); CASETITLES

RETURN
,
SHOW.STUB2 :
,
ZBLIP1$ = "-----"
PRINT #2, TAB(8); ZBLIP1$ + ZBLIP1$
PRINT #2, TAB(8); "      1986      ";
PRINT #2, "***** NEW TECHNOLOGY SYSTEM *****";
PRINT #2, TAB(8); "[From IMGEO Model]    TECHNOL.  ";
PRINT #2, "% OF 1986      % COST      % OF NEW      ";
PRINT #2, TAB(8); "      *****      ";
PRINT #2, "TECHNOLOGY CHANGE      TECH. TOTAL"
PRINT #2, TAB(8); "ACCOUNT      % OF COST      ";
PRINT #2, "ELECT. COST FROM 1986    ELECT. COST"
ZBLIP2$ = "-----"
ZBLIP3$ = "-----"
PRINT #2, TAB(8); ZBLIP2$ + ZBLIP3$
RETURN
,
SHOW.STUB3 :
,
' For one-site mills/kwh display.
ZBLIP1$ = "-----"
PRINT #2, TAB(8); ZBLIP1$ + ZBLIP1$
PRINT #2, TAB(8); "      ----- Millio";
PRINT #2, "n $ ----- Mills/KWhour -----"
PRINT #2, TAB(8); "[From IMGEO Model]    Capital  ";
PRINT #2, " O&M      Capital      Total      ";
PRINT #2, TAB(8); "      Cost,      ";
PRINT #2, " Cost,      Part of      Busbar      ";
PRINT #2, TAB(8); "ACCOUNT      $      ";
PRINT #2, " $/Yr      System      Cost      ";
ZBLIP2$ = "-----"
ZBLIP3$ = "-----"
PRINT #2, TAB(8); ZBLIP2$ + ZBLIP3$
RETURN
,
SHOW.RESULT1 :
,
PRINT #2, TAB(12); ' "      TOTAL:      "; '*****
I = 11 : GOSUB SHOW.RESULT1.1
PRINT #2, TAB(12); ' "      RISK FRACTION:      "; '*****

```

```

I = 12 : GOSUB SHOW.RESUL1.1
PRINT #2, TAB(8); ZBLIP2$ + ZBLIP3$
'DATA ACCOUNTS
FOR I = 1 TO 10
PRINT #2, TAB(8); : PRINT #2, USING "##"; I; : PRINT #2, ". ";
  GOSUB SHOW.RESUL1.1
NEXT I
PRINT #2, TAB(8); ZBLIP1$ + ZBLIP1$
RETURN

```

SHOW.RESUL1.1 :

```

'SUBR: One line of #s for SHOW.MAIN1 output:
PRINT #2, ACCOUNT$(I); TAB(33);
PRINT #2, USING "####.#" ; SHOWOUT(I,1);
PRINT #2, USING "####.#" ; SHOWOUT(I,2);
IF SHOWOUT(I,3)>0 THEN ZBLIP4$=" " ELSE ZBLIP4$="- "
PRINT #2, ZBLIP4$;
PRINT #2, USING "####.#" ; ABS(SHOWOUT(I,3));
PRINT #2, USING "####.#" ; SHOWOUT(I,4)
RETURN
'*** END SUBR: One Line for SHOW.MAIN1 SUBR
'*** END of Main ACCOUNTS Output SUBRs *****

```

REGIONALS :

```

'** SUBR: Show RESULTS BY REGION
CLS
ZBLIPAS$ = "-----"
ZBLIPBS$ = "-----"
PRINT #2,TAB(8); "GEOTHERMAL COST OF POWER ESTIMATE "; DATES$; " - "; TTIMES
PRINT #2,TAB(8); "WEIGHTS = " + WEIGHTS$
PRINT #2,TAB(8); ZBLIPAS$
PRINT #2,TAB(8); "CAP. O&M CAP., O&M, TOTAL, TOTAL, %"
PRINT #2,TAB(8); "COST, COST, MILLS MILLS MILLS CHANGE"
PRINT #2,TAB(8); "REGION $M $M/Y /KWH /KWH /KWH FROM BASE"
PRINT #2,TAB(8); ZBLIPBS$
'PRINT "111.2 ++5.6 130.4 110.2 240.6 +45.2"
'PRINT "1. IV-FL bbxxx.xbbxxx.xbbxxx.xbbxxx.xbbxxx.xbbxxx.x"
FOR J = 1 TO 8
PRINT #2,TAB(8); : PRINT #2,USING "##"; J;
PRINT #2, ". "; SITESHORT$(J); " ";
FOR K=1 TO 5 : PRINT #2,USING " ###.##"; RESULTS(2,J,11,K);
NEXT K
B = RESULTS(1,J,11,5) : A = 100*(RESULTS(2,J,11,5)-B)/B
PRINT #2, USING " ###.##"; A
NEXT J :
PRINT #2,TAB(8); ZBLIPBS$
' Weighted averages:
PRINT #2,TAB(8); "WEIGHTED: " ;
FOR K = 1 TO 5
PRINT #2,USING " ###.##"; WCOLTL(2,K);
NEXT K

```

```

      B = WCOSTL(1,5)
      A = 100.*((WCOSTL(2,5)-B))/B
      PRINT #2,USING "   ###.##"; A
      PRINT #2,TAB(8);ZBLIPAS
      RETURN
'*** END SUBR: Show RESULTS BY REGION

'*** END OF MAJOR OUTPUT ROUTINES *****

'***** ROUTINES FOR PREPPING DATA FOR OUTPUT *****

LOAD.OUT.1 :
'
' Move one case results to SHOWOUT(12,4):
' Case Identification:
CASETITLE$ = "Region : "+STR$(JSITE)+" "+SITENAMES$(JSITE)
ZREPORT$ = "A" 'No-cost report
FOR I = 1 TO 12 :
' Base Case Percents:
  SHOWOUT(I,1) =
    100*(RESULTS(1,JSITE,I,5)/RESULTS(1,JSITE,11,5))
' Current/Base Totals:
  SHOWOUT(I,2) =
    100*(RESULTS(2,JSITE,I,5)/RESULTS(1,JSITE,11,5))
' Current, Change from Base:
  Z = RESULTS(1,JSITE,I,5)
  SHOWOUT(I,3) = 100*((RESULTS(2,JSITE,I,5)/Z) -1)
' Current Case Percents:
  SHOWOUT(I,4) =
    100*(RESULTS(2,JSITE,I,5)/RESULTS(2,JSITE,11,5))
NEXT I
RETURN
' *** END SUBR: LOAD.OUT.1

LOAD.OUT.COSTS :
'
' *** SUBR: Move 1-REGION cost results to SHOWOUT(12,4):
ZREPORT$ ="B" 'One-site 4-col costs.
' IXCOST = 1: Base Case      IXCOST = 2: Current Case.
' Capital, M$
FOR I=1 TO 12 : SHOWOUT(I,1)=RESULTS(IXCOST,JSITE,I,1) : NEXT I
' O&M, M$/Yr
FOR I=1 TO 12 : SHOWOUT(I,2) = RESULTS(IXCOST,JSITE,I,2) : NEXT I
' Capital, mills/kwh
FOR I=1 TO 12 : SHOWOUT(I,3) = RESULTS(IXCOST,JSITE,I,3) : NEXT I
' Total, mills/kwh
FOR I=1 TO 12 : SHOWOUT(I,4) = RESULTS(IXCOST,JSITE,I,5) : NEXT I
RETURN
'*** END SUBR: LOAD.OUT.COSTS

'***** END OF ROUTINES FOR PREPPING DATA *****

'*** END SECTION, ZOUTS.

```



```

'*** ZMISC
,
'*** MISCELLANEOUS ROUTINES SECTION *****

' Last Edited:    15 MARCH 87

COSTS.LIST :
,
'*** SUBR: PRINT BY-SITE COST DATA
CLS: PRINT "SHOULD BE PRINTING"
GOSUB ZOPEN.PRINTER ' As #2
'LPRINT: LPRINT: LPRINT : LPRINT
PRINT #2, TAB(8); "GEOTHERMAL COST OF POWER";
PRINT #2, " "; DATE$; " - "; TIME$
PRINT #2, TAB(8); "IM-GEO: ACCOUNTS-BY-SITE COST DATA"
PRINT #2, " "
S1$ = "EXPLRCNFRMWELLSPUMPSGATHRPLANT"
S2$ = "HTXCHSTABLENVIRINSURTOTALRISK "
STUB$ = S1$+S2$
FOR I = 1 TO 2
  IF I = 1 THEN PRINT #2, TAB(8); "BASE CASE VALUES, MILLS/KWH"
  IF I = 2 THEN PRINT #2, TAB(8); "CURRENT CASE VALUES, MILLS/KWH"
  PRINT #2, " "
  PRINT #2, TAB(8) ; " ";
  FOR J = 1 TO 8
    PRINT #2, SITESHORT$(J); " ";
  NEXT J
  PRINT #2, " " : PRINT #2, " "
  FOR K = 1 TO 12
    S$ = MID$(STUB$, (5*K-4), 5)
    IF K = 12 THEN PRINT #2, " " 'SPACER
    PRINT #2, TAB(8) ; S$ ; " ";
    FOR J = 1 TO 8
      PRINT #2, USING " ###.##"; RESULTS(I,J,K,5);
    NEXT J
    PRINT #2, " " ' CLOSE LINE
  NEXT K
  PRINT #2, " " : PRINT #2, " "
NEXT I
GOSUB ZCLOSE.PRINTER 'Close #2., Eject page.
ANS$ = "ZAP"
RETURN
'*** END SUBR: COSTS.LIST

```

```

'**** REPORT: STATUS OF SENSITIVITY FACTORS
/
RADACH.SCRN :
/
'*** SUBR: R&D Achievements Screen:
CLS
OPEN "SCRN:" FOR OUTPUT AS #2 : GOSUB RADACH.OUT : CLOSE #2
PRINT
PRINT TAB(8); "ENTER: P = Print Results, Z = Continue ==> ";
RADACH.SCRN1 : GOSUB INLETTER
  IF ANS$ = "P" THEN GOSUB RADACH.PRNT: GOTO RADACH.SCRN
  IF ANS$ = "Z" THEN ANS$ = "ZAP" : RETURN 'EXIT
GOTO RADACH.SCRN1
'*** END SUBR: R&D Ach's to Console
/
RADACH.PRNT:
/
GOSUB ZOPEN.PRINTER ' As #2
GOSUB RADACH.OUT
GOSUB ZCLOSE.PRINTER 'Close #2., Eject page.
CLS
RETURN
' *** END SUBR: R&D Ach's to Printer *****
/
RADACH.OUT :
/
'*** SUBR: Show R&D Achievements:
'Header:
PRINT #2, TAB(8); "IM-GEO: SENSITIVITY FACTORS IN EFFECT " ;
PRINT #2, DATE$; " - "; TIME$ : PRINT #2, ""
K = 0 'Toggle for "All Nominal" message
FOR I = 1 TO 35 : IF RADACH(REV(I)) = 1 THEN GOTO RADACH.OUT1
  K = 1 : PRINT #2, TAB(8); RADACH$(REV(I)); ": " ;
  PRINT #2, USING "###.##"; RADACH(REV(I))
RADACH.OUT1 :
NEXT I
IF K=1 THEN PRINT #2, "" 'Spacer
FOR I = 1 TO 38
  IF RADRISK(I) = 1 THEN GOTO RADACH.OUT2
  IF SITEUSE$(I) <> "YES" THEN GOTO RADACH.OUT2
  IF SITERISK$(I) <> "YES" THEN GOTO RADACH.OUT2
  K = 1 : PRINT #2, TAB(8); RADRISK$(I); " : " ;
  PRINT #2, USING "###.##"; RADRISK(I)
RADACH.OUT2 :
NEXT I
IF K = 1 THEN GOTO RADACH.OUT4
PRINT #2, TAB(8); "All Sensitivity Factors = 1.0 "
RADACH.OUT4 :
PRINT #2, " "
PRINT #2, TAB(8); "Regional Weights = "; WEIGHT$
RETURN
' *** End SUBR: Show Sensitivity Factors

```

SITE.TECH.FACS :

```
'*** SUBR: Print Site Detailed Technical Factors
CLS ' Programming Note: "TECHn:" used here for short labels.
PRINT " SHOULD BE PRINTING SITE-TECHNICAL-FACTORS REPORT *** "
GOSUB ZOPEN.PRINTER
```

```
PRINT #2,"          ***** SITE DETAILS ----- Page 1"
PRINT #2,"                                     "; DATES; " - "; TTIME$
PRINT #2,"          Region analyzed: "; JSITE; SITENAME$(JSITE)
PRINT #2,"
PRINT #2,"          ***** PROJECT MAJOR PARAMETERS *****"
PRINT #2,"          [S27] Plant Type 1=BIN 2=FLA 3=STEAM          "; PTYPE
PRINT #2,"          Plant net size, MWE                          "; POUT
PRINT #2,"          Plant Final GROSS Power estimate, MW         "; GROSS
PRINT #2,"          [S7] Well-Head Temperature, Deg-F            "; ZZT
PRINT #2,"          [S12] Brine Contam. Index = BCI               "; ZZB
PRINT #2,"          Flow Into Plant required, 10^6 lb/hr          "; TFLOWIN
PRINT #2,"          Flow From Plant, to Injectors, 10^6 lb/hr     "; TFLOWOUT
PRINT #2,"          [S28] Down Hole Pumps 1 = YES                 "; DPUMP
PRINT #2,"
PRINT #2,"          ***** WELL PARAMETERS AND COSTS *****"
PRINT #2,"          [S13] Well Depth, K-Feet = DEEP              "; ZZD
PRINT #2,"          [S21] Producer Well Flow, 10^6 lb/Hour        "; ZZF
PRINT #2,"          Injectors / producer                          "; WINJ
PRINT #2,"          Spare wells/ producer                         "; WSPR
PRINT #2,"          [S15]*[R6] Prod. redrill fract. add-on cost   "; WRED
PRINT #2,"          Dry Holes / Active Producer                   "; WDRY
PRINT #2,"          No. of Producer Wells (at plant start)        "; WNUM
PRINT #2,"          Producers plus spares                         "; WPRODSUM
PRINT #2,"          Injectors required                            "; WIJN
PRINT #2,"          Total Number of Initial Wells                "; WCNT
PRINT #2,"          Base cost (no risk) of bare well              "; WCBASE
PRINT #2,"          Fraction of wells to be extended              "; PR.EXTEND
PRINT #2,"          Fraction to be redrilled                      "; PR.REDRILL
PRINT #2,"          Cost to Extend bare well                      "; CST.EXTEND
PRINT #2,"          Cost to Redrill bare well                    "; CST.REDRILL
PRINT #2,"          Adjust: Per Well Cost Multiplier              "; FWLCS
PRINT #2,"          Well cost, w/incidents, no tests              "; WCPW
PRINT #2,"          Cost of 3-Day Well Test                       "; TEST.3D
PRINT #2,"          Cost of 10-Day Well Test                      "; TEST.10D
PRINT #2,"          Cost of 21-Day Well Test                     "; TEST.21D
PRINT #2,"          Test Cost for Wildcat, Inj., Dry              "; TEST1
PRINT #2,"          Test Cost for Confirmation Producers          "; TEST2
PRINT #2,"          Test Cost for Phase 3 Producers               "; TEST3
PRINT #2,"          Total Cost per Wildcat Well                   "; WC.WILD
PRINT #2,"          Total Cost per Confirmation Well              "; WC.CONF
PRINT #2,"          Total Cost per Producer Well in Phase 3      "; WC.PROD
PRINT #2,"          Total Cost per Injector or Dry Well          "; WC.GENL
PRINT #2,"          Capcost of all initial wells (in Phase 3)    "; WCTL
```

' Start Page 2 of report.

GOSUB EJECT.PAGE

PRINT #2," " : PRINT #2," " : PRINT #2," " : PRINT #2," "

PRINT #2," ***** SITE DETAILS ----- Page 2"

PRINT #2," "; DATES; " - "; TTIMES

PRINT #2," Region analyzed: "; JSITE; SITENAME\$(JSITE)

PRINT #2,"

PRINT #2," ***** IDENTIFY, CONFIRM RESERVOIR ***** "

PRINT #2," [S3]*[R1] P(success), Identification "; UPROB

PRINT #2," No. of Ident. units "; N.IDENT

PRINT #2," Cost, Geol. and Geophysics, Regional "; UCOST1

PRINT #2," Cost, Therm. Grad. Holes/ Wildcat, "; UCOST2

PRINT #2," # 50 MWe Power Plants/Area (per GROSS MWe) "; P.PER.SITE

PRINT #2," UNIT Identific. Cost, not P.V.'d "; UCOST.ID

PRINT #2," Years between plants, 4 = nominal "; BTWN.PLANTS

PRINT #2," Duration of Identific. period, years "; DUR.EXPL

PRINT #2," Total Regional Production Life, Yrs. "; AREA.LIFE

PRINT #2," Cap recov fact. for spread I.D. over plants "; EXPLRECOV

PRINT #2," TOTAL Identific. Cost, P.V.'d, Per Plant "; EXPL

PRINT #2," [S4]*R3], Prob. of Conf/Unit "; UPROB1

PRINT #2," No. of Confirm. Units "; N.CONF

PRINT #2," [R4] Unit Cost, Confirmation "; UCOST.CF

PRINT #2," Duration of confirmation, years. "; DUR.CONF

PRINT #2," Total confirm \$, P.V., All alloc'd to 1 plant"; CONF

PRINT #2," OK Producers after CONFIRM "; GOOD.PRODS

PRINT #2," OK Injectors after CONFIRM "; GOOD.INJS

PRINT #2,"

PRINT #2," ***** SUPPLEMENTAL WELLS ***** "

PRINT #2," [S24] Flow Rate Decline Coefficient. "; DRWDN

PRINT #2," Per [S19] Adjusted Decline Coefficient. "; DRWDN2

PRINT #2," [S23] ' Initial flow rate, for Decline Calcs "; VSTART/1000

PRINT #2," [S21] ' Minimum flow per initial well "; VNEEDED/1000

PRINT #2," No. of suppl. prod.s added over LIFE years "; NW1

PRINT #2," Discounted No. of supplemental wells. "; NWD

PRINT #2," Sum of Disc'td O&M Units for suppl. wells. "; SNWOAM

PRINT #2," Cap. Cost Part of Supplm., Final Unacost "; WDECLOM1

PRINT #2," O&M Part of Supplm., INCOMPLETE CALC. ***** "; WDECLOM2

PRINT #2,"

IF DPUMP = 0 THEN GOTO TECH15

PRINT #2," ***** DEEP WELL PUMPS ***** "

PRINT #2," Deep Pumps, No. to purchase at start "; PNUM

PRINT #2," No. of Pumps on line (active) at start "; WNUM

PRINT #2," Per pump horsepower (1000s) "; PER.PUMP

PRINT #2," FINAL, Net to D.W. PUMPS, MW "; PUMP.POWER

PRINT #2," Deep Pumps, Cap. Cost & Installation, \$M "; DPC

PRINT #2," Deep Pumps, Total capital cost, \$M "; DPTL

PRINT #2," O&M per active pump per year. "; DPM

PRINT #2," Deep Pumps, Total O&M, \$M/yr "; DPOM

TECH15 :

' Start Page 3 of report.

GOSUB EJECT.PAGE

PRINT #2," " : PRINT #2," " : PRINT #2," " : PRINT #2," "

PRINT #2," ***** SITE DETAILS ----- Page 3"

PRINT #2," "; DATE\$; " - "; TIME\$

PRINT #2," Region analyzed: "; JSITE; SITENAME\$(JSITE)

PRINT #2," "

PRINT #2," ***** GATHERING SYSTEM DETAILS *****"

PRINT #2," [S14] Sep. betw'n producer wells, Ft. "; SEPAR

PRINT #2," Length of prod. pipe, rectang. field,Ft. "; NFEET

PRINT #2," Production gath. cost cap. total, M\$ "; CPROD GATH

PRINT #2," Cost of pipe for four average injectors, M\$ "; COSTPER4

PRINT #2," Capcost of injector gathering, \$M "; CINJGATH

PRINT #2," Field Surface Equipment, Total Cap., \$M "; SPTL

PRINT #2," TOTAL Field, Cap, \$M (Includes Phase 3 Wells)"; TTL

PRINT #2," Length of pipe for supplm. gathering, feet "; NFEET2

PRINT #2," Gathering for supplm. producers, \$M, "; CPROD GATH2

PRINT #2," Gath for supplm. prod, as \$M/yr "; CPROD GATH3

PRINT #2," F1: Field staff annual cost, \$M/yr "; F1

PRINT #2," F2: Initial PROD and INJ wells annual cost "; F2

PRINT #2," F3: Gathering Pipes and valves annual cost "; F3

PRINT #2," F5: Supplm. wells, Capital portion, unacost "; F5

PRINT #2," F6: Supplm. wells, O&M portion, unacost "; F6

PRINT #2," F7: Supplm. wells Gath. capital, unacost "; F7

PRINT #2," F8: Supplm. Wells Gath. O&M, unacost "; F8

PRINT #2," "

PRINT #2," ***** POWER PLANT FACTORS ***** "

PRINT #2," IF PTYPE <> 1 THEN GOTO TECH25

PRINT #2," ----- BINARY SIZING DETAILS ----- "

PRINT #2," Binary net brine effectiveness 'Wh/LB, NET "; NETBE

PRINT #2," Added Gross to Make 1 More MWe net out. "; KBIN

PRINT #2," FITTED, Net to D.W. PUMPS, MW "; PUMPF

PRINT #2," ADJUSTED GROSS Brine Effectiveness "; GROBE1

PRINT #2," Aux Power, W/O D.W. Pumps (Prim. loop & cool)"; BARE.AUX

PRINT #2," ----- END, BINARY SIZING DETAILS ----- "

PRINT #2," TECH25 :

PRINT #2," Power Plant Capital cost, \$M "; PPC

PRINT #2," Plant O&M, \$M/Year, w/o Proper. Tax & Insur. "; POAM

PRINT #2," Brine Stabil., Cap. \$M "; BSCAP

PRINT #2," Brine Stabil., O&M, \$M/yr "; BSOAM

PRINT #2," [S11] H2S, ppm "; HSULF

PRINT #2," H2S Equip, \$M "; ENVCAP

PRINT #2," H2S O&M, \$M/yr "; ENVOAM

PRINT #2," "

PRINT #2," ***** FINANCIAL FACTORS *****"

PRINT #2," Power plant book life, Years "; LIFE

PRINT #2," Capital Recovery factor "; CAPRECOV

PRINT #2," Discount Rate, Plant and General "; DISC

PRINT #2," ECON: (Field VLAFCR)/(Plant VLAFCR) "; PTOF

PRINT #2," ECON: (Field DISC)/(Plant DISC) "; DTOF

PRINT #2," Discount Rate for Field Equipment "; FISC

PRINT #2," Income tax rate (Federal + State) "; INTXR

PRINT #2," Adj. all costs for ROYR, SEVR, (INTXR)*DEPL "; 1/SEVFAC

PRINT #2," "

PRINT #2," ***** FINAL COST FACTORS *****"

```

PRINT #2,"          Field Total cap, Reduced re tax credits      "; RESCAPADJ(3)
PRINT #2,"          Capital cost to be insured, $M              "; ZINSUR
GOSUB ZCLOSE.PRINTER
RETURN
'***** END SUBR: PRINT TECHNICAL FACTORS *****

```

WEIGHTS.SHOW :

```

'*** SUBR: Show/Print Regional Weights:
CLS
'Ensure weights match "risky" values:
  IF ZWAYZ = 1 THEN GOSUB WEIGHT.CAPACITY.EX
  IF ZWAYZ = 4 THEN GOSUB WEIGHT.RELEVANCE.EX
OPEN "SCRN:" FOR OUTPUT AS #2 : GOSUB WEIGHTS.OUT : CLOSE #2
PRINT
PRINT TAB(8); "ENTER: P = Print Results, Z = Continue ----> ";
WEIGHTS.SHOW1 :GOSUB INLETTER
  IF ANSS = "P" THEN GOSUB WEIGHTS.PRNT : GOTO WEIGHTS.SHOW
  IF ANSS = "Z" THEN ANSS = "ZAP" : RETURN 'EXIT
GOTO WEIGHTS.SHOW1
'*** END SUBR: Weights to Console

```

WEIGHTS.PRNT:

```

'*** SUBR: Regional Weights to Printer:
CLS : PRINT "PRINTING REGIONAL WEIGHTS"
GOSUB ZOPEN.PRINTER ' As #2
PRINT #2, " " : PRINT #2, " " '4 lines for blank page
PRINT #2, " " : PRINT #2, " "
GOSUB WEIGHTS.OUT
GOSUB ZCLOSE.PRINTER
RETURN
' *** END SUBR: Weights to Printer ***

```

WEIGHTS.OUT :

```

'*** SUBR: Weights Out via Channel #2.
PRINT #2, TAB(8); " REGIONAL WEIGHTS: "; WEIGHTS
PRINT #2, " "
PRINT #2, TAB(8); " IM-GEO Program "; DATES; " - "; TTIMES
PRINT #2, " "
PRINT #2, TAB(8); " Region Weight"
PRINT #2, " "
FOR I = 1 TO 8
  A = WEIGHT(I) : IF A < .0001 THEN A = 0
  PRINT #2, TAB(8); " "; I; ". "; SITEMAMES(I); " ";
  PRINT #2, USING "#####.##"; A
NEXT I
ANSS = "ZAP" : RETURN
'*** END SUBR: WEIGHTS.OUT
'***** END: Show or Print Regional Weights *****

```

```

ZOPEN.PRINTER:
,
'PSWITCH$ = "P"      ' [[]][[]][[]] Set from above.
,
'*** SUBR: Open Printer or Scroll File as Device #2
,
IF PSWITCH$ = "P" THEN GOTO ZOPEN1 ELSE GOTO ZOPEN2
ZOPEN1 :
'Open PRINTER as Device #2:
WIDTH "SCRN:", 255 : CLS
PRINT: PRINT: PRINT " SHOULD BE PRINTING" : PRINT
OPEN "LPT1:" FOR OUTPUT AS #2 : GOTO ZOPEN3
ZOPEN2 :
' Open SCROLL FILE for "PRINTER" output:
WIDTH "SCRN:", 255 : CLS
PRINT: PRINT: PRINT " Scrolling that Report To FILE IMGEOU.TXT"
PRINT
OPEN "IMGEOU.TXT" FOR APPEND AS #2
ZOPEN3 :
' 4 Blank Lines for header:
PRINT #2," " : PRINT #2," " : PRINT #2," " : PRINT #2," "
' ***** DRAFT WARNING *****
'PRINT #2, "      ** DRAFT RESULTS, NOT ACCURATE FOR CITATION **"
RETURN
'*** END SUBR: Open PRINTER or SCROLL FILE.

ZCLOSE.PRINTER :
,
'*** SUBR: Close PRINTER or SCROLL file as Device #2:
GOSUB EJECT.PAGE      ' At either device.
CLOSE #2 : CLS        ' Close either device.
IF PSWITCH$ = "P" THEN RETURN      ' Done at printer.
' For Scroll File, Signal progress to SCREEN:
LOCATE 10,10 : PRINT " Sent those results to file IMGEOU.TXT"
LOCATE 13,10 : PRINT " PRESS ANY KEY TO CONTINUE -----> "
GOSUB INLETTER : CLS
RETURN      ' Scroll File is closed.
,
' *** END SUBR: Close "Printing" Output Channel

EJECT.PAGE :
,
'*** SUBR: Eject Page at PRINTER or SCROLL file.
IF PSWITCH$ <> "P" THEN GOTO ZEJECT2
' Eject page from PRINTER, using a Form Feed:
LPRINT CHR$(12); : RETURN      ' Form feed sent.
ZEJECT2 :      ' Mark page border in Scroll File:
PRINT #2, "" : PRINT #2, TAB(8); "**** END OF PAGE **** "
PRINT #2, ""
RETURN      ' Page break marked.
'*** END SUBR: Eject Page.
,

'*** END OF --- ZMISC --- MISCELLANEOUS ROUTINES *****

```


APPENDIX G

PROGRAMMER NOTES

PROGRAMMER NOTES

1. The TIME Stamp

The time-stamp for reports, TTIME\$, is reset from TIME\$ any time that the user has actually selected a sensitivity item for editing. This is achieved by setting TTIME\$ from within the datum changing code of the SUBDATAACH routine. Merely entering an Editor Option and viewing the editable lines does not change the time stamp.

The time-stamp is also updated when the WEIGHT selection is changed.

2. Reports to Screen, Printer, and Text File

The program makes extensive use of redirection of output from the same lines of code to either the Screen or the Printer. This is accomplished by the use of "PRINT #2, ----" code. The desired target device is opened as channel #2 before the PRINT lines are expressed. This makes for efficient use of output code. It also ensures that exactly the same material appears on both the Screen and printed copy.

At the very end of the BASIC source code you will find the code that handles the users option to redirect output intended for the printer to the file "IMGEOUT.TXT". This is a documentation aid for capturing "printer" output in a file for later manual editing. "IMGEOUT.TXT" is set up to APPEND output, and is automatically emptied at the beginning of each run of IM-GEO.

3. EDITFLAG\$ and EDITFLAG2\$.

These two logical flags handle most of the interactions that ensure that the results of sensitivity factor editing are reflected accurately in the preseneted results.

If EDITFLAG\$ is "YES", that means that both the current single-site or multi-site results need to be recalculated to reflect current sensitivity factor conditions. EDITFLAG\$ is reset to "NO" after a single-site or multiple-site is performed

If EDITFLAG2\$ is "YES", and EDITFLAG\$ is "NO", that means that only the current single site (user's JSITE) results are correct. Any other site needs to be recalculated before being shown.

- Asking for a different JSITE during this condition makes IMGEO recalculate that one site. EDITFLAG2\$ remains "YES" to indicate that some other single site results (and therefore the multi-site results in general) are not current.
- Asking for a multi-site report under this condition makes IMGEO redo the multi-site calculations. EDFLAG2\$ is then reset to "NO".

EDFLAG\$ is set to "YES" any time the user alters a sensitivity factor. This includes user's selection of a different set of Regional Weights.

4. Changing the Site Data Base

You can change the contents of the Site Data Base, but you must use the "Official Version" provided with the model (or approved as changed later) for all final estimates of impacts of R&D achievements.

IM-GEO reads the contents of file "SITEDATO.DAT" when it initializes the Site data base. The file "SITEDATO.MAS" is the "master" version of this data base, and should not be altered.

To change the Site data values, edit the file "SITEDATO.DAT" using an "ASCII-only" word processor, such the N-mode of WordStar or the non-document mode or "programming" mode of other word processors. Then run IM-GEO. If you have made serious editing errors, then you'll get error warnings or uninterpretable results from the IM-GEO reports. If that is the case, use BASICA or GW-BASIC to run the Microsoft interpreter BASIC program "DATATEST.BAS" on the distribution diskette, i.e. D> BASICA DATATEST <Enter>.

DATATEST.BAS simply reads file "SITEDATO.DAT" and outputs its contents to the screen in the expected order, type, and number of variables. Use <Scroll Lock> to halt the display and look for places errors of data type or number have occurred. Better yet, if you are using DOS 3.X, redirect the output from DATATEST.BAS to a scrolling file, e.g.:

```
D> BASICA DATATEST > SCROLL.TXT <Enter>
```

then edit the file SCROLL.TXT to find where the errors are.

5. Hints for Revising the Code

Break the code into the eight modules at the ZINIT, ZENG, etc. boundaries. These are in reasonable size for editing.

Write a "COMPILER.BAT" procedure that concatenates those modules into a single file, e.g., "ZNEW.BAS", and then compiles and links the code into the either the "BRUN" (best for development work) or "BCOM" (best for exporting the final version) versions of output from QUICK BASIC.

The compiler used in "separate compilation" mode generates DOS ERRORLEVEL reports suitable for detecting when fatal compilation errors have occurred. These can be used to abort the linking step.

APPENDIX H
PREVIOUS STUDIES

PREVIOUS STUDIES

- ° U.S. Dept. of Energy (DOE/ET/27242-T1). Geothermal Well Field and Power Plant Investment Decision Analysis. Philadelphia Pennsylvania, Technecon Analytic Research, Inc., May 31, 1981.

Good explication of the Technecon model of geothermal industry utility preferences. All databases used here have (probably) been updated after 1981.

- ° U.S. Department of Energy, Bonneville Power Administration. Resource Assessment: Evaluation and Ranking of Geothermal Resources for Electrical Generation or Electrical offset in Idaho, Montana, Oregon and Washington. Portland, Oregon, Washington State Energy Office, June 1985.

This is the most recent extensive analysis of resource availability and engineering characteristics in the Pacific Northwest. Should be factored into any site characteristics database, if one is used in your study. Some of the data points were criticized as overly conservative by industry representatives at 1985 GRC annual meeting.

- ° U.S. Department of Energy (DOE/CS/30674-2). Geothermal Power Plant R&D. An Analysis of Cost-Performance Tradeoffs and the Heber Binary-Cycle Demonstration Project. Philadelphia, Pennsylvania, Technecon Analytic Research, Inc., June 30, 1983.

Sections 1.2, 1.3, and 1.4 are relevant to impacts of R&D on binary plants to cost of power. Results are expressed in

differential megawatts, not cost of power. It is not clear whether the impacts of R&D assumed (in Table 1-2 and 1-3) are in fact supported by a coherent R&D plan by GTD to "develop" such technologies... the issue here is what the cost of the R&D would be.

- ° U.S. Dept. of Energy (DOE/ET/27242-T2) National Forecast for Geothermal Resource Exploration and Development. Philadelphia, Pennsylvania, Technecon Analytic Research, Inc., March 31, 1982.

The model/database for this study is one of the best attempts to deal with mid-term development/usage of "undiscovered" portions of the hydrothermal resource.

- ° U.S. Dept. of Energy (DOE/SF/11727-T1). Federal Geothermal Royal Income Derived from the Benefits of Government-Sponsored R&D. Philadelphia, Pennsylvania, Technecon Analytic Research, Inc., January 31, 1984.

Uses a block of eight Federal R&D impacts (Table 1-1, page 4). Considers three modes of pricing Federal royalty payments (coal, oil, avoided cost). Estimates not R&D costs, but rather R&D budget that could be supported by net present value of anticipated differential royalty income (Table 1-2, p. 6).

This is one of the few (the only?) Technecon geothermal analysis whose output is expressed in terms of dollars. Almost all other Technecon reports express results in terms of (differential) power on line.

- ° Office of Technology Assessment (OTA-E-246). New Electric Power Technologies: Problems and Prospects for the 1990's. Washington, D.C., U.S. Government Printing Office, July 1985.

The OTA report reflects the most recent attempt we know of, as of July 1986, to update estimates of costs of geothermal flash and binary plants. See Table A-4, and its extensive footnotes on pp. 309 and 310. We've not read the OTA report thoroughly enough to ascertain if cost estimates assume "R&D" or "no "R&D".

It might be worth contacting OTA staff to ask for copies of correspondence from Walter & Hinsly and from Gibbs & Hill (Footnote 1 in Table A-4), referenced in footnotes 28, 29 and others, since these appear to be basis of cost estimates for flash and binary.

° The MITRE Corporation. Benefit/Cost Analysis of Geothermal Technology R&D, Volume 1: Summary of the Analysis. May 1979.

Most comprehensive analysis of cost impacts of geothermal R&D. While R&D impacts and cost-analysis model (GELCOM) are both hopelessly out of date, this analysis provides a good structure for the disaggregation of geothermal R&D program areas.

One major lesson: Some sizable impacts, e.g. on well costs at the Geysers, and of modular well-head units on prospect-opening, will not fit well into any standard cost-impact analysis model. These must be estimated "on the side" to get full credit assigned to geothermal program impacts.

Note: Dan Entingh of Meridian was the project leader on this study at MITRE. He is as experienced as anyone in the community at aggregating R&D program elements (projects, etc.) into groups that have dissociable/independent impacts on the

input parameters (e.g., well cost) of geothermal R&D program economic benefit (i.e., differential power on line or differential cost of power on line) models.

- ° U.S. Dept. of Energy. Update and Assessment of Geothermal Economic Models, Geothermal Fluid Flow, Heat Distribution Models and Geothermal Databases.

Authoritative source on capabilities and status of all major geothermal cost of power models. Some of these accept site physical characteristics and impacts of R&D as input data or parameters.

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