Decision Analysis for Geothermal Energy

by

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Abstract

One of the key impediments to the development of enhanced geothermal systems is a deficiency in the tools available to project planners and developers. Weak tool sets make it difficult to accurately estimate the cost and schedule requirements of a proposed geothermal plant, and thus make it more difficult for those projects to survive an economic decision-making process.

This project, part of a larger effort led by the Department of Energy, seeks to develop a suite of decision analysis tools capable of accurately gauging the economic costs and benefits of geothermal projects with uncertain outcomes. In particular, this project seeks to adapt a set of existing tools, the Decision Aids for Tunnelling, to the context of well-drilling, and make them suitable for use as a core software set around which additional software models can be added.

We assess the usefulness of the Decision Aids for Tunnelling (DAT) by creating two realistic case studies to serve as proofs of concept. These case studies are then put through sensitity analyses designed to reflect project risks to which geothermal wells are vulnerable. We find that the DAT have sufficient flexibility to model geothermal projects accurately and provide cost and schedule distributions on potential outcomes of geothermal projects, and recommend methods of usage appropriate to well drilling scenarios.

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Acknowledgments

Above all, I would like to thank my thesis advisor, Prof. Herbert Einstein, for his patient support and guidance during the course of my research. I would also like to thank my friends and research colleagues, who have let me bounce ideas and equations off of them for the better part of two years. Finally, I would like to thank my family– they might not have provided much direct input into the thesis itself, but without them I could not be the person I am today.

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Chapter 1

Introduction

1.1 Problem Statement

In developing decision analysis tools for geothermal energy, one of the most important areas of analysis is the cost and time associated with exploration, production, and injection well drilling. Intelligent management of the well drilling process is important for traditional geothermal power, where these activities represent 30% of the total capital cost, but is even more important for enhanced geothermal systems (EGS) where exploration and drilling account for 60% or more of the capital investment [Petty et al, 1992] [Pierce and Livesay, 1993] [Pierce and Livesay, 1994]. Correct and responsive decision making during the well drilling process could prove a critical factor in the economic viability of EGS.

Many efforts at EGS cost and time estimation (e.g. the MIT EGS model and GETEM) have focused on the problem in aggregate, developing levelized cost estimates that serve the purposes of long-term economic forecasting, but lack the granularity and specificity necessary to aid in project management. We focus instead on cost and schedule prediction for the project manager, and aim to develop a tool that can produce cost and time estimates that are both specific to the particular well being drilled, and detailed enough to aid in making design choices in project planning.

There are multiple sources of uncertainty that make it difficult to estimate the cost and time requirements of geothermal well drilling. These sources of uncertainty range from traditional project risks, such as input cost fluctuations or failures during construction, to geology related issues, such as poor lithology or lower than expected temperature. As such, a tool that aids the project manager of EGS wells should be flexible enough to accommodate many aspects of design and uncertainty, including well parameters such as depth, production diameter, and drilling angle, site geology parameters such as rock strength, abrasiveness, porosity, and temperature, and potential adverse events such as drill string breaks, stuck casing, and detrimental effects due to overpressure or underpressure.

The tools focused on in this report will be based on the Decision Aids for Tunneling (DAT) also developed at MIT and used in practice. The DAT already have much of the functionality desired of an EGS cost and time estimation tool, including notably the ability to represent geology and the construction process using a probabilistic approach, as shown in the DAT manual [Min et al, 2009]. While the context may be different (tunnel analysis vs. well analysis), the practical differences between these two applications of the DAT are minimal, and the tools should be capable of producing accurate time-cost distributions with appropriate changes to either the program itself or the way in which the program is utilized by the end user. In addition, the DAT will be integrated with the other decision analysis programs being looked at for this project– for example, some of the geological inputs into the DAT will originate from the GEOFRAC fracture pattern model and supplemented by lithological and other geological information.

In total, there are three potential points of interest to explore. The first is to test how well the DAT can be used to model EGS projects without major modifications. The second is to identify any modifications to the DAT that could enhance their capabilities vis-a-vis geothermal applications. And lastly, the DAT should be evaluated for compatability with the other elements of EGS decision analysis, including fracturing models, thermal models, surface plant cost and time estimation, etc.

Our goal is to demonstrate the applicability of the Decision Aids for Tunneling to well drilling problems by working through two prototypical examples of injection well drilling. In these examples, the injection well will be modeled as a very simple sort of tunnel, beginning at the surface, and terminating at the desired well depth. We will demonstrate how the DAT are equipped to model the sources of project risk associated with geothermal well drilling, and thus offer project managers an attractive means of cost and time estimation.

1.2 Background on Geology and Geothermal Well Drilling

The current state of the art in geothermal drilling is essentially that of oil and gas drilling, incorporating engineering solutions to problems that are specific to the geothermal context, i.e. temperature effects on instrumentation, thermal expansion of casing strings, and lost circulation.

A typical geothermal well drilling project involves three more-or-less distinct stages of construction: drilling and casing an injection well, hydraulically fracturing a volume of rock to prepare a thermal reservoir, and then drilling and casing one or more production wells into that fractured volume. During plant operation, the injection well will serve as the channel through which a working fluid, typically water, will be pumped underground and passed through the thermal reservoir. After being heated by contact with the hot rock of the reservoir, the working fluid will return to the surface through the production wells.

The order in which these construction activities take place is set by basic considerations of the well drilling problem: fracturing must occur after a well is drilled but before it is completely cased, and production wells can only be located once it is known where the fractures have been created.

Radical changes to this construction approach are unlikely. Technological improvements to geothermal well drilling are likely to change the speed and cost at which these activities can be performed, but not alter the sequence of activities themselves. Improvements in drilling may result in shorter drill times, better casing may reduce the number of casing strings necessary to secure a wellbore, and improved instruments may yield more accurate logging of well and geological conditions, but the choices that a project planner faces will stay the same. The constancy of the decision problems associated with EGS well drilling make it an attractive problem for modeling– while the parameters of the problem may change, if the fundamental dynamics do not, then good decision analysis software would avoid obsolescence for some time to come.

Similarly, radical changes to related activities are unlikely as well. Many of the fields adjacent to geothermal well drilling, such as thermal plant technology, are long-established technology– it is unlikely that some other area in EGS will change to a degree that overhauls project planning in well drilling and other subsurface activities.

In sum, EGS projects make an ideal arena for decision aids; the projects are complex and require probabilistic estimation, yet are not so dynamic as to thwart computer-aided attempts at decision making.

1.3 Structure of the Report

We divide the remainder of this paper into four distinct sections:

Chapter 2 explains the DAT and their organization. It goes into detail on how cost estimation models are built using the DAT and how this approach would be applied to well-drilling applications. It also briefly discusses modeling techniques that minimize the effort needed to model well-drilling projects.

Chapter 3 describes two proof-of-concept tests for the DAT, one drawn from MIT's report on enhanced geothermal systems, and the other drawn from Sandia research on technological issues in enhanced geothermal systems. These tests consist of of a well design, a modeling of that well design in the DAT, and sensitivity analyses of the well design's cost and completion time. Each of these case studies is advanced as a test of the DAT's functionality; the ease or challenge in modeling these case examples with the DAT is meant to illuminate how the DAT might work as a practical tool of EGS project planning and management, as well as highlight modeling needs left unmet by the DAT.

Chapter 4 summarizes the results of the analyses performed in Chapter 3. and presents the outputs that result from DAT modeling work.

Chapter 5 is a discussion of the proof-of-concept tests: what lessons were learned, suggested best-practices for using the DAT in a well-drilling context, potential improvements to the software, and so on.

In the appendices of this report, we include a glossary of drilling terminology, as well as the relevant sections of the MIT and Sandia reports from which the proof-of-concept tests were drawn.

Chapter 2

Using the Decision Aid for Tunneling for Well-Drilling Applications

2.1 A Brief Summary of the DAT and its Features

The Decision Aids to Tunnelling (DAT) approach to modeling revolves around the use of what the DAT term "Methods." A method is comprised of a network of "Activities." The activity network defines the order in which a set of activities takes place. Each activity defines both a cost and a time equation using method-specific variables (called Method Variables) and global variables (called General Variables) whose values are randomly generated by a user-defined probabilistic distribution. To calculate the total cost and schedule of a project, the DAT sum the cost and time results of each method that is utilized by the construction project; the cost and time results are in turn the sum of the cost and time equation results of each activity within the method's activity network. The remainder of this chapter is devoted to explaining the method-based modelling approach in greater detail.

To determine which methods are utilized within a given construction project, the DAT use two inputs: a Geometry and a Ground Class. The user specifies a finite

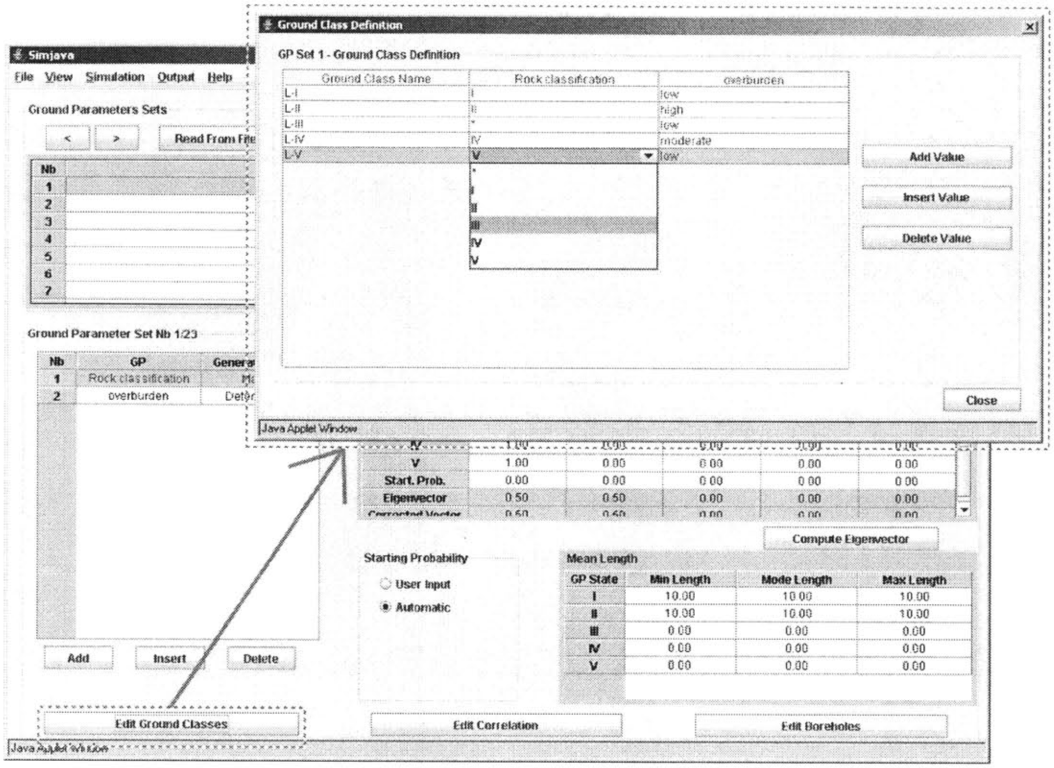


Figure 2-1: The Ground Class Determination Window of the DAT.

set of geometries and ground classes, and for each possible combination of geometry and ground class, the user specifies a probability that each method will be utilized. Figure 2-1 shows the ground class determination screen of the DAT, while Figure 2-2 shows the method determination screen.

Ground classes are determined through the use of Areas, Zones, and Ground Parameters. An area is a region in which well placement takes place (e.g. from 0 ft to 20000 ft). Zones are subsets of areas, specifying some fraction of the region in which construction takes place, defined either deterministically or probabilistically.

The user defines a set of ground parameters, and each ground parameter has a set of possible states. Within each zone, the user specifies a generation method for each ground parameter. In this manner, the user defines how a set of ground parameters will be probabilistically generated across the entire region in which construction activity takes place. Figure 2-3 provides an example of an Area-Zone-Ground Parameter

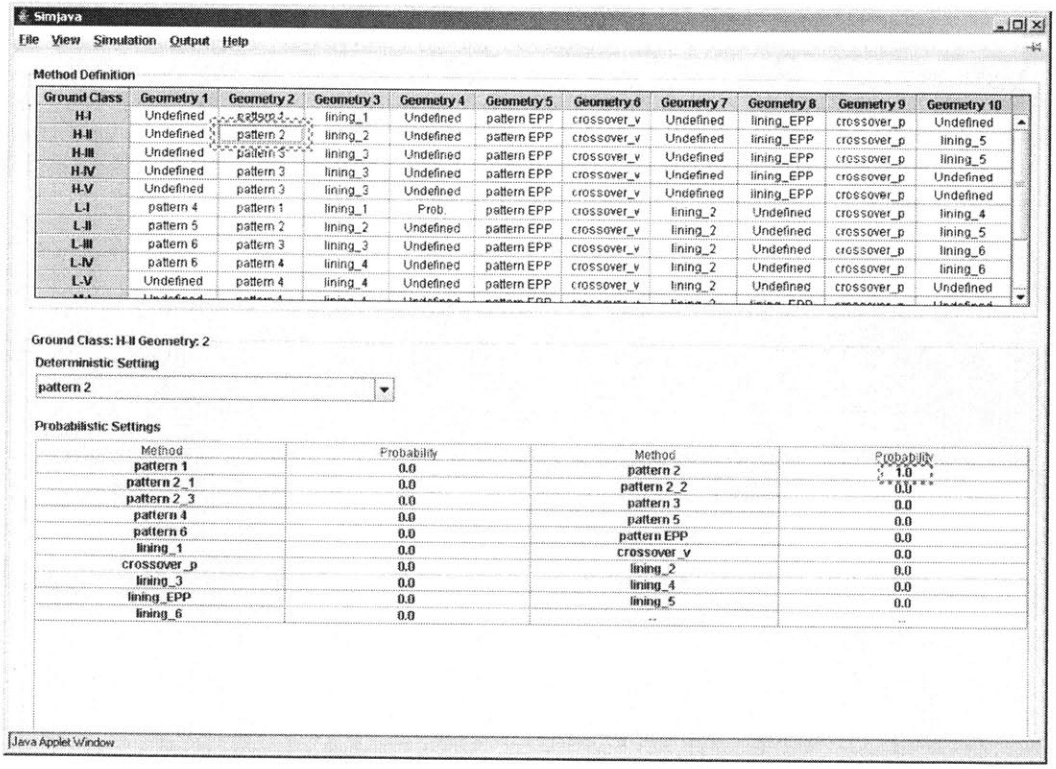


Figure 2-2: The Method Determination Window of the DAT.

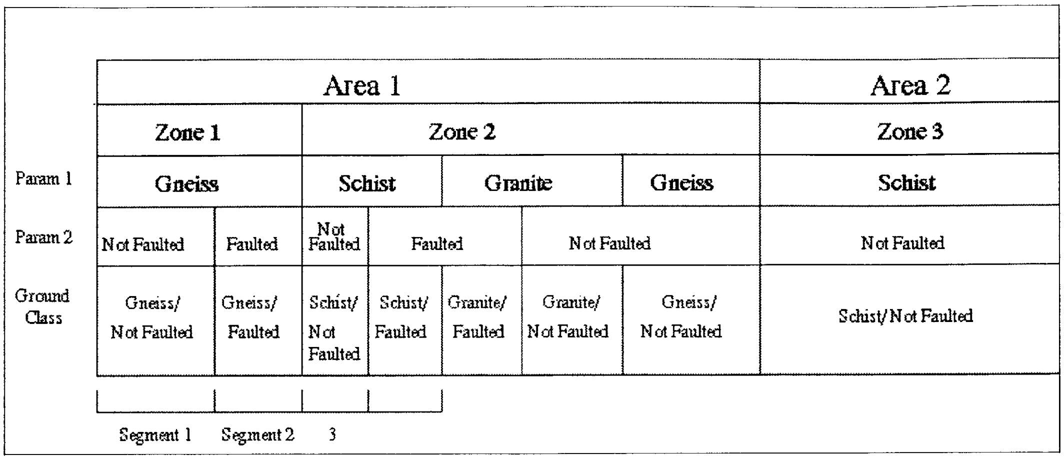


Figure 2-3: The Area-Zone hierarchy of the DAT. Within zones, ground parameter values are generated, and these parameter values, in combination with user-supplied logic, define ground classes.

hierarchy.

Ground parameters are used to define ground classes. The user specifies a finite set of ground classes. Then, for each possible combination of ground parameter states, the user assigns a probability to each ground class.

Geometries are determined through a Tunnel Network. A tunnel network (or, in this context, a well network) is a network of construction stages, where each arc in the network specifies a particular geometry, the region in which the arc takes place, and any additional fixed costs or delays. Figure 2-4 is an example well/tunnel network screenshot from the DAT. For each possible combination of geometry and ground class, the user assigns a probability to each method, and then, the DAT define the resulting method used at each locale in the construction region.

The DAT thus use a multi-stage Monte Carlo simulation that generates project costs and schedules as follows: First, the DAT generate the zones within each area. Then, the DAT generate ground parameter states across the entire region of interest. Using the resulting sets of ground parameters, the DAT generate ground classes across the entire region of interest. Then, by looking at the geometry specified in each segment of the well network and the ground class(es) that was generated within the region specified in the well segment, the DAT generate which methods will be used in

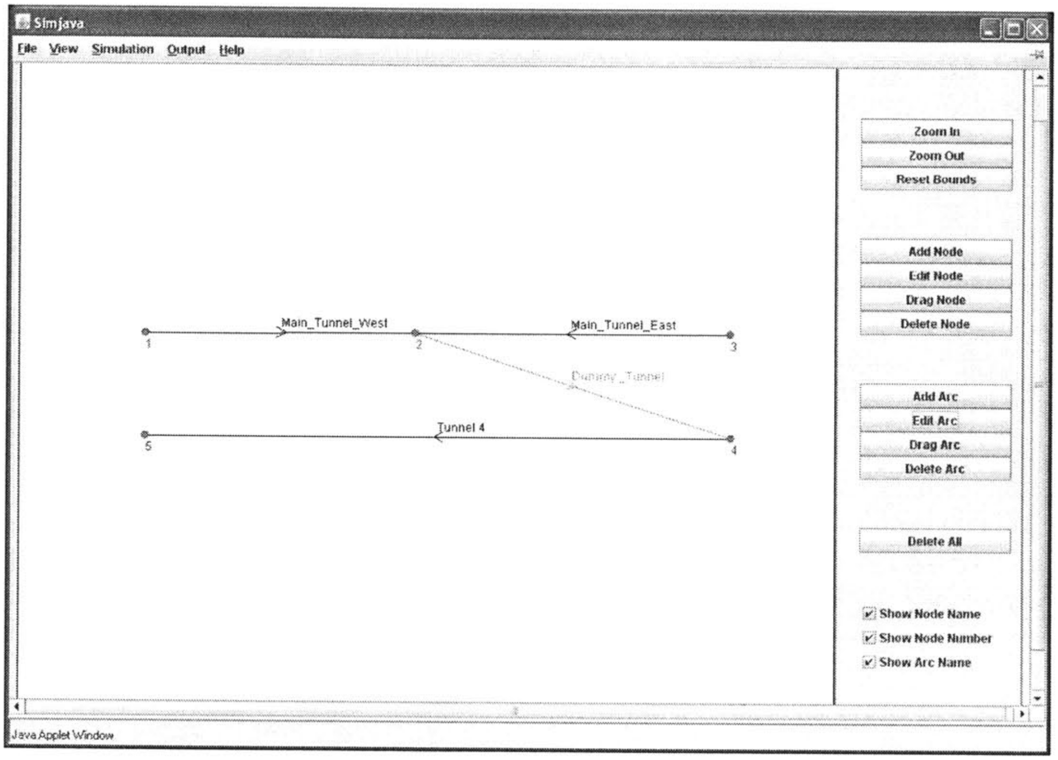


Figure 2-4: A simple tunnel network.

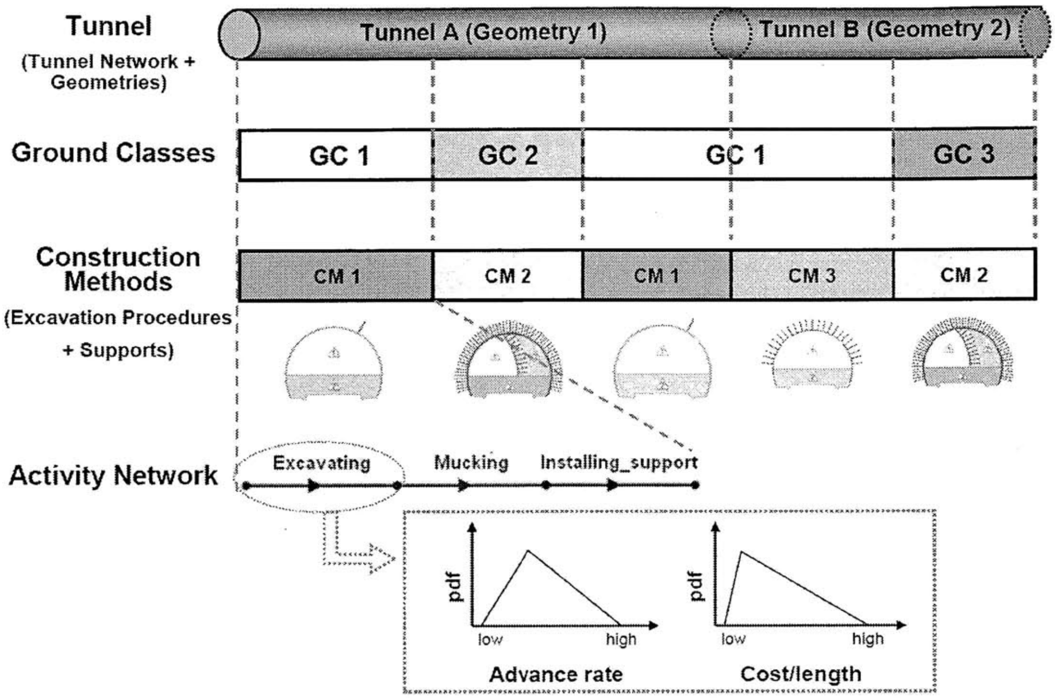


Figure 2-5: A Summary of the DAT Approach to Construction Modeling. Figure 2-5 shows the DAT's layered approach to modeling, taking the construction-specific conditions (the 'geometry'), and the geological conditions (the 'ground classes') to determine which of a variety of construction methods are used, which in turn define the set of activities that constitute the project, which in turn define the parameters and their probabilistic distributions that will produce the end estimate of cost and time requirements for the project.

the construction process. Figure 2-5, a tunnel example, provides a graphical summary of the DAT approach to modeling.

Once each method has been specified, the DAT begin generating values for the variables that enter into the activity equations within each method. Then, the DAT solve the cost and time equations for each activity, and sum the results from each activity within each used method as well as the fixed delays and costs specified in the well network to output a final cost and time estimation.

2.2 The DAT in Depth

2.2.1 Areas and Zones

The geology along a well can be subdivided into Areas and Zones. An Area is a set of continuous and sequential regions that may consist of only one Zone or many Zones. The term Zone is used to express what can be described as a geologically homogeneous Zone, namely, a stretch of ground in which a particular set of parameters and parameter states may occur. Each of these zones consists of a set of segments, where the term segment refers to a continuous ground section characterized by a specific set of parameter states. As with Areas, Zones may also consist of only one segment. The parameter state sets are usually called Ground Classes. Figure 2-3 is an illustration of the Area-Zone hierarchy.

The Area is the uppermost level of the organization for input in geology. It consists of a set of consecutive Zones.

The Zone is the basic unit of geology for input. It declares a length of ground, and what it consists of.

Zones have three distinct generation methods, labeled within the DAT as Mode 1, Mode 2, and Mode 3. In Mode 1, the zone is estimated to vary between a minimum and maximum length. It generates a variable length between the specificed minimum and maximum values, using the minimum and maximum bounds, and probabilities for minimum, maximum, and modal values. In Mode 2, the zone is estimated to vary between a minimum and maximum endpoint. Similar to Mode 1, it defines the zone using five parameters: a minimum and maximum endpoint, and probabilities for the minimum, maximum, and modal endpoints. Finally, Mode 3 generates a zone length in the same manner as Mode 1, and then checks to make sure that the zone falls between minimum and maximum endpoint values. Figure 2-6 shows a screenshot of the DAT zone generation screen.

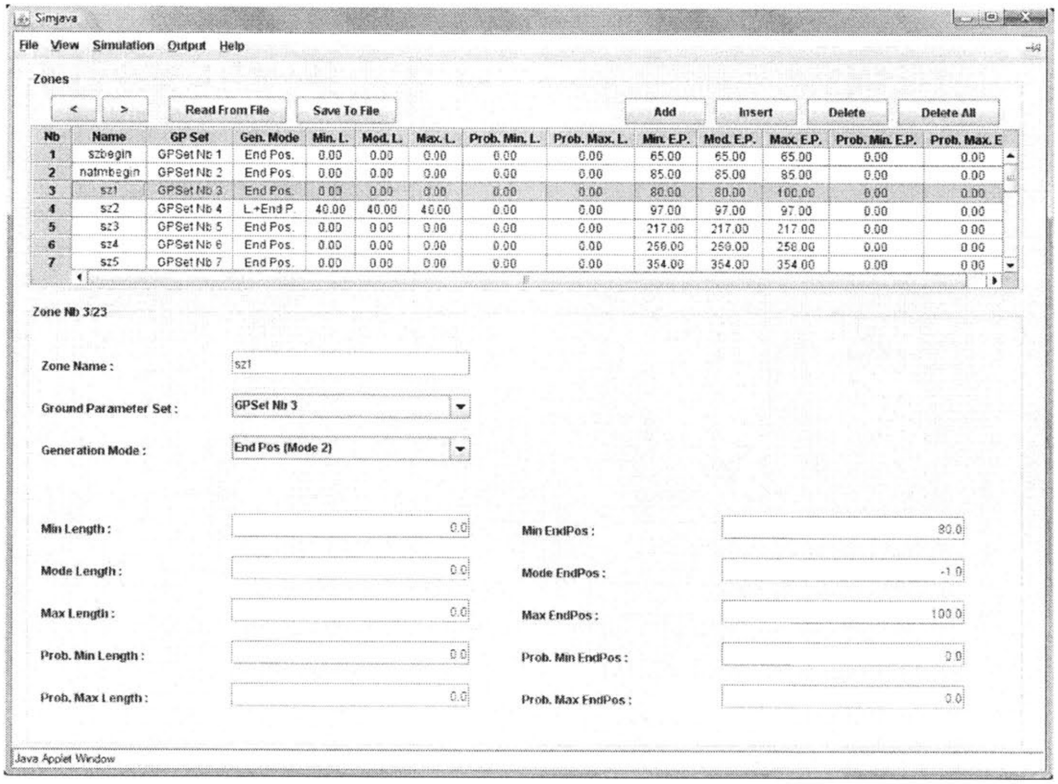


Figure 2-6: The Zone Generation Window of the DAT. Generation mode 2 (end position) is being used in this example to generate zone sz1. In this particular zone generation, the minimum end position is at 80, the modal end position is at 80, and the maximum end position is at 100.

2.2.2 Ground Parameters and Ground Classes

Before defining ground classes or distributions of ground parameter states, the user needs to first define the ground parameters. The parameters denote particular geologic conditions in a section (usually a zone) of the ground. A parameter usually has several parameter states. An example is the hypothetical parameter Lithology that has the states, Granite, Shale and Gneiss. The user can define the name of parameters and their states. GP Name sets the name of the parameter (like Lithology) and GP state shows the list of possible states for this parameter.

Following this the user will have to define the occurrence of parameters and parameter states, their association with Ground Classes and all other information on the geology. The distribution of parameter states can be determined using five different generation methods: Markov, Fixed Markov, Semi-Fixed Markov, Deterministic, and Semi-Deterministic.

Markov indicates that the parameter states are probabilistically defined using a Markov process. This allows the program to generate certain parameters based on the estimated length and the matrix that defines the probability of transition between all the pairwise sets of ground parameter states. Specifically, the DAT assign the initial ground state according to the initial probabilities that the user assigns to each state. Then, they determine a length over which the parameter state will remain the same, selecting the length over an exponential distribution of lengths. At the end of this length, there is a probability of transition to each of the other possible parameter states– these probabilities are defined by the user. Upon transition, another length is probabilistically determined from an exponential distribution, and this process continues over the length of the segment over which the ground parameter is generated using the Markov process.

Fixed Markov produces a Markov-style generation; the difference between it and the "Markov" mode is that the lengths are first generated based on the mean length and then stay the same during the Markov generation, and the Markov generation only takes care of the transition between different states.

Semi-Fixed Markov is an option that allows one to have Markov transitions and triangularly distributed lengths. This is different from "Fixed Markov", which is only based on Markov transitions and fixed length, and from Markov which is based on Markov transitions and exponential lengths.

Deterministic allows the user to deterministically specify the length and state of each segment.

Semi-Deterministic allows the user to specify the state and length of each state probabilistically but in a deterministic sequence. This works very much the same as the definition of the zone sequence.

Ground Classes describe the ground conditions along the well's length and are a particular combination of Parameter States. These Ground Classes will ultimately be used to determine the construction method used to construct a well. Ground Classes are defined by logic rules set by the user– specifically, the user defines a set of ground classes, and for each class defines the set of ground parameters that fall into that class.

2.2.3 The Well Network

Well construction is modeled by first defining the well system followed by the definition of the well geometry ("type cross sections"). This information and the geology (Ground Classes), will then be combined to form construction methods.

Specifically, the geology and the well geometry lead to particular excavation procedures and support requirements. The combinations of excavation procedures and support requirements are called Construction Methods.

Since the DAT will eventually produce construction time and cost, the methods need to be described in these terms. The simplest way to do this is in the form of cost per linear unit of well depth drilled and of advance rate. Cost per unit length includes the material-labor-equipment costs to build a unit length of well. Analogously, advance rate expresses the time to build a unit length of well. Rather than express cost and time in this simple way it is possible to simulate construction as a number of parallel or sequential activities (drilling, tripping, circulating, logging,

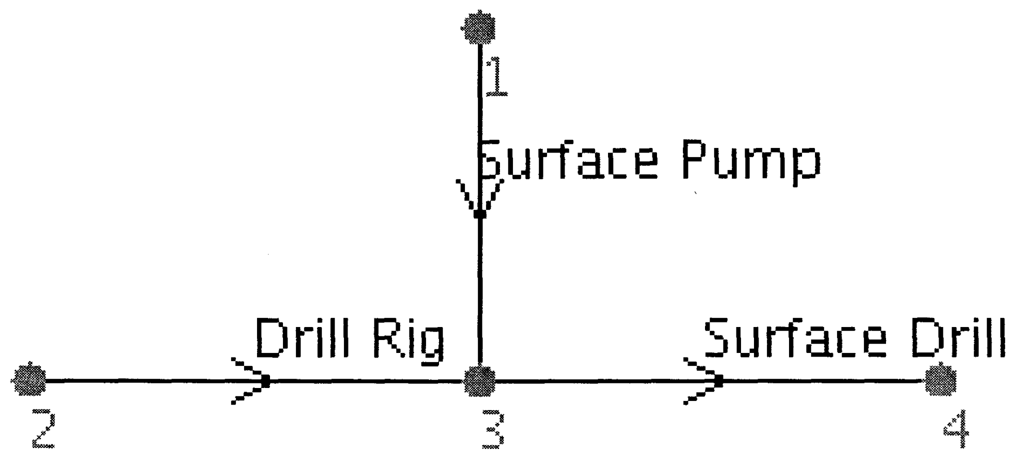


Figure 2-7: An Example Network. Figure 2-7 shows a simple example of a network–in this example, construction begins with the Drill Rig and Surface Pump sections, and as soon as both are complete (the filled circle representing Node 3 indicates an AND node, while a hollow circle would indicate an OR node), construction of the Surface Drill section would begin.

casing etc.). In either case other costs such as interest costs, mobilization costs, and cost and time to build other structures can also be considered.

A well network consists of nodes and arcs. Nodes have two functions: they are endpoints and junctions. In either case, the number of the node has no influence on the simulation, only the type of node will be important. The arcs usually represent physical well sections; each arc is a well section of a single geometry.

The concept of an arc can sometimes be used for types of construction processes different than actual physical well sections. The user may need for example to define more than one well when different construction methods need to be applied in the same well sections at different times. For example, if the lining/casing is placed after the entire well is excavated, the lining process can be represented by defining it as a different construction method in an imaginary "casing arc." Figure 2-8 depicts this example.

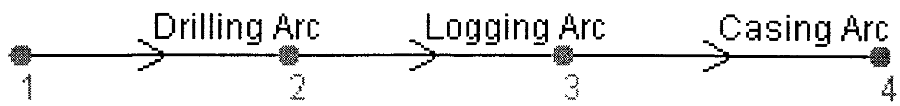


Figure 2-8: An Example of Non-Literal Well Network Arcs. Figure 2-8 shows a simple example of a well network, including distinct drilling, logging, and casing stages.

2.2.4 Methods, Geometry, and Method Selection

In addition to specifying well segments by their position, users need to categorize segments by another dimension, called geometry. The geometry category will be used in conjunction with ground class to define the method that will be used over the length of that well segment– it is important therefore to define geometry in a way that aids in proper method selection.

Method selection is a process of user-specified logical rules, much in the same manner as ground class determination. For each pairwise couple of geometry and ground class, the user defines a probability of selection for each of the available methods– most typically, this process will be deterministic, and the user will specify that a geometry-ground class combination will select a particular method in 100% of instances.

Methods themselves are a combination of two features, an activity network, which, through its selection of activities, defines the set of cost and time equations that a method will invoke during a simulation, and a cycle procedure. The latter feature deserves some explanation here– the DAT invoke a method's related cost and time equations once for each "cycle" that occurs within that segment. The method itself defines the length of these cycles– at one extreme, the entire segment could be defined as one cycle, at another, a cycle could be set to be a very small value, thus invoking the method's cost and time equations multiple times over the construction of that segment. Because the cost and time equations of a method are designed with cycle

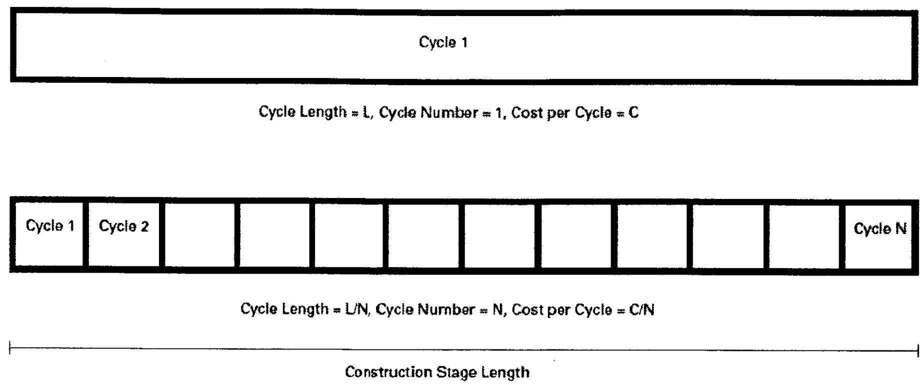


Figure 2-9: Single and Multi-Cycle Modeling Approaches. If a single cycle is used, then the cost and time equations for that cycle represents the cost and time associated with the entire construction stage. If instead more cycles are used, each cycle incurs only a fraction of the construction stage's total cost and time, with the fraction depending on the number of cycles used.

numbers in mind, there is often no practical difference between breaking an activity into several smaller cycles and invoking small costs with each cycle versus running it over fewer, larger cycles and invoking large costs per cycle. Figure 2-9 illustrates the concept of single vs multi cycle approaches.

Of more importance than cycles are the activity networks and associated activities that define a method.

2.2.5 Activities and Time and Cost Equations

A Construction Method is described by the so-called Activity Network, and by activity equations and variables. The construction methods, with their activity networks, activity equations, and numerical variable values, are related to the particular well section, Ground Class, and geometry. The Activity Network contains a sequence of activities represented by arcs. The network relates activities, that is, the sequence in

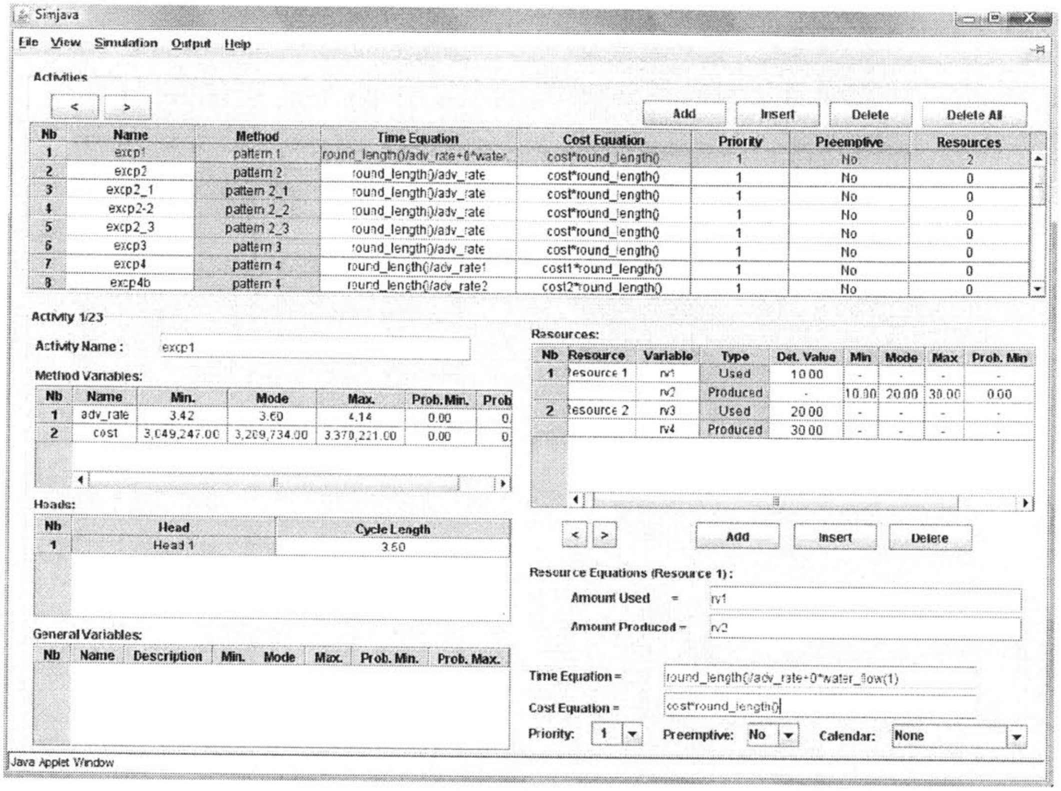


Figure 2-10: Activity Time and Cost Equations. Figure 2-10 shows a typical activity screen from the DAT. In this example, each activity has relatively simple time and cost equations, usually involving just two unique parameters: a rate at which the activity proceeds (measured in units of time per unit of length) and a cost per unit length. The example in the figure is a tunnel-based example from the DAT manual.

which they will be performed, to each other. Figure 2-10 shows an example activities screen from the DAT, showing a selection of activities and their associated time and cost equations. Figure 2-11 shows an example activity network.

Each activity defines two equations: a cost equation, which contributes to overall project cost, and a time equation, which contributes to the overall time required to complete the project. These equations can be defined using almost all common operators, as well as any user-defined variables.

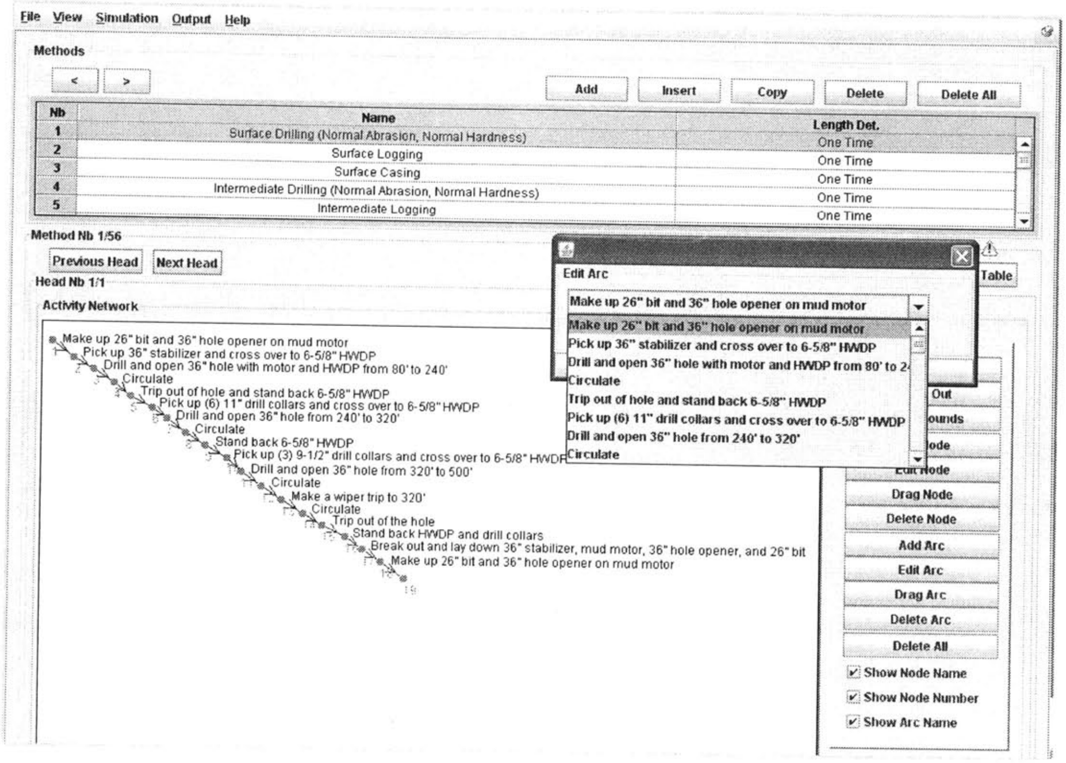


Figure 2-11: An Example Activity Network. Activity networks consist of a directed graph of AND and OR nodes. The arcs between nodes consist of activities, selected from a dropdown menu.

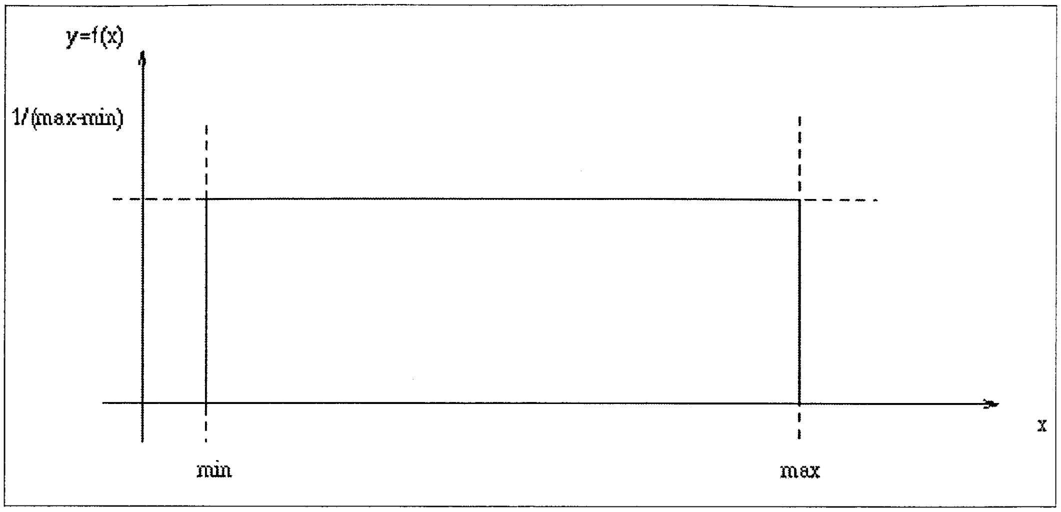


Figure 2-12: The Uniform Distribution Function.

2.2.6 General and Method Variables

There are two types of variables in the DAT: method variables, which have values that are unique to specific methods, and general variables, which take values common to all methods.

The DAT use four types of probabilistic distributions for its variables: the uniform distribution, the triangular distribution, the bounded triangular distribution, and the lognormal distribution.

The Uniform Distribution

The simplest probability density function for a random variable is a uniform function (see Figure 2-12). In this case, the variable always has the same probability of taking on any value between min and max.

The Triangular Distribution

A triangular distribution function is defined by three parameters: a minimum value, a modal value, and a maximum value. These values are then used to generate a probability distribution function (see Figure 2-13). The probability distribution function

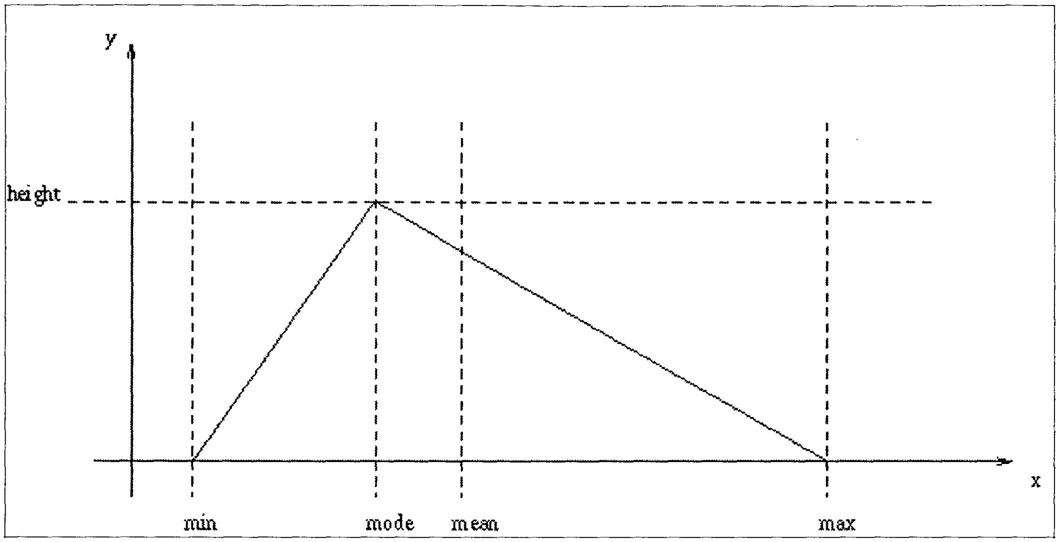


Figure 2-13: The Triangular Distribution Function.

must be normalized such that the integral of the function over its range is equal to 1. This is accomplished by setting the height of the triangle equal to 2 divided by the difference between the minimum and maximum values.

The Bounded Triangular Distribution

Similar to the triangular distribution function is the bounded triangular distribution function. A bounded triangular distribution function is defined by five parameters: a minimum value, a modal value, a maximum value, a probability of the minimum value, and a probability of the maximum value. These values are then used to generate a probability distribution function (see Figure 2-14). Different from the triangular distribution function, the height of the modal peak of the bounded triangular function is described by Equation 2.1

$$TrianglePeak = 2 * (1 - Pr(min) - Pr(max))/(max - min) \qquad (2.1)$$

and the probabilities at the minimum and maximum values are equal to the values specified by the user, rather than zero as in the triangular distribution function.

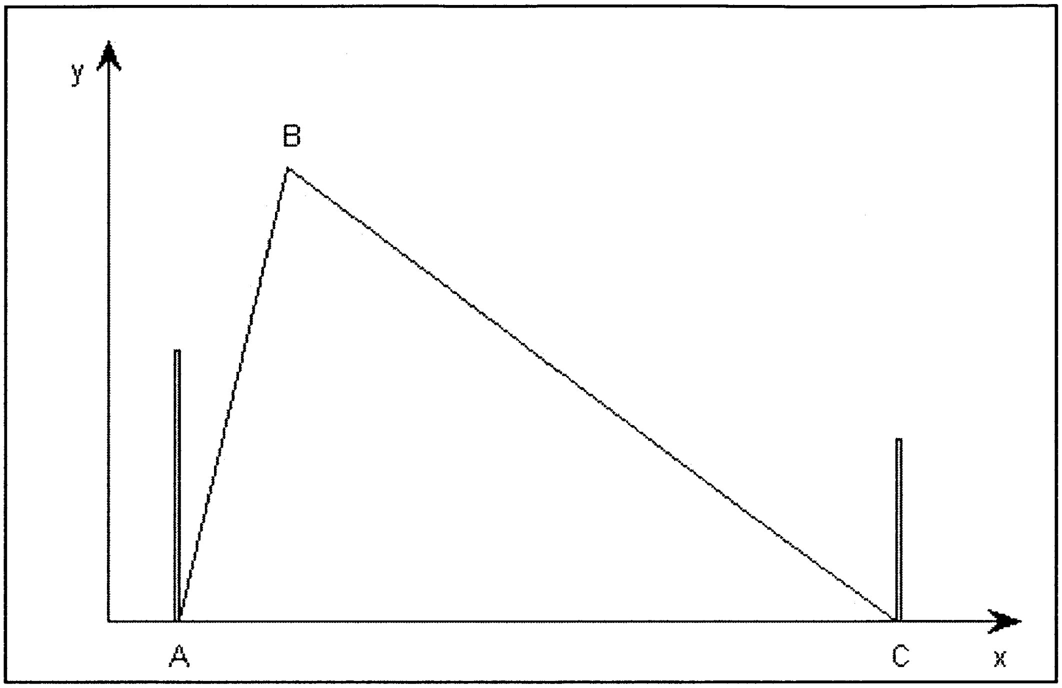


Figure 2-14: The Bounded Triangular Distribution Function.

The Lognormal Distribution Function

The DAT generate lognormal distribution functions in a somewhat unique manner, designed to be useful to project managers while reducing the computational costs that come from using the method: it uses a minimum value, a modal value, a maximum value, and a probability that the distribution exceeds this maximum value (See Figure 2-15).

2.3 Using the DAT in a Well Drilling Context

2.3.1 Areas and Zones

Areas and zones serve as the basic structure around which ground parameter values are generated. In their treatment of areas and zones, users should define the entire well length as a single area, and then designate zones as needed to help define the probability distribution of ground parameters– if there is any sort of discontinuity

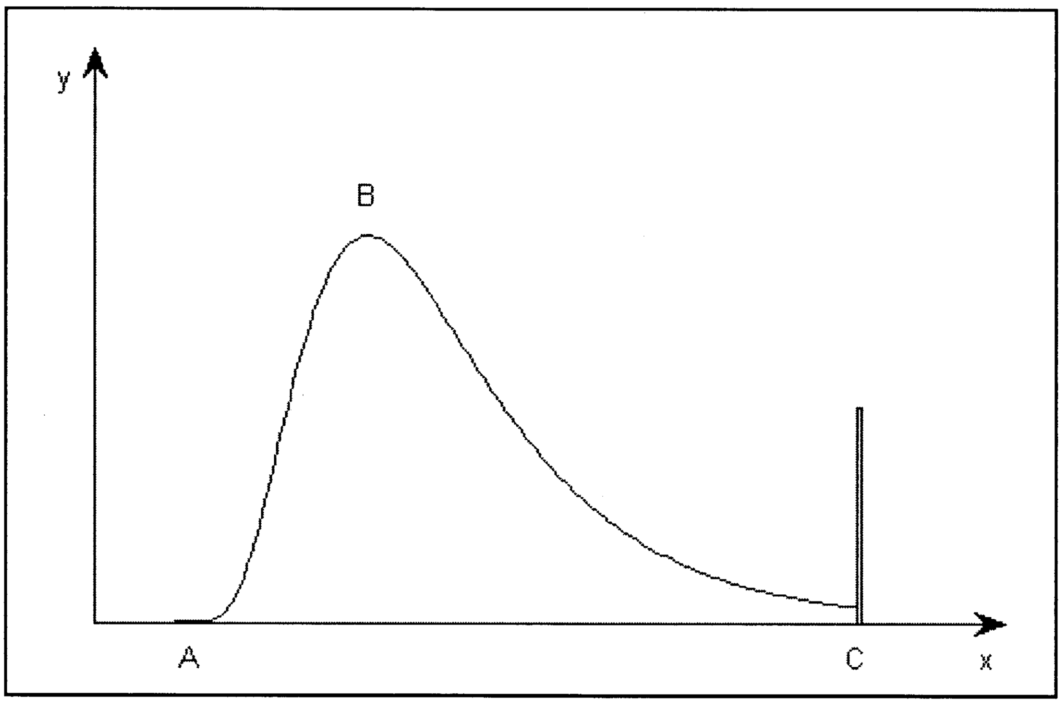


Figure 2-15: The Lognormal Distribution Function. It is parametrized by A) a minimum value, B) a modal value, C) a maximum value, and a probability of exceeding the maximum value.

or shift in the probabilistic distribution of a ground parameter, designate a zone to distinguish between the regions before and after that breakpoint. The appropriateness of the three different zone length determination methods (by Length, End Position, or Length AND End Position) is dependent on where the user believes these breakpoints will occurs and/or how their occurrence is probabilistically defined.

2.3.2 Ground Parameter Sets and Ground Classes

In using ground parameters, the user has three main options: use ground parameters to define rock properties (strength, abrasiveness, porosity, etc), to define lithology (gneiss, schist, etc), or to create lexicographical sets of ground types (good, bad, normal, etc). The upside of using the parameters to define rock properties is that the translation of these properties into project costs and delays is direct. The downside is that the distributions of rock properties are not independently random, and so care must be given in the ground parameter generation stage. Conversely, using rock lithology offers a somewhat easier parameter generation problem, but a more difficult translation from ground class to activity cost and schedules. Using a lexicographical ground parameter set attempts to remove the difficulties inherent in both problems by abstracting out geological detail while retaining the ultimate functionality of the geology section of the DAT, which is to aid in generating final cost and time distributions. Each of the three methods has strengths and weaknesses, and the choice between them largely depends on the information available to the modeler. What is important is to adopt a mutually exclusive, collectively exhaustive approach to ground parameter generation. Some relevant parameters, like overpressure, are often independent of rock properties or lithology, and so can be defined separately, regardless of the choice made between the three major parameter organization schemes.

2.3.3 The Well Network

The well network input is relatively straigt-forward. For most wells, construction will proceed linearly, with the drilling and casing of progressively deeper sections– as such, the well network is often linear.

2.3.4 Methods, Geometry, and Method Selection

Method selection is the first major avenue for introducing variation into a DAT model. As the input of methods can be time intensive, the user should try to use as few methods as possible while retaining desired features. Also, because method development is time intensive, the user should organize his modeling approach so as to make use of the method copying feature as frequently as possible– any activities, method variables, well networks, or other components of a method that are common across the set of methods that a user plans on creating, should be created once in a baseline method, and then the development of other methods can begin from copies of that baseline method.

Well geometry, while also useful as a feature that defines methods on the basis of a well bore profile, should be more generally used to delineate methods that are different, despite sharing the same ground class– for example, a well logging stage can be given a different geometry than a well casing stage– even though the two construction stages utilize the same wellbore, designating logging as one type of geometry and casing as another can make it easier for the user to specify that both a logging and a casing stage will occur across a particular well segment, even though both are being performed over geologically identical sections.

The user has two main options when it comes to method selection– one option is to define methods deterministically from geometry and ground class, while the other is to define methods probabilistically, with a pairwise combination of geometry and ground class potentially leading to more than one method. Neither approach is invalid, however it is more straightforward to keep method selection as a deterministic process, and define all uncertainty either within the ground class generation process or the method and general variable generation processes. By limiting uncertainty to these domains, the model is more transparent, and allows a user to view all of the model variability on a smaller number of program windows. When probabilistic method definition is used, it should be used sparingly, for example as a minor aid to the ground class generation process, and certainly not utilized so as to take responsibility for generating variability from both ground class generation and parameter generation at the same time.

2.3.5 Activities

It is important to define activities in parallel with activity networks. Because the activities in an activity network are selected using a dropdown menu, it is easier to select activities that appear at the extremes of the menu, rather than its middle. Creating all of the activities in a model, and only afterward creating all of the activity networks makes the user interface more challenging to work with, as it requires the modeler to frequently search for activities within the dropdown menu rather than scroll to them instantly. Figure 2-11 demonstrates this phenomenon.

As a strictly top-down exercise, it is useful to think of activities as relating directly to physical actions taken during the construction process. A typical activity network will consist of drilling, logging, casing, and other activities. However, while this convention is wise as a general rule of thumb, it need not be followed strictly. In particular, the user may find it easier to define activities that do not have a direct relation to the construction project. This could be done either as a way of reducing the amount of user input necessary to build a model, or as a creative way of representing uncertainty. These activities can be used to add cost and schedule terms that cannot easily be associated with physical processes, or otherwise just make it easier for the user to obtain the cost and time distribution shape that is desired. Figure 2-16 shows one potential such activity, dealing with project risk due to exchange rate fluctuations.

2.3.6 General and Method Variables

Experience with construction projects suggests that lognormal distributions are particularly well suited to cost representation, while triangular distributions are good approximations of schedule requirements. It is up to the modeler to decide which parameter distributions are most appropriate, or even to create new parameter dis-

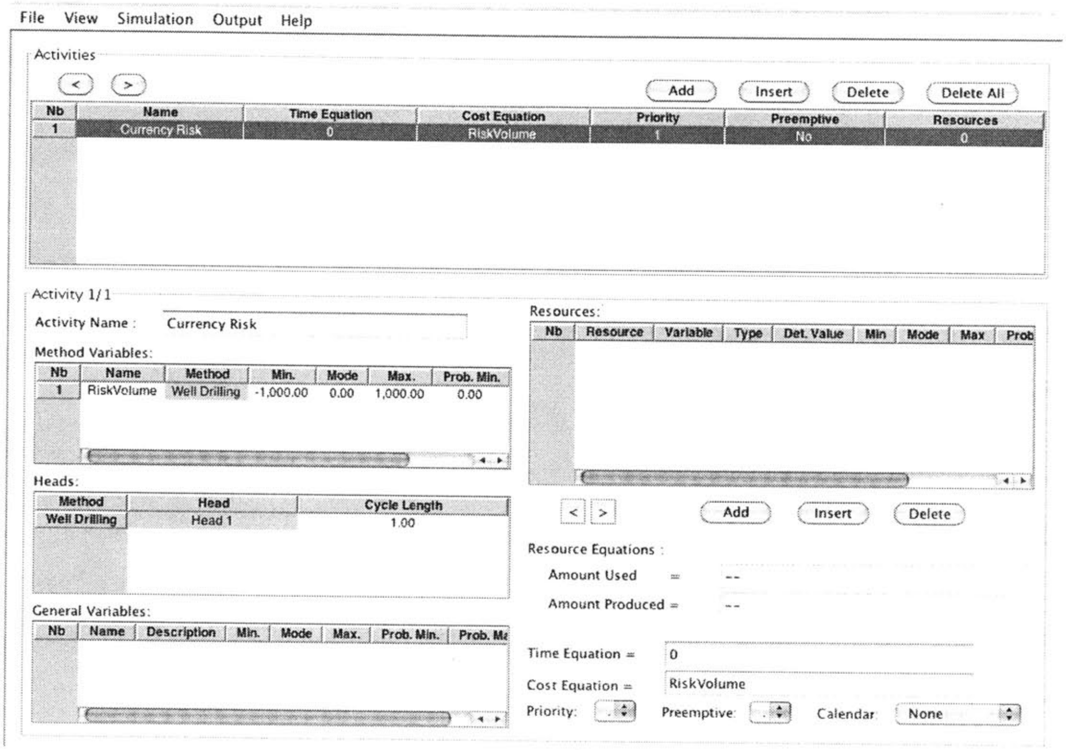


Figure 2-16: Activities Do Not Need to Directly Relate to Construction Processes. Here is a simple activity a user could input into the DAT to account for risk due to exchange rate fluctuations, with the potential for a \$1000 reduction in costs if exchange rates are favorable, and a \$1000 increase in costs if they are unfavorable.

tributions through the creative use of equations. However, as a default, the user should consider using lognormal distributions for parameters that appear in activity cost equations, and triangular distributions for parameters that appear in time equations. The modeler should also be careful not to use method variables where general variables are required or vice versa– if the values that a variable takes are method specific, they should be method variables– otherwise they should be general variables.

As with activity networks and time and cost equations, method variables can be duplicated through the process of method copying, and so method variables should be entered into the DAT in an order that offers he greatest opportunity to reduce redundant input with method copying.

2.3.7 Time and Cost Equations

Where possible, simple time and cost equations should be used in lieu of complex ones. In a top-down analysis, cost can simply be equal to the cost per unit length constructed, multiplied by the length constructed. In a bottom-up analysis, cost can simply be the sum of fixed costs associated with a project, added to the product of the time spent in construction and the per-hour costs associated with construction.

As with activity networks and method variables, time and cost equations can be duplicated through the process of method copying, and so equations should be entered into the DAT in an order that offers he greatest opportunity to reduce redundant input with method copying.

Chapter 3

Applying the DAT to Example Geothermal Wells

3.1 The Synthetic Case

3.1.1 Introduction

The first case modeled using the DAT (which we refer to henceforth as the "synthetic" case) is a well example borrowed from the MIT Future of Geothermal Energy study [Tester et al, 2006], referred to henceforth as the Tester report for its lead author, Dr. Jefferson Tester.

In exploring the cost of drilling enhanced geothermal wells, the Tester report developed a set of prototypical wells to serve as the design bases for which costs could be estimated and its models could be validated. The cost of drilling enhanced geothermal wells, exclusive of well stimulation costs, was modeled for a set of comparable geologic conditions and with the identical completion diameters for depths between 1,500 and 10,000m using historical data from the Joint Association Survey on Drilling Costs. The geology was assumed to be a layered sedimentary rock followed by abrasive granitic rock. Bottom-hole temperature was assumed to be 200°C. For up to 1000m above the production region, the rates of penetration and bit life for each well were assumed equal to the penetration rate and bit life of conventional drilling through sedimentary rock, while the final 1000 meters used figures corresponding to drilling through granite. The completion diameter of each well was assumed to be 10 5/8". The wells were modeled as largely trouble free, with a 10% assumed contingency for minor troubles during drilling.

We take the most developed of the Tester report's base case examples, the four-interval, 5000-meter EGS well configuration, and model it using the DAT. Figure 3-1 is an illustration of the 5000m well profile used in the Tester report.

For the 5000m, four-interval well, the Tester Report provides a detailed breakdown of component costs. The report separates costs by casing intervals, assigning component costs differentially to each casing string. These breakdowns take into account casing design, the rate of penetration, bit life, and some degree of trouble event potential. Furthermore, the breakdown separates the time requirements for each interval as well, assigning rotating time and trip time to each section. Ultimately, the end estimate of an interval's cost is calculated by taking the material and time requirements for each interval, assigning fixed costs where appropriate, and then multiplying the time required to complete the interval by the hourly cost for all related cost elements. The final, total cost is calculated as the sum of all of the individual interval costs, and these costs are presented as an "authorization for expenditures" form– a template used by many in the industry for cost estimation.

The report makes some remarks on potential variability in costs without delving too deeply into quantitative estimation. For example, the report concludes that well cost estimates might vary between production and injection wells, as some production well designs may require tieback liners or specialized pumps which would introduce additional costs. The report also speculates on costs in deeper wells as well as wells located in different geologies.

While these cost breakdowns are useful, our modeling approach is more interested in adopting the top-down, historical-data-informed technique that the Tester report applies to most of its well cost analysis. Thus, while the Tester report demonstrates the potential for more sophisticated estimation techniques, our DAT model does not go to the lengths that the Tester report has, instead opting for a more abstracted

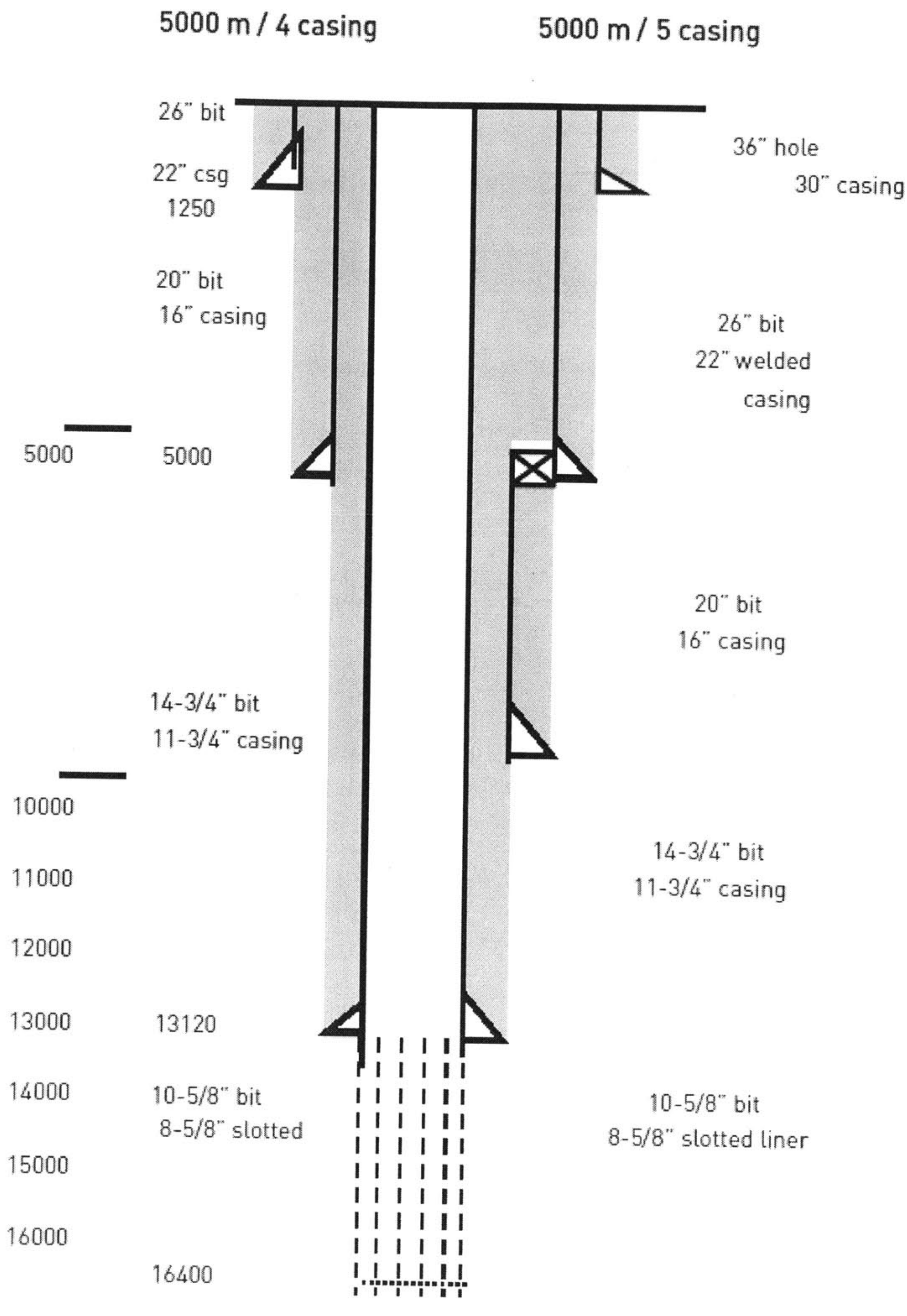


Figure 3-1: Figure A.6.1 from the Tester report [Tester et al, 2006]; a comparison of two base-case wells, the 4-interval 5000m well, and the 5-interval 5000m well. We model the lefthand, 4-interval well using the DAT.

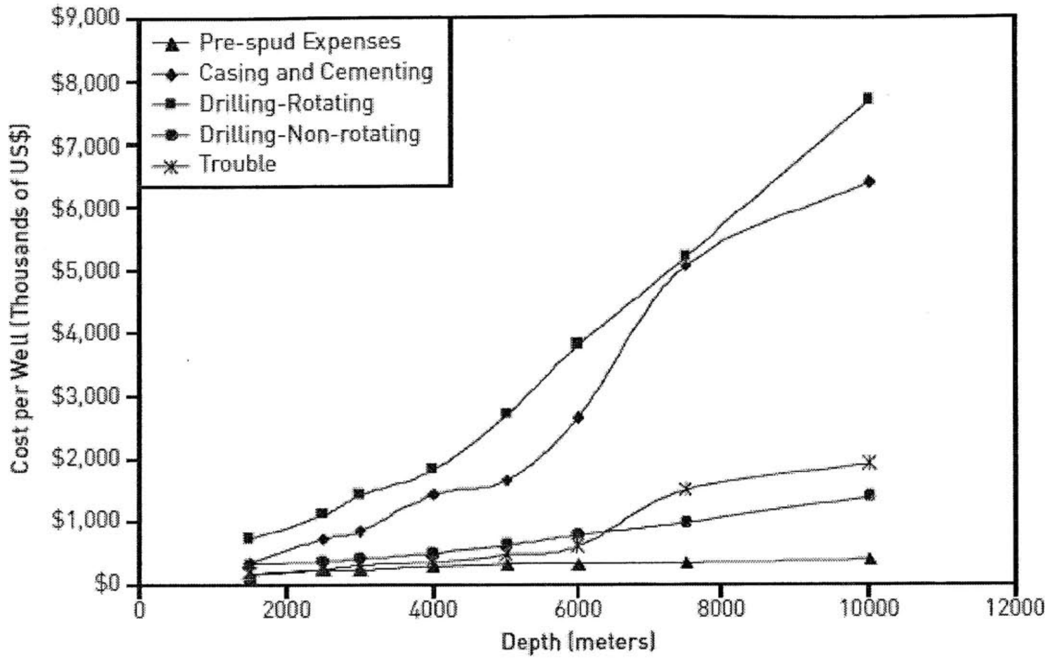


Figure 3-2: Figure 6.9 from the Tester report [Tester et al, 2006]; a high-level breakdown of well project costs by well depth. The data in the figure are drawn from Wellcost Lite, a model that uses past well-drilling experience to estimate geothermal well costs. We look at the relative distribution of costs for 5000m wells to help inform a sensitivity analysis that looks at independent variation in these high-level cost categories.

version of its cost analysis. In our treatment, cost assignment to each of the casing intervals is performed using a top-down approach. This approach to the problem is more congruent with the first-pass estimation techniques used at project outsets, and in that sense is representative of many real-life project management problems in the well-drilling sphere.

Beside the well profile that the Tester report used for its drilling cost model validation, we also make use of one of the report's cost breakdowns, generated by Wellcost Lite [Tester et al, 2006], an experience-based cost estimation tool very similar to that used in the Tester report, to help inform a top-down sensitivity analysis. The cost breakdown, provided in the Tester report but left relatively underutilized by the report's main analysis, is provided in Figure 3-2.

This breakdown between the five high level cost components of well drilling offers

Segment Name	Diameter	Starting Position	Ending Position
Leg A1	28"	0m	381m
Leg B1	20"	381m	1000m
Leg B2		1000m	1524m
Leg C1	14.75"	1524m	2400m
Leg C2		2400m	3200m
Leg C3		3200m	4000m
Leg D1	10.38"	4000m	4500m
Leg D2		4500m	5000m

Table 3.1: A breakdown of the well dimensions used in the synthetic example.

the ability to characterize the costs of a well project as either highly variable (like the trouble cost contribution), or only slightly variable (like drilling fixed costs).

3.1.2 Description of the Synthetic Case

Casing String Features

The features of the prototypical well used in our synthetic example follow those of the example used in the Tester report. The total depth of the well is 5,000m. The outer diameter of the well bore is 28" from 0 to 381m, 20" from 381 to 1,524m, 14.75" from 1,524 to 4000m, and 10.38" from 4,000m to 5,000m. Table 3.1 summarizes the dimensions of the synthetic well example.

For the purposes of simulation, this well length is divided into eight drilling legs:

Each leg is assigned a fixed cost that is drawn from the drilling-non-rotating costs provided in Figure 3-2 and is proportional to the length of the drilling segment. Leg A1 is unique: in addition to drilling-non-rotating costs, its fixed costs include the pre-spud costs associated with the construction project.

Each leg also draws, from a triangular distribution, values for three per-meter cost buckets: drilling rotating costs, casing costs, and trouble costs. The mean value of these distributions is equal to the per-meter costs for the same-named cost buckets in the Tester report, while the endpoints of these distributions reflect assumptions made by us. Trouble costs, being the most uncertain, vary between 0 and 200% of the per-meter value, while casing costs and drilling variable costs vary by 10% and

20% respectively.

Cost Sensitivity Assumptions

For each drilling leg, the three variable cost buckets (Drilling Rotating Costs, Casing Costs, and Trouble Costs) are summed to obtain the total cost. While Casing Costs and Trouble costs are used as-is, Drilling Rotating costs are multiplied from their base value by three separate multipliers. This reflects deviations from the average per-meter cost due to depth, diameter, and geology. These multipliers reflect somewhat arbitrary assumptions about cost variation, assumptions that are common to high-level, first-pass estimations.

Depth Drilling costs increase with depth. In the deepest leg, total per-meter costs are assumed to be 25% greater than the well average, while in the shallowest leg, per-meter costs are assumed to be 25% less than average. The cost multiplier for drilling segments at intermediate depth vary linearly with the average depth of the segment. The depth mutliplier for a well segment was therefore calculated to be:

$$DepthMultiplier = 1 + (Depth - 2500)/10000 \tag{3.1}$$

Diameter Drilling costs increase with diameter. In the highest diameter leg, total per meter costs are assumed to be 16% greater than the well average, while in the narrowest leg, per-meter costs are assumed to be 16% less than average. The cost multiplier for drilling segments of intermediate diameter vary with the square of the diameter.

$$DiameterMultiplier = 1 + (Diameter^2 - 280)/1680 \tag{3.2}$$

Geology Underlying geological conditions are considered an important cost factor in well drilling operations, and so particular attention is given to this cost bucket. Drilling in the worst geological conditions is assumed to cost 50% more than drilling under average conditions, and drilling in the best geological conditions is assumed to cost 50% less. The geological conditions themselves are generated by independently drawing states for four parameters– lithology, stress pattern, temperature, and overpressure– and holistically amalgamating all of the unique combinations of these parameters into five geological conditions of varying "goodness," i.e. Very Good, Good, Average, Bad, and Very Bad.

The advance rate of construction is treated more simply– it is drawn from a triangular distribution with a mean value that corresponds to the advance rate in the Tester report, and is, for now, treated as depth and diameter independent. As with cost, there is a multiplier associated with geological conditions, with drilling in favorable geological conditions performed at -50% time, and in unfavorable conditions performed at +50% time.

Hydraulic fracturing is also given a simple treatment within this simulation– it is a construction stage that has a fixed cost and schedule, and does not depend on any other parameters or conditions.

3.1.3 Modeling the Synthetic Case with the DAT

Areas and Zones

The first step in creating the simulation is to describe the ground that the well is being drilled into. For this simulation, we have defined a single area (the Drilling Area) of 5,001 meters, and divided it up into two zones, a Drilling Zone from 0 to 5,000m, and a dummy Fracing Zone from 5,000 to 5,001m that is used as a placeholder for the hydraulic fracturing process. Figure 3-3 and Figure 3-4 are screenshots of the DAT detailing these model inputs.

Ground Parameters and Parameter States

Within the Drilling Area, we independently define four parameters across the length of the area: Lithology, Stress Pattern, Temperature, and Overpressure. Each of these parameters have five discrete states, reflecting either distinct states (such as Gneiss for Lithology) or a range of values (such as 100-150 C for Temperature). Figure 3-5

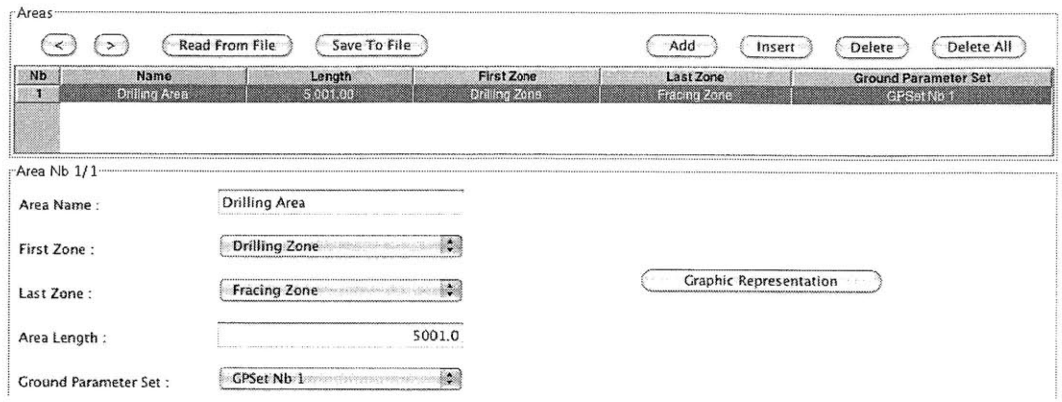


Figure 3-3: The Synthetic Case, The Areas Screen. This figure is a screenshot of the DAT Areas screen showing the 5001 meter area defined for the synthetic well.

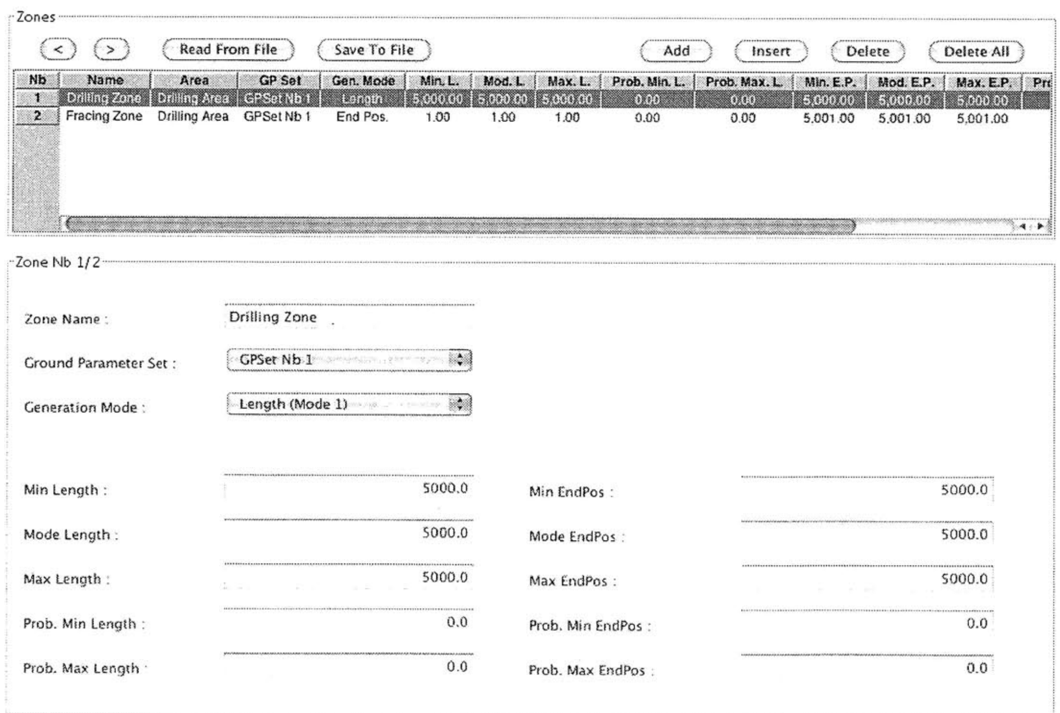


Figure 3-4: The Synthetic Case, The Zones Screen. This figure is a screenshot of the DAT Zones screen showing the two zones defined for the synthetic example.

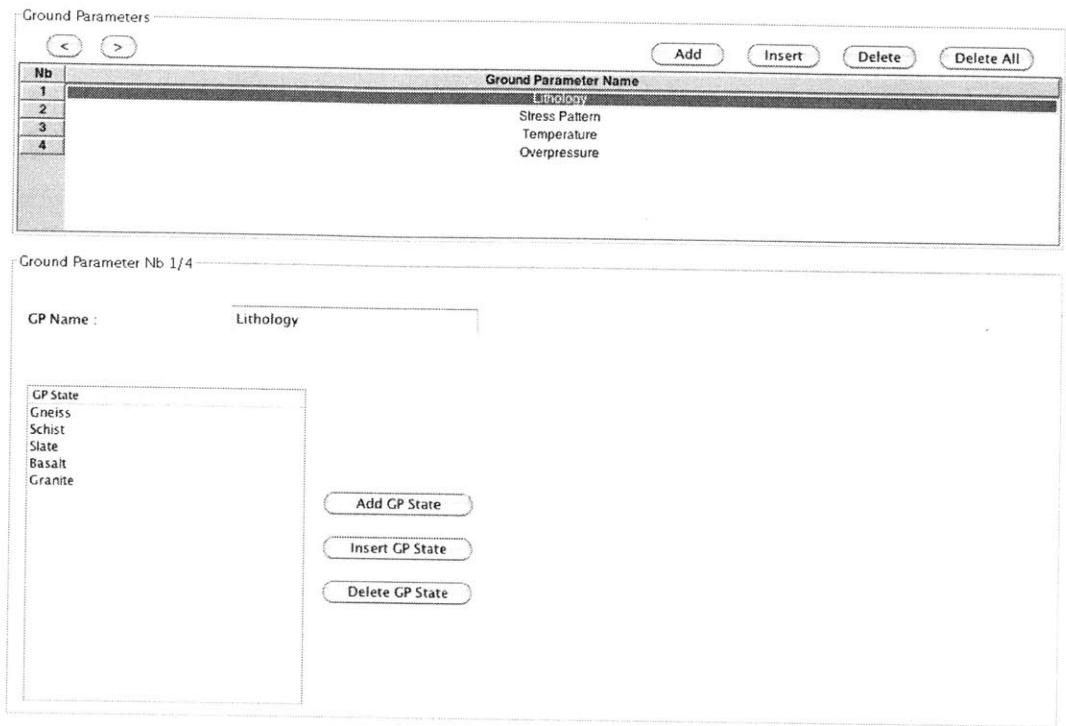


Figure 3-5: The Synthetic Case, The Ground Parameters Screen. This figure is a screenshot of the DAT Ground Parameters screen showing the four ground parameters defined for the synthetic well.

shows the four ground parameters as modeled with the DAT.

The value of a ground parameter across the length of the Drilling Area is determined with an ordered progression of states with varying lengths for each state. In a real case, these parameters and their uncertainties would be highly site specific. Here we have assumed an arbitrary set of ground parameter distributions, however, it would be equally easy to define a distribution of ground parameters that reflects the real-life stochastic behavior of the modeled parameters. Temperature, for example, would be well suited to an ordered progression from one state to the next (reflecting an uncertain, but positively-trending temperature-depth profile), while parameters such as lithology could, depending on the a priori knowledge of the site, be represented with a Markov or semi-fixed Markov model. Figure 3-6 shows the ground parameter distributions for the ground parameters.

At each point in the Drilling Area, the combination of generated parameter states

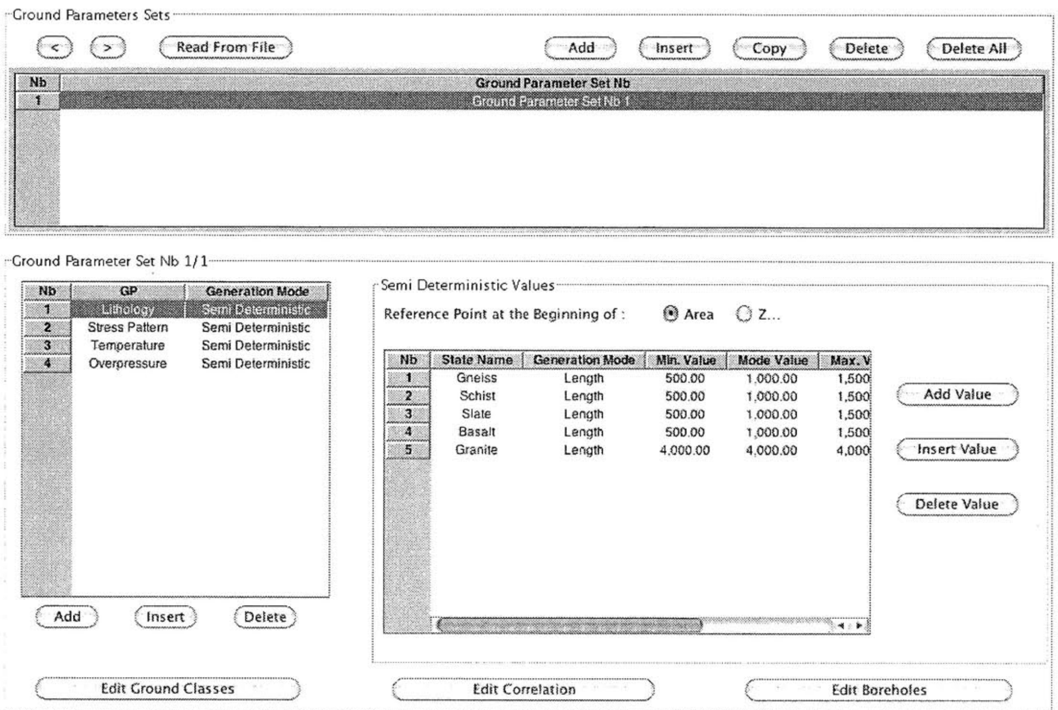


Figure 3-6: The Synthetic Case, The Ground Parameter Sets Screen. This figure is a screenshot of the DAT Ground Parameters Set screen showing the semi-deterministic distribution of the "Lithology" parameter. The other three parameters are identically defined, each with an ordered progression from their first state to their fifth.

defines what is termed a Ground Class. The ground class definition used in the synthetic case reflects a holistic approach where each parameter is treated as equally important. The five states of each parameter are ordered from notionally worst to notionally best, and then averaged together. So, for example, if two parameters are in their second worst state, and two parameters were in their second best state, holistically this combination will be treated as equal to a combination in which all four parameters take their third worst/best state. These averages are then divided into five domains, ranging from the worst possible average (all four parameters are in their worst state) to the best possible average (all four parameters are in their best states)– each domain corresponds to a Ground Class. Again, this is a fairly arbitrary designation (realistically, because ground classes determine methods, it would be important to use ground parameters to differentiate between ground classes only to the extent that the parameters themselves determine what construction methods must be used). However, because we are not attempting to make a rigorous analysis of the impact of geology on project costs, only to take a high-level look at the extent to which it could prove important, such detail is unnecessary.

Because the ground parameter distributions themselves are semi-deterministic, the ground class distribution is itself semi-deterministic as well, featuring an ordered progression from its best state ("Very Good") through the middle states ("Good," "Average," and "Bad") until reaching its ultimate state ("Very Bad"). Again, this distribution of ground classes is somewhat arbitrary– however, because of the variability with which these class transitions occur, it does provide a high-level representation of the total geology-related cost and schedule uncertainty.

Ground Classes, Methods, and Cost Equations

Each Ground Class defined in the DAT corresponds to a construction Method, and all stages of well drilling utilize the same construction method. In this synthetic case, a construction method is modeled as only having a single activity, a level of abstraction which is useful for a top-down analysis such as this. Figure 3-7 shows the method selection screen of the DAT– method selection has been simplified to the

Method Definition

Ground Class	Geometry 1	Geometry 2
Average	Average Dig	Hydrofracture
Bad	Hard Dig	Hydrofracture
Good	Easy Dig	Hydrofracture
Very Bad	Very Hard Dig	Hydrofracture
Very Good	Very Easy Dig	Hydrofracture

Figure 3-7: The Synthetic Case, The Method Definition Screen. This figure is a screenshot of the DAT Method Definition screen showing the straightforward correspondence between geological conditions and construction methods. Hydraulic fracturing is given its own dummy geometry, and its associated method has both a fixed cost and schedule.

point where it only depends on geology. Figure 3-8 shows an activity network for one of the methods– the activity network has a single element in it, reflecting that all of the cost and time estimates for each construction stage are provided in a single equation.

A construction method defines the cost and schedule equations that provide the outputs of the simulation. In the synthetic case presented, the five defined Methods are nearly identical: All five use cost equations that take five quantities as arguments: Drilling Variable Cost, Casing Cost, Trouble Cost, Depth, and Diameter, and both the generation method of these quantities, as well as the structure of the cost and schedule equations are identical across Methods. The only difference that separates the five Methods is the variation of a multiplier– in the Method that corresponds to the worst range of parameter state averages, both cost and time are 150% of normal, while in the Method that corresponds to the best range of parameter state averages, both cost and time are 50% of normal. The intermediate domains use intermediate multipliers of +25%, +0%, and -25%. Figure 3-9 shows the cost- and time equations used by the DAT.

Method and General Variables

The method and general variables are relatively straightforward. Figure 3-10 and Figure 3-11 are DAT screenshots showing the variables used in the synthetic case.

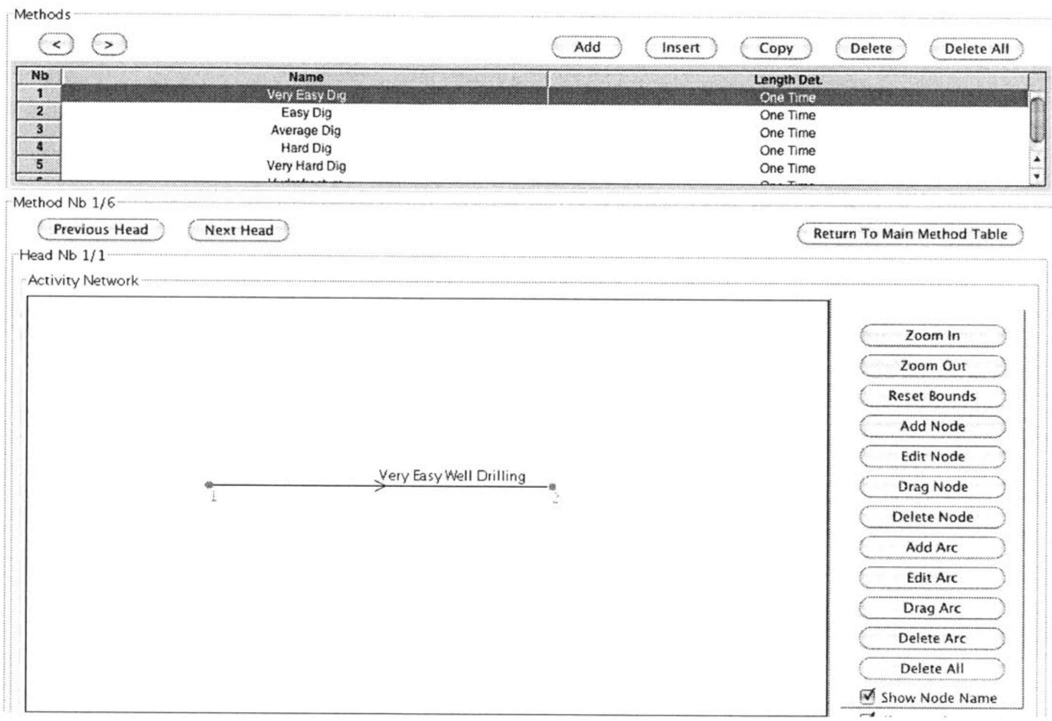


Figure 3-8: The Synthetic Case, The Activity Network Screen. This figure is a screenshot of the DAT Activity Network screen showing activity network for the construction method associated with the most favorable geology. It consists of a single activity.

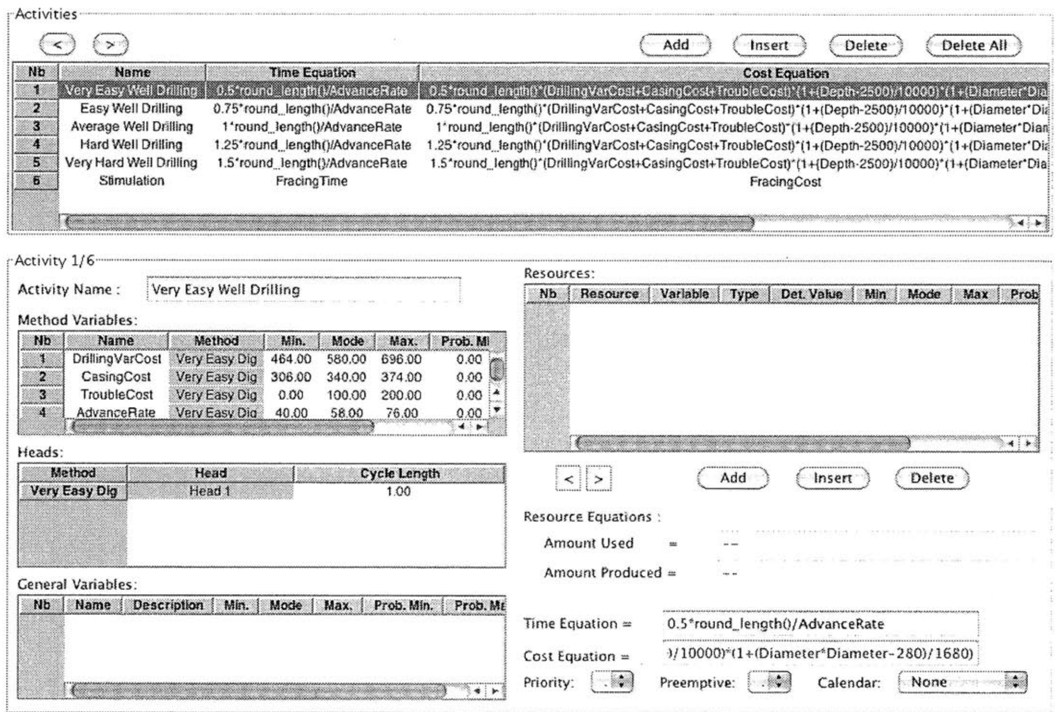


Figure 3-9: The Synthetic Case, The Activities Screen. This figure is a screenshot of the DAT Activities screen showing activity cost and time equations for the activity associated with the most favorable geology. The cost equations are simply the per meter costs of that stage, multiplied by the length, while the times are equal to the lengths divided by the advance rates. The depth and diameter multipliers introduce variation between each of the construction stages. The three variable cost buckets have triangular distributions.

Method Variables

Nb	Name	Method	Min.	Mode	Max.	Prob. Min.	Prob. Max.
1	DrillingVarCost	Very Easy Dig	580.00	580.00	580.00	0.00	0.00
2	DrillingFixCost	Very Easy Dig	140.00	140.00	140.00	0.00	0.00
3	CasingCost	Very Easy Dig	340.00	340.00	340.00	0.00	0.00
4	TroubleCost	Very Easy Dig	100.00	100.00	100.00	0.00	0.00
5	PreSpudCost	Very Easy Dig	60.00	60.00	60.00	0.00	0.00
6	AdvanceRate	Very Easy Dig	40.00	58.00	76.00	0.00	0.00
7	DrillingVarCost	Easy Dig	580.00	580.00	580.00	0.00	0.00
8	DrillingFixCost	Easy Dig	140.00	140.00	140.00	0.00	0.00
9	CasingCost	Easy Dig	340.00	340.00	340.00	0.00	0.00
10	TroubleCost	Easy Dig	100.00	100.00	100.00	0.00	0.00
11	PreSpudCost	Easy Dig	60.00	60.00	60.00	0.00	0.00
12	AdvanceRate	Easy Dig	40.00	58.00	58.00	0.00	0.00
13	DrillingVarCost	Average Dig	580.00	580.00	580.00	0.00	0.00
14	DrillingFixCost	Average Dig	140.00	140.00	140.00	0.00	0.00
15	CasingCost	Average Dig	340.00	340.00	340.00	0.00	0.00
16	TroubleCost	Average Dig	100.00	100.00	100.00	0.00	0.00
17	PreSpudCost	Average Dig	60.00	60.00	60.00	0.00	0.00
18	AdvanceRate	Average Dig	40.00	58.00	58.00	0.00	0.00
19	DrillingVarCost	Hard Dig	580.00	580.00	580.00	0.00	0.00
20	DrillingFixCost	Hard Dig	140.00	140.00	140.00	0.00	0.00
21	CasingCost	Hard Dig	340.00	340.00	340.00	0.00	0.00
22	TroubleCost	Hard Dig	100.00	100.00	100.00	0.00	0.00
23	PreSpudCost	Hard Dig	60.00	60.00	60.00	0.00	0.00
24	AdvanceRate	Hard Dig	40.00	58.00	58.00	0.00	0.00
25	DrillingVarCost	Very Hard Dig	580.00	580.00	580.00	0.00	0.00
26	DrillingFixCost	Very Hard Dig	140.00	140.00	140.00	0.00	0.00
27	CasingCost	Very Hard Dig	340.00	340.00	340.00	0.00	0.00
28	TroubleCost	Very Hard Dig	100.00	100.00	100.00	0.00	0.00
29	PreSpudCost	Very Hard Dig	60.00	60.00	60.00	0.00	0.00
30	AdvanceRate	Very Hard Dig	40.00	58.00	76.00	0.00	0.00
31	FracingCost	Hydrofracture	300,000.00	300,000.00	300,000.00	0.00	0.00
32	FracingTime	Hydrofracture	14.00	14.00	14.00	0.00	0.00

Figure 3-10: The Synthetic Case, The Method Variables Screen. This figure is a screenshot of the DAT method variables screen. The method variables are primarily the values for the per-meter cost buckets.

Structure Variables

Nb	Name	Tunnel	Min.	Mode	Max.	Prob. Min.	Prob. Max.
1	Diameter	LegA1	28.00	28.00	28.00	0.00	0.00
2	Depth	LegA1	190.00	190.00	190.00	0.00	0.00
3	Diameter	LegB1	20.00	20.00	20.00	0.00	0.00
4	Depth	LegB1	690.00	690.00	690.00	0.00	0.00
5	Diameter	LegB2	20.00	20.00	20.00	0.00	0.00
6	Depth	LegB2	1,262.00	1,262.00	1,262.00	0.00	0.00
7	Diameter	LegC1	14.75	14.75	14.75	0.00	0.00
8	Depth	LegC1	1,977.00	1,977.00	1,977.00	0.00	0.00
9	Diameter	LegC2	14.75	14.75	14.75	0.00	0.00
10	Depth	LegC2	2,800.00	2,800.00	2,800.00	0.00	0.00
11	Diameter	LegC3	14.75	14.75	14.75	0.00	0.00
12	Depth	LegC3	3,600.00	3,600.00	3,600.00	0.00	0.00
13	Diameter	LegD1	10.38	10.38	10.38	0.00	0.00
14	Depth	LegD1	4,250.00	4,250.00	4,250.00	0.00	0.00
15	Diameter	LegD2	10.38	10.38	10.38	0.00	0.00
16	Depth	LegD2	4,750.00	4,750.00	4,750.00	0.00	0.00
17	Permeability	Fracing	1.00	2.00	3.00	0.00	0.00
18	Porosity	Fracing	1.00	2.00	3.00	0.00	0.00
19	Thermal Output	Fracing	1.00	2.00	3.00	0.00	0.00

Figure 3-11: The Synthetic Case, The General Variables Screen. Depth and Diameter information is already provided when the well network is created, but including them as variables makes quick review of the model assumptions easy.

Fixed Costs

Nb	Tunnel	Min Fixed Cost	Mode Fixed Cost	Max Fixed Cost
1	LegA1	347,991.00	353,324.00	358,656.40
2	LegB1	68,439.74	76,044.15	83,648.57
3	LegB2	61,982.39	68,869.32	75,756.25
4	LegC1	100,715.73	111,906.37	123,097.00
5	LegC2	99,965.36	111,072.63	122,179.89
6	LegC3	107,729.66	119,699.63	131,669.59
7	LegD1	66,434.99	73,816.65	81,198.32
8	LegD2	69,262.01	76,957.79	84,653.57
9	Fracing	0.00	0.00	0.00

Figure 3-12: The Synthetic Case, The Fixed Costs Screen. Each well segment is assigned a fixed cost equal to its proportion (proportion determined by its fraction of the total well length) of the drilling fixed costs. The first leg is also assigned the pre-spud costs as an additional fixed cost.

Fixed Costs

Each well leg has a dedicated fixed cost, which is a combination of pre-spud costs (which are assumed to have no variability) and drilling fixed costs (which have the same variability as drilling variable costs). Figure 3-12 shows the DAT summary of well segment fixed costs, as modeled.

Hydraulic Fracturing

Hydraulic fracturing, included in the well network as a final construction stage, is represented very simply, with both a fixed cost and time requirement. There is no variability in the fracing costs or time. The total fracing cost was taken to be $300,000, while the fracing time was taken to be exactly 14 days. Figure 3-13 shows the DAT Activities Screen of the hydraulic stimulation activity.

3.1.4 Results and Discussion

Total Cost and Time Outputs

One thousand simulations were run of the synthetic case. The results are provided in Figure 3-14.

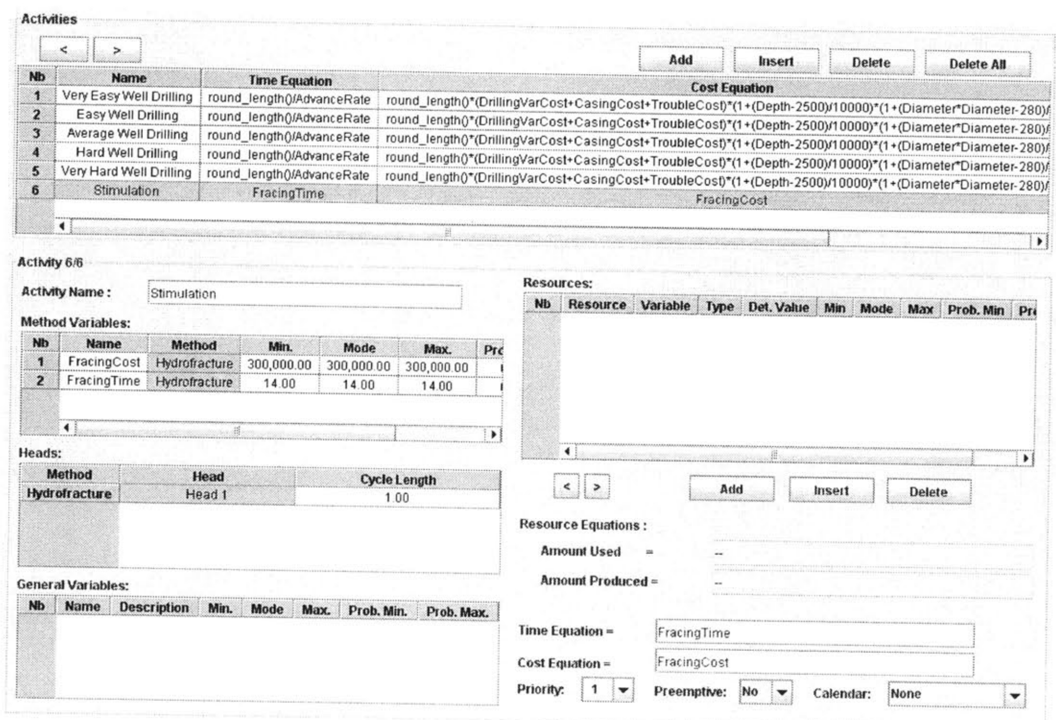


Figure 3-13: The Synthetic Case, The Activities Screen. Hydraulic fracturing is given a simple treatment in the synthetic case. The fracing method consists of a single activity, and that activity has a fixed cost and time.

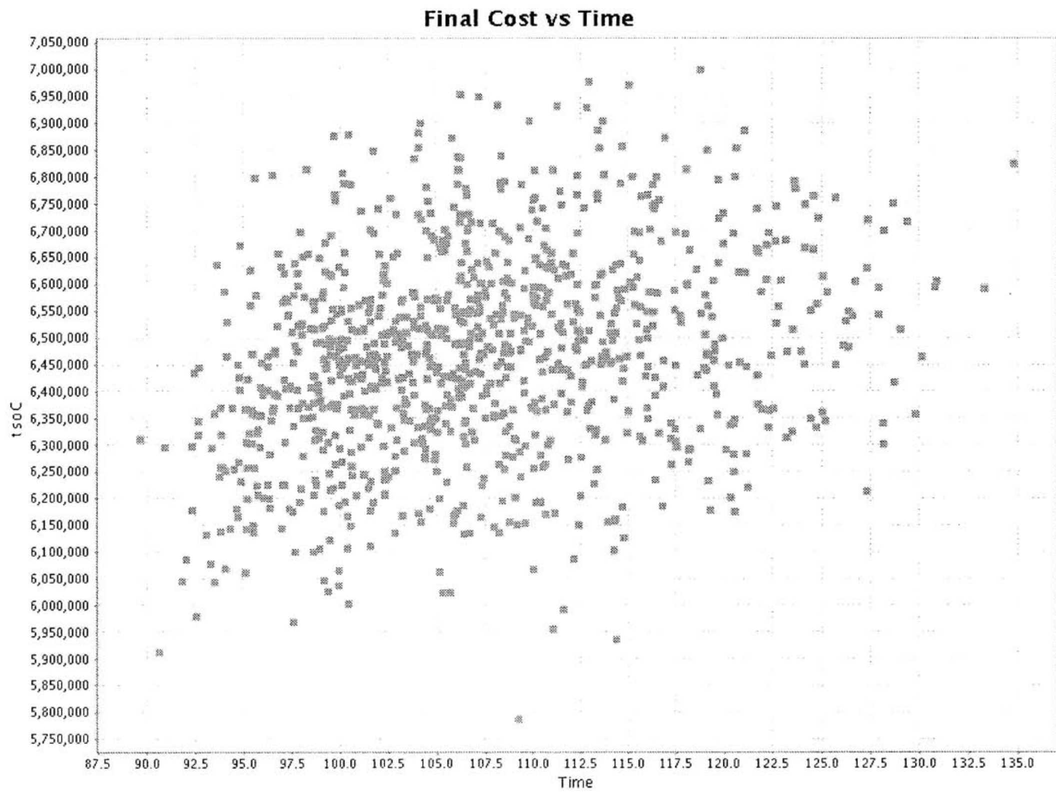


Figure 3-14: The Synthetic Case, The Final Time vs. Cost Screen. 1000 simulations were run of the synthetic case. Due to the relatively loose association between cost variation and time variation (only variation due to geological effects was considered correlated), the results do not show very strong correlation between cost and time outcomes (data points aligned along a diagonal).

Discussion

The synthetic case demonstrates a fundamental principle of modeling– the results reflect the assumptions that go into the model. In developing the synthetic case, we assumed only a weak correlation between the factors that impact project cost and the factors that impact project schedule, and accordingly, the results show only a weak correlation across these dimsensions. To achieve a tighter correlation, one could assign delays proportional to trouble costs, or otherwise create some linkage between the factors that affect project cost and those that affect project schedule.

3.2 The Sandia Case

One of the well examples modeled using the DAT is a baseline case developed by Sandia National Laboratories. Sandia, working with ThermaSource Inc, a geothermal drilling contractor, developed task-, time-, and cost descriptions of the construction process for a geothermal well. The well is designed to generate 5 MWe from 80kg/s of 200°C well head fluid produced from a depth of 20,000 ft. Sandia's descriptions reflect paper estimates of costs and schedules, and as such do not have a relation to an actual case, but they are representative of standard practices in the drilling field, and in that sense are of great relevance as a demonstration of the DAT as a practical part of the project manager's toolkit. As with any estimation, there is room for debate over the estimated tasks, costs, and completion times, but on the whole, Sandia's baseline well specification provides the basis for a rigorous and detailed synthetic proof of concept for DAT modeling and serves as a prototypical example of how the DAT, as a planning tool, could be used in conjunction with existing approaches to project management.

3.2.1 The Sandia Well Specification

In order to reach the designed depth of 20,000ft, Sandia's well design (See Figure 3-15 calls for five casing strings– a surface casing, an intermediate casing, and three production liners, labeled Production 1, Production 2, and Production 3. Each casing string overlaps the previous casing string by 200ft; for example, the Intermediate Casing descends all the way down to 10,000ft, but next casing string, the Production 1 Liner, begins at 9,800ft. A tieback liner rests on top of the Intermediate Casing and fits within the Surface Casing in order to create a sealed, smooth conduit for injection of a working fluid.

Sandia has produced a detailed list of construction activities (357 in total) necessary to bring the well from a stud-stage (in which a 50-ft deep surface hole has been dug and a short conductor pipe has been laid), all the way to the point where the well is completed and ready to be connected to a thermal plant for testing and operation.

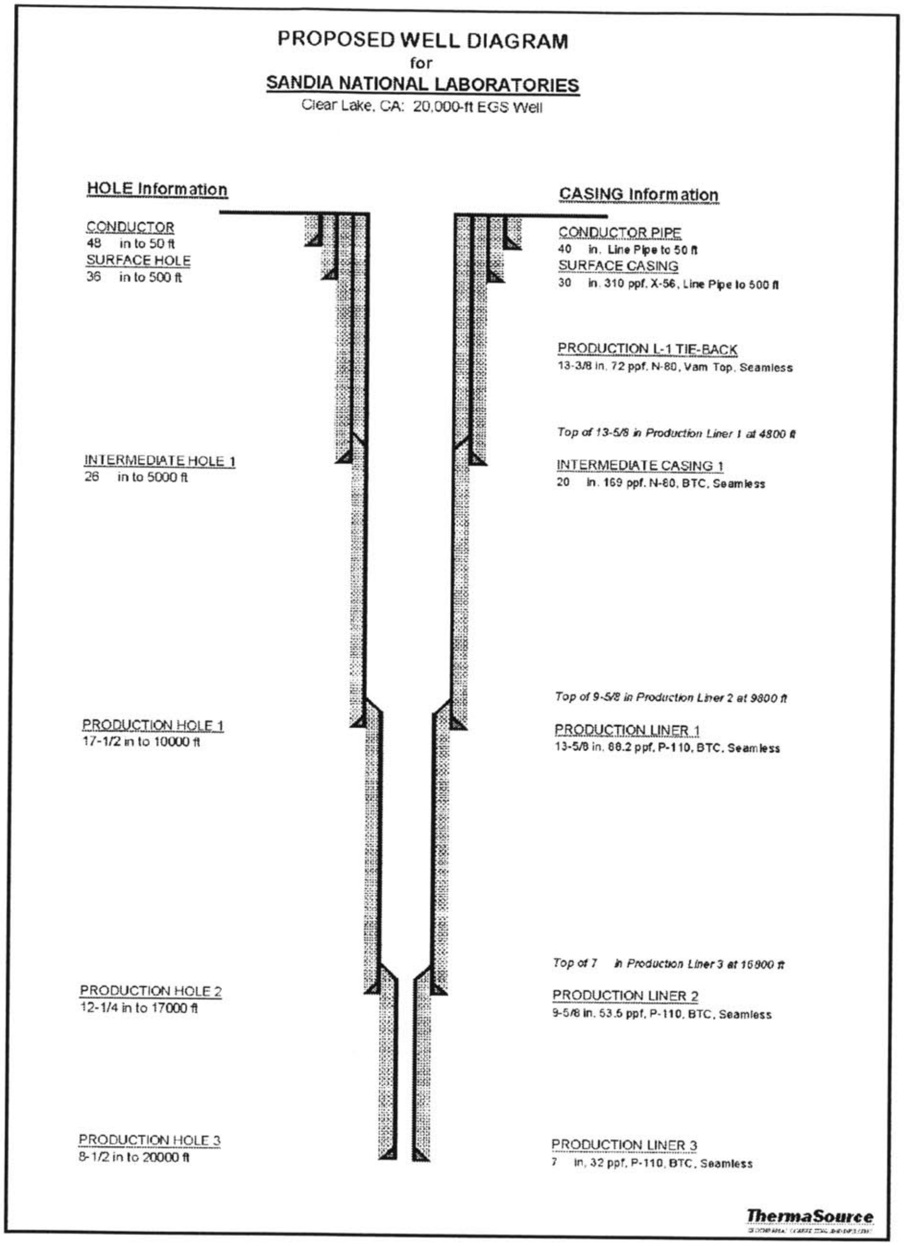


Figure 3-15: The Proposed Well Diagram from Sandia National Laboratories. Figure 3-15 describes the details of the well sections and casing strings, as well as their length. Various characteristics of the casing materials are also described, including the pounds per foot (ppf) of the casing material, the type of steel used (X-56, N-80, or P-110), the type of pipe (a line pipe, a buttress threaded casing, or 'BTC', or a 'Vam Top,' a brand name style of gas-tight, sealable pipe), and the type of welding done to the pipe (in all instances seamless welds are used, except for the line-pipe, which is not welded)

.

Designation	Abbr.	Description and Representative Tasks
Blowout Preventer	BOP	Connecting and testing the blowout preventer
Bottom Hole Assembly	BHA	Modifying the drill string; replacing drill bits, picking up and setting down the drill string, pressure testing
Cementing	Cement	Mixing and pumping cement, waiting to harden, cleaning off excess cement
Circulating	Circ	Circulating fluid through the well hole to clean debris
Drilling	Drill	Drilling
Logging	Log	Running formation evaluation logs and caliper logs
Rigging Up/Down	RigU/D	Connecting and disconnecting equipment from the drilling rig, particularly logging and casing running equipment
Running Casing	RunCsng	Setting and unsetting liner hangers, running casing into the hole
Tripping	Trip	Moving the drill string and other equipment in and out of the hole
Wellhead Operations	WHOps	Tasks associated with connecting the well head, including cutting, dressing, and welding casing heads, pressure testing, and connecting pipe sections

Table 3.2: A list of abbreviations used to designate types of well construction activity

Within each stage, activities are classified as either Blow Out Preventer related, Bottom Hole Assembly, Cementing, Circulation, Drilling, Logging, Rigging Up/Down, Running Casing, Tripping, and Wellhead Operations. The activities include a short description, and are given a scheduled number of hours to complete (see also Table 3.2).

By estimating the time required to complete each of the 357 individual construction activities, Sandia has produced an estimate of the total time required to complete the well. Excluding pre-stud and post-well-construction activities, the project is estimated to require 3,386 hours (roughly 141 days). The final listing from the Sandia study can be found in Table C.1 of Appendix C. The time estimates do not take into account unforeseen delays.

In addition to providing a construction activity list to estimate the project schedule, Sandia estimated project costs using a bottom-up approach. An itemized list of 82 distinct cost components was created, and the cost of each item was estimated. The estimation does not include most pre-spud mobilization costs (some construction materials from the pre-spud phase are included as fixed costs in the surface drilling stage, but most pre-spud expenses are not modeled by Sandia) or any post-well-construction demobilization costs. In total, the project was estimated to have $21,340,000 in non-time-discounted (overnight) costs. The full listing of cost items is provided in Table C.2 of Appendix C. The cost estimates do not take into account potential trouble costs.

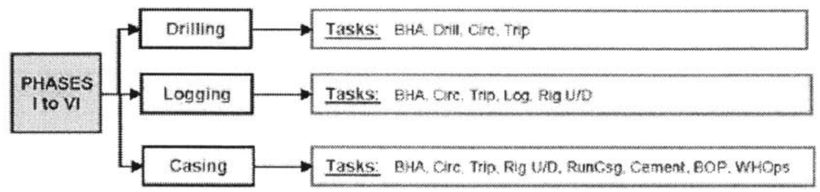
3.2.2 Modeling the Sandia Well with the DAT

Areas, Zones, and Ground Classes

Sandia's assumption in estimating the costs and schedule of its project is that the geology at the well site represents a "typical" project site, without a profile that is either particularly beneficial or detrimental to the goals of the well planner. Beyond this, Sandia does not specify its geological assumptions, or indicate how sensitive its result is to geological variation. As a result, Sandia's estimation does not suggest any readily apparent variation to introduce into the geology of the DAT model.

While the ThermaSource assessment on which the Sandia report bases its analysis highlights Clear Lake, California as the assumed project site, the Sandia well specification is for a baseline EGS well and as such (quoting from the Sandia report), "does not assume a specific lithology profile," and overall reflects geological conditions that are "in some respects conservative and others moderate." Sandia does not provide a "precise definition of the geology to be drilled." Accordingly, the geology modeled with the DAT is homogenous throughout the length of the well. In modeling the project deterministically, this is accomplished with a single area, containing a single zone, defined by a single ground parameter, which has a single possible state, and

				3,386	141.0
Phase	Activity	Task Code	GENERAL OPERATION TASKS	Hours	Days



Phase I: Surface			(36" Hole to 500' with 30" Casing)	180	7.5
1 Surface	DRILLING OPERATIONS			86	3.6
1 Surface	Drilling	BHA	1. Make up 26" bit and 36" hole opener on mud motor.	6	0.3
1 Surface	Drilling	BHA	2. Pick up 36" stabilizer and cross over to 6-5/8" HWDP.	4	0.2
1 Surface	Drilling	Drill	3. Drill and open 36" hole with motor and HWDP from 80' to 240'.	13	0.5
1 Surface	Drilling	Circ	4. Circulate	1	0.0
1 Surface	Drilling	BHA	5. Trip out of the hole and stand back 6-5/8" HWDP.	2	0.1
1 Surface	Drilling	BHA	6. Pick up (6) 11" drill collars and cross over to 6-5/8" HWDP.	8	0.3
1 Surface	Drilling	Drill	7. Drill and open 36" hole from 240' to 320'.	7	0.3
1 Surface	Drilling	Circ	8. Circulate	1	0.0
1 Surface	Drilling	BHA	9. Stand back 6-5/8" HWDP	2	0.1
1 Surface	Drilling	BHA	10. Pick up (3) 9-1/2" drill collars and cross over to 6-5/8" HWDP.	6	0.3
1 Surface	Drilling	Drill	11. Drill and open 36" hole from 320' to 500'.	15	0.6
1 Surface	Drilling	Circ	12. Circulate.	1	0.0
1 Surface	Drilling	Trip	13. Make a wiper trip to 320'.	4	0.2
1 Surface	Drilling	Circ	14. Circulate	1	0.0
1 Surface	Drilling	Trip	15. Trip out of the hole.	2	0.1
1 Surface	Drilling	BHA	16. Stand back HWDP and drill collars	7	0.3
1 Surface	Drilling	BHA	17. Break out and lay down 36" stabilizer, mud motor, 36" hole opener and 26" bit.	6	0.3

Figure 3-16: The Activity List of the "Surface Drilling" Construction Stage. Figure 3-16 is an extract from the appendix detailing the first major construction stage, Surface Drilling. More detailed activity listings are provided in Table C.1 in Appendix C

for which there is only a single possible ground class. Later, as sensitivity analyses are performed, the assumption of a homogenous geology will be relaxed, and the construction scenario will be analyzed to determine how cost and schedule needs might change with different advance rates and drill bit lifetimes, reflecting changing geology.

Well Network, Methods, and Method Selection

Sandia grouped the 357 activities into 16 major construction stages, to be conducted in sequential order. Note that while all stages in this example are sequential, the DAT also allow for parallel activities. The stages are listed in Table 3.3, and an example of the activity listing within the construction stage, Surface Drilling, is given in Figure 3-16.

Figure 3-17 shows the well network for the DAT which reflects the 16 major

Construction Stage	No. of Act.	Hours	Description of Task
Surface Drilling	17	86	Attach new 36" hole opener, drill to 500', clean out hole with circulating fluid
Surface Logging	3	7	Assess well diameter and stability from 0' to 500'
Surface Casing	17	87	Ready the hole for casing, run casing string down to 500', cement casing into place, cut and dress casing, weld on casing head, perform function and pressure tests
Intermediate Drilling	34	385	Attach new 26" drill bits, drill to 5000', clean out hole with circulating fluid
Intermediate Logging	8	34	Assess well diameter and stability from 500' to 5000'
Intermediate Casing	19	135	Ready the hole for casing, run casing string down to 5000', cement casing into place, cut and dress casing, weld on casing head, perform function and pressure tests
Production 1 Drilling	31	391	Attach new 17-1/2" drill bits, drill to 10000', clean out hole with circulating fluid
Production 1 Logging	8	60	Assess well diameter and stability from 5000' to 10000'
Production 1 Casing	25	138	Ready the hole for casing, run casing string from 4800' to 10000', cement casing into place, cut and dress casing, perform function and pressure tests
Production 2 Drilling	57	820	Attach new 12-1/4" drill bits, drill to 17000', clean out hole with circulating fluid
Production 2 Logging	8	95	Assess well diameter and stability from 10000' to 17000'
Production 2 Casing	22	113	Ready the hole for casing, run casing string from 9800' to 17000', cement casing into place, cut and dress casing, perform function and pressure tests
Production 3 Drilling	33	472	Attach new 8-1/2" drill bits, drill to 20000', clean out hole with circulating fluid
Production 3 Logging	8	114	Assess well diameter and stability from 17000' to 20000'
Production 3 Casing	33	219	Ready the hole for casing, run casing string from 16800' to 20000', cement casing into place, cut and dress casing, perform function and pressure tests
Tieback Casing	34	230	Ready the hole for casing, run casing string down to 500', cement casing into place, cut and dress casing, weld on casing head, install valves, perform function and pressure tests

Table 3.3: A listing of how many activities constitute each construction stage, the time they take to complete in summary, and a description of the typical constituent activities

construction stages being conducted sequentially. Figure 3-18 shows the DAT method selection process, which uses the geometry tied to each construction stage to select the appropriate construction 'method' for that stage.

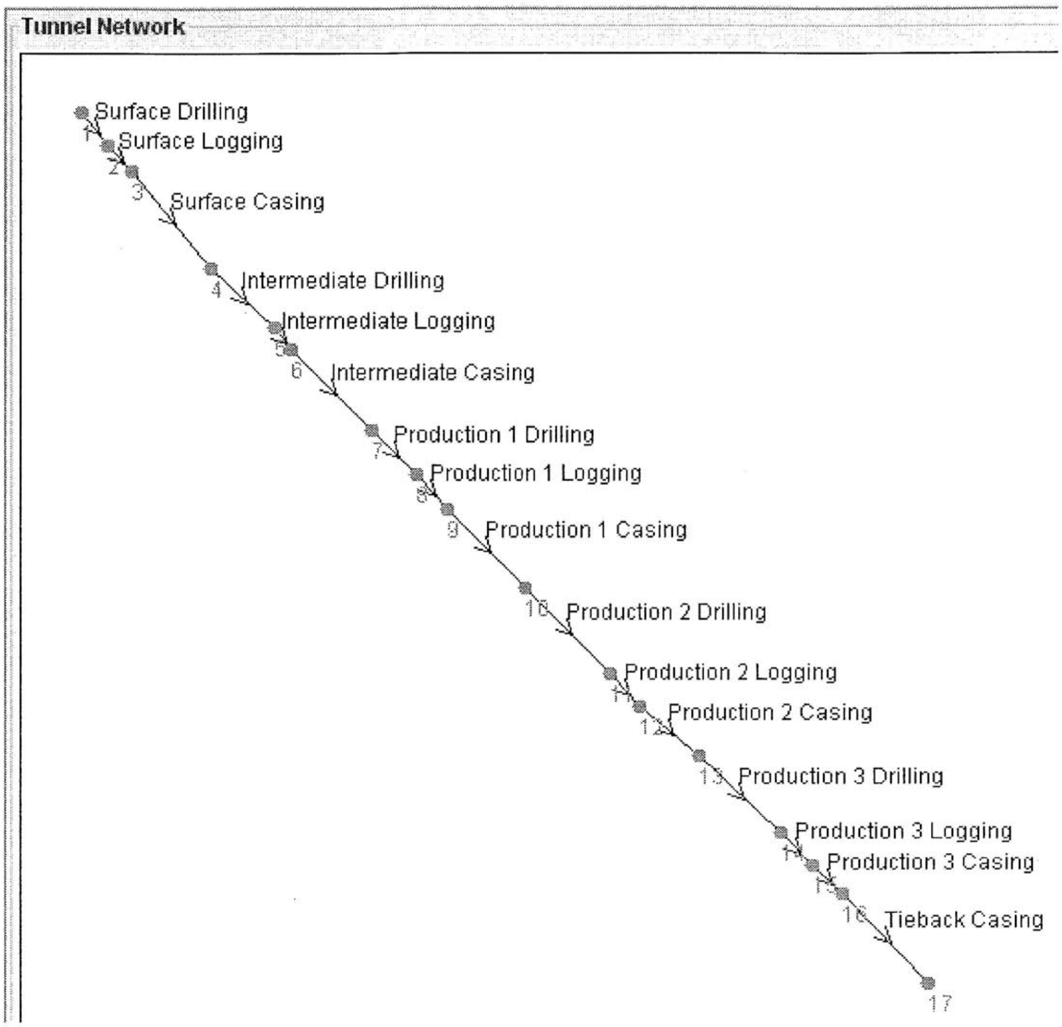


Figure 3-17: The Sandia Well Network, as Entered into the DAT. Figure 3-17 is a screenshot of the DAT well network. The well network entered into the DAT is a simple sequential chain of the sixteen major construction stages, as provided by Sandia. The numbers correspond to nodes, not arcs, thus 17 nodes are used to define 16 arcs.

Each construction stage is assigned a unique geometry (see Section 2.2.4 for a discussion of geometry in the DAT), and then this geometry is paired with a unique method.

Method Definition

Ground Class	Geometry 1	Geometry 2	Geometry 3	Geometry 4	Geometry 5	Geometry 6	Geometry 7	Geome
Method	Surface Drilling	Surface Logging	Surface Casing	Intermediate Drilling	Intermediate Logging	Intermediate Casing	Production 1 Drilling	Production

Figure 3-18: The Method-Geometry Pairing. Figure 3-18 is a DAT screenshot showing the assignment of methods to geometries. Each well construction stage in the DAT is assigned a unique geometry. This geometry is then paired with the corresponding method of a major activity group, e.g. the well network segment corresponding to the Surface Drilling stage is given Geometry 1, which then identifies the Surface Drilling Method as the method to be used in that well segment.

In this manner, all of the activities being modeled by the DAT are represented by the 16 methods, performed sequentially, with each method reflecting one of the major construction stages defined by Sandia.

Activities

The activity network for each of the 16 methods corresponds to the list of sub-activities provided by Sandia for that major construction stage. Each activity network is simple: it is constituted by the activities listed by Sandia and these activities are performed in a sequential order. Figure 3-19 illustrates the activity network of the first method, Surface Drilling.

Each method listed within the DAT well network is defined by its activity network. Each individual activity includes a time and cost equation– the aggregate of all of the activity cost and time equations defines the cost and schedule of the method. Figure 3-19 is a screenshot of the Surface Drilling method's activity network; the components of the network correspond to the activities listed by Sandia under Surface Drilling in Table C.1 of Appendix C.

Nomenclature

Before going further and explaining the variables and equations of the DAT model of the Sandia/Thermasource case, it is necessary to establish naming conventions for the various stages, activities, and variables that are used.

The cost and time equations used in the Sandia model call for four types of

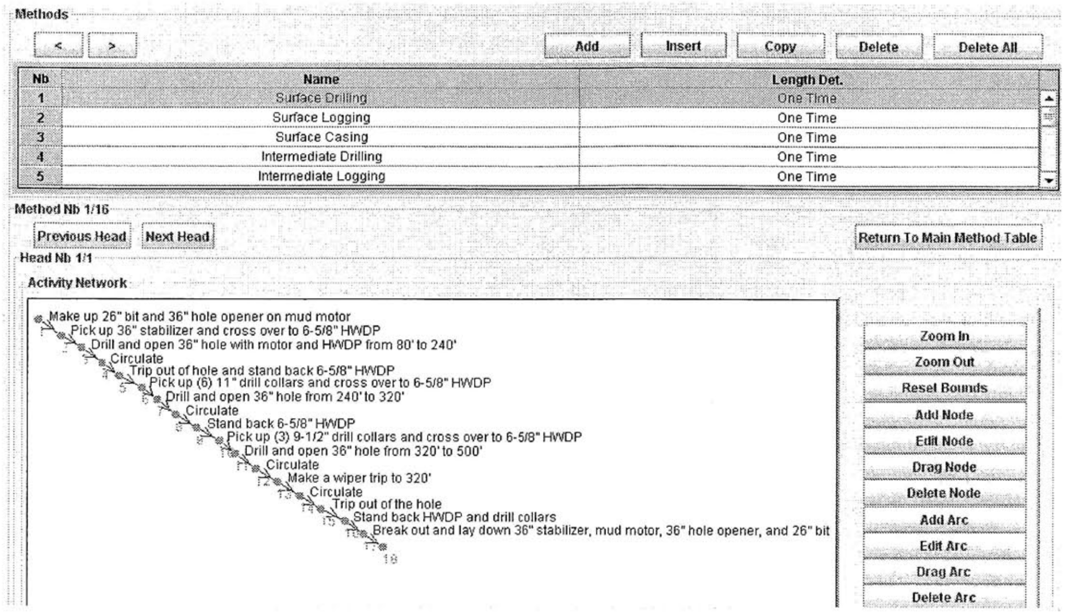


Figure 3-19: The Activity Network of the Surface Drilling Method / Construction Stage. Figure 3-19 is a screenshot of the 'Surface Drilling' method's activity network– the numbering corresponds to nodes within the network; in total, there are 17 activities in the Surface Drilling construction stage.

variables: 357 method variables that describe the baseline (Sandia provided) number of hours required for each activity in a method's activity network, 10 general variables (called activity class factors) that are used to introduce covariance across the time requirements of related sets of activities, 6 general variables that represent the hourly cost during construction stages, and 29 general variables that represent the fixed costs associated with given activities. The ten activity class factors are named by their abbreviations in Table 3.2; the remaining variables follow the conventions defined in Figure 3-20.

A subset of the 357 method variables is shown in Figure 3-22, and a full listing of the 45 general variables is provided in Figure 3-23.

Time and Cost Equations

The time and cost equations for each activity are straightforward. The time equation is simply the number of hours it takes to complete the activity as estimated by

Zone Abbreviations	
Surface	S
Intermediate	I
Production 1	P1
Production 2	P2
Production 3	P3
Tieback	T
General	G
Task Abbreviations	
Drilling	D
Logging	L
Casing	C

Label	Naming Convention	Example	Name
Construction Stage	Zone + Task	Surface Drilling	SD
Activity	Construction Stage + activity number within that stage	Third activity in the Surface Drilling stage	SD03
Activity Time Requirement	Construction Stage + H + activity number within that stage	The time requirement of the third activity within the surface drilling stage	SDH03
Fixed Cost	FC + Zone + order of appearance within Zone	Second fixed cost in the intermediate stage	FCI02
Hourly Cost	VC + Zone + order of appearance within Zone	First hourly cost in the Production 1 Stage	VCP101
General Hourly Cost	Unique	NA	GHrCost

Figure 3-20: DAT Variable Naming Conventions Used in the Sandia Well Example.

ThermaSource, multiplied by a factor that corresponds to the class of activity it belongs to (a list of the activity classes is provided in Table 3.2), with the activity class drawn from Sandia's classification of activities. By including this activity class factor in the equations, the modeler can then increase or decrease the amount of time it takes to complete a class of activities– for example, if the modeler is uncertain as to the advance rate that is achievable with his drilling equipment (irrespective of geological conditions) the modeler could make the "Drill" modifier uncertain. The activity class factors can thus be used to introduce common-cause uncertainties into the simulation of construction schedules and have them affect sets of related activities. For a deterministic baseline estimate, the modifiers are set to 1, and in that case the time equation is simply equal to the number of hours listed for that activity in the DAT.

$$Time = SandiaTimeEstimate * ClassModifier \tag{3.3}$$

The cost equation for each activity is only slightly more complex. The total cost is equal to an hourly cost plus a fixed cost. The hourly cost is equal to the number of hours spent on an activity (the number of hours provided by Sandia, multiplied by the activity class factor), multiplied by the cost per hour of activity (equal to a general hourly cost plus, if relevant, an hourly cost specific to the method). The fixed cost is equal to whatever materials costs are specific to that activity. An example set of equations is provided below in Figure 3-21, showing the cost and time equations of the 'Surface Drilling' method.

$$Cost = SandiaTimeEstimate * ClassModifier * HourlyCosts + FixedCosts \quad (3.4)$$

Name	Method	Time Equation	Cost Equation
Make up 26" bit and 36" hole opener on mud motor	Surface Drilling	SDH01*BHA	SDH01*BHA*(GHrCost+VCS01)+FCS01+FCS02+FCS03+FCG01
Pick up 36" stabilizer and cross over to 6-5/8" HWDP	Surface Drilling	SDH02*BHA	SDH02*BHA*(GHrCost+VCS01)
Drill and open 36" hole with motor and HWDP from 80' to 240'	Surface Drilling	SDH03*Drill	SDH03*Drill*(GHrCost+VCS01)
Circulate	Surface Drilling	SDH04*Circ	SDH04*Circ*(GHrCost+VCS01)
Trip out of hole and stand back 6-5/8" HWDP	Surface Drilling	SDH05*BHA	SDH05*BHA*(GHrCost+VCS01)
Pick up (6) 11" drill collars and cross over to 6-5/8" HWDP	Surface Drilling	SDH06*BHA	SDH06*BHA*(GHrCost+VCS01)
Drill and open 36" hole from 240' to 320'	Surface Drilling	SDH07*Drill	SDH07*Drill*(GHrCost+VCS01)
Circulate	Surface Drilling	SDH08*Circ	SDH08*Circ*(GHrCost+VCS01)
Stand back 6-5/8" HWDP	Surface Drilling	SDH09*BHA	SDH09*BHA*(GHrCost+VCS01)
Pick up (3) 9-1/2" drill collars and cross over to 6-5/8" HWDP	Surface Drilling	SDH10*BHA	SDH10*BHA*(GHrCost+VCS01)
Drill and open 36" hole from 320' to 500'	Surface Drilling	SDH11*Drill	SDH11*Drill*(GHrCost+VCS01)
Circulate	Surface Drilling	SDH12*Circ	SDH12*Circ*(GHrCost+VCS01)
Make a wiper trip to 320'	Surface Drilling	SDH13*Trip	SDH13*Trip*(GHrCost+VCS01)
Circulate	Surface Drilling	SDH14*Circ	SDH14*Circ*(GHrCost+VCS01)
Trip out of the hole	Surface Drilling	SDH15*Trip	SDH15*Trip*(GHrCost+VCS01)
Stand back HWDP and drill collars	Surface Drilling	SDH16*BHA	SDH16*BHA*(GHrCost+VCS01)
Break out and lay down 36" stabilizer, mud motor, 36" hole opener, and 26" bit	Surface Drilling	SDH17*BHA	SDH17*BHA*(GHrCost+VCS01)

Figure 3-21: Time and Cost Equations of the 'Surface Drilling' Method. Figure 3-21 lists the activities present under the 'Surface Drilling' construction stage, along with the time and cost equations associated with those activities. The time equations follow the format of the Sandia estimate on the time requirement, multiplied by an activity class factor. The cost equations are simply the time equations, multiplied by an hourly cost, with any relevant fixed costs added separately.

Each activity within a method has a time and cost equation. Figure 3-21 is a screenshot from the DAT showing a full listing of the Surface Drilling method's time and cost equations. The time and cost equations take a general form: the time equations are always equal to the method variable representing that activity's particular completion time multiplied by an appropriate activity-type multiplier (in the base case, all multipliers are equal to 1). The cost equation is equal to the time equation, multiplied by the hourly cost of that method, plus whatever fixed costs are assigned directly to that activity. For example, every cost equation is equal to the number of hours spent on the particular activity (the method variables beginning with SDH), multiplied by the hourly cost of the method (in the case of surface drilling, the hourly cost is equal to the general hourly cost, GHrCost, plus the additional hourly cost specific to the Surface Drilling stage, VCS01). The first activity in the method also has some fixed costs (FCS01, FCS02, FCS03, and FCG01) added to it, reflecting pre-spud insurance costs, pre-spud materials costs, and the cost of the 26" bit used in the method.

Variables

The four types of variables (time requirements, activity class factors, variable or hourly costs, and fixed costs, were calculated as follows:

The time requirements were drawn directly from Sandia's estimates of the time needed to complete that variable's respective activity. Figure 3-22 shows a subset of these variables and how they are input into the DAT.

As this is a baseline case, the ten activity class factors were assigned a value of 1.

To derive the values for hourly cost rates and fixed costs, we looked at the itemized costs provided by the Sandia report, reproduced in Table C.2 of Appendix C. From these itemized costs, we identified six hourly variable costs of interest: an hourly cost specific to each of the five drilling stages (Surface, Intermediate, Prod. 1, Prod. 2, and Prod. 3) corresponding to those stages' use of drilling fluid, and a general hourly cost that is applicable to all activities in all stages. These variable costs were given variable names VCS01, VCI01, VCP101, VCP201, VCP301, and GHrCost.

The five hourly costs specific to the drilling stages are simply equal to the total cost associated with drilling fluid materials at that stage (found under "Drilling Fluid Materials" in Table C.2 of Appendix C) divided by the total number of hours in all of the activities of that stage.

The general hourly cost, GHrCost, is more complex in its formulation. It is an aggregation of 41 individual cost items. The listing of the cost items which were incorporated into GHrCost is provided below in Table 3.4.

Figure 3-23 shows the full list of activity class factors, fixed cost variables, stage-specific hourly cost variables, and the general hourly cost, as input into the DAT.

In general, the cost items that were included into GHrCost fell into three categories. The first category, exemplified by Rig Site Management, Engineering Services,

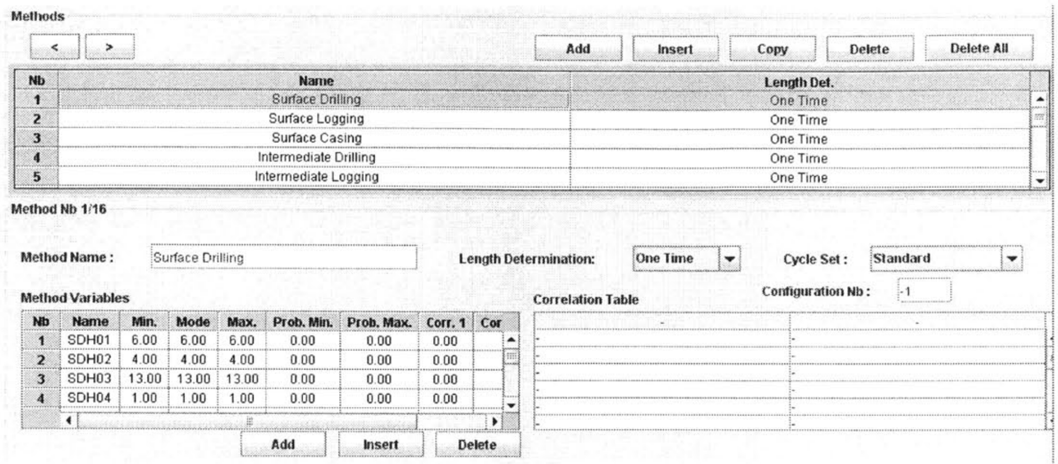


Figure 3-22: Example of the Method Variables Depicting Activity Time Requirements. Figure 3-22 is a screenshot of the DAT method screen. Within each method, method variables are defined– the method variables in this approach correspond to completion times, in hours, of the activities in the method (e.g. SDH01, the variable representing the number of hours required to complete the first activity in the Surface Drilling method (Make up 26" bit and 36" hole opener on mud motor), is equal to 6.

and Project Management are what one might consider true variable overhead costs. The cost of Rig Site Management is not strictly related to any one activity, and it is wholly appropriate to model it as an ongoing hourly cost applied to all activities. This type of overhead is labeled "true" overhead.

The second category, exemplified by the Rig Operating Day Rate, are not true variable overhead costs, but in practice can be treated as such. In theory, a well drilling project could rent a drilling rig in parcels of time according to when the rig is used. In practice, the project is unlikely to do this, and instead will rent the drilling rig for the duration of the project. This type of overhead is labeled "approximate" overhead.

The final category, exemplified by Fuel, Directional Drilling Equipment and Air Compressor Personnel, are itemized costs that are not true variable costs, and in practice need not be treated as such, but for which Sandia has provided insufficient information to determine which activities the costs are related to. The rate of fuel use is likely to be different between stages, as well as between activity types (one

Structure Variables

Nb	Name	Tunnel	Min.	Mode	Max.	Prob. Min.	Prob. Max.
1	BHA	Surface Drilling	1.00	1.00	1.00	0.00	0.00
2	Drill	Surface Drilling	1.00	1.00	1.00	0.00	0.00
3	Circ	Surface Drilling	1.00	1.00	1.00	0.00	0.00
4	Trip	Surface Drilling	1.00	1.00	1.00	0.00	0.00
5	RigUD	Surface Drilling	1.00	1.00	1.00	0.00	0.00
6	Log	Surface Drilling	1.00	1.00	1.00	0.00	0.00
7	RunCsng	Surface Drilling	1.00	1.00	1.00	0.00	0.00
8	Cement	Surface Drilling	1.00	1.00	1.00	0.00	0.00
9	WHOps	Surface Drilling	1.00	1.00	1.00	0.00	0.00
10	BOP	Surface Drilling	1.00	1.00	1.00	0.00	0.00
11	FCS01	Surface Drilling	25,000.00	25,000.00	25,000.00	0.00	0.00
12	FCS02	Surface Drilling	122,000.00	122,000.00	122,000.00	0.00	0.00
13	FCS03	Surface Drilling	80,000.00	80,000.00	80,000.00	0.00	0.00
14	FCS04	Surface Drilling	150,000.00	150,000.00	150,000.00	0.00	0.00
15	FCS05	Surface Drilling	202,500.00	202,500.00	202,500.00	0.00	0.00
16	FCS06	Surface Drilling	20,000.00	20,000.00	20,000.00	0.00	0.00
17	FCI01	Surface Drilling	85,000.00	85,000.00	85,000.00	0.00	0.00
18	FCI02	Surface Drilling	950,000.00	950,000.00	950,000.00	0.00	0.00
19	FCI03	Surface Drilling	1,207,850.00	1,207,850.00	1,207,850.00	0.00	0.00
20	FCP101	Surface Drilling	50,000.00	50,000.00	50,000.00	0.00	0.00
21	FCP102	Surface Drilling	1,123,200.00	1,123,200.00	1,123,200.00	0.00	0.00
22	FCP103	Surface Drilling	45,000.00	45,000.00	45,000.00	0.00	0.00
23	FCP104	Surface Drilling	714,400.00	714,400.00	714,400.00	0.00	0.00
24	FCP201	Surface Drilling	25,000.00	25,000.00	25,000.00	0.00	0.00
25	FCP202	Surface Drilling	705,600.00	705,600.00	705,600.00	0.00	0.00
26	FCP203	Surface Drilling	35,000.00	35,000.00	35,000.00	0.00	0.00
27	FCP204	Surface Drilling	552,000.00	552,000.00	552,000.00	0.00	0.00
28	FCP301	Surface Drilling	16,000.00	16,000.00	16,000.00	0.00	0.00
29	FCP302	Surface Drilling	217,600.00	217,600.00	217,600.00	0.00	0.00
30	FCP303	Surface Drilling	25,000.00	25,000.00	25,000.00	0.00	0.00
31	FCP304	Surface Drilling	336,950.00	336,950.00	336,950.00	0.00	0.00
32	FCT01	Surface Drilling	1,128,000.00	1,128,000.00	1,128,000.00	0.00	0.00
33	FCT02	Surface Drilling	640,200.00	640,200.00	640,200.00	0.00	0.00
34	FCT03	Surface Drilling	10,000.00	10,000.00	10,000.00	0.00	0.00
35	FCT04	Surface Drilling	35,000.00	35,000.00	35,000.00	0.00	0.00
36	FCT05	Surface Drilling	12,000.00	12,000.00	12,000.00	0.00	0.00
37	FCG01	Surface Drilling	10,000.00	10,000.00	10,000.00	0.00	0.00
38	FCG02	Surface Drilling	125,000.00	125,000.00	125,000.00	0.00	0.00
39	FCG03	Surface Drilling	12,000.00	12,000.00	12,000.00	0.00	0.00
40	VCS01	Surface Drilling	215.29	215.29	215.29	0.00	0.00
41	VCI01	Surface Drilling	383.92	383.92	383.92	0.00	0.00
42	VCP101	Surface Drilling	280.66	280.66	280.66	0.00	0.00
43	VCP201	Surface Drilling	131.65	131.65	131.65	0.00	0.00
44	VCP301	Surface Drilling	56.89	56.89	56.89	0.00	0.00
45	GHrCost	Surface Drilling	3,196.40	3,196.40	3,196.40	0.00	0.00

Figure 3-23: Screenshot from the DAT providing a list of all general variables used in the Sandia Case. The first ten are the activity class factors that allow the user to proportionally increase or decrease the estimated time spent on the ten activity types, while the bottom six are hourly cost variables. The remainder are fixed cost variables derived from the Sandia well specification.

could expect it to be very high during energy intensive activities, such as drilling, but low during less intensive activities, such as tripping), but what the exact difference is, we do not know, as it was left unspecified by ThermaSource. For simplicity, but not accuracy, these costs are incorporated into the general hourly cost. This type of overhead is labeled "unspecified" overhead.

The hourly cost of each cost item that was a component in the general hourly cost was computed by dividing the total cost of that item (the quantity used multiplied by the unit price) by the number of hours required to complete the entire project.

The remaining 29 cost items listed by Sandia were included in the DAT as general variables representing fixed costs.

Each fixed cost was assigned to a specific activity or activities, as appropriate. For example, the cost item "Surface Casing Head" is related to the 14th activity in the Surface Casing stage, "Weld on 30" SOW x API 30" 2000 casing head." The assignment of cost items to construction activities is detailed in Table 3.5.

The first column of Table 3.5 lists cost item from the Sandia report. The second column, Cost Type, indicates whether it is a fixed or hourly cost, and the major construction stage the cost is related to. The third column, Cost, is the magnitude of the cost item. The fourth column, Incident Activity, indicates which construction activity was assigned each cost. The activities are represented in an abbreviated format: S, I, P1, P2, P3, and T represent Surface, Intermediate, Production 1, Production 2, Production 3, and Tieback sections respectively, D, L, and C represent the Drilling, Logging, and Casing stages within those sections, and the number suffix represents the activity number within that stage that was assigned the fixed cost. So, for example, the Production 1 Liner Hanger and Running Services cost (found in Table C.2 of Appendix A), is assigned to activity P1C03– the third activity in the Production 1 Casing Stage, "Make up liner hanger assembly to 13-5/8" casing." The fifth column provides the name of the variable as used in the DAT.

There are two compelling reasons to adopt an opportunity-cost-based accounting rather than a cash-flow-based accounting. The first is that our primary purpose in using the DAT is to guide decision making, not serve as a logistics/financial planning

Cost item	Overhead Type	Hourly Cost
Rig Operating Day Rate	Approximate	1166.67
Fuel	Unspecified	442.71
Directional Drilling Equipment	Unspecified	321.68
Top Drive Rental	Approximate	133.33
Rig Site Management	True	83.33
Engineering Services	True	83.33
Directional Drilling Personnel	Unspecified	83.33
Mud Logging Services	Approximate	83.33
Sumpless Drilling and Cuttings Mgmt Services	Unspecified	62.5
BOP Rental	Unspecified	62.5
Shakers, Mud Cleaner, and Centrifuge Rental	Approximate	50
Air Compressor Operating Day Rate	Unspecified	49.53
Rig Crew Travel and Accommodations	True	41.67
Tubular Inspection Services	Approximate	41.67
Air Drilling Flow Line and Separator System Rental	Approximate	41.67
Drilling Fluids Engineer	Approximate	37.5
Project Management	True	34.25
Air Compressor Standby Day Rate	Unspecified	32.78
Mud Cooler Rental	Approximate	31.25
H2S Monitoring, Testing, and Training	Approximate	31.25
Air Compressor Personnel	Unspecified	29.72
Rig Welding Services	Approximate	29.17
Stabilizers, Roller Reamers, and Hole Openers Rental	Unspecified	24.13
Jars, Intensifiers, and Shock Subs Rental	Unspecified	21.45
Rig Site Living Accommodations	True	20.83
Equipment Transportation	True	20.83
Drill Pipe Hard Banding and Repair	Unspecified	20.4
Geologic Services	True	16.67
Rebuild Charges for Stabilizers, Reamers, and Openers	Unspecified	14.57
Rebuild Charges for Jars, Intensifiers, and Shock Subs	Unspecified	11.66
Communications	True	10.42
Rig Monitoring System	True	10.42
Rotating Head Rental	Unspecified	8.89
BOP Inspection and Repair	Unspecified	8.87
Shaker Screens	Unspecified	7.39
Potable Water and Power	True	6.25
Forklift and Manlift Rental	True	6.25
BOP Consumables	Unspecified	5.91
Drill Pipe, HWDP, and Drill Collar Rental	Unspecified	4.02
Rotating Head Rubbers	Unspecified	2.22
Vehicle Rental	True	2.08
TOTAL		\$3196.4/hr

Table 3.4: Individual contribution of each cost item to the general hourly cost (GhrCost). The hourly cost of each item was found by dividing the total cost of the item by the number of hours spent in the entire project. For example, Rig Site Management has a total listed cost of \$286,000. Divided by 3384 hours, this yields an hourly rate of \$83.33.

tool. If a company must make a decision as to whether it should continue or abandon a project, or if it wishes to calculate the option cost of a project, then opportunity cost is the appropriate measure. Secondly, using opportunity cost as the basis of incidence still allows one to approximate the time-discounted costs of a project, while using cash flow as the basis of incidence does not allow one to make an equally strong approximation of opportunity costs. A user with a model based upon opportunity costs can approximate net present discounted costs by including a fudge factor to account for parts being purchased earlier than their costs were modeled. Making mid-construction decisions, or estimating project option costs, on the other hand, is highly sensitive to the timing of costs– it is necessary to know what is economically recoverable and what is not at each moment in the project. For these reasons, our model of the Sandia baseline case assigns cost incidence to the activity which most significantly decreases the resale value of the material in question.

3.2.3 Results and Discussion

As can be expected, the results from the DAT model mirror those estimated by Sandia. Without uncertainty in either schedule or cost, the model is deterministic, and multiple Monte Carlo simulations yield the same answer. Figure 3-24 shows the results of this deterministic case.

A deterministic model such as this is of limited use to a project planner, however it provides a starting point for uncertainty estimation and sensitivity analysis.

3.2.4 Sensitivity Analysis

Introduction

In the previous section, we described how the Sandia/Thermasource geothermal well drilling project could be modeled using the DAT. As modeled, the project was deterministic– all cost and time variables were given specific values, and the list of construction activities was assumed to be complete. However, the most beneficial use of the DAT is not in the analysis of deterministic models, but instead in the simu-

Cost Bucket	Cost Type	Cost	Incident Activity	General Variable
Well Insurance	Fixed, Pre-Spud	25000	SD01	FCS01
Miscellaneous Materials	Fixed, Pre-Spud	122000	SD01	FCS02
Bits – Surface	Fixed, Surface	80000	SD01	FCS03
Surface Casing	Fixed, Surface	150000	SC02	FCS04
Cement – Surface	Fixed, Surface	220500	SC07	FCS05
Surface Casing Head	Fixed, Surface	20000	SC14	FCS06
Bits – Intermediate	Fixed, Intermediate	85000	ID01, ID14, ID23, IL04	FCI01
Intermediate Casing	Fixed, Intermediate	950000	IC02	FCI02
Cement – Intermediate	Fixed, Intermediate	1207850	IC07	FCI03
Bits – Production 1	Fixed, Production 1	50000	P1D01, P1D14, P1D23	FCP101
Production 1 Liner	Fixed, Production 1	1123200	P1C02	FCP102
Prod 1 Liner Hanger and Running Svcs	Fixed, Production 1	45000	P1C03	FCP103
Cement – Production 1	Fixed, Production 1	714400	P1C10	FCP104
Bits – Production 2	Fixed, Production 2	25000	P2D13, P2D22, P2D31, P2D40, P2D49, P2L04	FCP201
Production 2 Liner	Fixed, Production 2	705600	P2C02	FCP202
Prod 2 Liner Hanger and Running Svcs	Fixed, Production 2	35000	P2C03	FCP203
Cement – Production 2	Fixed, Production 2	552000	P2C10	FCP204
Bits – Production 3	Fixed, Production 3	16000	P3D13, P3D19, P3D25, P3L04	FCP301
Production 3 Liner	Fixed, Production 3	217600	P3C02	FCP302
Prod 3 Liner Hanger and Running Svcs	Fixed, Production 3	25000	P3C03	FCP303
Cement – Production 3	Fixed, Production 3	336950	P3C10	FCP304
Production Liner Tieback	Fixed, Tieback	1128000	TC06	FCT01
Cement – Tieback	Fixed, Tieback	640200	TC11	FCT02
Tieback Casing Head	Fixed, Tieback	10000	TC16	FCT03
Master Valves	Fixed, Tieback	35000	TC17	FCT04
Wing Valves	Fixed, Tieback	12000	TC17	FCT05
Casing Crews and Laydown Machine	Fixed, General	10000	SD01, SC01, IC01, P1C01, P2C01, P3C01, TC01	FCG01
Wireline Services	Fixed, General	125000	SL01, IL01, P1L01, P2L01, P3L01	FCG02
Wellhead Welding and Installation	Fixed, General	12000	SC14, IC15, TC16	FCG03
Drilling Fluids – Surface	Hourly, Surface Drill	215.29	SD	VCS01
Drilling Fluids – Int.	Hourly, Int. Drill	383.92	ID	VCI01
Drilling Fluids – Prod 1	Hourly, Prod 1 Drill	280.66	P1D	VCP101
Drilling Fluids – Prod 2	Hourly, Prod 2 Drill	131.65	P2D	VCP201
Drilling Fluids – Prod 3	Hourly, Prod 3 Drill	56.89	P3D	VCP301

Table 3.5: The Assignment of Cost Items Not Assigned to the General Hourly Cost. Table 3.5 lists the cost items provided by Sandia, their magnitude, the activity or construction stage they are incurred in, and their naming within the DAT.

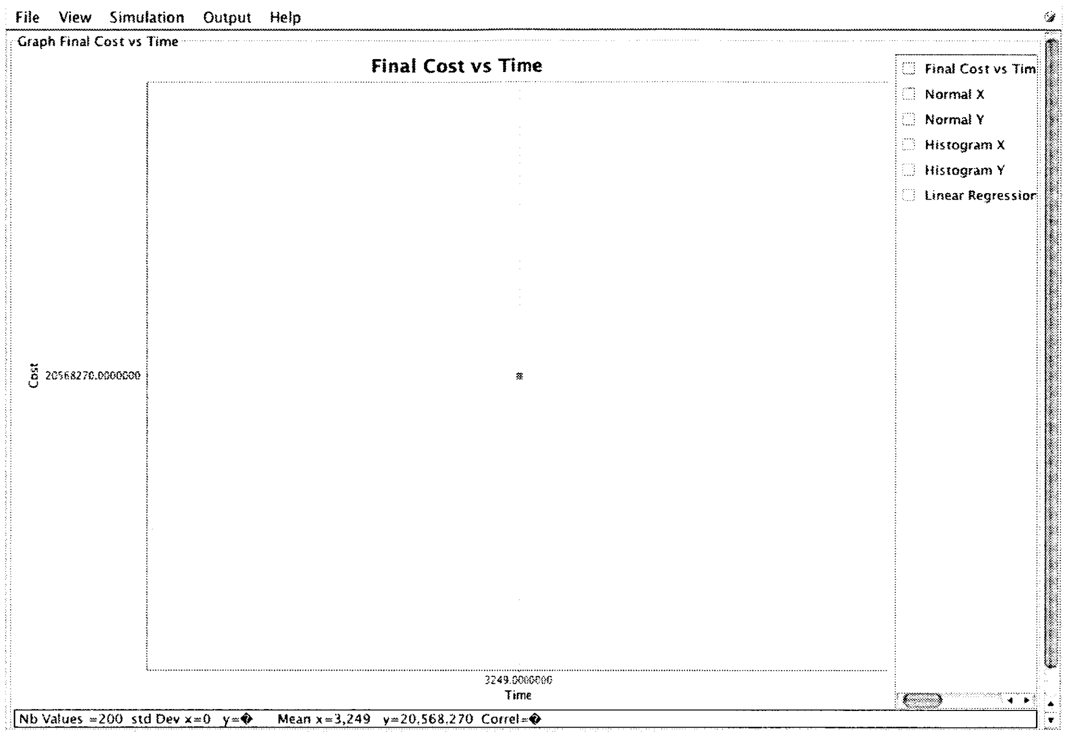


Figure 3-24: The Sandia Case, The Baseline Result. This figure is a screenshot of the DAT Cost vs. Time output screen showing the estimated cost and time to completion of the Sandia well, absent any variation from the baseline estimate.

lation of probabilistic models, in which the project cost and schedule are estimated, but uncertain. To demonstrate the functionality of the DAT as a decision aid in a geothermal context, we will update the model to account for three major sources of project uncertainty: variation in the cost of physical components and services, the occurrence of trouble events, and uncertain site geology. We will introduce each source of uncertainty individually, and then look at their combined effect. In doing so, we will show the versatility of the DAT in incorporating a broad and realistic set of project risks.

Component Cost Variation

Component Cost Variation and its Significance The first type of uncertainty we will look at is uncertainty in the purchase prices of the physical components and services needed to complete the construction project. Depending on location and the date of purchase, the real costs of the labor and materials that go into a geothermal well can vary significantly from initial estimates. As materials and services are purchased, these uncertainties are eliminated and estimates can be revised, but at the start of any geothermal project, cost estimates must account for considerable variability in market prices (for example, drilling rig rental rates are closely tied to the price of oil and fluctuate considerably). In general, uncertainty in material costs is increasing with the time between estimation and construction.

Variation in material costs represents one of the most common forms of project risk– in the context of geothermal well drilling, it represents a moderate source of uncertainty relative to other factors.

Sandia Figures on Component Cost Variability To obtain a ballpark estimate of the variance in material prices, we borrow from analysis in the Sandia report Geothermal Well Cost Analyses 2005, by Mansure, Bauer, and Livesay [Mansure, Bauer, and Livesay, 2005]. In their report, the authors perform a cost analysis using a database of actual geothermal project experiences. Although their primary purpose is to identify the major cost drivers of geothermal wells, they also calculate the mean and standard deviation (and thus, implicitly, the variance) of real (inflation-adjusted) costs of various categories of project materials. The cost contributions from contract labor, casing, drill bits, cement, and several other categories of materials and services were determined through the review of daily construction reports. In aggregate, these reports produce an average and standard deviation for the total project cost of each contributing category. These values are then converted into a per-foot basis, so as to help control for differences in project depth.

The variance estimates in the Sandia report are not the estimates of the variance due solely to fluctuations in the cost of raw inputs. Because components are not directly comparable across projects (and thus price variation cannot be estimated directly), estimates of the variance will necessarily reflect some degree of variation due to trouble events, differences in geological conditions, changes in drilling techniques, and depth-related variations in the per-foot use of different resources. As a consequence, the uncertainty estimated using this method will be higher than the uncertainty due purely to price fluctuations. It should be noted, therefore, that these estimates are not chosen for their fidelity to the real-life uncertainty being estimated, but instead were chosen as a reasonable proxy for uncertainty estimates as they might be found in a real construction project.

The estimates of mean materials costs and their standard deviations, taken from the Sandia report, are listed below in Table 3.6:

The general process by which these uncertainty estimates can be incorporated into the DAT model of the Sandia well is to use them to create triangular probability distributions on the material cost variables that are used in the model's cost equations.

Therefore, the first step in modeling price uncertainty using the DAT is to match the cost categories listed above in Table 3.6 with the cost components listed in Appendix A. The assignment of project costs to the categories of uncertainty is provided below in Table 3.7

The next step is to use the uncertainty estimates to determine the variance on each of the cost variables used in the DAT. For all of the variables except GHrCost, the process is relatively straightforward. The ratio between the standard deviation of the

Cost Category	Average Cost ($/ft)	Std. Dev. ($/ft)
Casing	$19.07	$1.29
Drilling Rig Day Rate	$37.27	$10.28
Mob/Demob Costs	$4.73	$1.52
Rig Fuel	$8.34	$2.96
Supervision	$0.87	$0.65
Contract Labor	$5.21	$1.29
Drill Bits	$28.12	$12.81
Reamers/Stabilizers	$4.81	$3.73
Drilling Fluids	$5.47	$2.85
Air Compressors	$7.96	$2.50
Cement	$12.03	$2.24
Equipment and Supplies	$1.53	$1.48
Wellhead Equipment	$1.74	$0.98
Rental Equipment	$3.81	$2.28
Fishing Tool Rental and Service	$9.60	$9.28
Rental Drill String and Bottom Hole Assembly	$5.89	$1.78
Environmental Fees, Expenses, and Permits	$1.84	$0.65
Freight and Hauling	$3.40	$0.67
Repairs	$17.90	$9.66
H2S Abatement	$1.42	$2.71

Table 3.6: Mean and Standard Deviation of Geothermal Well Materials Costs. Table 3.6 shows Sandia's uncertainty estimates for twenty separate categories of drilling individual costs. The standard deviation is normalized to a per-foot figure to reduce variation due to project scale. By defining the standard deviation as a coefficient of variation, these estimates allow for cost uncertainty to be scaled up as necessary– in this case, it will be scaled up to the size of the Sandia Well by re-normalizing the mean cost in the uncertainty estimates to the mean component cost in the Sandia Well.

Uncertainty Category	Well Project Cost Category	DAT Variable Name
Casing	Surface Casing	FCS04
	Intermediate Casing	FCI02
	Production 1 Liner	FCP102
	Production 2 Liner	FCP202
	Production 3 Liner	FCP302
	Tieback Casing	FCT01
Drilling Rig Day Rate	Rig Operating Day Rate	GHrCost
Mob/Demob Costs	–	–
Rig Fuel	Fuel	GHrCost
Supervision	Rig Site Management	GHrCost
	Project Management	GHrCost
	Contract Labor and Wireline Services	FCG02
	Wellhead Welding and Installation Services	FCG03
	Prod Liner 1 Hanger and Running Services	FCP103
	Prod Liner 2 Hanger and Running Services	FCP203
	Prod Liner 3 Hanger and Running Services	FCP303
	Casing Crews and Laydown Machine	FCG01
	Engineering Services	GHrCost
	Drilling Fluids Engineer	GHrCost
	Directional Drilling Personnel	GHrCost
	Air Compressor Personnel	GHrCost
	Rig Welding Services	GHrCost
	Mud Logging Services	GHrCost
	Tubular Inspection Services	GHrCost
	Geologic Services	GHrCost
	Sumpless Drilling and Cuttings Management	GHrCost
Drill Bits	Bits – Surface Hole	FCS03
	Bits – Intermediate Hole	FCI01
	Bits – Production Hole 1	FCP101
	Bits – Production Hole 2	FCP201
	Bits – Production Hole 3	FCP301
Reamers/Stabilizers	Stabilizers, Roller Reamers, and Hole Openers Rental	GHrCost
Drilling Fluids	Drilling Fluid Materials – Surface Hole	VCS01
	Drilling Fluid Materials – Intermediate Hole	VCI01
	Drilling Fluid Materials – Production Hole 1	VCP101
	Drilling Fluid Materials – Production Hole 2	VCP201
	Drilling Fluid Materials – Production Hole 3	VCP301
Air Compressors	Air Compressor Standby Day Rate	GHrCost
	Air Compressor Operating Day Rate	GHrCost
Cement	Cement – Surface	FCS05
	Cement – Intermediate	FCI03
	Cement – Production 1 Liner	FCP104
	Cement – Production 2 Liner	FCP204
	Cement – Production 3 Liner	FCP304
	Cement – Tieback	FCT02
Equipment and Supplies	Miscellaneous Materials	FCS02
	Potable Water and Power	GHrCost
	Shaker Screens	GHrCost
	Rotating Head Rubbers	GHrCost
	BOP Consumables	GHrCost
	Communications	GHrCost
	Rig Crew Travel and Accommodations	GHrCost
	Rig Site Living Accommodations	GHrCost
Wellhead Equipment	Surface Casing Head	FCS06
	Tieback Casing Head	FCT03
	Master Valves	FCT04
	Wing Valves	FCT05
	Rental Equipment and Vehicle Rental	GHrCost
	Mud Cooler Rental	GHrCost
	Forklift and Manlift Rental	GHrCost
	Air Drilling Flow Line and Separator System Rental	GHrCost
	Jars, Intensifiers, and Shock Subs Rental	GHrCost
Fishing Tool Rental	–	–
Rental Drill String / BHA	Rotating Head Rental	GHrCost
	Drill Pipe, HWDP, and Drill Collar Rental	GHrCost
	Directional Drilling Equipment	GHrCost
	Top Drive Rental	GHrCost
	BOP Rental	GHrCost
	Rig Monitoring System	GHrCost
	Shakers, Mud Cleaner, and Centrifuge Rental	GHrCost
Environmental Fees, Expenses, and Permits	Well Insurance	FCS01
Freight and Hauling	Equipment Transportation	GHrCost
Repairs	Rebuild Charges for Stabilizers, Roller Reamers, and Hole Openers	GHrCost
	Rebuild Charges for Jars, Intensifiers, and Shock Subs	GHrCost
	Drill Pipe Hard Banding and Repair	GHrCost
	BOP Inspection and Repair	GHrCost
H2S Abatement	H2S Monitoring, Testing, and Training	GHrCost

Table 3.7: Matching of Sandia's Uncertainty Estimates to ThermaSource's Cost Categories. Table 3.7 maps the various uncertainty categories used in Sandia's uncertainty estimates (from Table 3.6, in the first column) to the cost buckets used by ThermaSource (from Appendix A, in the second column

uncertainty estimate and the mean of the uncertainty estimate is assumed to be the same as the mean value of the related cost components and their standard deviations. For example, the "Casing" uncertainty category has a mean value of $19.07 and a standard deviation of $1.29. The related cost category, Surface Casing, has a value of $150,000. The standard deviation of Surface Casing is thus determined as $1.29 * $150,000 / $19.07, or $10146.83.

For GHrCost, which is a composite variable made up of several cost estimates, the process of determining the sample variance is a little more involved. It is assumed that there is no covariance between cost categories, and thus the variance of GHrCost is taken as a simple weighted sum of the variances of all of its subcomponents, where the variance of each subcomponent is derived in the same way as described above. Thus, the standard deviation on GHrCost (the square root of the variance) can be described as:

$$\sigma_{total} = \sqrt{\sum \sigma_a^2 + \sigma_b^2 + ... + \sigma_n^2} \tag{3.5}$$

By following this procedure, we derive a set of mean values and standard deviations for each of the cost variables used in the DAT.

The next step is to decide how these values of mean and standard deviation will be used to derive a triangular distribution (which is one of the probabilistic distributions that the DAT allow). We look at two possible scenarios.

The first scenario assumes that the underlying variation in material prices is normal (Gaussian) in nature. For each DAT variable, a triangular distribution is created such that the squared difference between the triangular distribution and the normal distribution that has the same mean and standard deviation (listed in Table 3.8) is minimized. This scenario produces distributions similar to that shown in Figure 3-25 and approximates an applicable procedure for converting objective estimates of price probability distributions into triangular or another DAT-compatible distribution.

The second scenario assumes that the underlying variation in material prices is lognormal in nature. For each DAT variable, a triangular distribution is created such

Cost Item	DAT Var. Name	Mean	Std. Dev.
Surface Casing	FCS04	150000	10146.83
Intermediate Casing	FCI02	950000	64263.24
Production 1 Liner	FCP102	1123200	75979.44
Production 2 Liner	FCP202	705600	47730.68
Production 3 Liner	FCP302	217600	14719.6
Tieback Casing	FCT01	1128000	76304.14
Wireline Services	FCG02	125000	30950.1
Wellhead Welding and Installation Svcs	FCG03	12000	2971.21
Prod Liner 1 Hanger and Running Svcs	FCP103	45000	11142.03
Prod Liner 2 Hanger and Running Svcs	FCP203	35000	8666.03
Prod Liner 3 Hanger and Running Svcs	FCP303	25000	6190.02
Casing Crews and Laydown Machine	FCG01	10000	2476.01
Bits – Surface Hole	FCS03	80000	36443.81
Bits – Intermediate Hole	FCI01	85000	38721.55
Bits – Production Hole 1	FCP101	50000	22777.38
Bits – Production Hole 2	FCP201	25000	11388.69
Bits – Production Hole 3	FCP301	16000	7288.76
Drilling Fluids – Surface Hole	VCS01	215.29	112.17
Drilling Fluids – Intermediate Hole	VCI01	383.92	200.03
Drilling Fluids – Production Hole 1	VCP101	280.66	146.23
Drilling Fluids – Production Hole 2	VCP201	131.65	68.59
Drilling Fluids – Production Hole 3	VCP301	56.89	29.64
Cement – Surface	FCS05	220500	41057.36
Cement – Intermediate	FCI03	1207850	224903.08
Cement – Production 1 Liner	FCP104	714400	133022.11
Cement – Production 2 Liner	FCP204	552000	102783.04
Cement – Production 3 Liner	FCP304	336950	62740.48
Cement – Tieback	FCT02	640200	119205.99
Miscellaneous Materials	FCS02	122000	118013.07
Surface Casing Head	FCS06	20000	11264.37
Tieback Casing Head	FCT03	10000	5632.18
Master Valves	FCT04	35000	19712.64
Wing Valves	FCT05	12000	6758.62
Well Insurance	FCS01	25000	8831.52
Other General Cost Items	GHrCost	3196.4	446.44

Table 3.8: Estimated Cost Uncertainty on the Cost Components used by ThermaSource. After mapping Sandia's uncertainty estimates to ThermaSource's cost groupings, the standard deviation of each grouping is calculated and provided above as a standard deviation on the value quoted by ThermaSource.

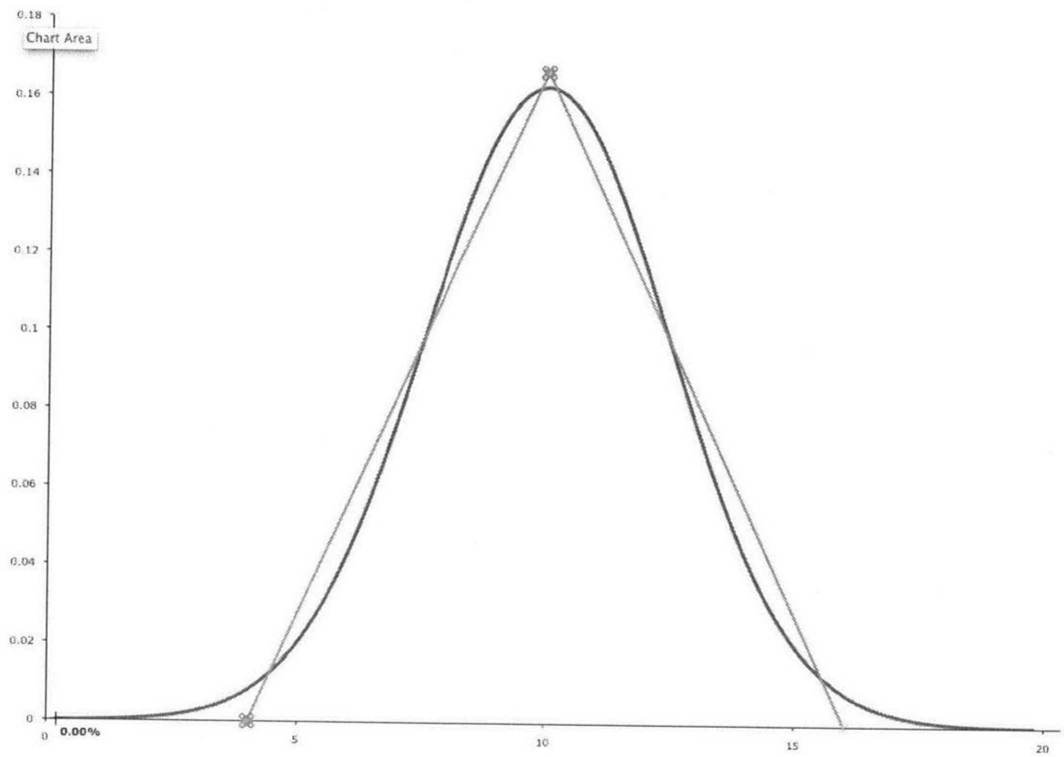


Figure 3-25: Normal distribution being parametrized into a triangular distribution. The normal distribution, represented by the blue line, has a mean of 10 and a standard deviation of $\sqrt{6}$. The triangular distribution, represented by the red line, has intercepts at 4 and 16, and minimizes the mean squared difference between itself and the normal distribution.

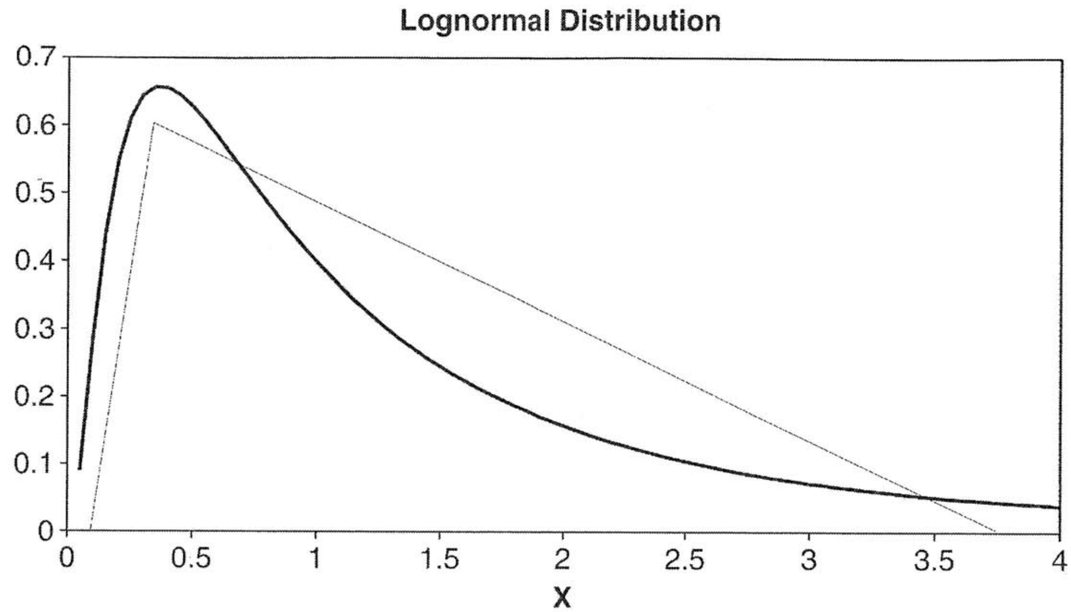


Figure 3-26: Lognormal distribution being parametrized into a triangular distribution. The minimum and maximum of the triangular distribution are set equal to the ends of the symmetric (i.e. the probability under the confidence interval is equal to the probability over the interval) 90% confidence interval of the lognormal distribution, while the mode remains the same as that of the lognormal distribution. In other words, the range of the triangular distribution is equal to the interval of the lognormal distribution that excludes the minimum and maximum five percent of the lognormal distribution, while the peak of the triangular distribution is set equal to the peak of the lognormal distribution.

that the lower bound of the distribution coincides with the lower bound of a symmetric 90% confidence interval on a lognormal distribution that has the same mean and standard deviation listed in Table 3.8. The upper bound of the triangular distribution coincides with the upper bound of that confidence interval, and the peak of the triangular distribution corresponds to the mode of the underlying lognormal distribution. This scenario approximates a realistic modeling scenario in which uncertainty estimates are subjectively derived (where the points given by the lognormal distribution serve as a proxy for expert-solicited minimum, maximum, and most-likely cost estimates.

Modeling Component Cost Variation with the DAT

Converting Uncertainty Estimates into Parameter Values THE NORMAL DISTRIBUTION Determining the parameters of a normal distribution that share the mean and standard deviation of the values in Table 3.8 is relatively straightforward–the parameters of the normal distribution itself are the mean and standard deviation, and therefore there is no transformation that needs to take place.

The parameters that determine the triangular distribution that minimizes the squared error between itself and the normal distribution is also relatively easy to derive. A triangular distribution minimizes the squared difference between it and a normal distribution when the lower bound is equal to

$$X_{lower} = \mu - \sigma * \sqrt{6} \tag{3.6}$$

the upper bound is equal to

$$X_{upper} = \mu + \sigma * \sqrt{6} \tag{3.7}$$

and the peak of the triangle simple equal to μ. An example of this sort of triangular fitting can be found in Figure 3-25.

When applied to the general variables used in the DAT model, we obtain the triangular distributions described in Table 3.9. Each of the cost variables in the DAT was given a triangular distribution as described in Table 3.9. The DAT input screen is shown in Figure 3-27.

Two simulations were then run, one with 20 sample runs, and another with 200 sample runs. Their results are given in Figures 3-28 and 3-29.

If the modeler is uncomfortable with the possibility of a negative value for the parameters (in real terms, such values are non-sensical), it is possible to apply a treatment to the probability distribution that removes the negative range of the distribution while preserving its mean and/or variance. For example, one method is to use a bounded triangular distribution (see Figure 3-30. A delta function is a probabilistic distribution that has a zero value over all of the distribution except for a single point, and some finite probability at that point. With a bounded triangular

Cost Item	Var. Name	Lower Bound , Peak , Upper Bound
Surface Casing	FCS04	125145.45 , 150000 , 174854.55
Intermediate Casing	FCI02	792587.85 , 950000 , 1107412.15
Production 1 Liner	FCP102	937089.13 , 1123200 , 1309310.87
Production 2 Liner	FCP202	588684.2 , 705600 , 822515.8
Production 3 Liner	FCP302	181544.33 , 217600 , 253655.67
Tieback Casing	FCT01	941093.79 , 1128000 , 1314906.21
Wireline Services	FCG02	49188.06 , 125000 , 200811.94
Wellhead Welding and Installation Svcs	FCG03	4722.05 , 12000 , 19277.95
Prod Liner 1 Hanger and Running Svcs	FCP103	17707.7 , 45000 , 72292.3
Prod Liner 2 Hanger and Running Svcs	FCP203	13772.66 , 35000 , 56227.34
Prod Liner 3 Hanger and Running Svcs	FCP303	9837.61 , 25000 , 40162.39
Casing Crews and Laydown Machine	FCG01	3935.04 , 10000 , 16064.96
Bits – Surface Hole	FCS03	-9268.74 , 80000 , 169268.74
Bits – Intermediate Hole	FCI01	-9848.04 , 85000 , 179848.04
Bits – Production 1	FCP101	-5792.97 , 50000 , 105792.97
Bits – Production 2	FCP201	-2896.48 , 25000 , 52896.48
Bits – Production 3	FCP301	-1853.75 , 16000 , 33853.75
Drilling Fluids – Surface Hole	VCS01	-59.47 , 215.29 , 490.05
Drilling Fluids – Intermediate Hole	VCI01	-106.05 , 383.92 , 873.89
Drilling Fluids – Production 1	VCP101	-77.53 , 280.66 , 638.86
Drilling Fluids – Production 2	VCP201	-36.37 , 131.65 , 299.66
Drilling Fluids – Production 3	VCP301	-15.72 , 56.89 , 129.49
Cement – Surface	FCS05	119930.43 , 220500 , 321069.57
Cement – Intermediate	FCI03	656952.22 , 1207850 , 1758747.78
Cement – Production 1 Liner	FCP104	388563.7 , 714400 , 1040236.3
Cement – Production 2 Liner	FCP204	300233.99 , 552000 , 803766.01
Cement – Production 3 Liner	FCP304	183267.83 , 336950 , 490632.17
Cement – Tieback	FCT02	348206.16 , 640200 , 932193.84
Miscellaneous Materials	FCS02	-167071.81 , 122000 , 411071.81
Surface Casing Head	FCS06	-7591.95 , 20000 , 47591.95
Tieback Casing Head	FCT03	-3795.98 , 10000 , 23795.98
Master Valves	FCT04	-13285.92 , 35000 , 83285.92
Wing Valves	FCT05	-4555.17 , 12000 , 28555.17
Well Insurance	FCS01	3367.28 , 25000 , 46632.72
Other General Cost Items	GHrCost	2102.85 , 3196.4 , 4289.95

Table 3.9: Parameters for the Triangular Distribution on Each DAT Variable (Normal Scenario)

General Variables

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Nb	Name	Description	Min.	Mode	Max.	Prob. Min.	Prob. Max.
11	FCS01		3.367.28	25.000.00	46,632.72	0.00	0.00
12	FCS02		-167,071.81	122,000.00	411,071.81	0.00	0.00
13	FCS03		-9,268.74	80,000.00	169,268.74	0.00	0.00
14	FCS04		125,145.45	150,000.00	174,854.55	0.00	0.00
15	FCS05		119,930.43	202,500.00	321,069.57	0.00	0.00
16	FCS06		-7,591.95	20,000.00	47,591.95	0.00	0.00
17	FCI01		-9,848.04	85,000.00	179,848.04	0.00	0.00
18	FCI02		792,587.85	950,000.00	1,107,412.15	0.00	0.00
19	FCI03		656,952.22	1.207,850.00	1,758,747.78	0.00	0.00
20	FCP101		-5,792.97	50,000.00	105,792.97	0.00	0.00
21	FCP102		937,089.13	1.123,200.00	1,309,310.87	0.00	0.00
22	FCP103		17,707.70	45,000.00	72.292.30	0.00	0.00
23	FCP104		388,563.70	714.400.00	1,040,236.30	0.00	0.00
24	FCP201		-2,896.48	25,000.00	52.896.48	0.00	0.00
25	FCP202		588,684.20	705.600.00	822,515.80	0.00	0.00
26	FCP203		13,772.66	35,000.00	56.227.34	0.00	0.00
27	FCP204		300,233.99	552.000.00	803,766.01	0.00	0.00
28	FCP301		-1,853.75	16,000.00	33,853.75	0.00	0.00
29	FCP302		181,544.33	217.600.00	253,655.67	0.00	0.00
30	FCP303		9,837.61	25,000.00	40,162.39	0.00	0.00
31	FCP304		183,267.83	336.950.00	490,632.17	0.00	0.00
32	FCT01		941,093.79	1,128,000.00	1,314,906.21	0.00	0.00
33	FCT02		348,206.16	640.200.00	932,193.84	0.00	0.00
34	FCT03		-3,795.98	10,000.00	23,795.98	0.00	0.00
35	FCT04		-13,285.92	35,000.00	83,285.92	0.00	0.00
36	FCT05		-4,555.17	12,000.00	28,555.17	0.00	0.00
37	FCG01		3,935.04	10,000.00	16,064.96	0.00	0.00
38	FCG02		49,188.06	125,000.00	200,811.94	0.00	0.00
39	FCG03		4,722.05	12,000.00	19,277.95	0.00	0.00
40	VCS01		-59.47	215.29	490.05	0.00	0.00
41	VCI01		-106.05	383.92	873.89	0.00	0.00
42	VCP101		-77.53	280.66	638.86	0.00	0.00
43	VCP201		-36.37	131.65	299.66	0.00	0.00
44	VCP301		-15.72	56.89	129.49	0.00	0.00
45	GHrCost		2.102.85	3.196.40	4.289.95	0.00	0.00

Figure 3-27: Screenshot of the DAT's general variable window, employing a triangular, least-squared error estimation of a normal uncertainty

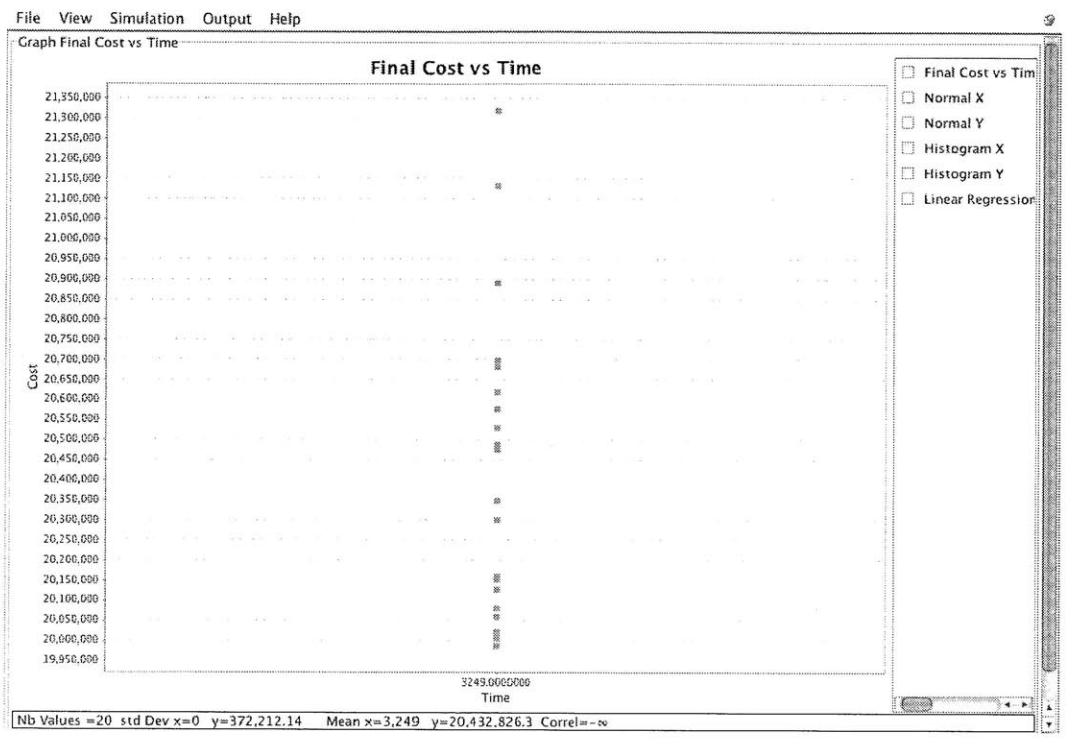


Figure 3-28: N=20 Simulations, Normal Uncertainty. The results vary only in cost, as price increases or decreases in project inputs do not affect project schedule.

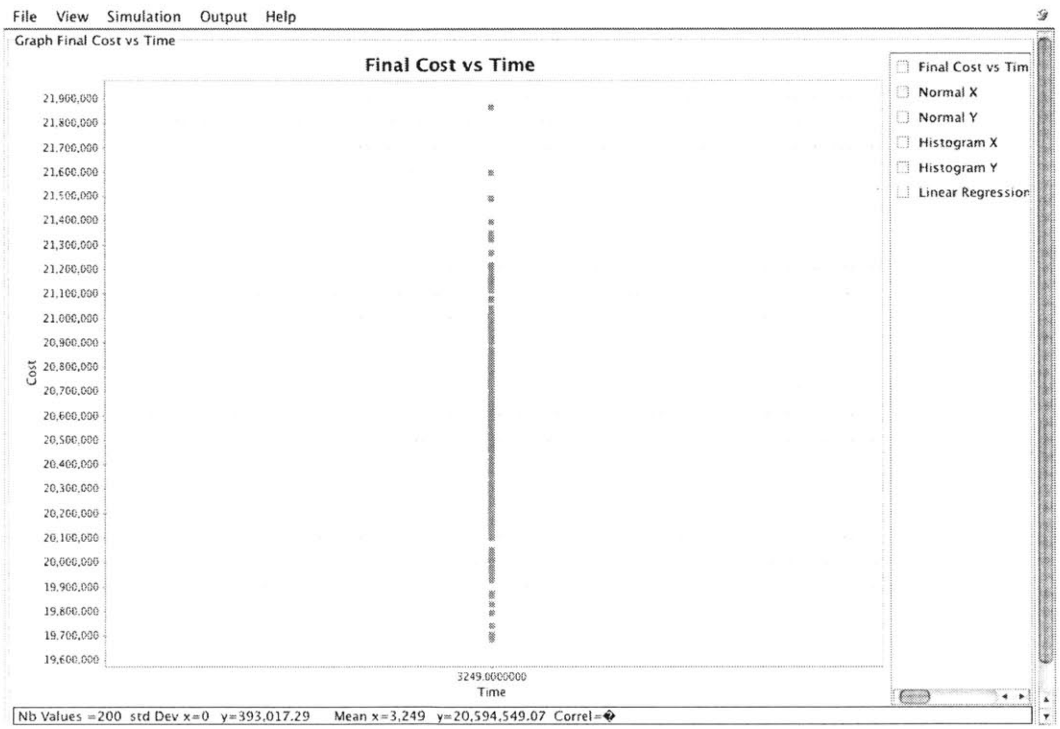


Figure 3-29: N=200 Simulations, Normal Uncertainty. The results vary only in cost, as price increases or decreases in project inputs do not affect project schedule.

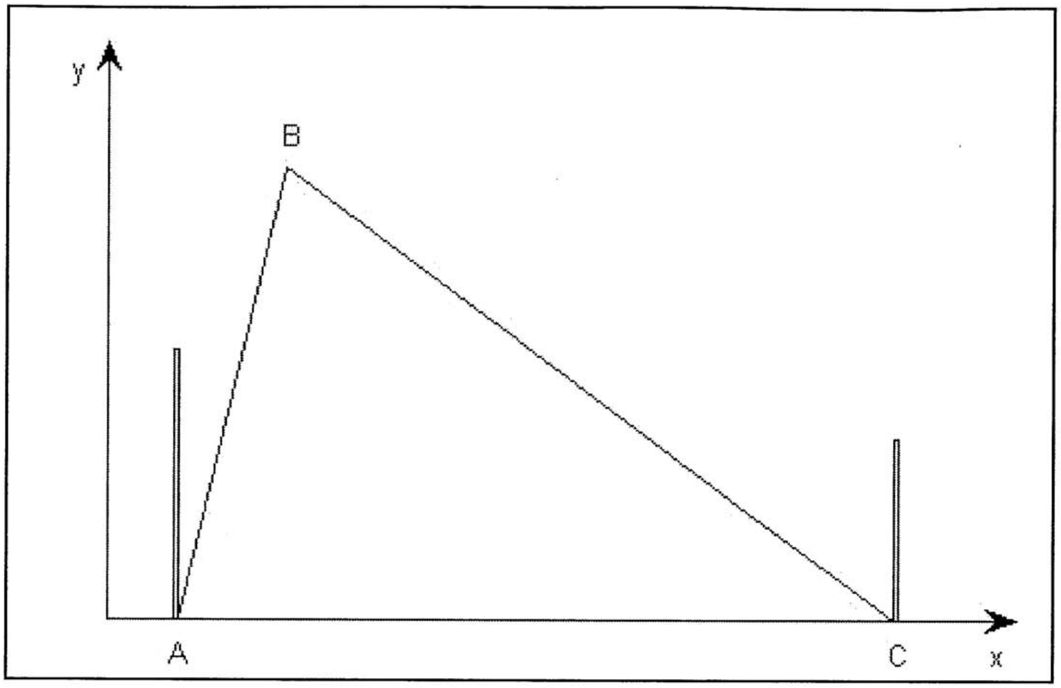


Figure 3-30: The DAT allow the user to assign probabilities to the extreme bounds of a triangular distribution, in essence adding a delta function to each end of the distribution.

distribution, it is possible to truncate the triangular distribution at zero and compensate by both adding a delta function to the PDF at zero with an area under the delta function equal to the area removed from the triangle, and increasing the upper bound by the amount needed to keep the mean of the distribution the same. Figure 3-31 is an example of this sort of triangular fitting.

If we define a new variable, L as the ratio between the peak of the distribution and the distance between the peak and the lower bound

$$L = \frac{\mu_{sample}}{\sigma_{sample} * \sqrt{6}} \tag{3.8}$$

for all distributions in which $\mu_{sample} < \sigma_{sample} * \sqrt{6}$, then it is simple to show that the total cumulative probability under the delta function is equal to:

$$Area_{Delta} = \frac{(1-L)^2}{2} \tag{3.9}$$

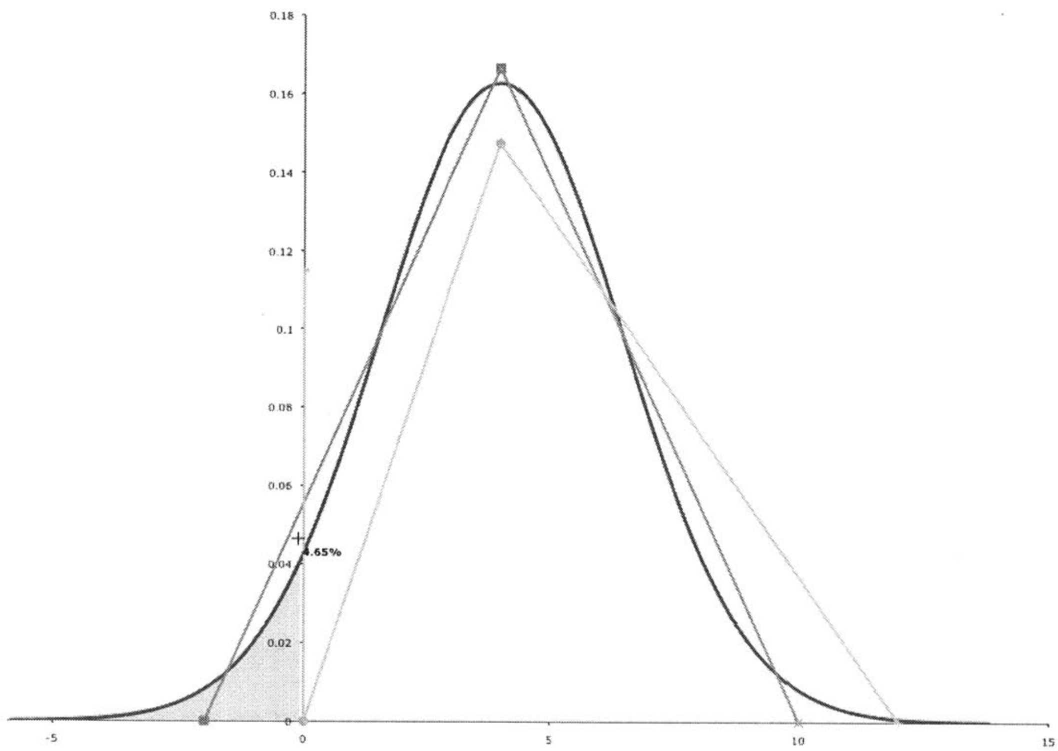
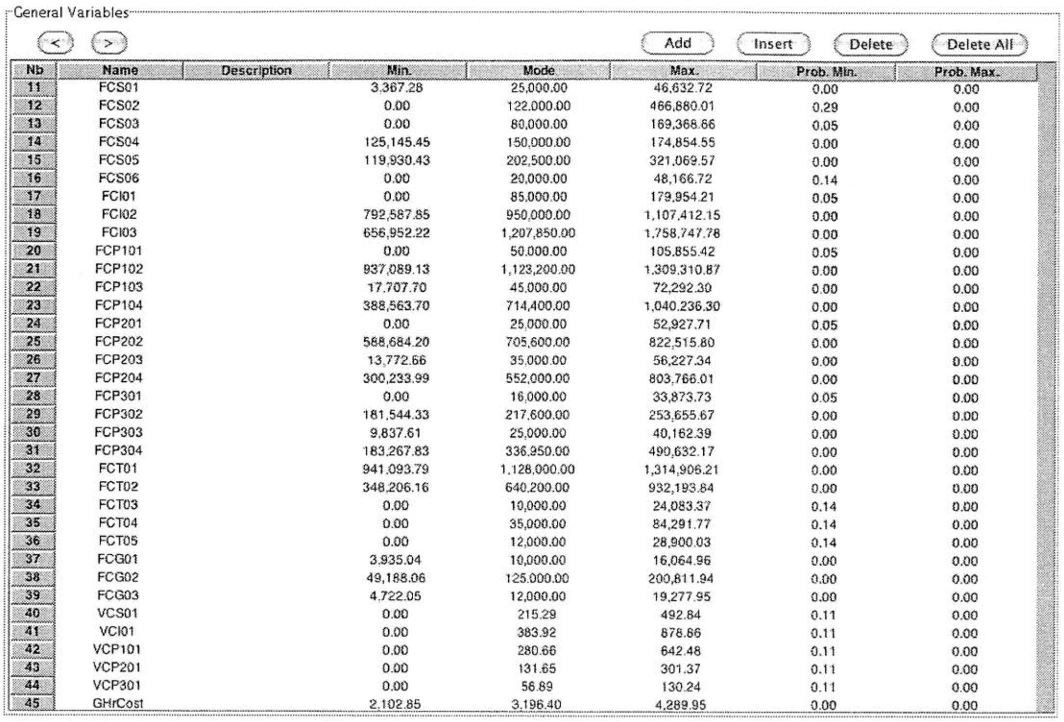


Figure 3-31: Example of one method of normal approximation using a bounded triangular distribution: the lower bound of the triangle is set to zero, a delta function with a probability equal to the truncated region is added at the lower bound, and the upper bound is re-adjusted so as to maintain the mean of the original triangular approximation. The normal distribution being approximated is shown in blue, the least-squared error triangular approximation is shown in red, and the adjusted triangular distribution is shown in orange. This process yields a triangular distribution that retains a mean and variance similar to the least-squares approximation.



General Variables

< > Add Insert Delete Delete All

Nb	Name	Description	Min.	Mode	Max.	Prob. Min.	Prob. Max.
11	FCS01		3,367.28	25,000.00	46,632.72	0.00	0.00
12	FCS02		0.00	122,000.00	466,880.01	0.29	0.00
13	FCS03		0.00	80,000.00	169,368.66	0.05	0.00
14	FCS04		125,145.45	150,000.00	174,854.55	0.00	0.00
15	FCS05		119,930.43	202,500.00	321,069.57	0.00	0.00
16	FCS06		0.00	20,000.00	48,166.72	0.14	0.00
17	FCI01		0.00	85,000.00	179,954.21	0.05	0.00
18	FCI02		792,587.85	950,000.00	1,107,412.15	0.00	0.00
19	FCI03		656,952.22	1,207,850.00	1,758,747.78	0.00	0.00
20	FCP101		0.00	50,000.00	105,855.42	0.05	0.00
21	FCP102		937,089.13	1,123,200.00	1,309,310.87	0.00	0.00
22	FCP103		17,707.70	45,000.00	72,292.30	0.00	0.00
23	FCP104		388,563.70	714,400.00	1,040,236.30	0.00	0.00
24	FCP201		0.00	25,000.00	52,927.71	0.05	0.00
25	FCP202		588,684.20	705,600.00	822,515.80	0.00	0.00
26	FCP203		13,772.66	35,000.00	56,227.34	0.00	0.00
27	FCP204		300,233.99	552,000.00	803,766.01	0.00	0.00
28	FCP301		0.00	16,000.00	33,873.73	0.05	0.00
29	FCP302		181,544.33	217,600.00	253,655.67	0.00	0.00
30	FCP303		9,837.61	25,000.00	40,162.39	0.00	0.00
31	FCP304		183,267.83	336,950.00	490,632.17	0.00	0.00
32	FCT01		941,093.79	1,128,000.00	1,314,906.21	0.00	0.00
33	FCT02		348,206.16	640,200.00	932,193.84	0.00	0.00
34	FCT03		0.00	10,000.00	24,083.37	0.14	0.00
35	FCT04		0.00	35,000.00	84,291.77	0.14	0.00
36	FCT05		0.00	12,000.00	28,900.03	0.14	0.00
37	FCG01		3,935.04	10,000.00	16,064.96	0.00	0.00
38	FCG02		49,188.06	125,000.00	200,811.94	0.00	0.00
39	FCG03		4,722.05	12,000.00	19,277.95	0.00	0.00
40	VCS01		0.00	215.29	492.84	0.11	0.00
41	VCI01		0.00	383.92	878.66	0.11	0.00
42	VCP101		0.00	280.66	642.48	0.11	0.00
43	VCP201		0.00	131.65	301.37	0.11	0.00
44	VCP301		0.00	56.89	130.24	0.11	0.00
45	GHrCost		2,102.85	3,196.40	4,289.95	0.00	0.00

Figure 3-32: Screenshot of the DAT's general variable window, employing a triangular, least-squared error estimation of a normal uncertainty

Furthermore, it can be shown that the amount by which the upper bound must increase in order to maintain the same mean value for the PDF is equal to

$$NewBound_{upper} = \mu_{sample} + 3 * (\frac{1}{3} - L + L^2 - \frac{1}{3} * L^3) * \sigma_{sample} * \sqrt{6} \tag{3.10}$$

Following this approach yields an updated table of triangular distributions (the probability of a zero minimum is provided in parentheses where appropriate). Each of the cost variables in the DAT was given a triangular distribution as described in Table 3.10. The DAT input screen is shown in Figure 3-32. Two simulations were then run, one with 20 sample runs, and another with 200 sample runs. Their results are given in Figures 3-33 and 3-34.

As should be expected, in either setup of the triangular distribution there is no schedule variation due to fluctuations in the price of construction inputs alone. On

Cost Item	Var. Name	Lower Bound , Peak , Upper Bound
Surface Casing	FCS04	125145.45 , 150000 , 174854.55
Intermediate Casing	FCI02	792587.85 , 950000 , 1107412.15
Production 1 Liner	FCP102	937089.13 , 1123200 , 1309310.87
Production 2 Liner	FCP202	588684.2 , 705600 , 822515.80
Production 3 Liner	FCP302	181544.33 , 217600 , 253655.67
Tieback Casing	FCT01	941093.79 , 1128000 , 1314906.21
Wireline Services	FCG02	49188.06 , 125000 , 200811.94
Wellhead Welding and Install Svcs	FCG03	4722.05 , 12000 , 19277.95
Prod 1 Liner Hanger and Running Svcs	FCP103	17707.7 , 45000 , 72292.30
Prod 2 Liner Hanger and Running Svcs	FCP203	13772.66 , 35000 , 56227.34
Prod 3 Liner Hanger and Running Svcs	FCP303	9837.61 , 25000 , 40162.39
Casing Crews and Laydown Machine	FCG01	3935.04 , 10000 , 16064.96
Bits – Surface Hole	FCS03	0 (5.19%) , 80000 , 169368.66
Bits – Intermediate Hole	FCI01	0 (5.19%) , 85000 , 179954.21
Bits – Production Hole 1	FCP101	0 (5.19%) , 50000 , 105855.42
Bits – Production Hole 2	FCP201	0 (5.19%) , 25000 , 52927.71
Bits – Production Hole 3	FCP301	0 (5.19%) , 16000 , 33873.73
Drilling Fluids – Surface Hole	VCS01	0 (10.82%) , 215.29 , 492.84
Drilling Fluids – Intermediate Hole	VCI01	0 (10.82%) , 383.92 , 878.86
Drilling Fluids – Production Hole 1	VCP101	0 (10.82%) , 280.66 , 642.48
Drilling Fluids – Production Hole 2	VCP201	0 (10.82%) , 131.65 , 301.37
Drilling Fluids – Production Hole 3	VCP301	0 (10.82%) , 56.89 , 130.24
Cement – Surface	FCS05	119930.43 , 220500 , 321069.57
Cement – Intermediate	FCI03	656952.22 , 1207850 , 1758747.78
Cement – Production 1 Liner	FCP104	388563.7 , 714400 , 1040236.3
Cement – Production 2 Liner	FCP204	300233.99 , 552000 , 803766.01
Cement – Production 3 Liner	FCP304	183267.83 , 336950 , 490632.17
Cement – Tieback	FCT02	348206.16 , 640200 , 932193.84
Miscellaneous Materials	FCS02	0 (28.90%) , 122000 , 466880.01
Surface Casing Head	FCS06	0 (13.76%) , 20000 , 48166.72
Tieback Casing Head	FCT03	0 (13.76%) , 10000 , 24083.37
Master Valves	FCT04	0 (13.76%) , 35000 , 84291.77
Wing Valves	FCT05	0 (13.76%) , 12000 , 28900.03
Well Insurance	FCS01	3367.28 , 25000 , 46632.72
Other General Cost Items	GHrCost	2102.85 , 3196.4 , 4289.95

Table 3.10: Parameters for the Triangular Distribution on each DAT variable (Normal Scenario). In parentheses, where appropriate, is the height of the delta function at the triangular distribution's lower bound.

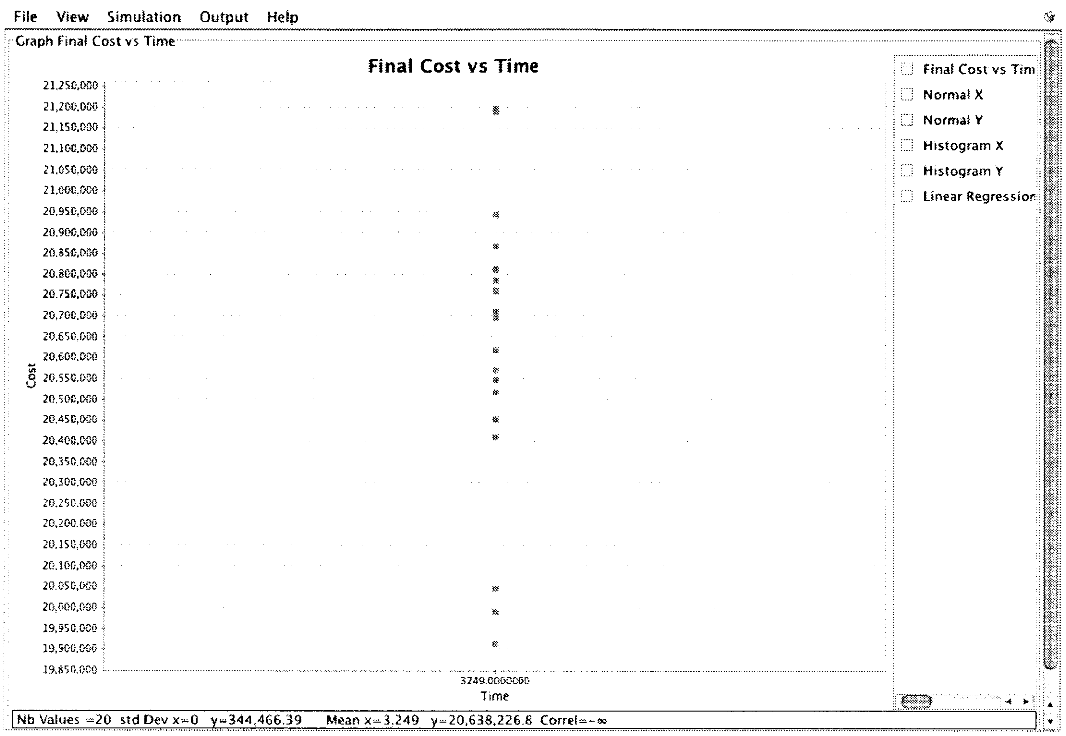


Figure 3-33: N=20 Simulations, Normal Uncertainty (Adjusted). The results vary only in cost, as price increases or decreases in project inputs do not affect project schedule.

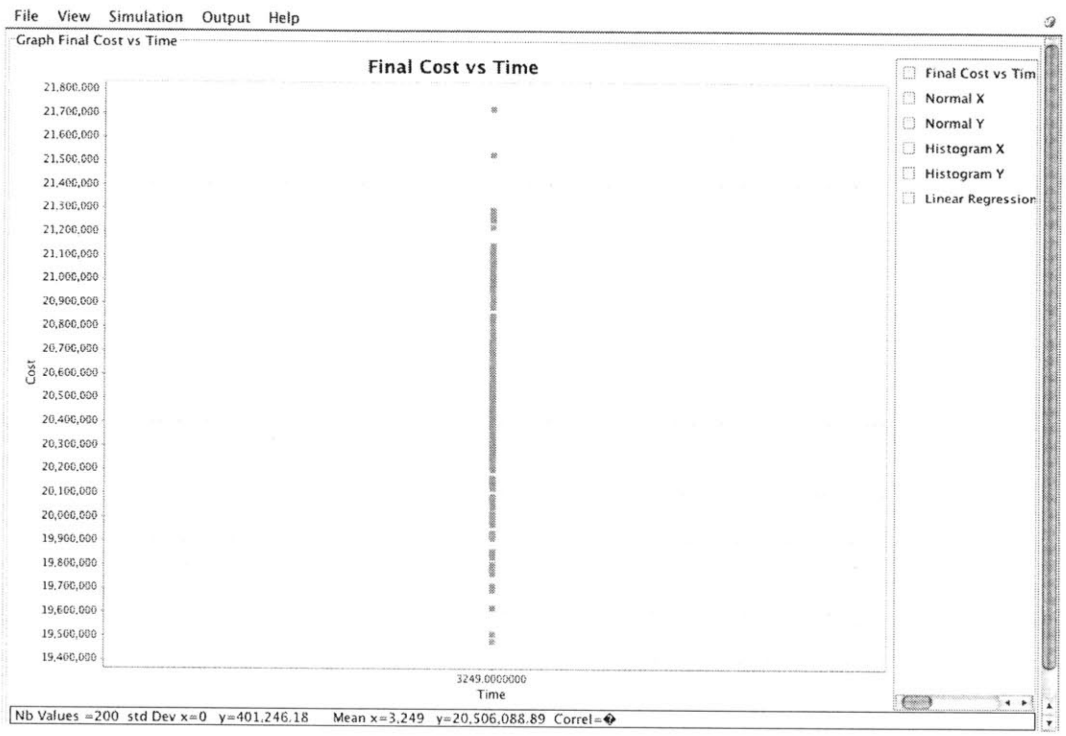


Figure 3-34: N=200 Simulations, Normal Uncertainty (Adjusted). The results vary only in cost, as price increases or decreases in project inputs do not affect project schedule.

the whole, component cost uncertainty of the degree given in Table 3.8 or Table 3.9 yields a total construction cost that varies between ± 10% of the value estimated by ThermaSource.

THE LOGNORMAL DISTRIBUTION Determining the parameters of a lognormal distribution using sample mean and sample standard deviation is less straightforward. The mean of a lognormal distribution is equal to

$$mean_{lognormal} = e^{\mu_{lognormal} + \frac{\sigma^2_{lognormal}}{2}} \tag{3.11}$$

And the variance is equal to

$$variance_{lognormal} = (e^{\sigma^2_{lognormal}} - 1) * e^{2*\mu_{lognormal} + \sigma^2_{lognormal}} \tag{3.12}$$

Solving for parameters μ and σ yields

$$\mu_{lognormal} = \frac{4 * \mu_{sample} - \mu^2_{sample} - \sigma_{sample}}{2} \tag{3.13}$$

and

$$\sigma^2_{lognormal} = \frac{2 * \mu_{sample} - \mu^2_{sample} - \sigma_{sample}}{2} \tag{3.14}$$

By deriving lognormal distributions from the sample means and variances provided by Sandia, we can then parametrize a triangular distribution for each cost variable using the distribution. We (semi-arbitrarily) choose three points from the lognormal distribution that are representative of an expert-solicited minimum, maximum, and most-likely values. Different points could be chosen with a reasonable rationalization (or the variables themselves could be represented using a lognormal distribution, a choice available in the DAT) but the primary motive of this process is to demonstrate the capability of the DAT to handle expert-solicited information, and the parametrization choices are appropriate in this context.

The peak of the triangle is set equal to the mode of the lognormal distribution

$$Peak = e^{\mu_{lognormal} - \sigma^2_{lognormal}} \tag{3.15}$$

while the lower and upper bounds are set equal to the bounds of a symmetric 95% confidence interval around the lognormal distribution, calculated using

$$0.05 = \frac{1}{2} + \frac{1}{2} * erf(\frac{ln(Bound_{lower}) - \mu_{lognormal}}{\sigma_{lognormal} * \sqrt{2}}) \tag{3.16}$$

and

$$0.05 = \frac{1}{2} + \frac{1}{2} * erf(\frac{ln(Bound_{upper}) - \mu_{lognormal}}{\sigma_{lognormal} * \sqrt{2}}) \tag{3.17}$$

respectively.

This process yields the set of triangular distributions provided in Table 3.11.

Each of the cost variables in the DAT was given a triangular distribution as described in Table 3.11. The DAT input screen is shown in Figure 3-35.

Results and Discussion of Component Cost Variation Two simulations were run, one with 20 sample runs, and another with 200 sample runs. Their results are given in Figures 3-36 and 3-37.

As should be expected, there is again no schedule variation due to fluctuations in the price of construction inputs. On the whole, component cost uncertainty of the degree given in Table 3.11 yields a total construction cost varies between +15%/-5% of its average value.

Trouble Cost Variation

Trouble Cost Variation and its Significance The second type of uncertainty we will look at is the potential for adverse "trouble" events during the construction process. Drillers encounter a variety of unforeseen project setbacks, ranging from drill string breakage, equipment losses necessitating fishing operations, and structural failures of the casing as it is being run. The frequency of these trouble events can depend greatly on site geology- for example, in drilling regions with high fluid loss

Cost Item	Var. Name	Lower Bound , Peak , Upper Bound
Surface Casing	FCS04	133907.95 , 148976.28 , 167250.50
Intermediate Casing	FCI02	848061.04 , 943516.42 , 1059253.10
Production 1 Liner	FCP102	1002700.90 , 1115534.36 , 1252372.70
Production 2 Liner	FCP202	629894.67 , 700784.41 , 786746.50
Production 3 Liner	FCP302	194251.29 , 216114.93 , 242624.60
Tieback Casing	FCT01	1007021.88 , 1120301.60 , 1257723.60
Wireline Services	FCG02	81240.63 , 114327.05 , 181233.70
Wellhead Welding and Installation Svcs	FCG03	7799.10 , 10975.40 , 17398.44
Prod 1 Liner Hanger and Running Svcs	FCP103	29246.65 , 41157.74 , 65244.10
Prod 2 Liner Hanger and Running Svcs	FCP203	22747.36 , 32011.57 , 50745.46
Prod 3 Liner Hanger and Running Svcs	FCP303	16248.12 , 22865.41 , 36246.75
Casing Crews and Laydown Machine	FCG01	6499.25 , 9146.16 , 14498.70
Bits – Surface Hole	FCS03	27533.40 , 60290.17 , 148712.50
Bits – Intermediate Hole	FCI01	29254.20 , 64058.31 , 158007.20
Bits – Production Hole 1	FCP101	17208.36 , 37681.36 , 92945.40
Bits – Production Hole 2	FCP201	8604.18 , 18840.68 , 46472.70
Bits – Production Hole 3	FCP301	7128.85 , 12058.04 , 29742.53
Drilling Fluids – Surface Hole	VCS01	54.03 , 150.17 , 427.51
Drilling Fluids – Intermediate Hole	VCI01	96.35 , 267.78 , 762.38
Drilling Fluids – Production Hole 1	VCP101	70.43 , 195.76 , 557.33
Drilling Fluids – Production Hole 2	VCP201	33.04 , 91.83 , 261.42
Drilling Fluids – Production Hole 3	VCP301	14.28 , 39.68 , 112.97
Cement – Surface	FCS05	159999.16 , 209510.24 , 293689.50
Cement – Intermediate	FCI03	876439.21 , 1147650.55 , 1608767.00
Cement – Production 1 Liner	FCP104	518382.42 , 678794.18 , 5951528.00
Cement – Production 2 Liner	FCP204	400541.96 , 524488.23 , 735223.00
Cement – Production 3 Liner	FCP304	244497.42 , 320156.35 , 448792.50
Cement – Tieback	FCT02	464541.51 , 608292.32 , 852699.00
Miscellaneous Materials	FCS02	23034.02 , 45300.18 , 333802.00
Surface Casing Head	FCS06	7349.31 , 13229.55 , 41320.40
Tieback Casing Head	FCT03	3674.66 , 6614.78 , 20660.20
Master Valves	FCT04	12861.32 , 23151.71 , 72310.65
Wing Valves	FCT05	4409.59 , 7937.73 , 24792.22
Well Insurance	FCS01	13410.32 , 20957.09 , 41435.65
Other General Cost Items	GHrCost	2518.62 , 3105.10 , 3978.85

Table 3.11: Parameters for the Triangular Distribution on each DAT variable (Lognormal Scenario)

General Variables

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Nb	Name	Description	Min.	Mode	Max.	Prob. Min.	Prob. Max.
11	FCS01		13,410.32	20,957.09	41,435.65	0.00	0.00
12	FCS02		23,034.02	45,300.18	333,802.00	0.00	0.00
13	FCS03		27,533.40	60,290.17	148,712.50	0.00	0.00
14	FCS04		133,907.95	148,976.28	167,250.50	0.00	0.00
15	FCS05		159,999.16	209,510.24	293,689.50	0.00	0.00
16	FCS06		7,349.31	13,229.55	41,320.40	0.00	0.00
17	FCI01		29,254.20	64,058.31	158,007.20	0.00	0.00
18	FCI02		848,061.04	943,516.42	1,059,253.10	0.00	0.00
19	FCI03		876,439.21	1,147,650.55	1,608,767.00	0.00	0.00
20	FCP101		17,208.36	37,681.36	92,945.40	0.00	0.00
21	FCP102		1,002,700.90	1,115,534.36	1,252,372.70	0.00	0.00
22	FCP103		29,246.65	41,157.74	65,244.10	0.00	0.00
23	FCP104		518,382.42	678,794.18	951,528.00	0.00	0.00
24	FCP201		8,604.18	18,840.68	46,472.70	0.00	0.00
25	FCP202		629,894.67	700,784.41	786,746.50	0.00	0.00
26	FCP203		22,747.36	32,011.57	50,745.46	0.00	0.00
27	FCP204		400,541.96	524,488.23	735,223.00	0.00	0.00
28	FCP301		7,128.85	12,058.04	29,742.53	0.00	0.00
29	FCP302		194,251.29	216,114.93	242,624.60	0.00	0.00
30	FCP303		16,248.12	22,865.41	36,246.75	0.00	0.00
31	FCP304		244,497.42	320,156.35	448,792.50	0.00	0.00
32	FCT01		1,007,021.88	1,120,301.60	1,257,723.60	0.00	0.00
33	FCT02		464,541.51	608,292.32	852,699.00	0.00	0.00
34	FCT03		3,674.66	6,614.78	20,660.20	0.00	0.00
35	FCT04		12,861.32	23,151.71	72,310.65	0.00	0.00
36	FCT05		4,409.59	7,937.73	24,792.22	0.00	0.00
37	FCG01		6,499.25	9,146.16	14,498.70	0.00	0.00
38	FCG02		81,240.63	114,327.05	181,233.70	0.00	0.00
39	FCG03		7,799.10	10,975.40	17,398.44	0.00	0.00
40	VCS01		54.03	150.17	427.51	0.00	0.00
41	VCI01		96.35	267.78	762.38	0.00	0.00
42	VCP101		70.43	195.76	557.33	0.00	0.00
43	VCP201		33.04	91.83	261.42	0.00	0.00
44	VCP301		14.28	39.68	112.97	0.00	0.00
45	GHrCost		2,518.62	3,105.10	3,978.85	0.00	0.00

Figure 3-35: Screenshot of the DAT's general variable window, employing a triangular, least-squared error estimation of a normal uncertainty

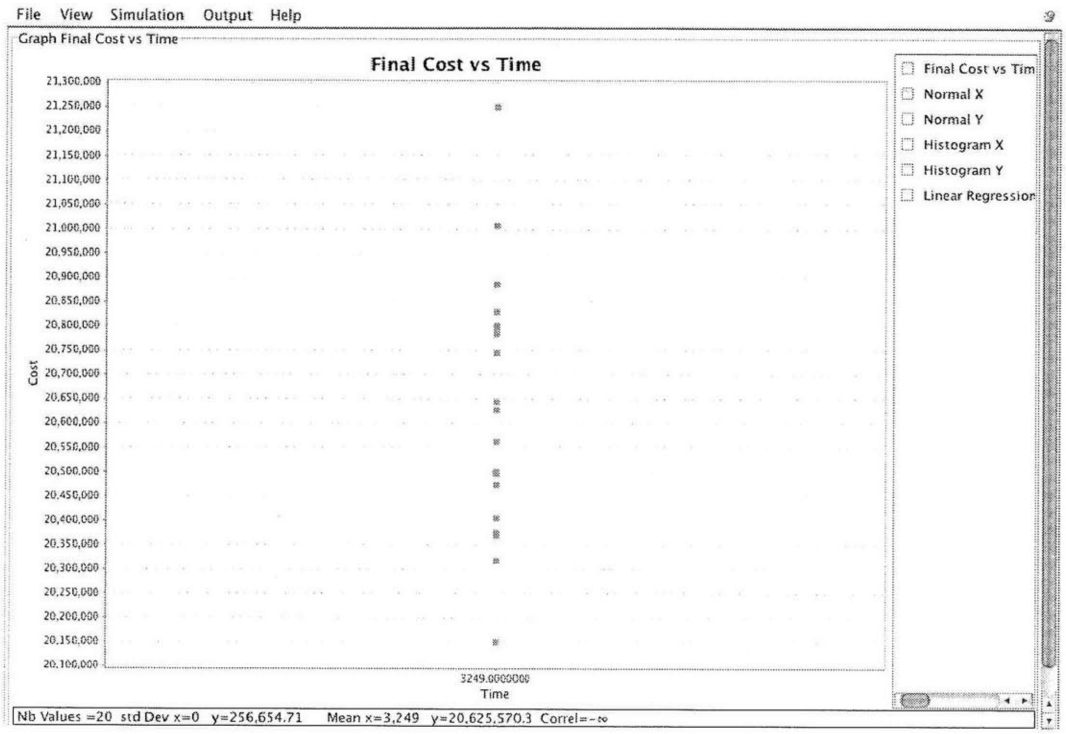


Figure 3-36: N=20 Simulations, Lognormal Uncertainty. The results vary only in cost, as price increases or decreases in project inputs do not affect project schedule.

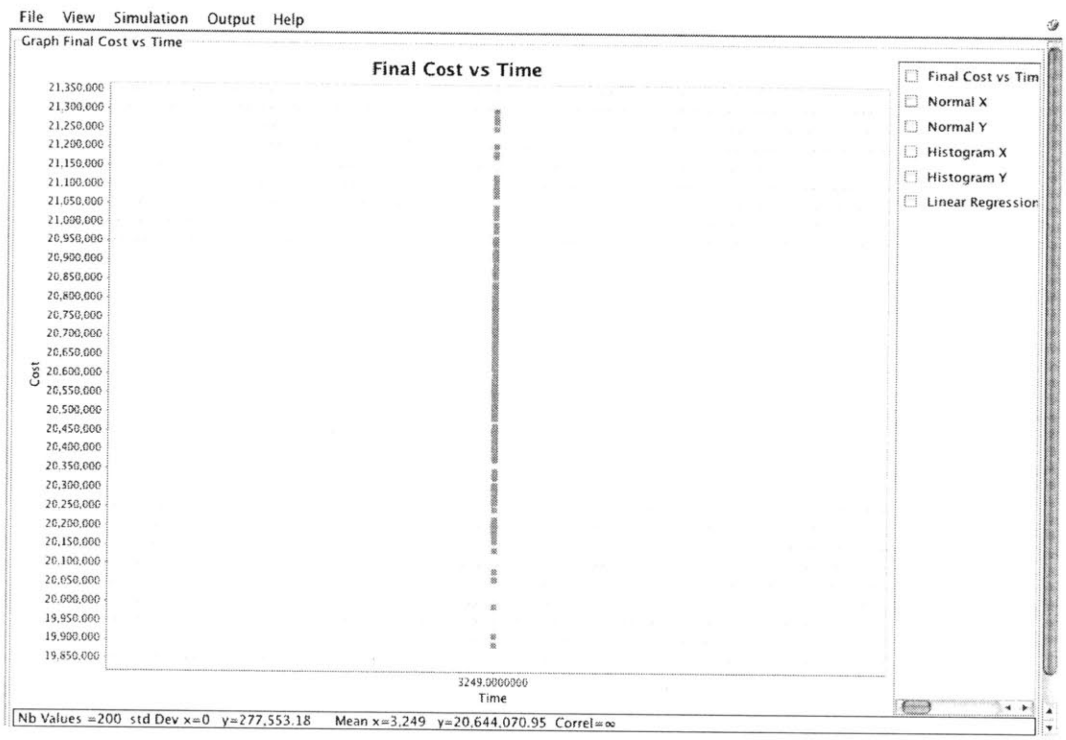


Figure 3-37: N=200 Simulations, Lognormal Uncertainty. The results vary only in cost, as price increases or decreases in project inputs do not affect project schedule.

(often due to ground permeability), it is possible to build up a cake of mud around the drill pipe. This 'filter cake' can provide such a strong suction force that it becomes nearly impossible to withdraw the drillpipe from the wellbore.

While some degree of trouble is accounted for in project planning (ThermaSource's own estimates provide for limited banging, repair, and other recovery costs from small problems), the more serious trouble events are difficult to plan for because of the infrequency of the events and the severity of their consequences. Trouble events can contribute costs that are two to three times larger than the total planned project cost, and may even require the abandonment of a well drilling attempt.

The nature of trouble events (infrequent, but with serious consequences) mean that traditional, deterministic cost and schedule estimation belies the true uncertainty of a well drilling project, and makes a probabilistic approach, as utilized by the DAT, a valuable tool for giving project managers a more accurate description of project risk.

Modeling Trouble Cost Variation with the DAT There are a variety of alternatives for modeling trouble events using the DAT, however the easiest and most accurate is to create for each individual method a "trouble activity" within each method's activity network. Then, for each method, the expectations of trouble delays and costs can be represented in the cost and time equations of that method's trouble activity. The modified activity network for the Surface Drilling method is shown in Figure 3-38.

While geology is often a significant factor in the frequency of trouble events, we wished to analyze the impact of trouble events first in isolation, without introducing the interaction effects that geology and trouble events have on total project risk. As such, there remains no geological variation in the DAT model, and the entire drilling region is presumed to be of a given, baseline geology. In the holistic sensitivity analysis section (Section 3.2.4), geology's impact on trouble cost will be introduced, namely by increasing the probability of trouble events in drilling regions that have poor geological characteristics, and decreasing the probability of trouble events in regions with good geological conditions.

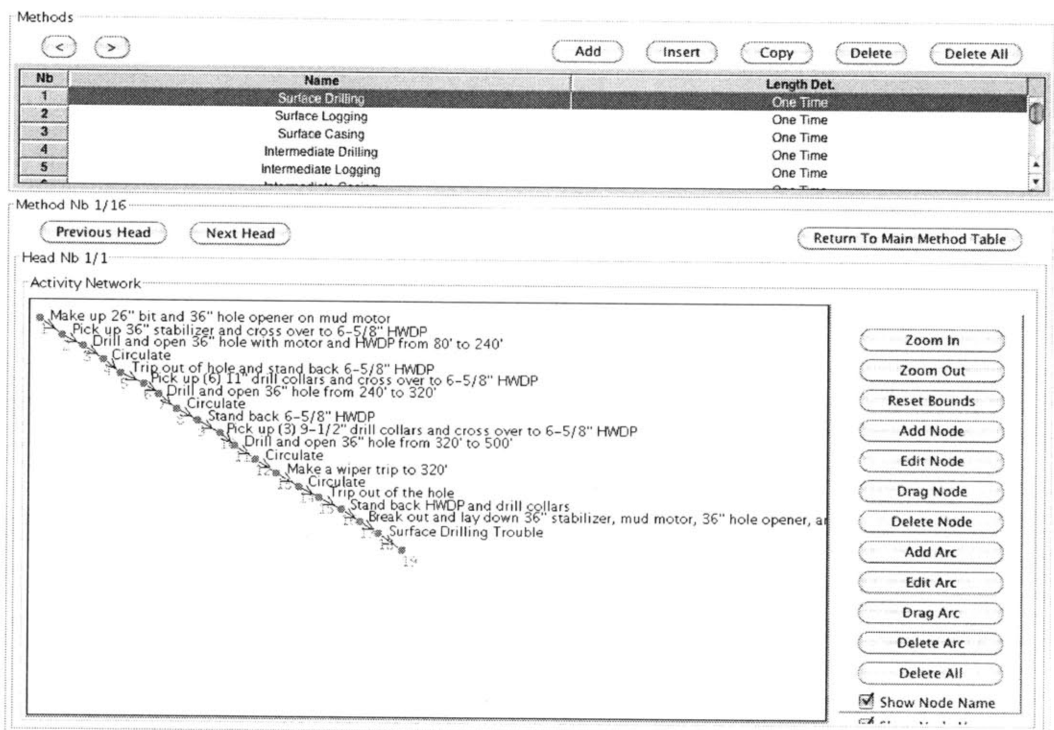


Figure 3-38: The Activity Network, Including Trouble Activities. Each activity network is modified to include an additional trouble activity at the end of the regular construction sequence, simulating a potential trouble-event-response activity.

In order to improve the transparency of the modeling, trouble events were assumed to have a simple impact on project cost and schedule. While it would be possible to model a more complex form of trouble event impact using more detailed cost and time equations, or even account for multiple, distinct types of trouble events by including multiple trouble activities in a method, we chose to model trouble events by using a bounded triangular distribution to represent the time spent responding to trouble activities, and by calculating the cost of responding to the trouble event as simply the time spent responding to it multiplied by the hourly cost of the method in which the trouble occurred (Figure 3-39 shows the cost and time equations of one such trouble activity). Thus, for each method, there are a limited set of parameters that define the frequency and extremity of potential trouble events: the probability that is assigned to the lower bound of the triangular distribution (set at zero and representing an absence of trouble events), the peak of the triangular distribution, set equal to the estimated most likely delay caused by an unforeseen trouble event, and finally the upper bound of the triangular distribution, set equal to a high, but reasonable estimate of the delay caused by a very serious trouble event. In effect, the distributions on trouble cost and time mirror the bounded triangular distributions described in Figure 3-30, but with much taller delta functions representing the much higher relative likelihood of the costs being equal to zero (not encountering trouble).

Assumptions Drawing upon the well drilling literature, we estimated the list of parameters for our trouble activity schedule distributions provided in Table 3.12

This set of assumptions is designed so that, on average, a trouble event will occur once every five well projects. A 20% frequency rate of trouble events is roughly consistent with historical experience in geothermal well drilling. As for the consequences of a trouble event, the cost and time implications of experiencing trouble are modeled as perfectly correlated– an hour's delay in the project completion time is assumed to have related costs equal to the average hourly cost of the project– as well as proportional to the size of the construction method that was disrupted. Furthermore, the delay caused by a trouble event depends on the type of construction method that te

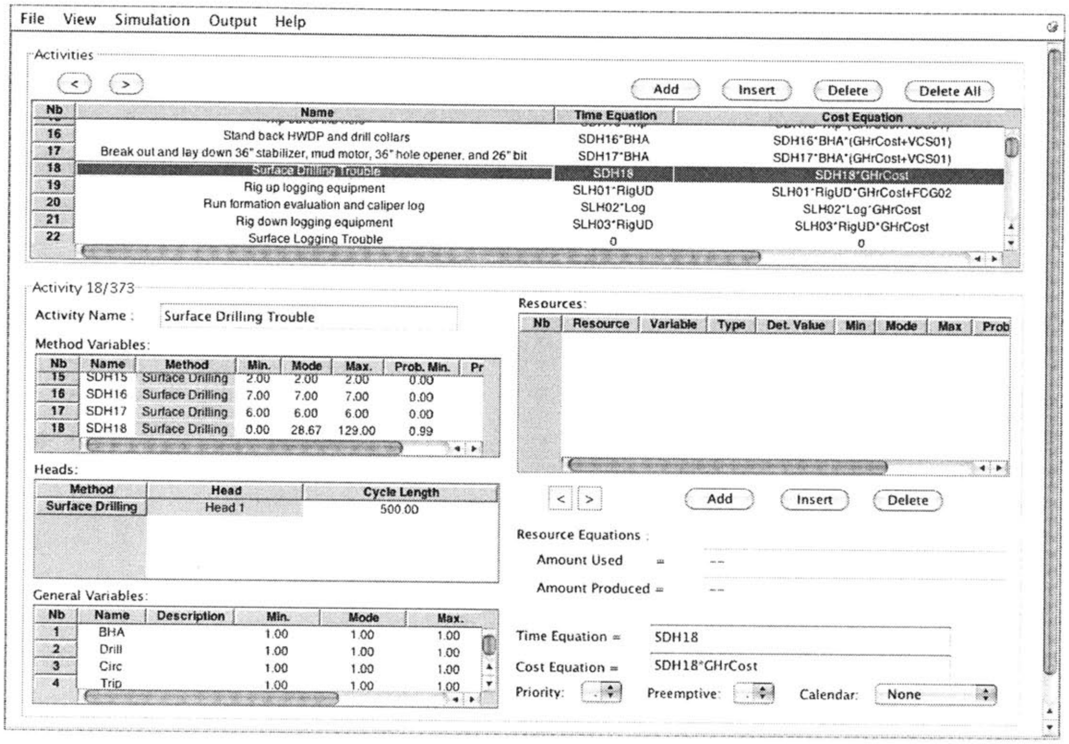


Figure 3-39: Trouble Activity Equations. The delay due to trouble events is directly equal to the method variable used to model the trouble event severity distribution, while the cost due to trouble events is equal to the delay multiplied by the hourly cost for the relevant activity. No trouble events are modeled for any logging construction stage.

Construction Stage	Prob. of Zero Trouble Events	Most Likely Delay	Maximum Delay
Surface Drilling	99.38%	28.67	129.00
Surface Logging	100%	0	0
Surface Casing	99.38%	42.50	255.00
Intermediate Drilling	97.24%	128.33	577.50
Intermediate Logging	100%	0	0
Intermediate Casing	99.02%	67.50	405
Production 1 Drilling	97.20%	130.33	586.50
Production 1 Logging	100%	0	0
Production 1 Casing	99.00%	69.00	414.00
Production 2 Drilling	94.22%	273.33	1230.00
Production 2 Logging	100%	0	0
Production 2 Casing	99.18%	56.50	339.00
Production 3 Drilling	96.63%	157.33	708.00
Production 3 Logging	100%	0	0
Production 3 Casing	98.42%	109.50	657.00
Tieback Casing	98.34%	115.00	690.00

Table 3.12: Parameters for the Triangular Distribution on each Trouble Activity Schedule Distribution. The probabilities of a trouble event occurrence are the result of normalizing a 20 percent proect-wide trouble event frequency across the sixteen different consrtruction stages. The delay values are taken from relevant literature.

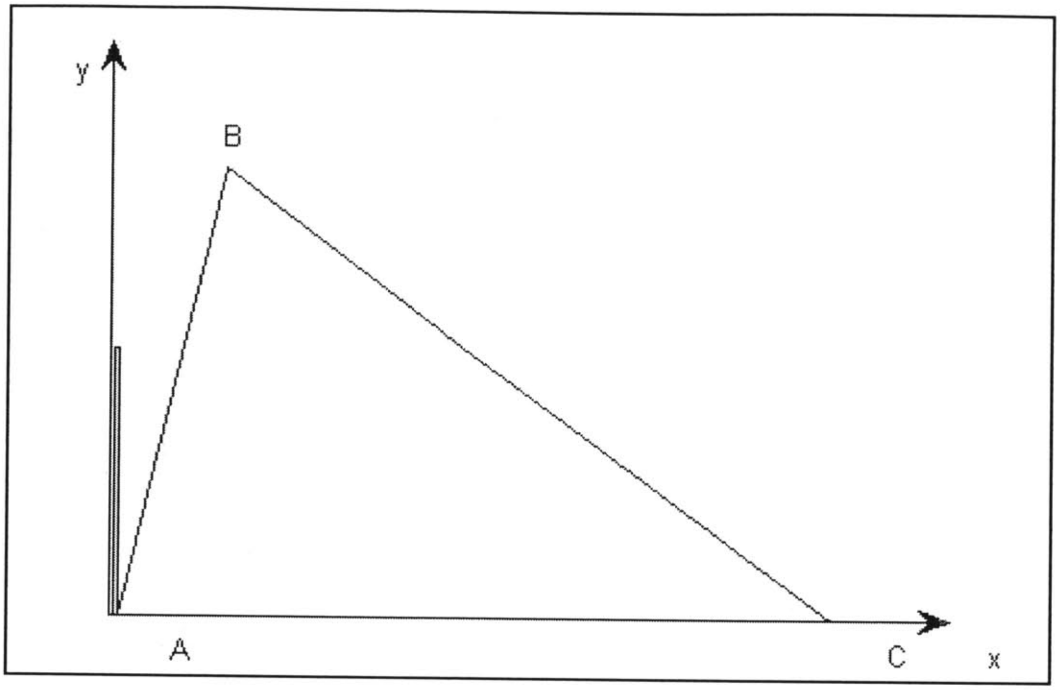


Figure 3-40: The Trouble Event Distributions. The distribution of trouble event severity is a bounded triangular distribution, with a large delta function at the lower bound of trouble delay = 0 (no trouble events)

trouble occurred in. Trouble events were assumed not to occur during logging stages, but for drilling and casing stages, the delay distribution was determined as follows: the minimum delay for both casing and drilling was set equal to zero, the modal delay was set equal to one third of a drilling section's total time requirement and half of a casing section's total time requirement, and the maximum delay was set equal to 1.5x of a drilling section's total time requirement and three times a casing section's total time requirement. Thus, trouble events occuring during relatively small construction stages, such as surface drilling or casing, were less consequential than those occurring during the longer and deeper construction stages.

There are a variety of other approaches that could have been taken in regards to trouble event costs and delays. One alternative would be to keep the intensity of trouble events constant across methods and increase the per-foot probability of trouble in more difficult well sections. Another would be to make both the probability and

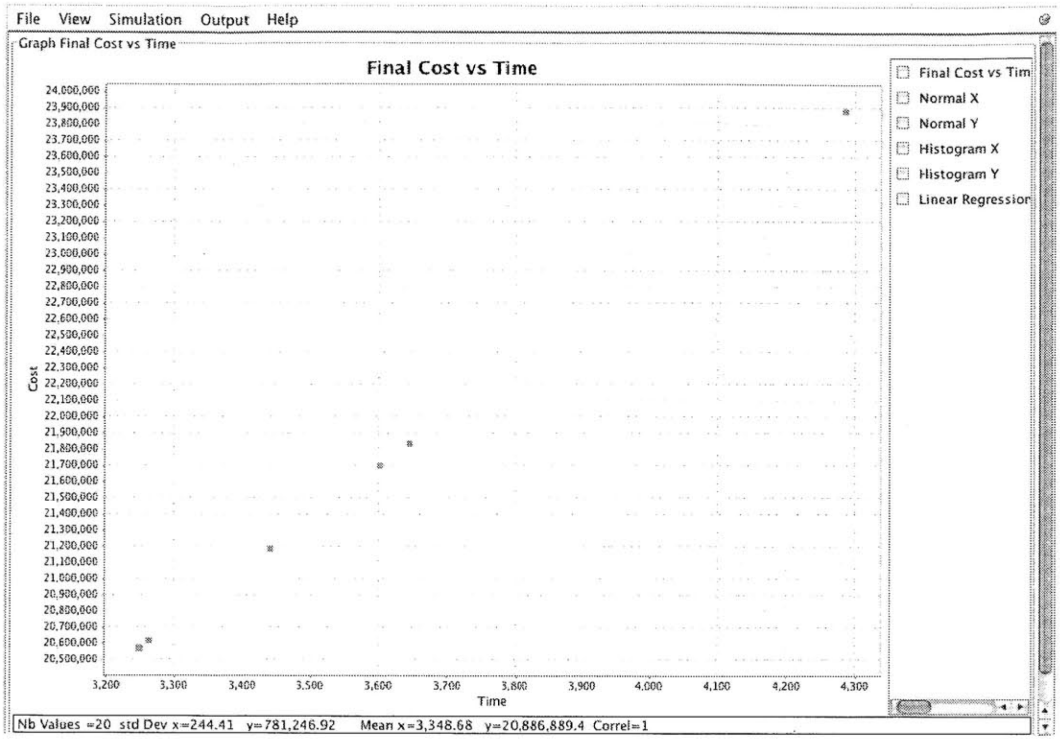


Figure 3-41: N=20 Simulations, Trouble Event Sensitivity

severity of trouble events increase with depth. It would also be possible to include entirely new variables into the model to account for trouble-specific costs, like the rental of fishing equipment. In general, by adding a separate trouble activity, it is possible to represent trouble with almost any underlying probability distribution, and ultimately it is up to the modeler to decide what they believe is the most realistic approach to unforeseen events. As project experience in enhanced geothermal drilling is gained, it will be easier to use historical data and take an empirical approach to trouble event modeling.

Results and Discussion of Trouble Cost Variation Two sets of simulations were run, one with N=20 cases, and another with N=200 cases. The results are given in Figure 3-41 and Figure 3-42.

It is important to note that in each of these plots, the bottom left outcome is the outcome for all simulations that did not encounter trouble events (i.e. in Figure 3-41,

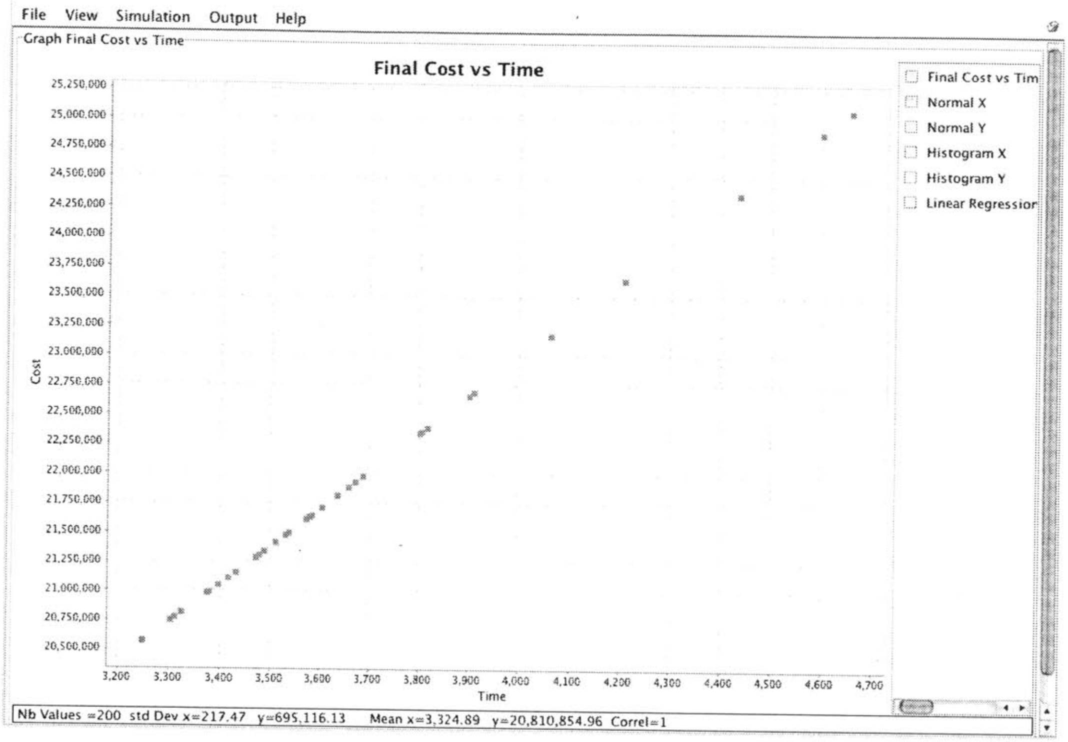


Figure 3-42: N=200 Simulations, Trouble Event Sensitivity

the bottom left point represents 15 simulations, not just one).

Because of the assumptions used, there is a perfect correlation between cost and schedule– a more sophisticated analysis of trouble events (particularly one that had significant variations between the relative cost and time impacts of different trouble events) could remove this feature, but as a first pass approximation, it is reasonable to model trouble costs as proportional to trouble delays.

Much work remains in the estimation of trouble event impact as it relates to enhanced geothermal well drilling. More project experience is needed before trouble event likelihood can be reliably estimated. However, given the flexibility of the DAT in representing trouble events, the ability to use our full knowledge in simulating cost and delays due to trouble events should keep pace as that knowledge improves.

Geological Cost Variation

Geological Cost Variation and its Significance Geothermal well projects are usually started with incomplete information on the rock properties, temperature, fracture patterns, and stresses that occur in the volume of rock being drilled through. Geological profiles are often constant laterally, and so after an initial well has been drilled, the profiles that will be encountered by subsequent wells can be estimated with a higher degree of accuracy, but before an initial well is drilled, geological factors represent a very large source of project risk.

Geology can affect the cost and time requirements of a project through several avenues: high rock strength can increase the time it takes for a drill bit to penetrate the rock, requiring lengthier drilling times; high rock abrasiveness can decrease bit life and necessitate more frequent drill replacement; high rock conductivity can lead to increased fluid loss and thus higher quantities of drilling mud and other fluids; high temperatures can interfere with the operation of some equipment, particularly logging equipment; disadvantageous stress patterns can case casing failures; a variety of conditions can cause damage to the drill string, increase the likelihood of trouble events, etc. Geology can also have significant effects on other aspects of the project besides drilling, such as the efficacy of hydrofracing, quality of the geothermal reservoir, pumping power requirements during operation, and so on.

Adapting to adverse geological conditions is difficult after a construction project has begun. Generally, much of the profile of a geothermal well must be determined in advance of spud activities– the width of each casing string is constrained by fluid flow requirements for the finished plant, and the length of each casing string is limited by stability concerns. The choice of drilling technology is similarly limited by the nature of the drill string. Again, while subsequent wells can be designed based on relavent geological conditions, the initial well of a geothermal project faces a considerable degree of project risk.

Modeling Geological Cost Variation with the DAT To demonstrate the ability of the DAT to model geology-related project risk, we look at two specific pathways

Hole Size (inches)	Construction Stage	ROP (ft/r)	Effective Drilling Rate (ft/day)
26" Bit / 36" Opener	Surface	12ft/hr	110ft/day
26 Inch	Intermediate	15ft/hr	275ft/day
17.5 Inch	Production 1	18ft/hr	275ft/day
12.25 Inch	Production 2	12.5ft/hr	205ft/day
8.5 Inch	Production 3	12ft/hr	150ft/day

Table 3.13: Drill Bit Rate of Penetration and Summary Drilling Rate Assumptions Made by Sandia and ThermaSource

by which geology affects cost and schedule: changes in advance rates, and changes in bit life. Other pathways can be modeled using similar techniques.

Modeling Changes in Drill Bit Advance Rate If geology slows down the rate at which a drill bit penetrates through rock, but does not alter the number of bits required per meter, it is relatively easy to model the effect by changing the amount of time required to complete a drilling activity. For each distinct geology classification that is modeled, an appropriate advance rate can be chosen, and the time required to complete a section of drilling is then equal to the distance divided by the advance rate. In our simple example, we use three distinct geologies corresponding notionally to a low rock strength lithology, a normal rock strength lithology, and a high rock strength lithology.

The assumed advance rates for the Sandia well are provided in the well documentation, and are provided in Table 3.13

These assumptions are generally consistent with historical data on geothermal wells– Fenton Hill, for example, had very similar advance rates, and previous work by Aliko suggests that over a reasonable range of lithologies, rate of penetration varies by a factor of two [Aliko et al, 2006]– therefore, we take the advance rates in high-strength rock to be half those assumed by Sandia, and advance rates in low-strength rock to be twice the assumed rates.

To model these three different scenarios, we duplicate each of the five drilling methods (Surface Drilling, Intermediate Drilling, Production 1 Drilling, Production 2 Drilling, and Production 3 Drilling) twice, once to create a set of methods that

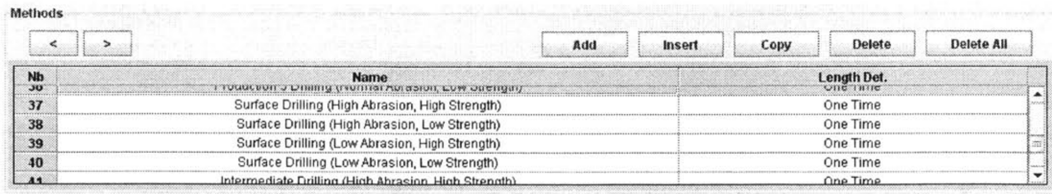


Figure 3-43: A Screenshot of the DAT Method Screen, Showing Method Duplication. In this screenshot, the surface method has been duplicated four times, with slight alterations made to each method.

correspond to low-strength rock, and a second set of methods that correspond to high-strength rock (the original set serves as the baseline). Figure 3-43 is an example of this method duplication. In the first set, the time spent on each drilling activity is half its normal value, while in the second set, the time requirement is twice its normal value.

We make one exception in the doubling and halving of drill times, and that is where the drilling out of man-made components occurs. The act of drilling out pack off bushing or a set of drill collars does not depend upon geology, and so the time requirements for these activities are left unchanged. An example of the changes in method variables between methods can be seen in Figure 3-44

Modeling Changes in Drill Bit Lifetime Modeling the effect of increases and decreases in drill bit lifetime is somewhat more difficult than modeling changes in drill bit advance rates. Notionally, the geological factor that affects drill bit lifetime but not advance rate may be thought of as rock abrasiveness. Assuming that the effect of rock abrasiveness shows up purely as a decrease in bit lifetime, the same amount of time will be spent drilling regardless of rock abrasiveness, however additional time is required to trip back to the surface and replace worn out bits, and additional costs are incurred not simply as hourly overhead during the extra tripping and bottom hole assembly activities, but also in the form of additional bits.

For each distinct rock abrasiveness value modeled, it is necessary to create a new method that adds or subtracts activities from its activity network to account for increased or decreased tripping and bit replacement requirements. As we did in mod-

Method Variables

Nb	Name	Method	Min.	Mode	Max.	Prob. Min.	Prob. Max.
1102	SDH01	Surface Drilling (High Abrasion, Low Strength)	6.00	6.00	6.00	0.00	0.00
1103	SDH02	Surface Drilling (High Abrasion, Low Strength)	4.00	4.00	4.00	0.00	0.00
1104	SDH03	Surface Drilling (High Abrasion, Low Strength)	6.50	6.50	6.50	0.00	0.00
1105	SDH04	Surface Drilling (High Abrasion, Low Strength)	1.00	1.00	1.00	0.00	0.00
1106	SDH05	Surface Drilling (High Abrasion, Low Strength)	2.00	2.00	2.00	0.00	0.00
1107	SDH06	Surface Drilling (High Abrasion, Low Strength)	8.00	8.00	8.00	0.00	0.00
1108	SDH07	Surface Drilling (High Abrasion, Low Strength)	3.50	3.50	3.50	0.00	0.00
1109	SDH08	Surface Drilling (High Abrasion, Low Strength)	1.00	1.00	1.00	0.00	0.00
1110	SDH09	Surface Drilling (High Abrasion, Low Strength)	2.00	2.00	2.00	0.00	0.00
1111	SDH10	Surface Drilling (High Abrasion, Low Strength)	6.00	6.00	6.00	0.00	0.00
1112	SDH11	Surface Drilling (High Abrasion, Low Strength)	7.50	7.50	7.50	0.00	0.00
1113	SDH12	Surface Drilling (High Abrasion, Low Strength)	1.00	1.00	1.00	0.00	0.00
1114	SDH13	Surface Drilling (High Abrasion, Low Strength)	4.00	4.00	4.00	0.00	0.00
1115	SDH14	Surface Drilling (High Abrasion, Low Strength)	1.00	1.00	1.00	0.00	0.00
1116	SDH15	Surface Drilling (High Abrasion, Low Strength)	2.00	2.00	2.00	0.00	0.00
1117	SDH16	Surface Drilling (High Abrasion, Low Strength)	7.00	7.00	7.00	0.00	0.00
1118	SDH17	Surface Drilling (High Abrasion, Low Strength)	6.00	6.00	6.00	0.00	0.00
1119	SDH18	Surface Drilling (High Abrasion, Low Strength)	0.00	0.00	0.00	0.00	0.00
1120	SDH19	Surface Drilling (High Abrasion, Low Strength)	6.00	6.00	6.00	0.00	0.00
1121	SDH01	Surface Drilling (Low Abrasion, High Strength)	6.00	6.00	6.00	0.00	0.00
1122	SDH02	Surface Drilling (Low Abrasion, High Strength)	4.00	4.00	4.00	0.00	0.00
1123	SDH03	Surface Drilling (Low Abrasion, High Strength)	26.00	26.00	26.00	0.00	0.00
1124	SDH04	Surface Drilling (Low Abrasion, High Strength)	1.00	1.00	1.00	0.00	0.00
1125	SDH05	Surface Drilling (Low Abrasion, High Strength)	2.00	2.00	2.00	0.00	0.00
1126	SDH06	Surface Drilling (Low Abrasion, High Strength)	8.00	8.00	8.00	0.00	0.00
1127	SDH07	Surface Drilling (Low Abrasion, High Strength)	14.00	14.00	14.00	0.00	0.00
1128	SDH08	Surface Drilling (Low Abrasion, High Strength)	1.00	1.00	1.00	0.00	0.00
1129	SDH09	Surface Drilling (Low Abrasion, High Strength)	2.00	2.00	2.00	0.00	0.00
1130	SDH10	Surface Drilling (Low Abrasion, High Strength)	6.00	6.00	6.00	0.00	0.00
1131	SDH11	Surface Drilling (Low Abrasion, High Strength)	30.00	30.00	30.00	0.00	0.00
1132	SDH12	Surface Drilling (Low Abrasion, High Strength)	1.00	1.00	1.00	0.00	0.00
1133	SDH13	Surface Drilling (Low Abrasion, High Strength)	4.00	4.00	4.00	0.00	0.00
1134	SDH14	Surface Drilling (Low Abrasion, High Strength)	1.00	1.00	1.00	0.00	0.00
1135	SDH15	Surface Drilling (Low Abrasion, High Strength)	2.00	2.00	2.00	0.00	0.00

Figure 3-44: Screenshot of the DAT's method variable screen, highlighting the differences in method variable values between the surface drilling method used in low strength geology vs. high strength geology. SDH03, SDH07, and SDH11, the method variables representing the time spent drilling in the surface construction stage, are four times higher for a high-strength geology than they are for a low-strength geology.

Hole Size (inches)	Construction Stage	Bit Life
26" Bit / 36" Opener	Surface	500ft
26 Inch	Intermediate	1500ft
17.5 Inch	Production 1	2000ft
12.25 Inch	Production 2	1500ft
8.5 Inch	Production 3	1000ft

Table 3.14: Drill Bit Rate of Penetration and Summary Drilling Rate Assumptions Made by Sandia and ThermaSource

eling variation in drill rates, we model variations in bit life by creating three different methods to account for high, normal, and low rock abrasiveness. We duplicate and modify two new sets of methods, one for the high abrasiveness scenario, and a second for the low abrasiveness scenario (the original scenario represents the third, baseline condition). Thus, for each construction method that was originally modeled, we have nine methods, representing the full combinatorial set of high, normal, and low rock strength matched with high, normal, and low rock abrasiveness.

Sandia's well documentation includes its assumptions on bit lifetime, as described in Table 3.14

In determining the number of bits used for low and high rock abrasiveness geologies, bit lifetimes of double and half the assumed lifetime are used. For each additional bit replacement that is needed as a result of the high abrasiveness conditions, four additional activities are inserted into the activity network of the method: a drill replacement activity and a wiper activity which each have a constant time requirement, and two tripping activities (one out of the well and one back in) whose time requirements are assumed to be the average between the tripping activity that occurs prior and the tripping activity that occurs after the newly inserted activities. Table 3.15 displays the activity removals and additions for each of the five drilling methods.

An example of one such subsitution is shown in Figure 3-45.

Modeling Geological Uncertainty In total, we model nine different ground classes and nine different associated methods:

Method	Additions (High Abrasiveness)	Subtractions (Low Abrasiveness)
Surface Drilling	+1 Replacement at 320'	No Change
Intermediate Drilling	+3 Replacements at 1250', 3500', and 4250'	-1 Replacement at 2000'
Production 1 Drilling	+3 Replacements at 6000', 8000' and 10000'	-1 Replacement at 7000'
Production 2 Drilling	+4 Replacements at 10750', 12250', 14500', and 15250'	-3 Replacements at 10010', 13000', and 16000'
Production 3 Drilling	+4 Replacements at 16800', 17500', 18500', and 19500'	-2 Replacements at 17010' and 19000'

Table 3.15: The Activity Additions and Subtractions of Each Method

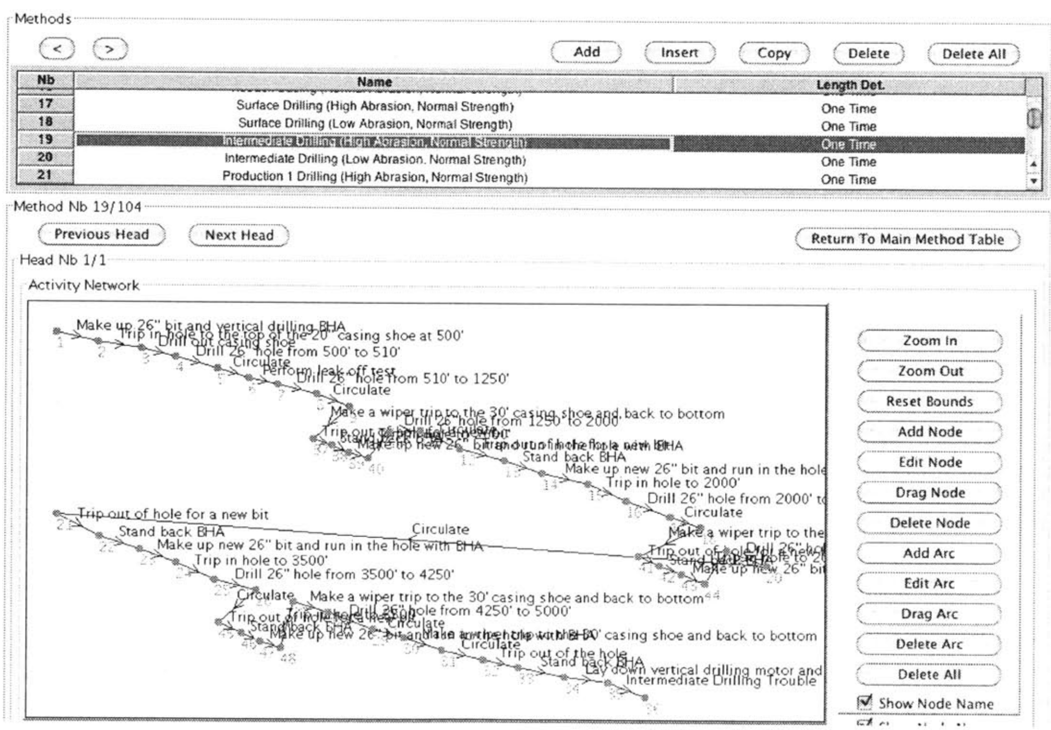


Figure 3-45: Screenshot of the activity network for the Intermediate Drilling (High Abrasion, Normal Strength) stage. Additional segments have been joined to the network to represent additional tripping, wiping, and bit replacement activities. Three extra chains of activities have been added in total.

	High Strength	Average Strength	Soft Strength
High Abrasion	+ Drilling, + Trips	+ Trips	- Drilling, + Trips
Average Abrasion	+ Drilling	Baseline	- Drilling
Low Abrasion	+ Drilling, - Trips	- Trips	- Drilling, - Trips

Table 3.16: The Nine Different Geological Conditions Simulated With the DAT.

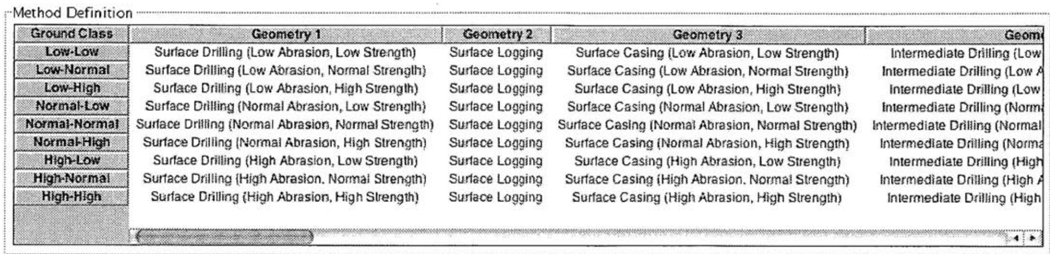


Figure 3-46: Screenshot of the DAT's method selection screen. For each of the nine different possible ground classes, there is a unique construction method associated with each drilling stage. These methods differ in their estimation of the time required to perform drilling activities, and include differing numbers of tripping and equipment replacement activities.

For each drilling construction stage, method selection is a simple one-to-one pairing between the nine ground classes and nine drilling methods created for that stage. Figure 3-46 shows the method selection screen for the geological sensitivity analysis. It can be contrasted with the method selection screen shown in Figure 3-18.

With the methods themselves settled in the two previous sections, the question now is how we model the probability of encountering the various rock types. The DAT offer a variety of approaches– we select one that shares similarity with a well construction project that has not conducted significant exploration of the well drilling region. A well construction project that obtains information on the ground lithology prior to drilling activities could incorporate this information by using a ground class generation method that is more deterministic.

For a construction project that has not placed an exploration well or conducted significant geological surveys, the geology that will be encountered can best be described as consisting of an unknown number of layers, of unknown composition, with unknown thicknesses. Thus, we choose to determine our ground parameter distribu-

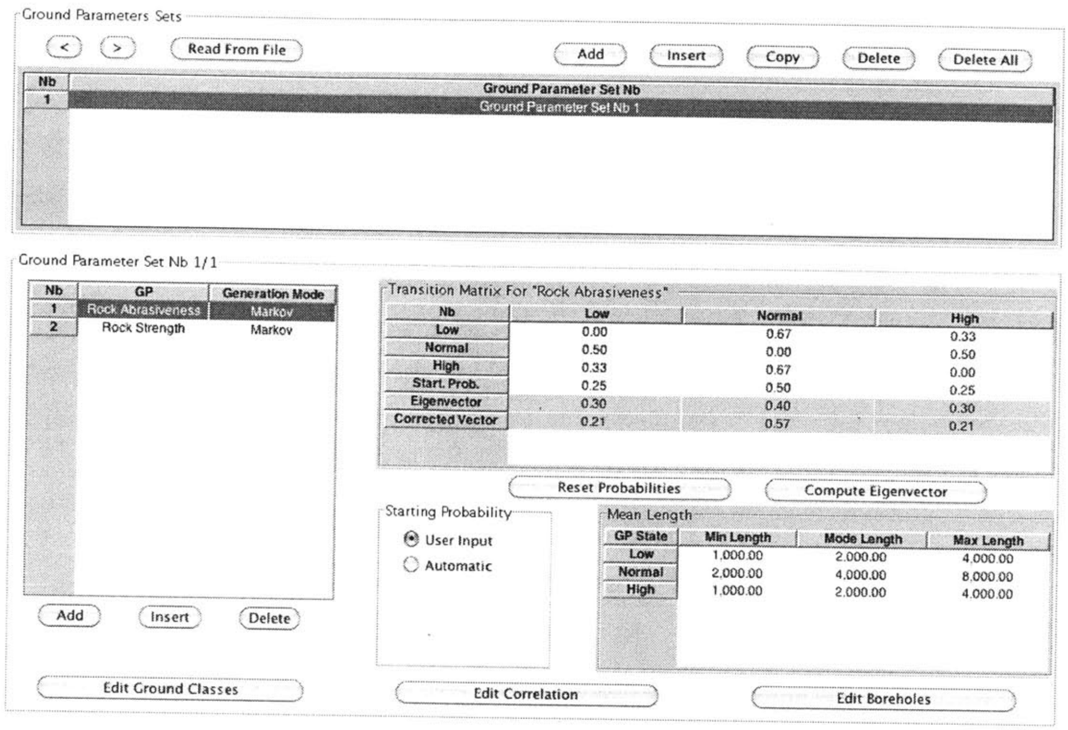


Figure 3-47: The Markov Assumptions used in the DAT Model of Geological Sensitivity

tion through a Markov model. This model creates a series of random layers, 1,000 to 8,000 feet in thickness, such that on average, the drilling region has normal rock parameters for a slight majority (56%) of its length, and high and low rock parameters for a minority (22% each) of its length (the parameters were chosen to produce a distribution close to a 50-25-25 distribution). A DAT screenshot of the Markov setup is provided in Figure 3-47.

In order to take into account geological variation, one further modification to the model is needed. In the deterministic/baseline case, as well as the component cost and trouble cost sensitivity analyses, it was sufficient to run the simulations for each construction stage with a cycle length equal to the length of the construction stage(e.g. to use a cycle length of 500 feet for the 500-foot long surface construction stages). This was possible because none of the variations being analyzed required the creation of new construction methods– the uncertainty was modeled as variation in the parameters of a given method, not a change between methods themselves.

For analyses that require the addition of new methods, it is important to set the cycle length to a small number– if the cycle length is large, then every time there is a transition between ground states, there will be a significant double counting of the cost and time requirements imposed by a method (e.g. if the ground state transitions from high strength/high abrasion to normal strength/normal abrasion, the full costs of both the high-high and normal-normal methods would be incurred). In other words, for every method used, the DAT would assume that the method was continued for the full length of its associated construction stage, when in actuality, the cost of a method should only be incurred over the length of the well section that it was actually in use. Figure 3-48 offers a reminder of how cycle length operates. If only one method is used over the course of a construction stage, the cycle length can be set to the length of the stage without risk of double counting.

To correct for this problem, we set the cycle length to a reasonably small value (in this case 1 foot). Accordingly however, we must also modify the cost and time equations of each method.

This is a simple enough modification. For each method, the cost and time are divided by the number of cycle lengths in the construction stage. So, for the Tieback Casing stage, which is performed over 4800 feet, the cost of running a single cycle of one foot is set equal to 1/4800th of the total cost of the section. Figure 3-49 shows the revised equations for the surface drilling method.

In this manner, the cost of each construction stage is the average of the costs of the methods used during the stage, weighted by the length of the construction stage in which the method was used.

Results and Discussion of the Geological Cost Variation Twenty simulations were run using the Markovian ground parameter distribution process detailed in Figure 3-47. In addition, for each ground class, an additional simulation was run, showing the results of a well construction in a drilling region comprised of only a single ground class. In Figure 3-50, the results from the 20 Markov simulations, as well as the nine deterministic scenarios are overlaid on one another, with the blue diamonds

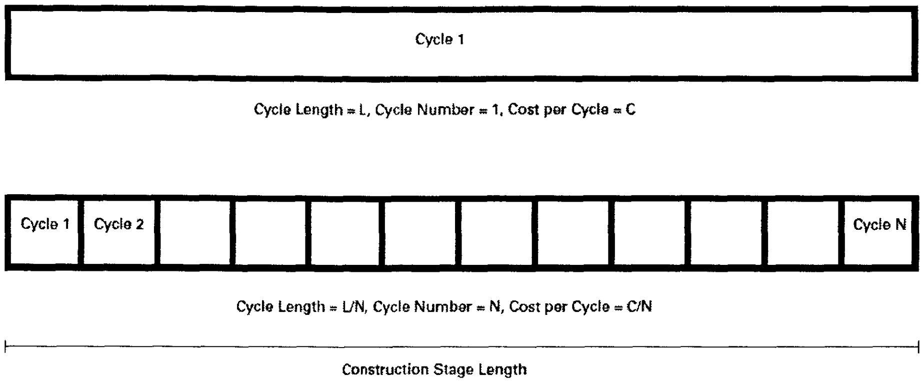


Figure 3-48: A construction stage can be performed over any number of cycles. To account for a change from a single-cycle approach to an n-cycle approach requires the cost and time equations relating to each cycle to be divided by the number of cycles.

representing deterministic simulations, and the red circles representing Markovian simulations.

Holistic Cost Variation

In constructing a holistic picture of total project risk, we combine together the three types of risk assessment that we have previously performed– namely we put together a model that has the construction method diversity of the geological sensitivity analysis, the activity additions of the trouble sensitivity analysis, and the parametric uncertainty of the component cost sensitivity analysis.

For the most part, this is a straightforward combination, as none of the three modifications to the baseline are exclusive or contradictory– it is quite possible to have a selection of methods, with an added trouble activity to each method, and simultaneously have the parameters that define the cost and time equations of each activity be probabilistically determined. However, combining the various sensitivity

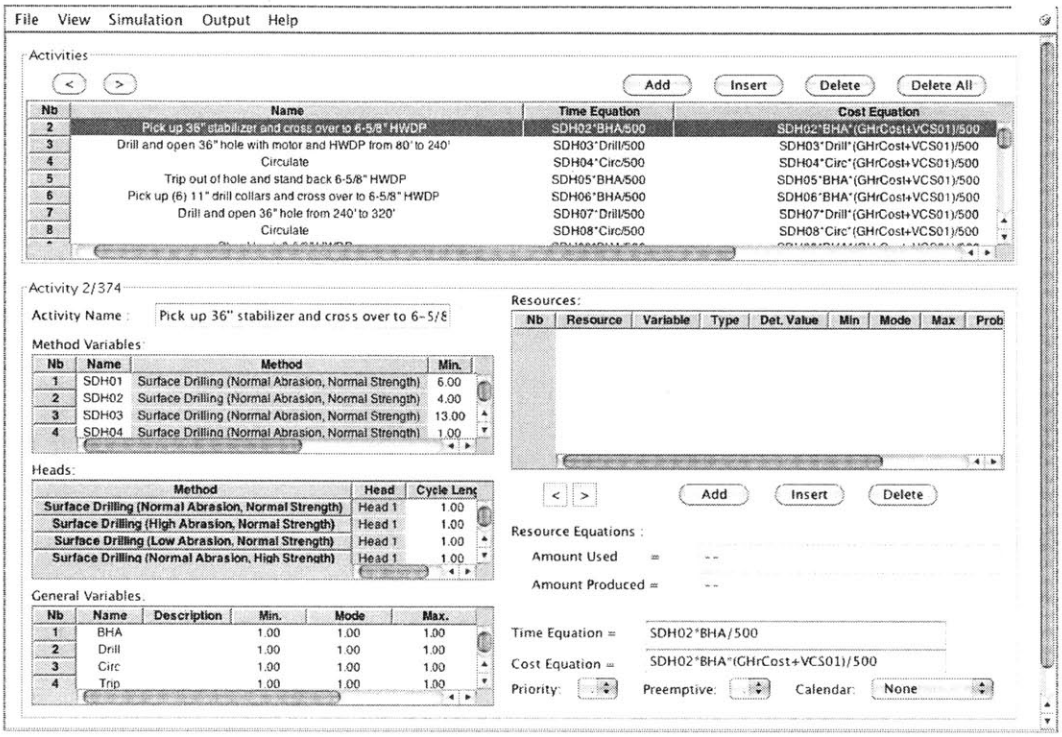


Figure 3-49: The Activity Equations of the Surface Drilling Stage, Revised for a Modified Cycle Length. A construction stage can be performed over any number of cycles. To account for a change from a single-cycle approach to an n-cycle approach requires the cost and time equations relating to each cycle to be divided by the number of cycles.

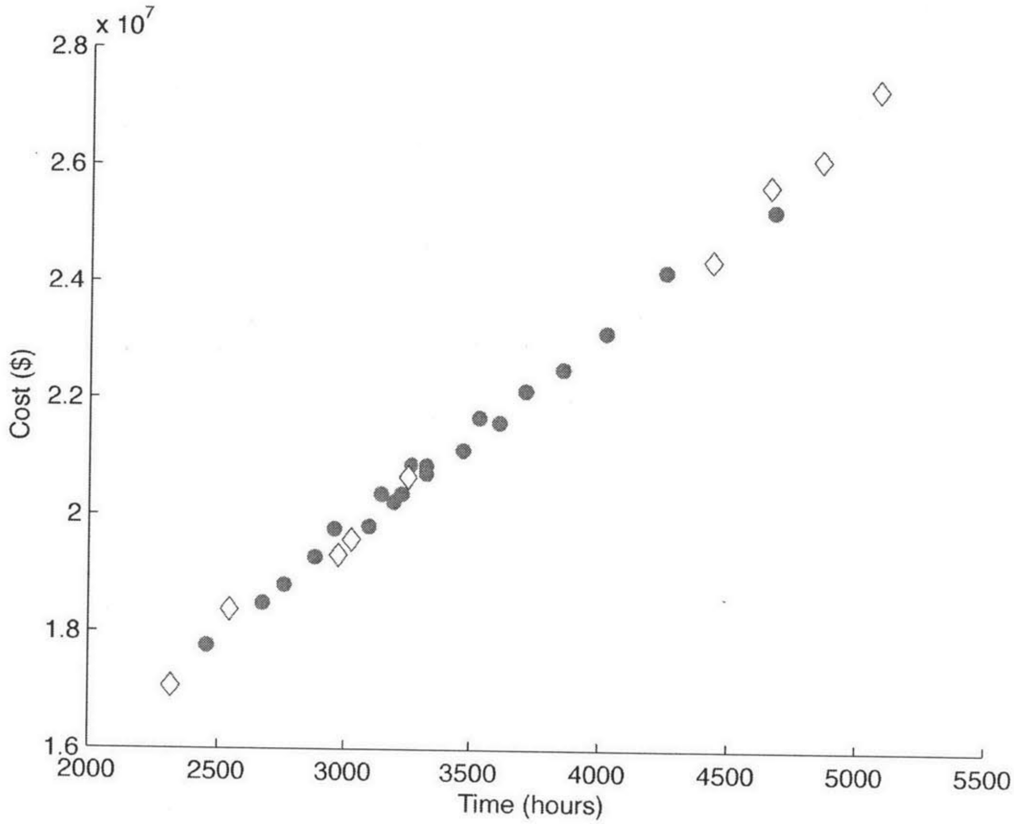


Figure 3-50: The Results of the Geological Sensitivity Analysis. 20 construction simulations (represented by the full circles), are overlaid on the nine cost-time outcomes (the hollow diamonds) that result from performing all construction stages in the same ground type. The diamonds are the results of the nine possible geologies, Low-Low, Low-Normal, Low-High, Normal-Low, etc.)

	High Strength	Average Strength	Low Strength
High Abrasion	40%	30%	20%
Average Abrasion	30%	20%	10%
Low Abrasion	20%	10%	0%

Table 3.17: The assumed probability of encountering a trouble event for constructing the entire Sandia Well in each of the ground classes.

analyses into a complete project risk assessment still requires a few steps in order to make the various techniques fit together.

The first addition that is necessary is to model the interaction between trouble events and geology. One way to do this would be to define one or more new ground parameter states that correlate with frequency of trouble events; many types of trouble are highly correlated with lithological factors such as porosity. For simplicity, we use the ground parameter states that are already defined.

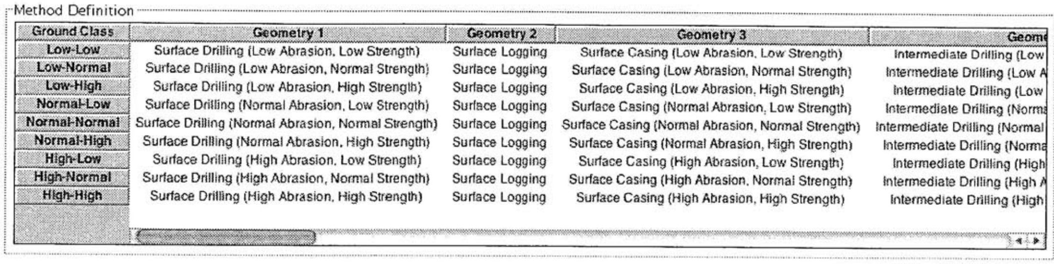
In the baseline scenario, the probability of trouble events in each stage was constructed so that the probability of an event in each stage was proportional to the time spent on each stage, and the total project-wide probability of a trouble event occurring was 20%. For the eight different ground states that were modeled in the geological sensitivity stage, we perform the exact same construction, with a minor modification for each ground type, the probability of a trouble event in each stage is normalized to create a different total project risk. A summary of the trouble probabilities assumed under each geological profile is provided in Table 3.17. This process yields the parametrizations for the distributions on the trouble cost activity for each method as described in Table 3.18.

In the trouble sensitivity analysis, trouble costs are assumed to be proportional to trouble delays, with the trouble cost equal to the trouble delay multiplied by the hourly cost of the construction stage.

As is apparent from Table 3.18, creating a trouble-geology linkage necessitates the creation of new methods for each casing stage, much in the same way the addition of geological uncertainty necessitated the creation of new methods for each affected drilling stage. For each unique parametrization of the trouble event activity, we create

Low-Low				Low-Normal			Low-High		
Const. Stage	Prob.	Modal Delay	Max Delay	Prob.	Modal Delay	Max Delay	Prob.	Modal Delay	Max Delay
Surf. Drilling	100%	N/A	N/A	99.68%	28.67	129.00	99.37%	40.33	181.50
Surf. Casing	100%	N/A	N/A	99.69%	42.50	255.00	99.56%	42.50	255.00
Int. Drilling	100%	N/A	N/A	98.63%	124.33	559.50	96.54%	224.33	1009.50
Int. Casing	100%	N/A	N/A	99.50%	67.50	405.00	99.30%	67.50	405.00
Prod. 1 Drill	100%	N/A	N/A	98.65%	123.00	553.50	96.65%	216.67	975.00
Prod. 1 Casing	100%	N/A	N/A	99.49%	69.00	414.00	99.28%	69.00	414.00
Prod. 2 Drill	100%	N/A	N/A	97.38%	239.33	1077.00	93.62%	419.67	1888.50
Prod. 2 Casing	100%	N/A	N/A	99.58%	56.50	339.00	99.41%	56.50	339.00
Prod. 3 Drill	100%	N/A	N/A	98.59%	128.00	576.00	96.72%	212.00	954.00
Prod. 3 Casing	100%	N/A	N/A	99.19%	109.50	657.00	98.86%	109.50	657.00
Tieback Casing	100%	N/A	N/A	99.15%	115.00	690.00	98.80%	115.00	690.00
Normal-Low				Normal-Normal			Normal-High		
Surf. Drilling	99.70%	22.83	102.75	99.38%	28.67	129.00	99.04%	40.33	181.50
Surf. Casing	99.62%	42.50	255.00	99.38%	42.50	255.00	99.33%	42.50	255.00
Int. Drilling	98.96%	78.33	352.50	97.24%	128.33	577.50	94.70%	228.33	1027.50
Int. Casing	99.40%	67.50	405.00	99.02%	67.50	405.00	98.93%	67.50	405.00
Prod. 1 Drill	98.89%	83.50	375.75	97.20%	130.33	586.50	94.79%	224.00	1008.00
Prod. 1 Casing	99.39%	69.00	414.00	99.00%	69.00	414.00	98.91%	69.00	414.00
Prod. 2 Drill	97.59%	183.17	824.25	94.22%	273.33	1230.00	89.74%	453.67	2041.50
Prod. 2 Casing	99.50%	56.50	339.00	99.18%	56.50	339.00	99.10%	56.50	339.00
Prod. 3 Drill	98.47%	115.33	519.00	96.63%	157.33	708.00	94.40%	241.33	1086.00
Prod. 3 Casing	99.03%	109.50	657.00	98.42%	109.50	657.00	98.27%	109.50	657.00
Tieback Casing	98.98%	115.00	690.00	98.34%	115.00	690.00	98.19%	115.00	690.00
High-Low				High-Normal			High-High		
Surf. Drilling	99.41%	24.83	111.75	99.07%	30.67	138.00	98.69%	42.33	190.50
Surf. Casing	99.32%	42.50	255.00	99.14%	42.50	255.00	99.12%	42.50	255.00
Int. Drilling	97.83%	91.67	412.50	95.77%	141.67	637.50	92.74%	241.67	1087.50
Int. Casing	98.93%	67.50	405.00	98.64%	67.50	405.00	98.61%	67.50	405.00
Prod. 1 Drill	97.48%	106.83	975.00	95.42%	153.67	619.50	92.58%	247.33	1113.00
Prod. 1 Casing	98.91%	69.00	414.00	98.61%	69.00	414.00	98.58%	69.00	414.00
Prod. 2 Drill	94.65%	229.83	1888.50	90.69%	320.00	1440.00	85.55%	500.33	2251.50
Prod. 2 Casing	99.10%	56.50	339.00	98.86%	56.50	339.00	98.83%	56.50	339.00
Prod. 3 Drill	95.94%	173.33	954.00	93.64%	215.33	969.00	91.09%	299.33	1347.00
Prod. 3 Casing	98.27%	109.50	657.00	97.80%	109.50	657.00	97.75%	109.50	657.00
Tieback Casing	98.18%	115.00	690.00	97.69%	115.00	690.00	97.64%	115.00	690.00

Table 3.18: The full set of parameters for the triangular distribution on each trouble activity schedule distribution for each possible geology. The Prob. columns represent the probability that there will be no incident during that construction stage, while the modal and max delay columns indicate the most likely and maximum number of hours spent recovering from a trouble event in that construction stage and geology. The probability of a trouble event occuring in any single stage is low, never going above 15%, even in the most extreme case. However, the cumulative probability of a trouble event– that is to say the probability of a trouble event occurring during the course of the entire project remains high, varying between 0 and 40% depending upon geology. The parameters for trouble events in the logging stages are not listed, as it is assumed that trouble will not occur in any logging stage. In the low-low scenario, trouble events do not occur.



Method Definition

Ground Class	Geometry 1	Geometry 2	Geometry 3	Geome
Low-Low	Surface Drilling (Low Abrasion, Low Strength)	Surface Logging	Surface Casing (Low Abrasion, Low Strength)	Intermediate Drilling (Low
Low-Normal	Surface Drilling (Low Abrasion, Normal Strength)	Surface Logging	Surface Casing (Low Abrasion, Normal Strength)	Intermediate Drilling (Low A
Low-High	Surface Drilling (Low Abrasion, High Strength)	Surface Logging	Surface Casing (Low Abrasion, High Strength)	Intermediate Drilling (Low
Normal-Low	Surface Drilling (Normal Abrasion, Low Strength)	Surface Logging	Surface Casing (Normal Abrasion, Low Strength)	Intermediate Drilling (Norma
Normal-Normal	Surface Drilling (Normal Abrasion, Normal Strength)	Surface Logging	Surface Casing (Normal Abrasion, Normal Strength)	Intermediate Drilling (Normal
Normal-High	Surface Drilling (Normal Abrasion, High Strength)	Surface Logging	Surface Casing (Normal Abrasion, High Strength)	Intermediate Drilling (Norma
High-Low	Surface Drilling (High Abrasion, Low Strength)	Surface Logging	Surface Casing (High Abrasion, Low Strength)	Intermediate Drilling (High
High-Normal	Surface Drilling (High Abrasion, Normal Strength)	Surface Logging	Surface Casing (High Abrasion, Normal Strength)	Intermediate Drilling (High A
High-High	Surface Drilling (High Abrasion, High Strength)	Surface Logging	Surface Casing (High Abrasion, High Strength)	Intermediate Drilling (High

Figure 3-51: Screenshot of the DAT's method selection screen. For each of the nine different possible ground classes, there is a unique construction method associated with each drilling and casing stage. The drilling methods differ in their estimation of the time required to perform drilling activities, the number included tripping and equipment replacement activities, and the parameters of their trouble event activities. The casing methods differ only in their trouble event activity parameters. This figure can be contrasted with the method selection screen shown in Figure 3-46

a new casing method that is otherwise identical to the baseline method, but uses a different parametrization on its trouble event activity. Figure 3-51 displays a subset of the new method selection process.

As was the case with the geological sensitivity analysis, the ground class is used to select between methods, and the selection is straightforward: for example, a ground class of high rock strength and normal abrasiveness selects for the casing method that parametrizes its trouble event activity for a high-strength, normal-abrasiveness geology, as per Table 3.18.

Besides the creation of these new construction methods and their related method selection rules, the holistic project risk model is a fairly predictable combination of the previous sensitivity analyses. All of the general cost variables (fixed component costs, hourly costs, etc) have distributions taken from the component cost sensitivity section– specifcially, we use the distributions provided in Table 3.10. Figure 3-52, a screen shot of the DAT's general variable window, is included for reference. A method has an associated trouble activity (with the cost and time distribution of that activity described in Table 3.18), and finally, each drilling method has a different activity method and scheduled drilling times, depending on the ground parameters. The ground parameters themselves are selected using the same Markovian approach, detailed in Figure 3-47.

General Variables

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Nb	Name	Description	Min.	Mode	Max.	Prob. Min.	Prob. Max.
11	FCS01		3,367.28	25,000.00	46,632.72	0.00	0.00
12	FCS02		0.00	122,000.00	466,880.01	0.29	0.00
13	FCS03		0.00	80,000.00	169,368.66	0.05	0.00
14	FCS04		125,145.45	150,000.00	174,854.55	0.00	0.00
15	FCS05		119,930.43	202,500.00	321,069.57	0.00	0.00
16	FCS06		0.00	20,000.00	48,166.72	0.14	0.00
17	FCI01		0.00	85,000.00	179,954.21	0.05	0.00
18	FCI02		792,587.85	950,000.00	1.107,412.15	0.00	0.00
19	FCI03		656,952.22	1,207,850.00	1,758,747.78	0.00	0.00
20	FCP101		0.00	50,000.00	105,855.42	0.05	0.00
21	FCP102		937,089.13	1,123,200.00	1,309,310.87	0.00	0.00
22	FCP103		17,707.70	45,000.00	72,292.30	0.00	0.00
23	FCP104		388,563.70	714,400.00	1,040,236.30	0.00	0.00
24	FCP201		0.00	25,000.00	52,927.71	0.05	0.00
25	FCP202		588,684.20	705,600.00	822,515.80	0.00	0.00
26	FCP203		13,772.66	35,000.00	56,227.34	0.00	0.00
27	FCP204		300,233.99	552,000.00	803,766.01	0.00	0.00
28	FCP301		0.00	16,000.00	33.873.73	0.05	0.00
29	FCP302		181,544.33	217,600.00	253,655.67	0.00	0.00
30	FCP303		9.837.61	25,000.00	40.162.39	0.00	0.00
31	FCP304		183,267.83	336,950.00	490.632.17	0.00	0.00
32	FCT01		941,093.79	1.128,000.00	1,314,906.21	0.00	0.00
33	FCT02		348,206.16	640,200.00	932.193.84	0.00	0.00
34	FCT03		0.00	10,000.00	24.083.37	0.14	0.00
35	FCT04		0.00	35,000.00	84.291.77	0.14	0.00
36	FCT05		0.00	12,000.00	28.900.03	0.14	0.00
37	FCG01		3.935.04	10,000.00	16.064.96	0.00	0.00
38	FCG02		49,188.06	125,000.00	200.811.94	0.00	0.00
39	FCG03		4,722.05	12,000.00	19.277.95	0.00	0.00
40	VCS01		0.00	215.29	492.84	0.11	0.00
41	VCI01		0.00	383.92	878.86	0.11	0.00
42	VCP101		0.00	280.66	642.48	0.11	0.00
43	VCP201		0.00	131.65	301.37	0.11	0.00
44	VCP301		0.00	56.89	130.24	0.11	0.00
45	GHrCost		2.102.85	3.196.40	4.289.95	0.00	0.00

Figure 3-52: Screenshot of the DAT's general variables screen for the holistic sensitivity analysis. It shows the distributions on each of the variables that feed into the model's cost equations. The holistic sensitivity analysis uses the truncated normal distribution introduced in Figure 3-31; accordingly, some of the triangular distributions used by the general variables have their minimums at zero, and non-zero probabilities of those minima occurring.

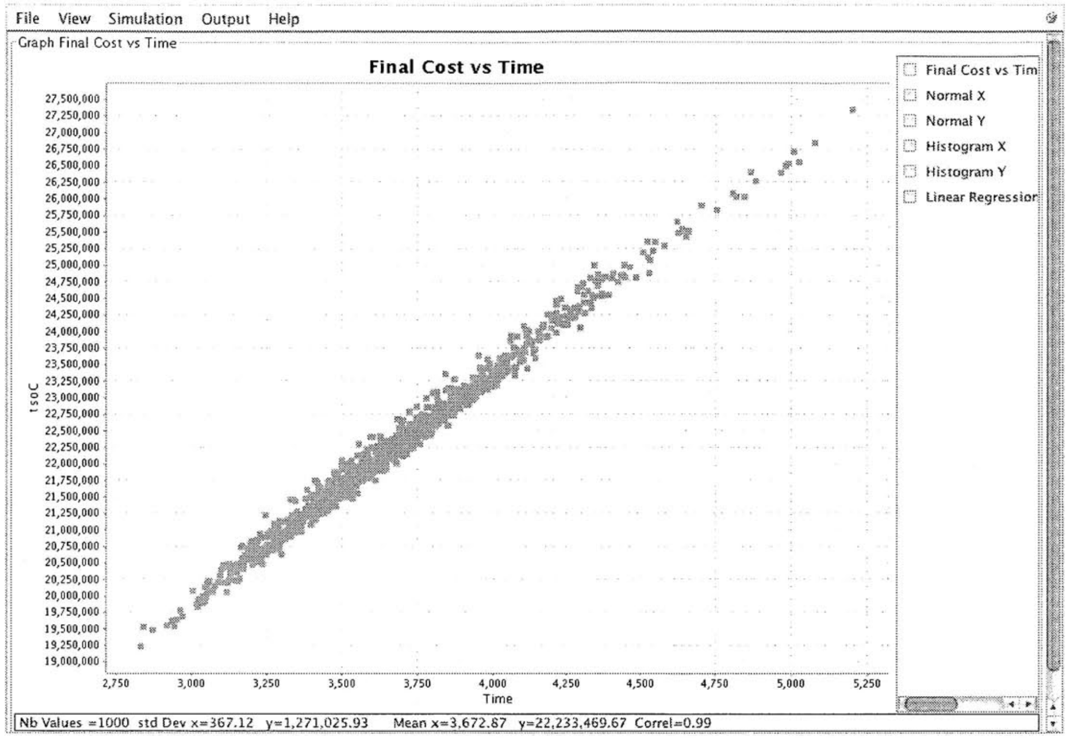

Figure 3-53: Holistic Sensitivity Analysis Results. 1000 construction simulations were performed, taking into account component cost uncertainty, trouble events, and geological variation. Figure 3-53 is a screenshot of the DAT output– as can be expected, there is a strong correlation between cost and time in the outcomes, and the results vary widely from the deterministic, baseline scenario.

Results and Discussion of the Holistic Cost Variation 1000 simulations were performed using the updated model. The results are shown in Figure 3-53.

Conclusions from Sensitivity Analysis

We have modeled three different types of project risk: component cost uncertainty, unforeseen ("trouble") events, and geological variation. In all of these scenarios, the DAT have succeeded at simulating the cost and schedule consequences of these project risks. However, there are many other forms of project risk that could be included, as well as different variations on the forms of project risk that have been modeled. Because the ultimate goal is to demonstrate the DAT, it is important to dsicuss whether or not the experience of modeling these forms of project risk suggest that the DAT will be capable of modeling other, more complicated forms of risk.

We conclude that the DAT are well-suited to geothermal applications. The three methods that we employed to model variability give the user a wide array of approaches in defining project risk. The user can introduce uncertainty into the parameters of the DAT's cost and time equations themselves, they can introduce new cost and time equations to deal with specific uncertainties, and they can define entirely new sets of cost and time equations and probabilistically assign which sets of equations are used. In total, these layers of modeling tools provide the user with an easy means of describing specific forms of project risk, but also for combining different risks together with minimal effort.

In addition, the DAT are very input flexible. The Monte-Carlo-based approach and range of probabilistic distributions makes it easy to incorporate many different estimation sources, ranging from expert solicitation to empirical or historical analysis. This flexibility allows users to substitute their own estimates into given models, and ensures that the DAT will not be outdated as future cost and time estimates are refined by better evidence. It also suggests that the DAT would be a suitable component in a broader, Bayesian project management tool.

Chapter 4

Results

In summary, seven different cases were modeled:

1. A synthetic, top down, simple case with a generalized form of cost and schedule variation (See Figure 4-1)

2. An example-based, bottoms-up, detailed case with no variation (See Figure 4-2)

3. An example-based, bottoms-up, detailed case with empirically-derived component cost variation (See Figure 4-3)

4. An example-based, bottoms-up, detailed case with expert-derived component cost variation (See Figure 4-4)

5. An example-based, bottoms-up, detailed case with trouble-event-based cost and schedule variation (See Figure 4-5)

6. An example-based, bottoms-up, detailed case with geologic-uncertainty-based cost and schedule variation (See Figure 4-6)

7. An example-based, bottoms-up, detailed case with multiple forms of cost and schedule variation (See Figure 4-7)

The DAT proved capable of modeling the full extent of desired variability in each scenario.

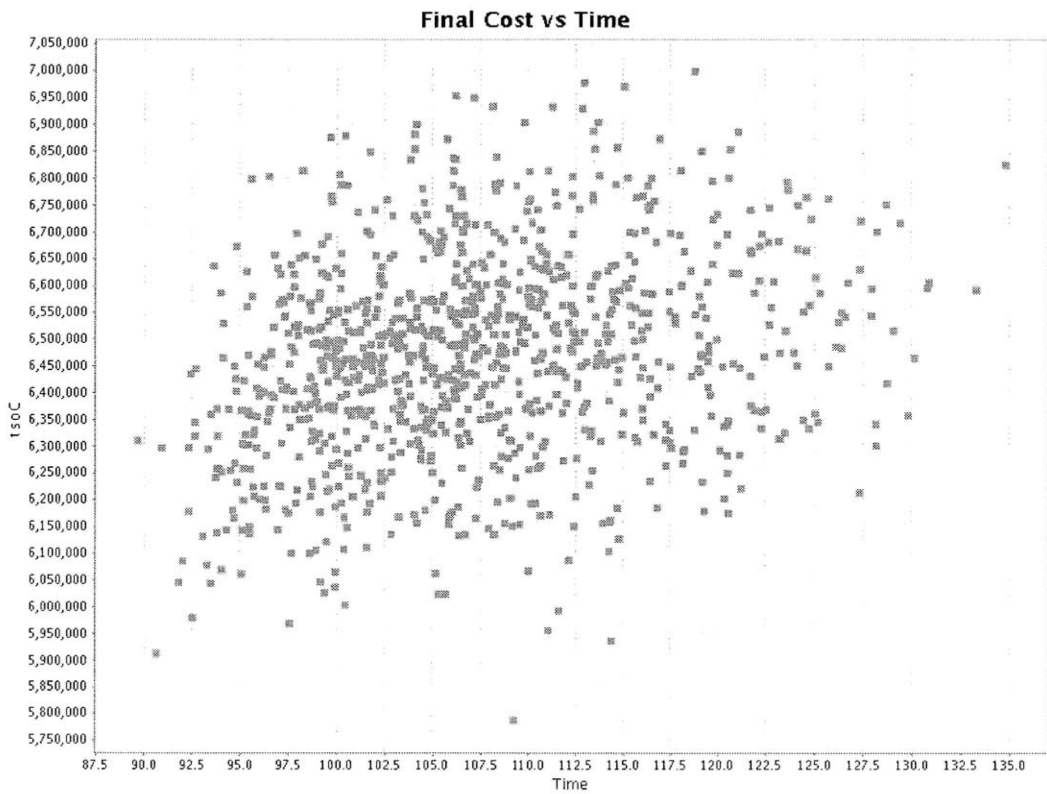

Figure 4-1: 200 simulated results from the synthetic case. The project cost and time show a relatively weak correlation, which reflects the assumptions made in modeling.

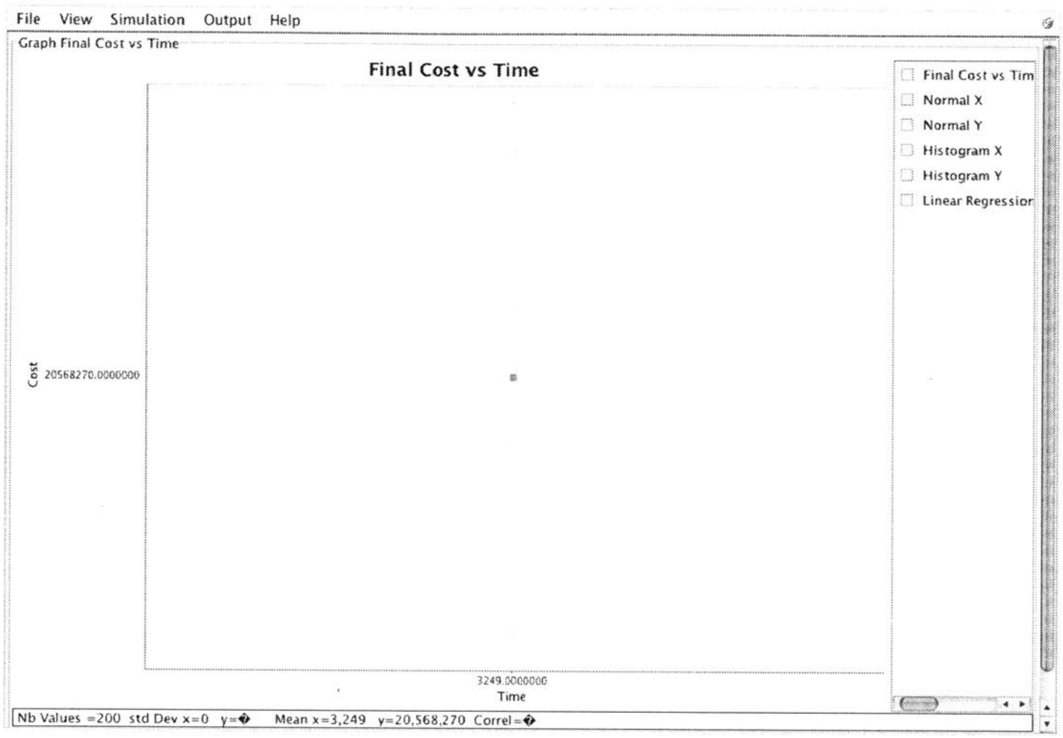

Figure 4-2: The simulated result from the deterministic Sandia Case. As this is a deterministic case, the outcome is a reflection of the baseline estimates that were put into the model, a strict totalling of the number of hours spent in construction, the estimated cost per hour in each stage, and the various labor and materials costs.

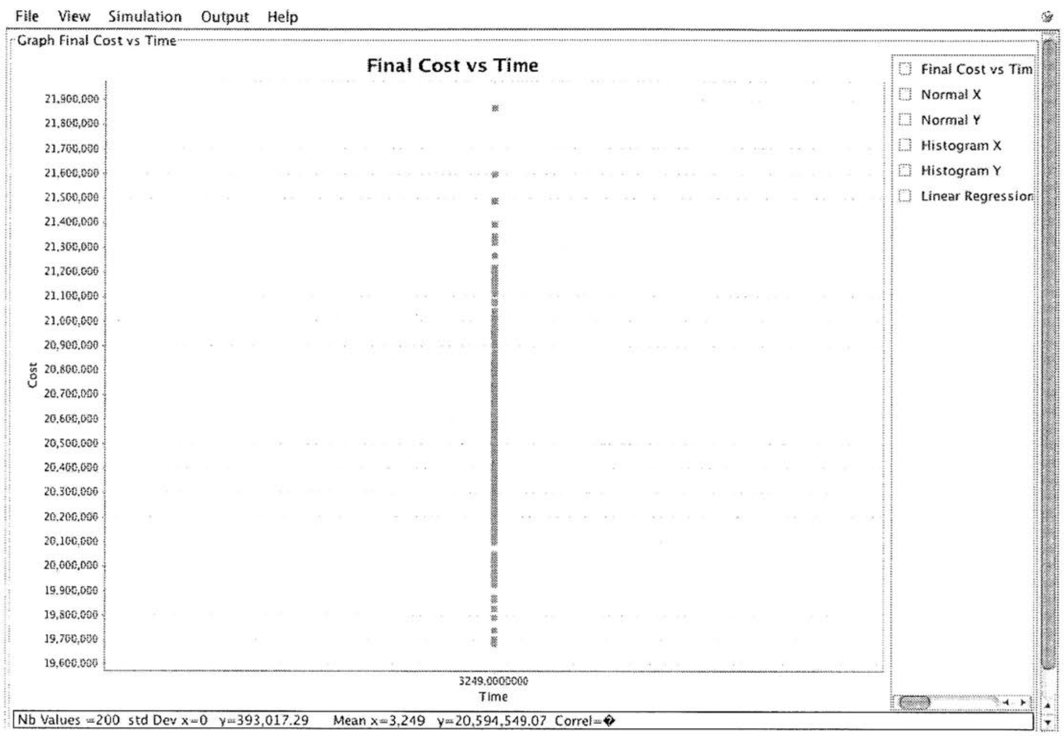

Figure 4-3: 200 simulated results from the Sandia Case component cost sensitivity analysis (normal uncertainty). This sensitivity analysis, using the DAT's parameter distributions, demonstrates the DAT's ability to approximate new probabilistic distributions using a set of available distributions, as well as the DAT's ability to make use of objective, empirical data as inputs into the model. Here the DAT take empirically estimated values of project cost component variation, and use it to approximate a normal distribution on those costs. As the price of labor and materials do not affect project schedule, the results are invariate in this regard.

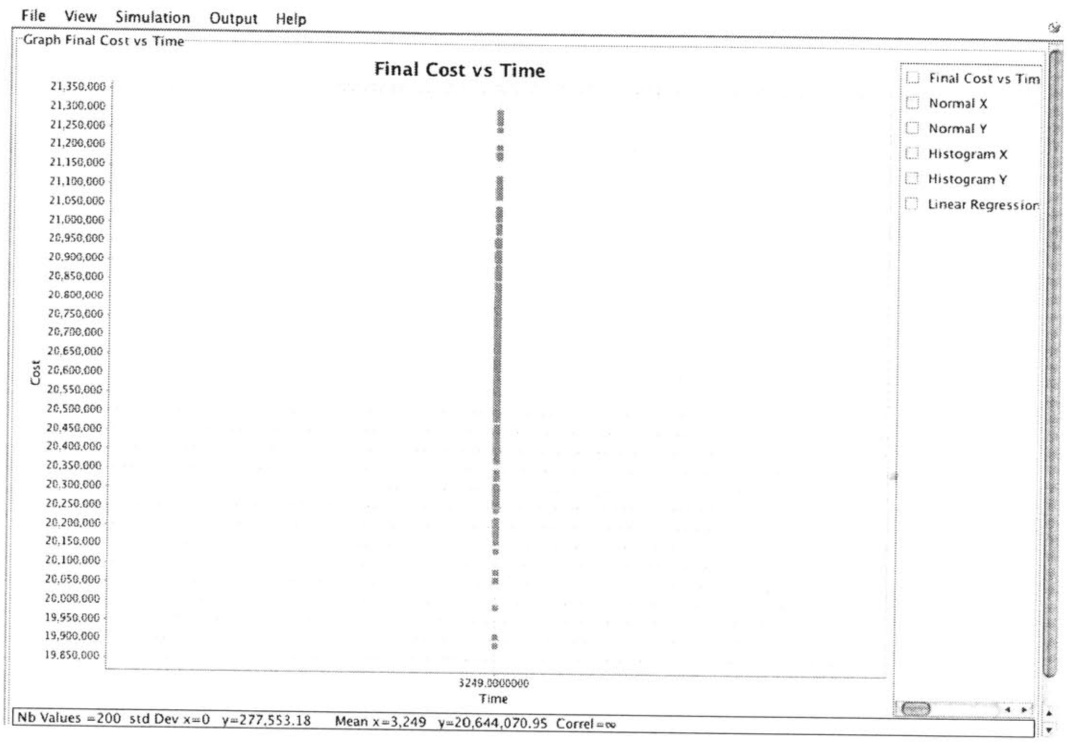

Figure 4-4: 200 simulated results from the Sandia Case component cost sensitivity analysis (lognormal uncertainty). This sensitivity analysis, using the DAT's parameter distributions, demonstrates the DAT's ability to make use of subjective, expert-solicited estimates as inputs into the model. Here, previous estimates of component cost uncertainty were used to postulate possible expert estimations of the minimum, mode, and maximum component costs, and these estimates were then used as the basis for probabilistic distributions on those costs. As the price of labor and materials do not affect project schedule, the results are invariate in this regard.

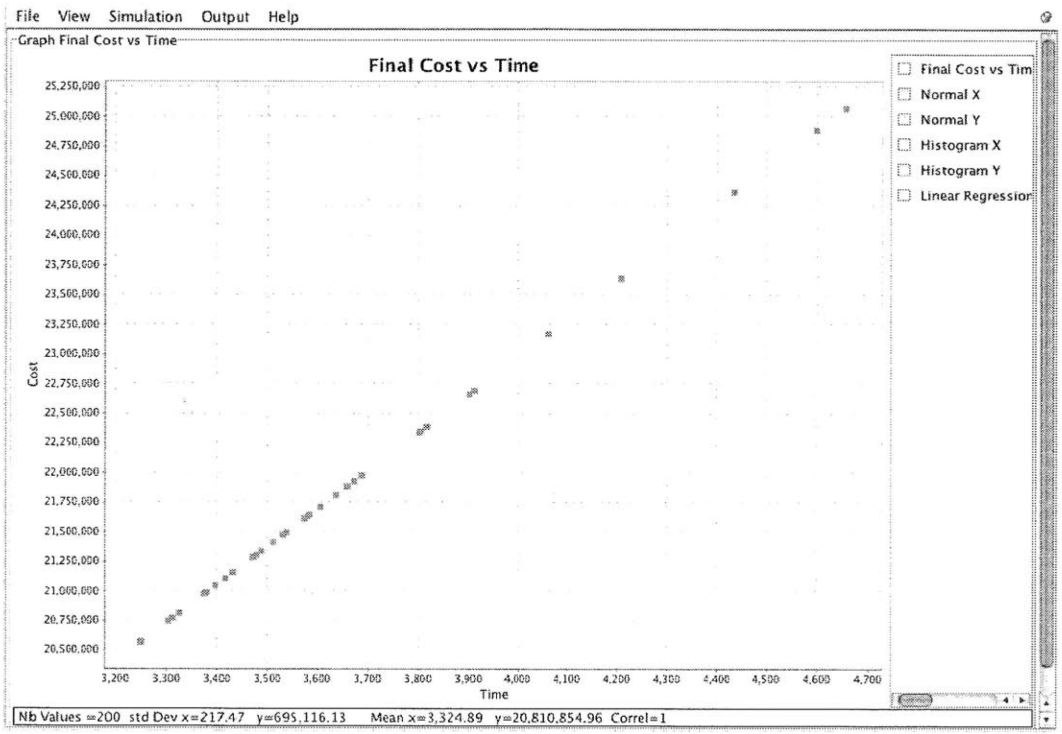

Figure 4-5: 200 simulated results from the Sandia Case trouble event sensitivity analysis. This sensitivity analysis, using activity additions, demonstrates the ability of the DAT to model common trouble events, such as drill pipe stickage, casing failure, and so on.

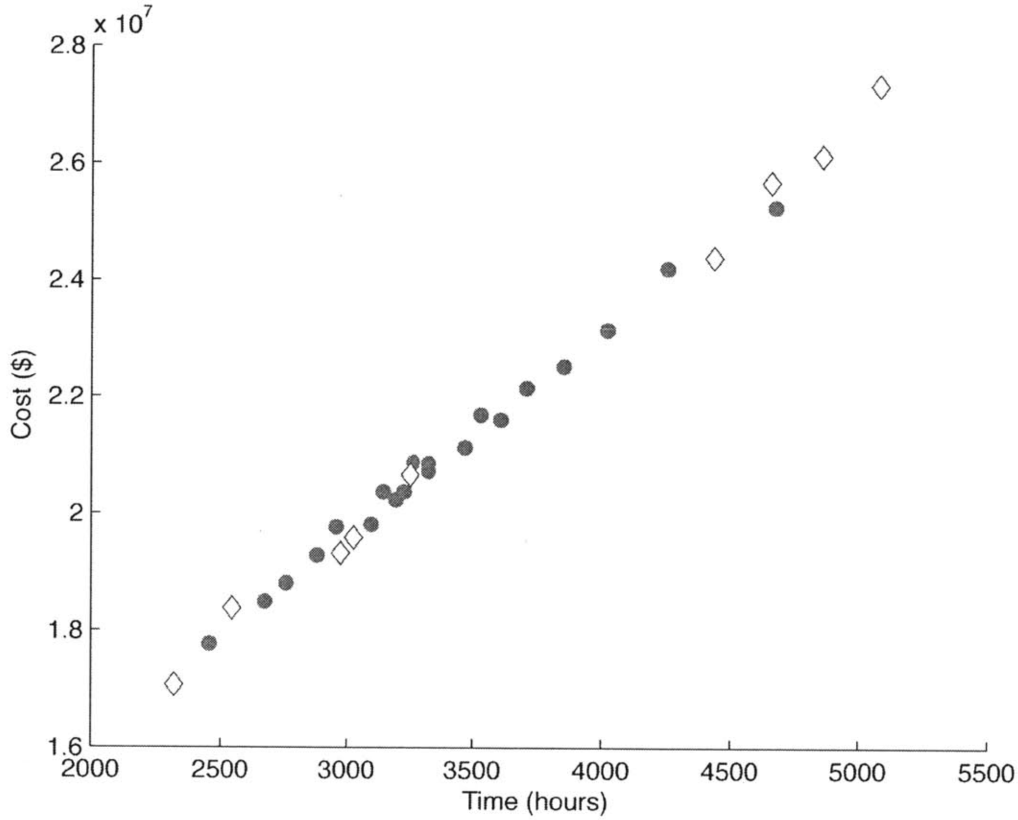

Figure 4-6: 200 simulated results from the Sandia Case geological sensitivity analysis. This sensitivity analysis, using method additions, demonstrates the ability of the DAT to model common effects of geological variability. The diamond symbols represent the nine 'pure' geological cases, where the entire drilling area consists of a single, constant ground class (there are nine diamonds, one for each of the nine ground classes, such as Low-Low, Low-Normal, Low-High, Normal-Low, etc). The circles represent hybrid cases produced probabilistically using Markov methods.

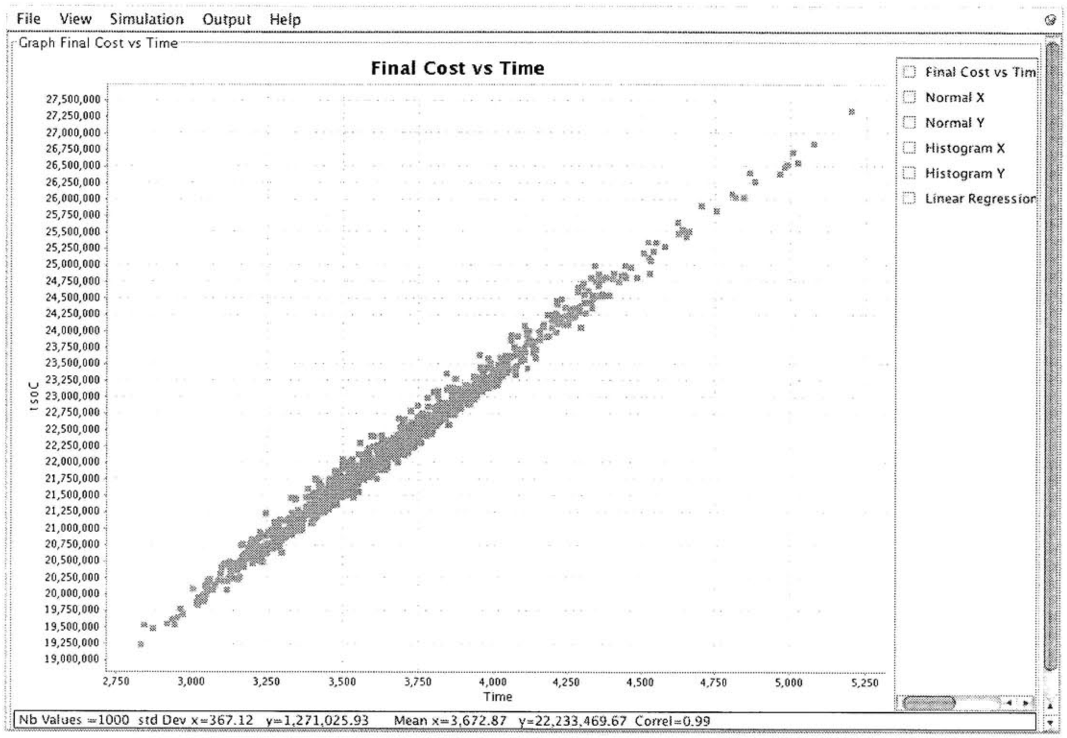

Figure 4-7: 2000 simulated results from the Sandia Case holistic sensitivity analysis. This sensitivity analysis demonstrates the ability of the DAT to integrate multiple forms of project risk

Chapter 5

Discussion

Having put the DAT through its paces, it is now worthwhile to make an assessment of the program, both as a stand-alone tool for EGS cost and schedule estimation, as well as a component in a broader, integrated suite of tools.

5.1 Interoperability of the DAT With Other Programs

If the DAT are to be used as a subcomponent within a larger decision analysis tool for enhanced geothermal systems, the input and output of the program need to be not only correct in terms of content, but also be of a format that is usable by other programs.

From a content perpective, the DAT provide an important piece of functionality– they take a set of well design choices, geological information, and other parameters and turn it into a cost and schedule estimation for the entire project. Furthermore, many of the components of the DAT are separable– the generation of the geology and ground state parameters is distinct from the depiction of the well construction activities, which are in turn distinct from the generation of the cost parameters, and so on, so as the project advances and activities are performed, the site geology better characterized, or the cost parameters realized, it is possible to update a DAT model

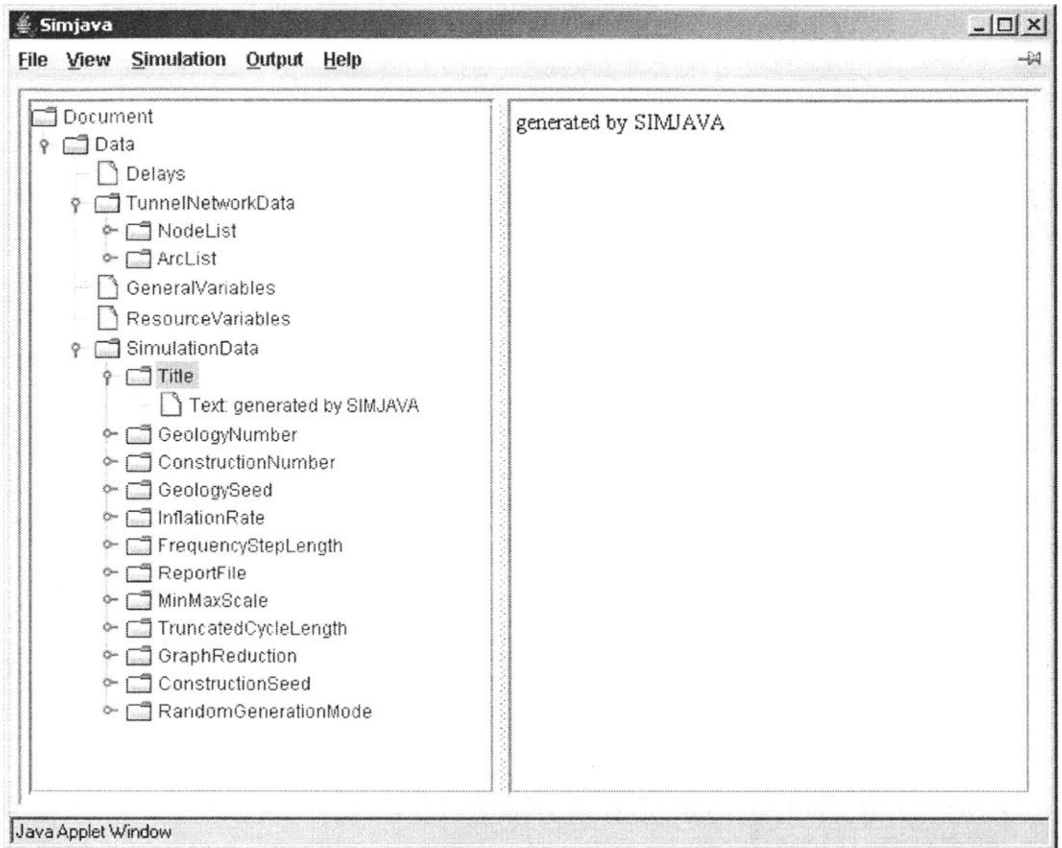

Figure 5-1: Screenshot of the DAT's XML save screen. It shows the various types of information that can be saved in an alternate format. The user has the option of saving almost all of the DAT's outputs in both Excel and XML forms.

to reflect this new information and thus update the cost and schedule predictions that the DAT provides.

From a format perspective, the DAT is also quite suitable. Many of the DAT's input and output files can be given in XML or Excel format, which are convenient formats for other programs to read. This should make it possible for the DAT to be integrated with a set of other tools to create a single, streamlined program. Work is being done to improve the functionality of Excel and XML I/O transfers and document it more fully. Figure 5-1 shows the various parts of a DAT model that can be saved as XML files.

5.2 DAT Input Flexibility

The DAT, in many ways, are like a blank slate. They make no assumptions about site geology, the well structure, construction methods, or even the cost and time requirements of construction activities, and instead leave the characterization of these to the user. Because of this, the DAT are compatible with a range of estimation techniques. As our example cases and analyses have demonstrated, both top-down and bottoms-up estimation are possible, and estimates can be gathered from both expert solicitation as well as empirical or historical sources. The traditional downside of allowing new assumptions to be input with each project is that it requires fresh input every time a new project is undertaken. However, in this case the separability of the DAT's different components makes it easy to develop preset geological profiles, parameter estimations, and so on. For a new project, it should be possible to load preset information from a database or past expert solicitation. As more experience with geothermal projects is gained, these presets will have more data to rely upon and offer a reliable, standardized set of beliefs to inform future projects as well as update older projects. These beliefs can be stored as Excel files and used repeatedly by users. In particular, the following presets are useful:

1. Sets of ground state parameters and associated distributions that reflect the state of knowledge about a region's geology, without site-specific exploration.

2. Sets of ground state parameters and associated distributions that reflect the state of knowledge about a region's geology, updated for various possible site-specific exploration results.

3. Sets of cost and time equations for common drilling technologies.

4. Estimates of common component costs (labor, materials, and so on), updated for inflation.

5. Common well construction profiles.

These presets can be used to estimate the baseline costs of a variety of EGS drilling projects in a variety of geologies, updated for site-specific conditions, and form the foundation for more customized DAT models.

5.3 The range of DAT modelling capabilities

The DAT offer two primary means of reflecting uncertainty:

1. Variation in the parameters that are used in a model's cost and time equations.

2. Variation in the cost and time equations that are used.

The first type of variation can be performed with a range of parameter probability distributions, including uniform, triangular, bounded triangular, and lognormal. The second type of variation is expressed through method selection. Variability in method selection can be direct, by assigning different probabilities to different methods, or indirect, through a probabilistic distribution of ground states and a linking between ground states and construction methods.

We demonstrated the DAT's ability to handle different types of project risk by using three different methods of DAT modelling (probabilistic distributions on existing parameters, the creation of new parameters specifically for uncertainty accounting, and variation of construction methods) to analyze three forms of risk (component cost variation, trouble events, and geological uncertainty). Ultimately, the basis of these demonstrations was not to determine whether or not the DAT are capable of modelling those specific forms of project risk under the specific set of assumptions that were used, but instead the purpose was to make a qualified inference as to whether the DAT are capable of handling all of the forms of project risk of relevance in a geothermal well drilling scenario.

There are areas of potential improvement for the DAT. These include: adding new probability distributions (both to ground state parameters as well as method and general variables), introducing position-dependent probability distributions (so that depth-related parameters can be more easily modeled), and improving the ability to create correlated and covariant parameters. However, these improvements are not of critical importance; not only are the existing tools apt for the modelling task (lognormal and triangular distributions are realistic approximations of our experience with well cost and time requirements), but many of the more sophisticated tools that can be added to the DAT can be replicated from the existing capabilities: depth-dependency, for example, can be created by having distinct methods for discrete depth ranges, and assigning different equations or parameters to each depth range. Covariance and correlation can be created by introducing new parameters– if the end goal is to have two correlated parameters, this can be accomplished with three parameters, a, b, and c, where a and c define the value of one parameter while b and c define the other.

Moreover, the primary limitation in well cost estimation is not a dearth of modelling options, but rather a dearth of data with which to inform estimates. It does not matter whether or not a tool is capable of both top-down and bottom-up estimation if there is only sufficient information to perform a top-down estimate– similarly, the DAT's functionality currently exceeds our ability to use that functionality effectively.

As it stands, the blank slate nature of the DAT means that virtually all conceivable sources of project risk can be assessed using the program. Not only are the terms in a DAT model's cost and time equations equipped with a healthy range of distribution options, but the very equations themselves can be probabilistically determined– these layers of randomness mean that the DAT is highly configurable. Although it may require some thought to model various types of risk, we find it hard to conceive of risks that could not be accounted for.

5.4 Conclusions

We conclude that the DAT are sufficient for the purposes of geothermal cost and time estimation, and recommend that future work on improving the DAT be focused on improving ease of use: developing presets that reflect a current state of knowledge about geothermal projects, introducing new variable types and templates that integrate smoothly with the project management standards and modelling needs that will be developed as the field grows, and ensuring that the input and output options of the DAT make it interoperable with other decision analysis tools as they appear.

Chapter 6

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Appendix A

Glossary

The intent of this glossary is to explain the well drilling terms used in the main report. Many of the definitions have been taken from Schluberger's Oilfield Glossary, a leading glossary of well drilling technology [Schlumberger].

abandonment costs

The costs associated with abandoning a well or production facility. Such costs typically cover the plugging of wells; removal of well equipment, production tanks and associated installations; and surface remediation.

abnormal events

A term to indicate features in seismic data other than reflections, including events such as diffractions, multiples, refractions and surface waves. Although the term suggests that such events are not common, they often occur in seismic data.

abnormal pressure

A subsurface condition in which the pore pressure of a geologic formation exceeds or is less than the expected, or normal, formation pressure. Abnormally high formation pressures are largely caused by trapped fluid. Excess pressure, called overpressure or geopressure, can cause a well to blowout or become uncontrollable during drilling. Severe underpressure can cause the drillpipe to stick to the underpressured formation.

abrasion test

A laboratory test to evaluate material for potential abrasiveness. The test mea-

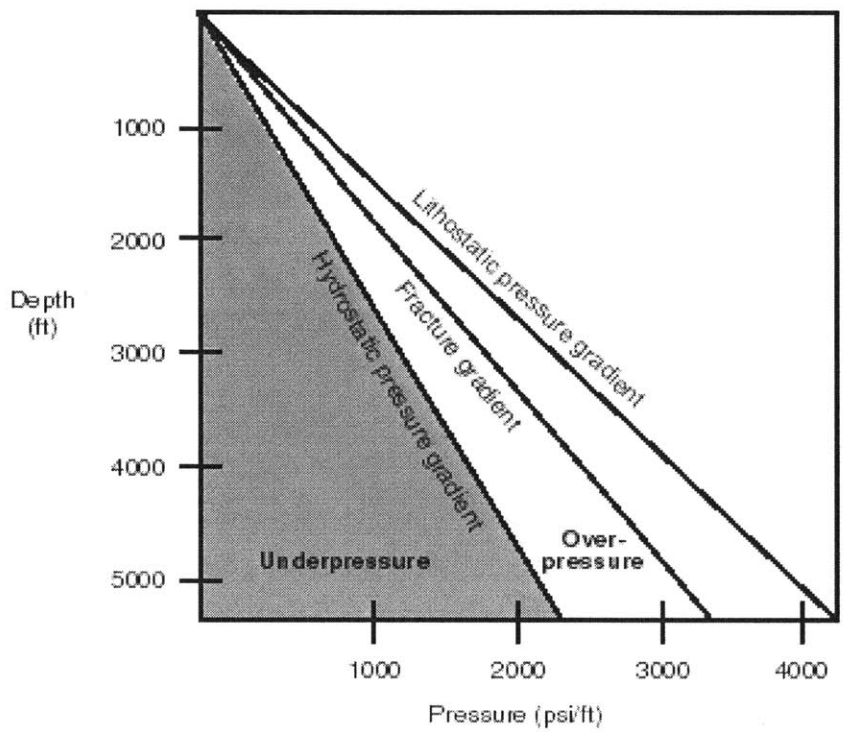


Figure A-1: Abnormal pressure. Formation pressure tends to increase with depth according to the hydrostatic pressure gradient, in this case 0.433 psi/ft. Deviations from the normal pressure gradient and its associated pressure at a given depth are considered abnormal pressure [SOG-AP].

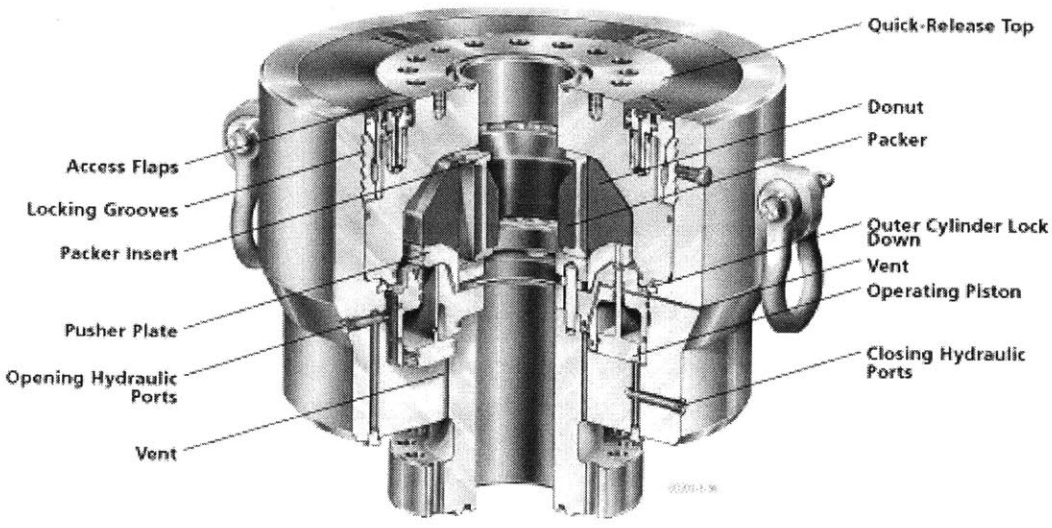


Figure A-2: Annular Blowout Preventer. In the event of a sudden pressure release, annular blowout preventers are designed to inwardly squeeze an annular seal to close off the well bore. Annular blowout preventers are different from ram blowout preventers, which act by shearing the well pipe from the side to stop pipe flow [CAM-ABP].

sures weight loss of a specially shaped, stainless-steel mixer blade after 20 minutes at 11,000 rpm running in a laboratory-prepared mud sample. Abrasiveness is quantified by the rate of weight loss, reported in units of mg/min.

abrasiveness

A material property that expresses the effect of particular materials or rocks on the wear and tear suffered by drilling equipment in the course of well drilling.

annular blowout preventer

A large valve used to control wellbore fluids. In this type of valve, the sealing element resembles a large rubber doughnut that is mechanically squeezed inward to seal on either pipe (drill collar, drillpipe, casing, or tubing) or the openhole. The ability to seal a variety of pipe sizes is one advantage the annular blowout preventer has over the ram blowout preventer. Most blowout preventer (BOP) stacks contain at least one annular BOP at the top of the BOP stack, and one or more ram-type preventers below.

area (DAT)

A group of zones in the DAT. It defines the length of the whole field in which the well drilling will proceed. The length of an area is fixed.

back off

To unscrew drillstring components downhole. The drillstring, including drillpipe and the bottomhole assembly, are coupled by various threadforms known as connections, or tool joints. Often when a drillstring becomes stuck it is necessary to "back off" the string as deep as possible to recover as much of the string as possible. To facilitate the fishing or recovery operation, the backoff is usually accomplished by applying reverse torque and detonating an explosive charge inside a selected threaded connection. The force of the explosion enlarges the female (outer) thread enough that the threaded connection unscrews instantly. A torqueless backoff may be performed as well. In that case, tension is applied, and the threads slide by each other without turning when the explosive detonates. Backing off can also occur unintentionally.

bedrock

Solid rock either exposed at the surface or situated below surface soil, unconsolidated sediments and weathered rock.

bit

The tool used to crush or cut rock. Everything on a drilling rig directly or indirectly assists the bit in crushing or cutting the rock. The bit is on the bottom of the drillstring and must be changed when it becomes excessively dull or stops making progress.

bit record

A historical record of how a bit performed in a particular wellbore. The bit record includes such data as the depth the bit was put into the well, the distance the bit drilled, the hours the bit was being used "on bottom" or "rotating", the mud type and weight, the nozzle sizes, the weight placed on the bit, the rotating speed and hydraulic flow information. The data are usually updated daily. When the bit is pulled at the end of its use, the condition of the bit and the reason it was pulled out of the hole are also recorded. Bit records are often shared among operators and bit companies and are one of many valuable sources of data from offset wells for well design engineers.

bit trip

The process of pulling the drillstring out of the wellbore for the purpose of changing a worn or underperforming drill bit. Upon reaching the surface, the bit is usually inspected and graded on the basis of how worn the teeth are, whether it is still in gauge and whether its components are still intact.

blowdown

To vent gas from a well or production system. Wells that have been shut in for a period frequently develop a gas cap caused by gas percolating through the fluid column in the wellbore. It is often desirable to remove or vent the free gas before starting well intervention work.

blowout

An uncontrolled flow of reservoir fluids into the wellbore, and sometimes catastrophically to the surface. Blowouts occur in all types of exploration and production operations, not just during drilling operations.

blowout preventer (BOP)

A large, fast-acting valve or series of valves at the top of a well that may be closed if the drilling crew loses control of formation fluids in order to prevent eruption. By closing this valve (usually operated remotely via hydraulic actuators), the drilling crew usually regains control of the reservoir, and procedures can then be initiated to increase the mud density until it is possible to open the BOP and retain pressure control of the formation. BOPs come in a variety of styles, sizes and pressure ratings. Some can effectively close over an open wellbore, some are designed to seal around tubular components in the well (drillpipe, casing or tubing) and others are fitted with hardened steel shearing surfaces that can actually cut through drillpipe. Since BOPs are critically important to the safety of the crew, the rig and the wellbore itself, BOPs are inspected, tested and refurbished at regular intervals determined by a combination of risk assessment, local practice, well type and legal requirements. BOP tests vary from daily function testing on critical wells to monthly or less frequent testing on wells thought to have low probability of well control problems.

blowout preventer stack

A set of two or more BOPs used to ensure pressure control of a well. A typical stack might consist of one to six ram-type preventers and, optionally, one or two annular-type preventers. A typical stack configuration has the ram preventers on the bottom and the annular preventers at the top. The configuration of the stack preventers is optimized to provide maximum pressure integrity, safety and flexibility in the event of a well control incident. For example, in a multiple ram configuration, one set of rams might be fitted to close on 5-in. diameter drillpipe, another set configured for 4 1/2-in. drillpipe, a third fitted with blind rams to close on the openhole and a fourth fitted with a shear ram that can cut and hang-off the drillpipe as a last resort. It is common to have an annular preventer or two on the top of the stack since annulars can be closed over a wide range of tubular sizes and the openhole, but are typically not rated for pressures as high as ram preventers. The BOP stack also includes various spools, adapters and piping outlets to permit the circulation of wellbore fluids under pressure in the event of a well control incident.

borehole

The wellbore itself, including the openhole or uncased portion of the well. Borehole may refer to the inside diameter of the wellbore wall, the rock face that bounds the drilled hole.

bottomhole assembly (BHA)

The lower portion of the drillstring, consisting of (from the bottom up in a vertical well) the bit, bit sub, a mud motor (in certain cases), stabilizers, drill collar, heavy-weight drillpipe, jarring devices ("jars") and crossovers for various threadforms. The bottomhole assembly must provide force for the bit to break the rock (weight on bit), survive a hostile mechanical environment and provide the driller with directional control of the well. Oftentimes the assembly includes a mud motor, directional drilling and measuring equipment, measurements-while-drilling tools, logging-while-drilling tools and other specialized devices.

bottomhole temperature (BHT)

A measured temperature in the borehole at its total depth. The bottom-hole

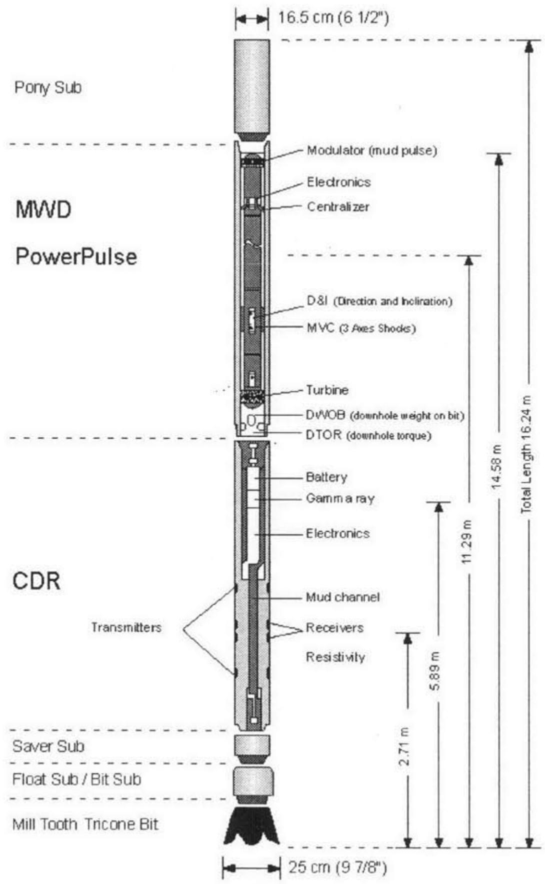


Figure A-3: Bottomhole assembly. This is a bottomhole assembly designed for logging-while-drilling operations.

temperature (BHT) is taken as the maximum recorded temperature during a logging run or, preferably, the last series of runs during the same operation. BHT is the temperature used for the interpretation of logs and heat flow at geothermal gradient. Farther up the hole, the correct temperature is calculated by assuming a certain temperature gradient.

break out

To unscrew drillstring components, which are coupled by various threadforms, including tool joints and other threaded connections.

bridge plug

A downhole tool that is located and set to isolate the lower part of the wellbore. Bridge plugs may be permanent or retrievable, enabling the lower wellbore to be permanently sealed from production or temporarily isolated from a treatment conducted on an upper zone.

caliper log

A representation of the measured diameter of a borehole along its depth. Caliper logs are usually measured mechanically, with only a few using sonic devices. The tools measure diameter at a specific chord across the well. Since wellbores are usually irregular (rugose), it is important to have a tool that measures diameter at several different locations simultaneously. Such a tool is called a multifinger caliper. Drilling engineers or rigsite personnel use caliper measurement as a qualitative indication of both the condition of the wellbore and the degree to which the mud system has maintained hole stability. Caliper data are integrated to determine the volume of the openhole, which is then used in planning cementing operations.

casing

Large-diameter pipe lowered into an openhole and cemented in place. The well designer must design casing to withstand a variety of forces, such as collapse, burst, and tensile failure, as well as chemically aggressive brines. Most casing joints are fabricated with male threads on each end, and short-length casing couplings with female threads are used to join the individual joints of casing together, or joints of casing may be fabricated with male threads on one end and female threads on the

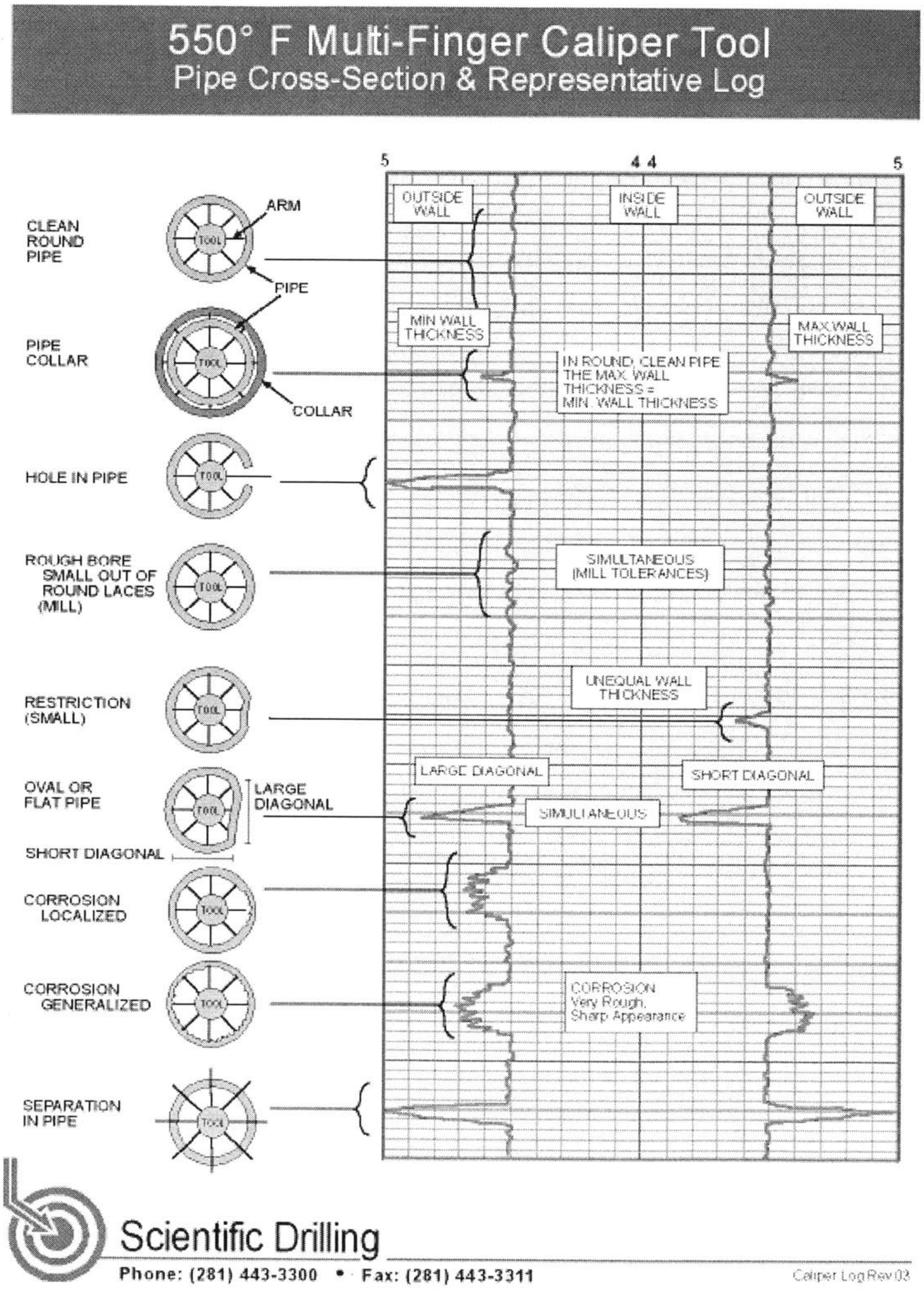


Figure A-4: An Example Caliper Log. A caliper log provides drilling engineers with considerable information on the integrity of drill pipe, wellbores, and casing. Here is an example readout from a multifinger caliper, with corresponding conditions and log readouts [SD-CL].

other. Casing is run to protect fresh water formations, isolate a zone of lost returns or isolate formations with significantly different pressure gradients. The operation during which the casing is put into the wellbore is commonly called "running pipe." Casing is usually manufactured from plain carbon steel that is heat-treated to varying strengths, but may be specially fabricated of stainless steel, aluminum, titanium, fiberglass and other materials. Steel pipe cemented in place during the construction process to stabilize the wellbore. The casing forms a major structural component of the wellbore and serves several important functions: preventing the formation wall from caving into the wellbore, isolating the different formations to prevent the flow or crossflow of formation fluid, and providing a means of maintaining control of formation fluids and pressure as the well is drilled. The casing string provides a means of securing surface pressure control equipment and downhole production equipment, such as the drilling blowout preventer (BOP) or production packer. Casing is available in a range of sizes and material grades. Figure A-5 shows a typical casing arrangment.

casing collar

The threaded collar used to connect two joints of casing. The resulting connection must provide adequate mechanical strength to enable the casing string to be run and cemented in place. The casing collar must also provide sufficient hydraulic isolation under the design conditions determined by internal and external pressure conditions and fluid characteristics.

casing hanger

The subassembly of a wellhead that supports the casing string when it is run into the wellbore. The casing hanger provides a means of ensuring that the string is correctly located and generally incorporates a sealing device or system to isolate the casing annulus from upper wellhead components.

casing shoe

The bottom of the casing string, including the cement around it, or the equipment run at the bottom of the casing string. A short assembly, typically manufactured from a heavy steel collar and profiled cement interior, that is screwed to the bottom of a casing string. The rounded profile helps guide the casing string past any ledges

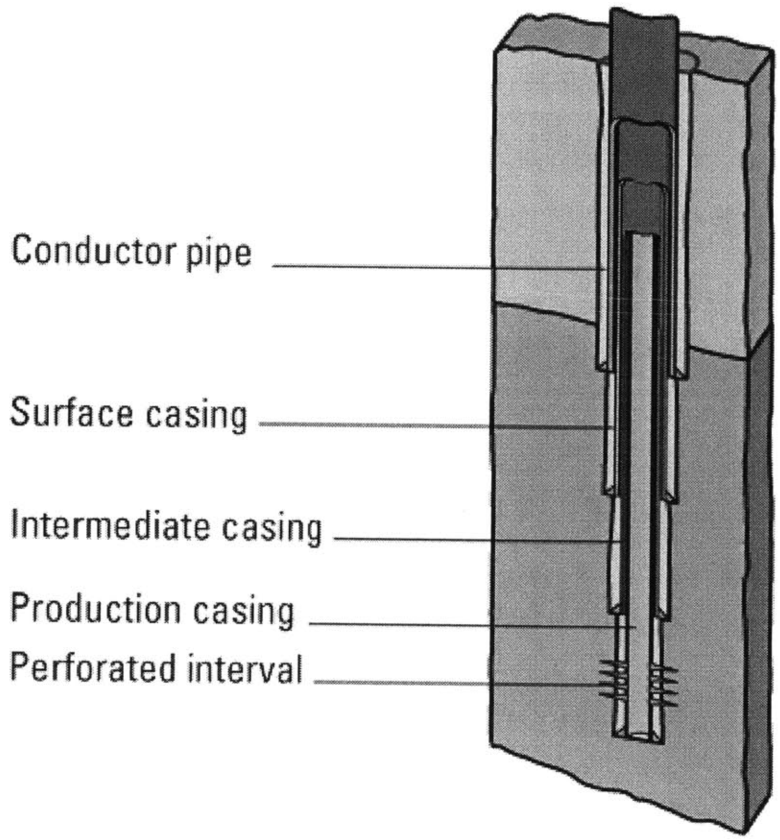


Figure A-5: Casing. The casing strings used in the design and construction of a wellbore can be configured in a range of sizes and depths, mainly determined by the formation characteristics and local availability. The wellbore configuration shown is commonly found in conventional vertical wells, with the casing setting depth for each string determined by the specific formation or reservoir conditions.

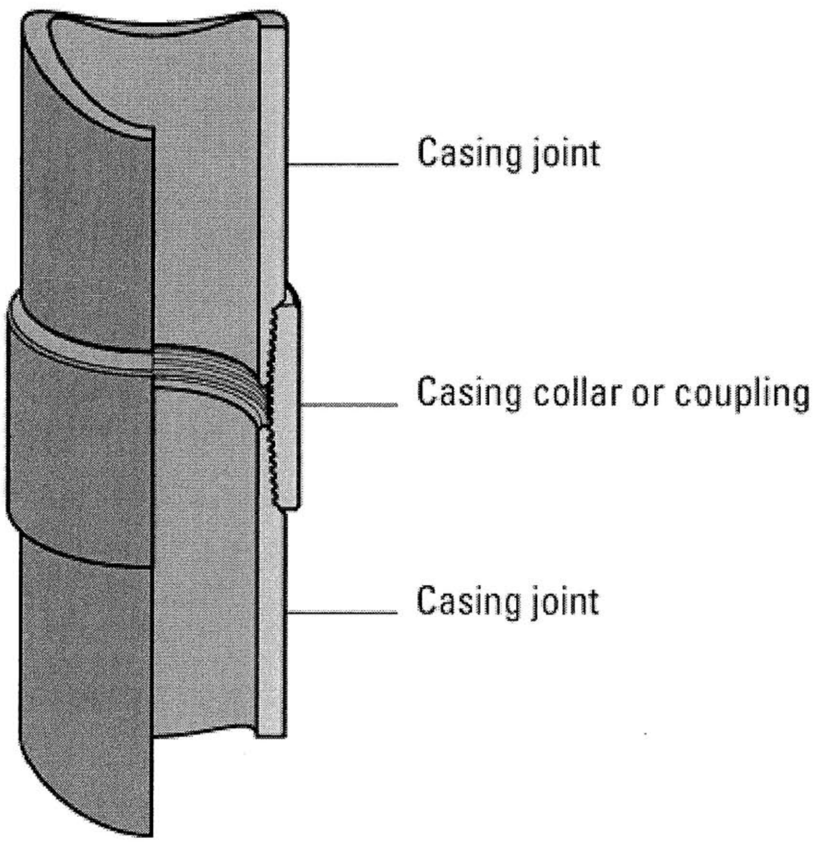


Figure A-6: Casing collar or coupling. Casing collars are preinstalled on one end of the casing joint. When run into the wellbore, the casing joint is run with the collar uppermost to facilitate handling and enable easy connection of the subsequent casing joint.

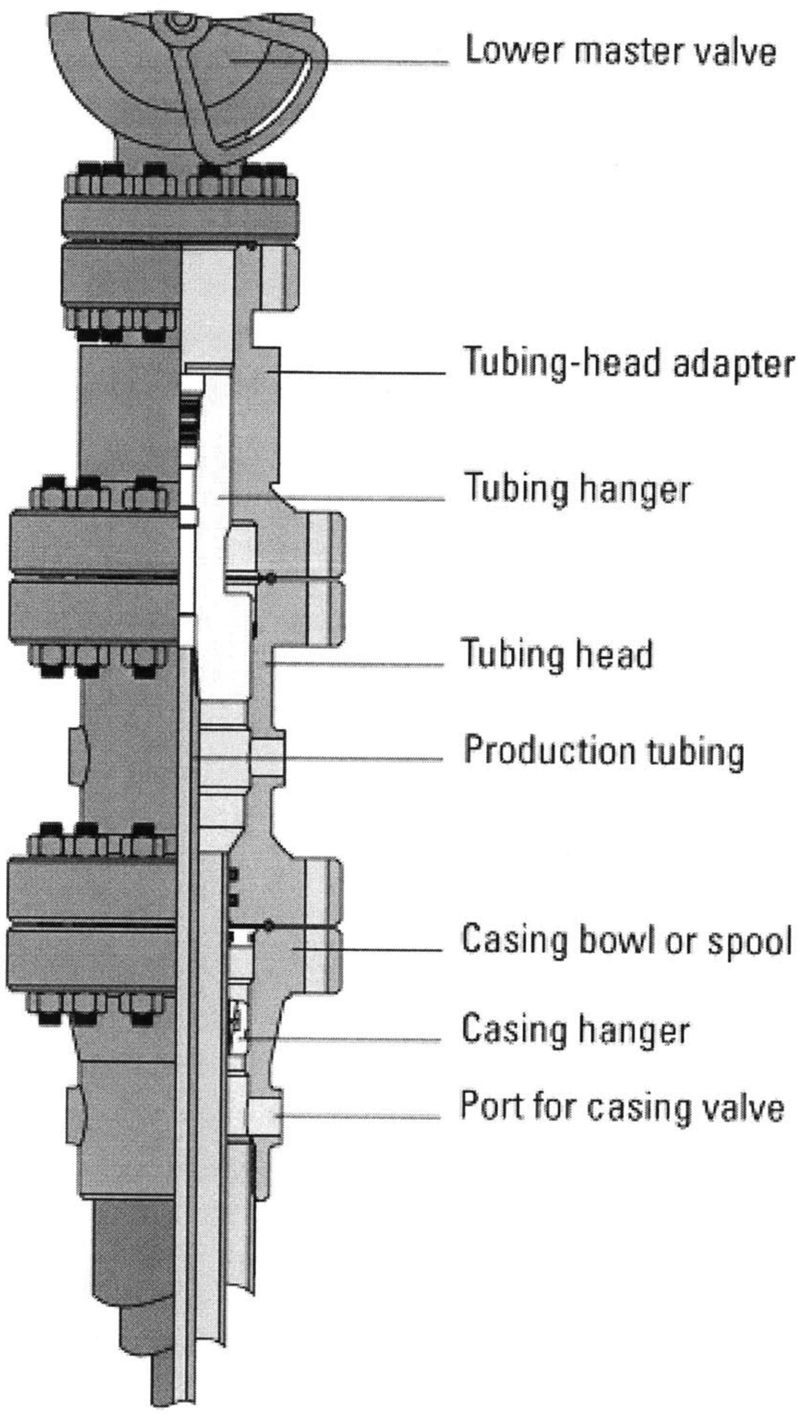


Figure A-7: Casing hanger. Attached to the topmost joint of casing, the casing hanger incorporates features to suspend the casing string and provide hydraulic isolation once engaged in the casing bowl.

or obstructions that would prevent the string from being correctly located in the wellbore.

casing string

An assembled length of steel pipe configured to suit a specific wellbore. The sections of pipe are connected and lowered into a wellbore, then cemented in place. The pipe sections are typically approximately 40 ft [12 m] in length, male threaded on each end and connected with short lengths of double-female threaded pipe called couplings. Long casing strings may require higher strength materials on the upper portion of the string to withstand the string load. Lower portions of the string may be assembled with casing of a greater wall thickness to withstand the extreme pressures likely at depth.

casinghead

The adapter between the first casing string and either the BOP stack (during drilling) or the wellhead (after completion). This adapter may be threaded or welded onto the casing, and may have a flanged or clamped connection to match the BOP stack or wellhead.

cement

The material used to permanently seal annular spaces between casing and borehole walls. Cement is also used to seal formations to prevent loss of drilling fluid and for operations ranging from setting kick-off plugs to plug and abandonment. The cement slurry, commonly formed by mixing Portland cement, water and assorted dry and liquid additives, is pumped into place and allowed to solidify (typically for 12 to 24 hours) before additional drilling activity can resume.

cement plug

A balanced plug of cement slurry placed in the wellbore. Cement plugs are used for a variety of applications including hydraulic isolation, provision of a secure platform, and in window-milling operations for sidetracking a new wellbore.

collar

A threaded coupling used to join two lengths of pipe such as production tubing, casing or liner. The type of thread and style of collar varies with the specifications

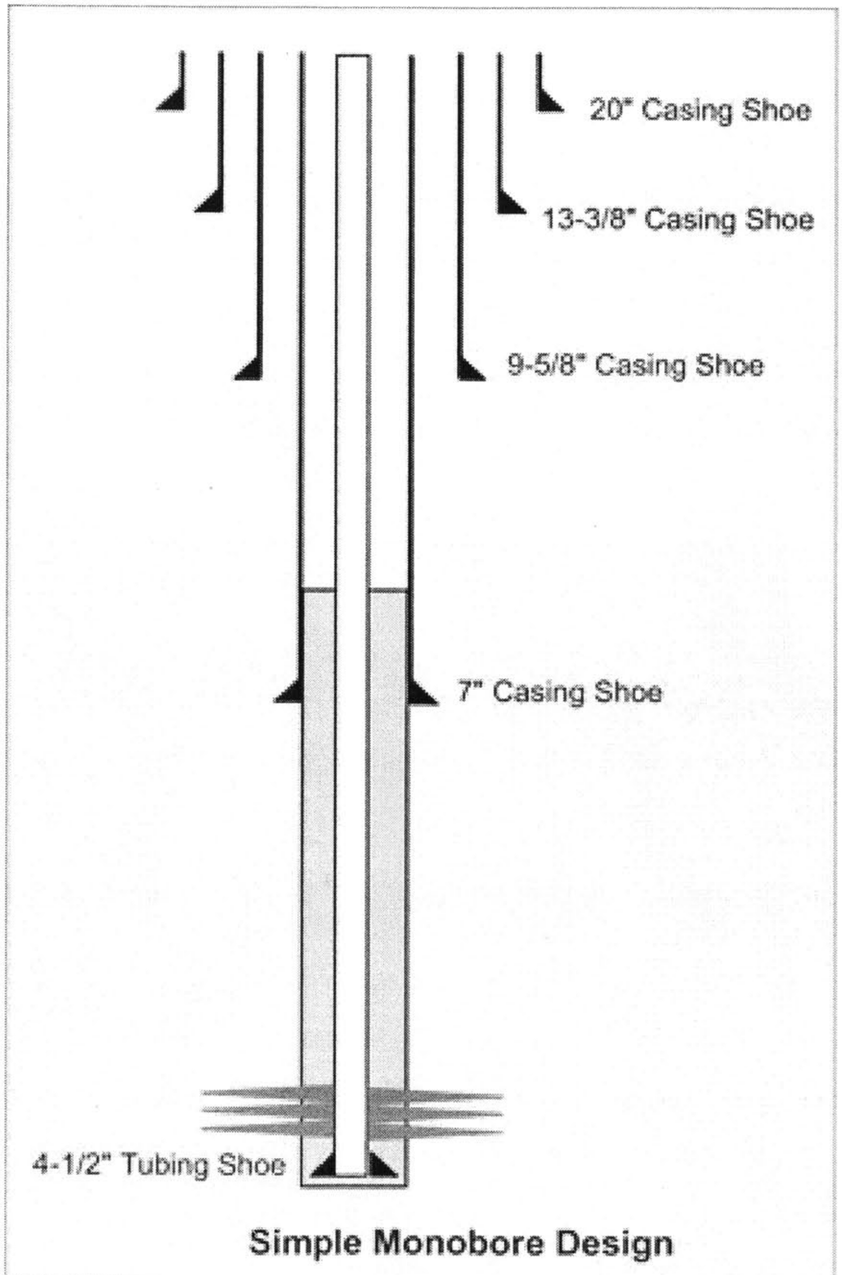


Figure A-8: Casing string. Pipe is run into the wellbore and cemented in place to protect aquifers, to provide pressure integrity and to ensure isolation of producing formations.

and manufacturer of the tubing.

conductor pipe

A short string of large-diameter casing set to support the surface formations. The conductor pipe is typically set soon after drilling has commenced since the unconsolidated shallow formations can quickly wash out or cave in. Where loose surface soil exists, the conductor pipe may be driven into place before the drilling commences. This casing is sometimes called the drive pipe.

core

A cylindrical sample of geologic formation, usually reservoir rock, taken during or after drilling a well. Cores can be full-diameter cores (that is, they are nearly as large in diameter as the drill bit) taken at the time of drilling the zone, or sidewall cores (generally less than 1 in. [2.5 cm] in diameter) taken after a hole has been drilled.

core testing

Laboratory analyses performed on formation core samples as part of a stimulation-treatment design process. Tests such as the formation flow potential, fracture orientation and fluid compatibility tests are commonly run in preparation for stimulation treatments.

cuttings

Small pieces of rock that break away due to the action of the bit teeth. Cuttings are screened out of the liquid mud system at the shakers and are monitored for composition, size, shape, color, texture, hydrocarbon content and other properties by the mud engineer, the mud logger and other on-site personnel. The mud logger usually captures samples of cuttings for subsequent analysis and archiving.

cycle (DAT)

Length of tunnel that is excavated in one operation (term used in the DAT). It is also used for the length of wellbore when the DAT is used in a single-cycle approach.

deterministically defined (DAT)

The user divides the zone into segments, defines the beginning and ending position of each segment, as well as the state of the parameter in this segment.

differential sticking

A condition whereby the drillstring cannot be moved (rotated or reciprocated) along the axis of the wellbore. Differential sticking typically occurs when high-contact forces caused by low reservoir pressures, high wellbore pressures, or both, are exerted over a sufficiently large area of the drillstring. Differential sticking is, for most drilling organizations, the greatest drilling problem worldwide in terms of time and financial cost. It is important to note that the sticking force is a product of the differential pressure between the wellbore and the reservoir and the area that the differential pressure is acting upon. This means that a relatively low differential pressure (delta p) applied over a large working area can be just as effective in sticking the pipe as can a high differential pressure applied over a small area. Differential sticking is often the result of the drilling assembly becoming stuck in filter cake that was previously deposited on a permeable zone. The force required to pull the pipe free can exceed the strength of the pipe. Methods used to get the pipe free, in addition to pulling and torquing the pipe, include: (1) lowering hydrostatic pressure in the wellbore, (2) placing a spotting fluid next to the stuck zone and (3) applying shock force just above the stuck point by mechanical jarring, or (4) all the above. The most common approach, however, to getting free is to place a spot of oil, oil-base mud, or special spotting fluid.

directional drilling

The intentional deviation of a wellbore from the path it would naturally take, sometimes called slant drilling or deviated drilling. The general concept is simple: point the bit in the direction that one wants to drill. The most common way is through the use of a bend near the bit in a downhole steerable mud motor. The bend points the bit in a direction different from the axis of the wellbore when the entire drillstring is not rotating. By pumping mud through the mud motor, the bit turns while the drillstring does not rotate, allowing the bit to drill in the direction it points. When a particular wellbore direction is achieved, that direction may be maintained by rotating the entire drillstring (including the bent section) so that the bit does not drill in a single direction off the wellbore axis, but instead sweeps around and its net direction coincides with the existing wellbore. Rotary steerable tools

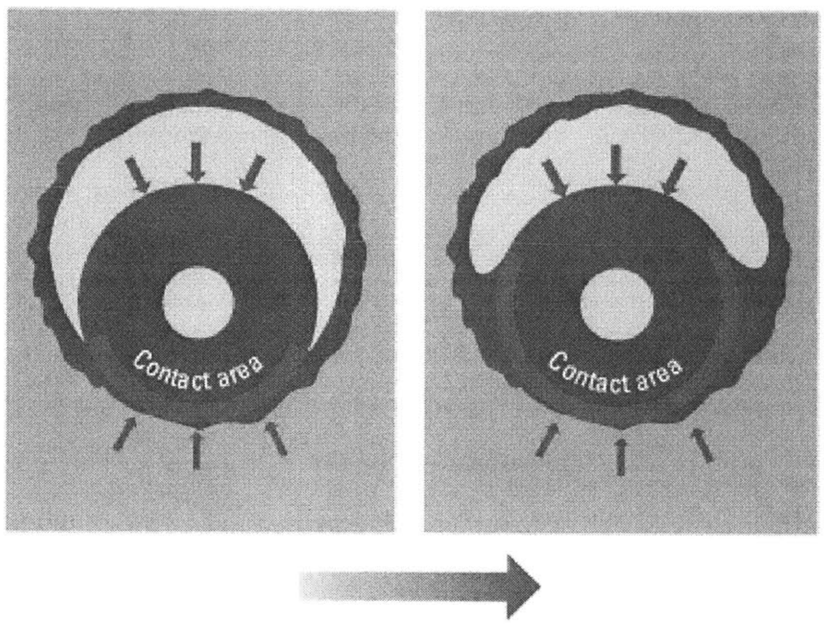


Figure A-9: Differential sticking. These cross-sectional views show a drill collar embedded in mudcake and pinned to the borehole wall by the pressure differential between the drilling mud and the formation. As time passes, if the drillstring remains stationary, the area of contact can increase (right) making it more difficult to free the drillstring.

allow steering while rotating, usually with higher rates of penetration and ultimately smoother boreholes. Figure ?? illustrates a typical arrangement, with a separate downhole motor excavating a sufficient bore length for the main drill string to resume drilling at a new angle.

directional well

A wellbore that requires the use of special tools or techniques to ensure that the wellbore path hits a particular subsurface target, typically located away from (as opposed to directly under) the surface location of the well.

drill collar

A component of a drillstring that provides weight on bit for drilling. Drill collars are thick-walled tubular pieces machined from solid bars of steel, usually plain carbon steel but sometimes of nonmagnetic nickel-copper alloy or other nonmagnetic premium alloys. The bars of steel are drilled from end to end to provide a passage to pumping drilling fluids through the collars. The outside diameter of the steel bars may be machined slightly to ensure roundness, and in some cases may be machined with helical grooves ("spiral collars"). Last, threaded connections, male on one end and female on the other, are cut so multiple collars can be screwed together along with other downhole tools to make a bottomhole assembly (BHA). Gravity acts on the large mass of the collars to provide the downward force needed for the bits to efficiently break rock. To accurately control the amount of force applied to the bit. the driller carefully monitors the surface weight measured while the bit is just off the bottom of the wellbore. Next, the drillstring (and the drill bit), is slowly and carefully lowered until it touches bottom. After that point, as the driller continues to lower the top of the drillstring, more and more weight is applied to the bit, and correspondingly less weight is measured as hanging at the surface. If the surface measurement shows 20,000 pounds [9080 kg] less weight than with the bit off bottom, then there should be 20,000 pounds force on the bit (in a vertical hole). Downhole MWD sensors measure weight-on-bit more accurately and transmit the data to the surface.

drilling fluid

Any of a number of liquid and gaseous fluids and mixtures of fluids and solids

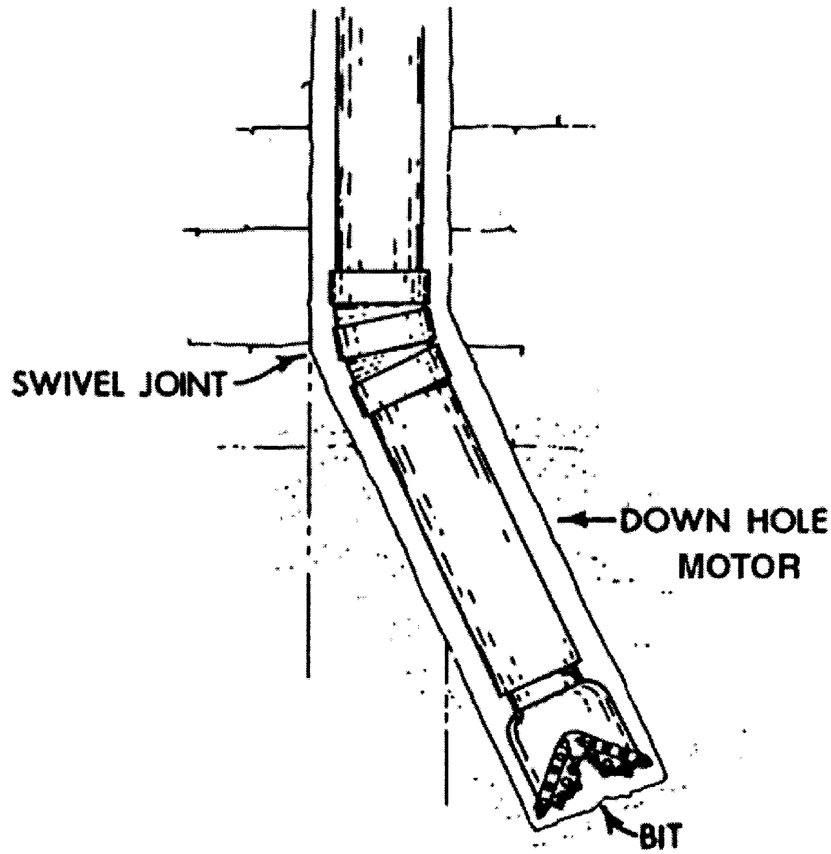


Figure A-10: Directional Drilling. Deviating the path of a wellbore is most typically achieved through the use of a steerable downhole motor. This downhole motor is sufficient to turn the bit of the drill string and bore into the surrounding rock at an angle. This downhole arrangement must be capable of drilling far enough at the desired angle for the drill string to be placed into the newly formed path– otherwise the use of a flexible drill string or other technology would be necessary to continue regular drilling after the desired angle was achieved.

(as solid suspensions, mixtures and emulsions of liquids, gases and solids) used in operations to drill boreholes into the earth. Synonymous with "drilling mud" in general usage, although some prefer to reserve the term "drilling fluid" for more sophisticated and well-defined "muds."

drilling rate (penetration rate / rate of penetration)

The speed at which the drill bit can break the rock under it and thus deepen the wellbore. This speed is usually reported in units of feet per hour or meters per hour.

drillpipe

A tubular steel conduit fitted with special threaded ends called tool joints. The drillpipe connects the rig surface equipment with the bottomhole assembly and the bit, both to pump drilling fluid to the bit and to be able to raise, lower and rotate the bottomhole assembly and bit.

drillstring

The combination of the drillpipe, the bottomhole assembly and any other tools used to make the drill bit turn at the bottom of the wellbore.

eigenvector (DAT)

Based on the transition matrix, this will tell how often a particular state will be the one present in a segment.

excess cement

The cement slurry remaining in the wellbore following a cement squeeze in which the objective is to squeeze slurry into the perforations and behind the casing or liner. The volume of slurry required to effect a successful squeeze is often difficult to estimate. In most cases, an excess allowance is made since a shortage of slurry would result in failure of the operation. Removal of the excess cement slurry before it sets has been a key objective in the development of modern cement-squeeze techniques.

expendable plug

A temporary plug, inserted in the completion assembly before it is run, to enable pressure testing of the completed string. With the operation complete, the expendable plug can be pumped out of the assembly, thereby avoiding a separate retrieval run.

filter cake

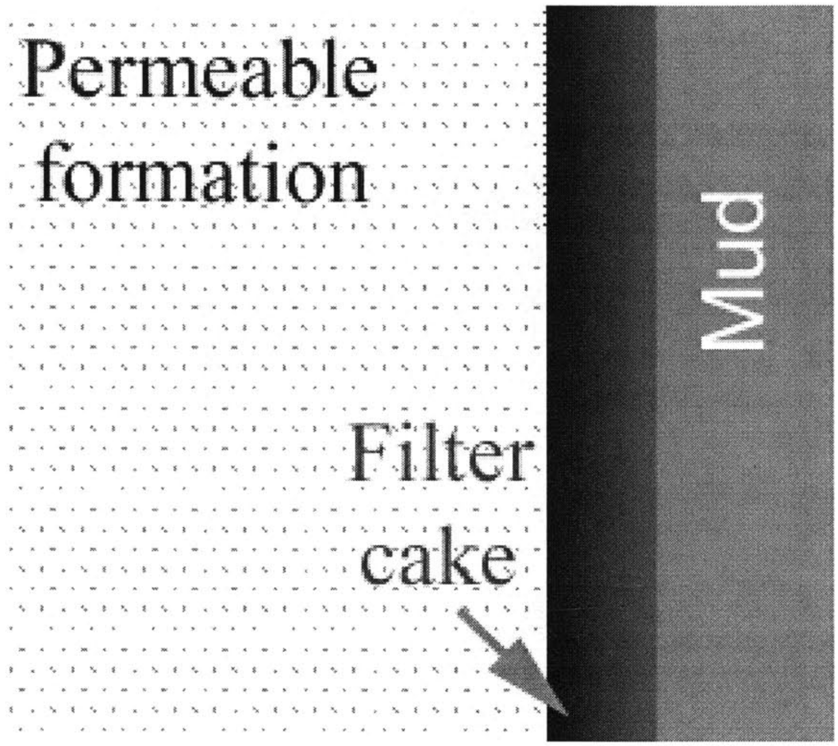


Figure A-11: Filter Cake. Filter cake forms at the interface of the wellbore and the surrounding permeable rock. "Internal" cake buildup in the well bore itself can lead to drill pipe sticking and other issues, while "external" cake buildup in the permeable rock can reduce fluid loss and slightly improve drilling operations.

The residue deposited on a permeable medium when a slurry, such as a drilling fluid, is forced against the medium under a pressure. Filtrate is the liquid that passes through the medium, leaving the cake on the medium. Drilling muds are tested to determine filtration rate and filter-cake properties. Cake properties such as cake thickness, toughness, slickness and permeability are important because the cake that forms on permeable zones in the wellbore can cause stuck pipe and other drilling problems. A certain degree of cake buildup is desirable to isolate formations from drilling fluids. In openhole completions in high-angle or horizontal holes, the formation of an external filter cake is preferable to a cake that forms partly inside the formation. The latter has a higher potential for formation damage. Figure A-11 shows, in a generalized fashion, the region of filter cake build-up.

fishing

The application of tools, equipment and techniques for the removal of junk, debris or equipment from a wellbore. The key elements of a fishing operation include an understanding of the dimensions and nature of the equipment to be removed, the wellbore conditions, the tools and techniques employed and the process by which the recovered equipment will be handled at surface.

fishing tool

A general term for special mechanical devices used to aid the recovery of equipment lost downhole. These devices generally fall into four classes: diagnostic, inside grappling, outside grappling, and force intensifiers or jars. Diagnostic devices may range from a simple impression block made in a soft metal, usually lead, that is dropped rapidly onto the top of the fish so that upon inspection at the surface, the fisherman may be able to custom design a tool to facilitate attachment to and removal of the fish. Other diagnostic tools may include electronic instruments and even downhole sonic or visual-bandwidth cameras. Inside grappling devices, usually called spears, generally have a tapered and threaded profile, enabling the fisherman to first guide the tool into the top of the fish, and then thread the fishing tool into the top of the fish so that recovery may be attempted. Outside grappling devices, usually called overshots, are fitted with threads or another shape that "swallows" the fish and does not release it as it is pulled out of the hole. Overshots are also fitted with a crude drilling surface at the bottom, so that the overshot may be lightly drilled over the fish, sometimes to remove rock or metallic junk that may be part of the sticking mechanism. Jars are mechanical downhole hammers, which enable the fisherman to deliver high-impact loads to the fish, far in excess of what could be applied in a quasi-static pull from the surface. Figure reffig:gfishingtool shows a typical fishing string used in vertical drilling.

flange

A connection profile used in pipe work and associated equipment to provide a means of assembling and disassembling components. Most drilling flanges feature a bolt-hole pattern to allow the joint to be secured and a gasket profile to ensure a pressure-tight seal. The design and specification of a flange relates to the size and

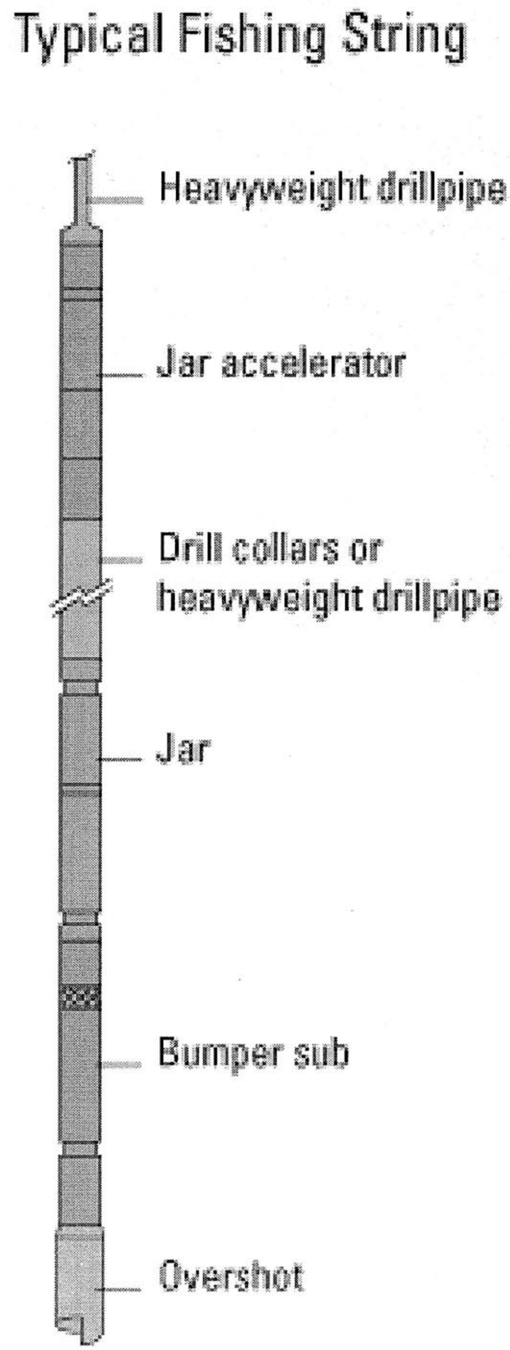


Figure A-12: Fishing tool. Many different types of fishing tools are used to retrieve junk from a borehole. An overshot is an outside grappling device that fits over the equipment and latches onto it.

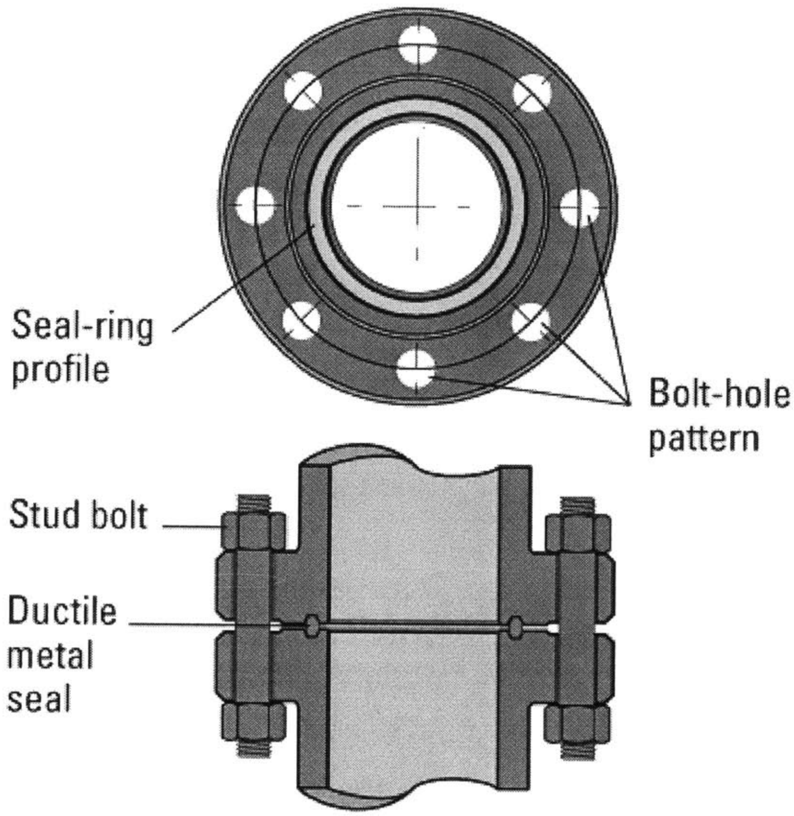


Figure A-13: Flange. Various flange designs are commonly encountered in well equipment. The bolt-hole pattern and gasket type often can be used to visually identify the type or specification of the flange connection.

pressure capacity of the equipment to which it is fitted.

float collar

A component installed near the bottom of the casing string on which cement plugs land during the primary cementing operation. It typically consists of a short length of casing fitted with a check valve. The check-valve assembly fixed within the float collar prevents flowback of the cement slurry when pumping is stopped. Without a float collar, the cement slurry placed in the annulus could U-tube, or reverse flow back into the casing. The greater density of cement slurries than the displacement mud inside the casing causes the U-tube effect.

float shoe

A rounded profile component attached to the downhole end of a casing string. A

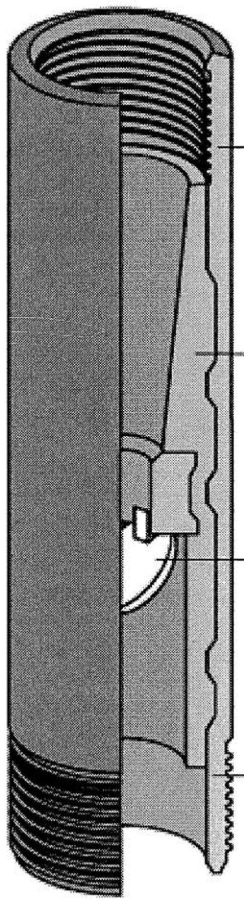


Figure A-14: Float collar. The float collar provides two important functions during a cementing operation: when the cementing plug is landed on the float collar, positive indication is obtained at surface that the cement slurry has been properly displaced. Subsequently, when the pump pressure is bled off, a check-valve assembly in the float collar closes to prevent the backflow of cement into the casing string.

check valve in the float shoe prevents reverse flow, or U-tubing, of cement slurry from the annulus into the casing or flow of wellbore fluids into the casing string as it is run. The float shoe also guides the casing toward the center of the hole to minimize hitting rock ledges as the casing is run into the wellbore. By resting at the bottom of the wellbore, the casing string can be floated into position, avoiding the need for the rig to carry the entire weight of the casing string. The outer portions of the float shoe are made of steel and generally match the casing size and threads, although not necessarily the casing grade. The inside (including the taper) is usually made of cement or thermoplastic, since this material must be drilled out if the well is to be deepened beyond the casing point. Figure A-15 shoes a typical float shoe for use in vertical drilling.

fluid loss

The leakage of liquid drilling fluid, slurry or treatment fluid containing solid particles into the formation matrix. The resulting buildup of solid material or filter cake may be undesirable, as may the penetration and/or loss of filtrate and fluid through the formation.

formation

A general term for the rock around the borehole. In the context of formation evaluation, the term refers to the volume of rock seen by a measurement made in the borehole, as in a log or a well test. These measurements indicate the physical properties of this volume. Extrapolation of the properties beyond the measurement volume requires a geological model.

formation evaluation

The measurement and analysis of formation and fluid properties through examination of formation cuttings or through the use of tools integrated into the bottomhole assembly while drilling, or conveyed on wireline or drillpipe after a borehole has been drilled. Formation evaluation is performed to assess the quantity and producibility of fluids from a reservoir. Formation evaluation guides wellsite decisions, such as placement of perforations and hydraulic fracture stages, and reservoir development and production planning.

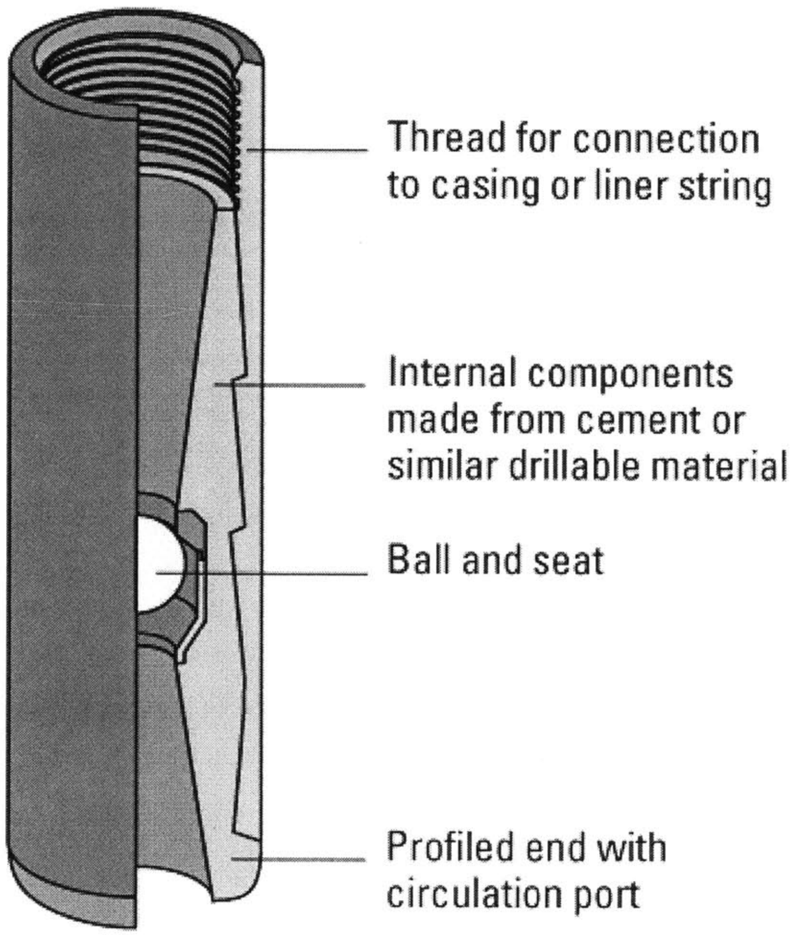


Figure A-15: Float shoe. A float shoe is used to guide the casing or liner into the wellbore. The check-valve assembly within the float shoe prevents the flow of fluids into the casing during the running process or following the cementing operation.

fracture

A crack or surface of breakage within rock not related to foliation or cleavage in metamorphic rock along which there has been no shear movement (known as a fault). Fractures may also be referred to as natural fractures to distinguish them from fractures induced as part of a reservoir stimulation or drilling operation. Fractures can enhance permeability of rocks greatly by connecting pores together. Fractures may be caused by shear or tensile failure and may exist as fully or partly propped open or sealed joints.

fracture network

Patterns in multiple fractures that intersect with each other. Fractures are formed when rock is stressed or strained, as by the forces associated with plate-tectonic activity. When multiple fractures are propagated, they often form patterns that are referred to as fracture networks. Fracture networks may make an important contribution to both the storage (porosity) and the fluid flow rates (permeability or conductivity) of formations.

fracture conductivity

That portion of a dual-porosity reservoir's permeability that is associated with the secondary porosity created by open, natural fractures. In many of these reservoirs, fracture permeability can be the major controlling factor of the flow of fluids.

fracture porosity

A type of secondary porosity produced by the tectonic fracturing of rock. Fractures themselves typically do not have much volume, but by joining preexisting pores, they enhance porosity significantly. In exceedingly rare cases, nonreservoir rocks such as granite can become reservoir rocks if sufficient fracturing occurs.

fractured well analysis

Analysis of a well that passes through a natural fracture or that has been hydraulically fractured.

fracturing fluid

A fluid injected into a well as part of a stimulation operation. Fracturing fluids for shale reservoirs usually contain water, proppant, and a small amount of nonaqueous fluids designed to reduce friction pressure while pumping the fluid into the wellbore. These fluids typically include gels, friction reducers, crosslinkers, breakers and surfactants similar to household cosmetics and cleaning products; these additives are selected for their capability to improve the results of the stimulation operation and the permeability of the reservoir.

generation mode (DAT)

The method that the program uses to generate the length of the zone. The generation of a chain of zones can be done by either choosing the length of the zone or the end point of the zone.

geothermal gradient

The natural increase of temperature with depth in the earth. Temperature gradients vary widely over the Earth, sometimes increasing dramatically around volcanic areas. It is particularly important for engineers to know the geothermal gradient in an area when they are designing a deep well. The downhole temperature can be calculated by adding the surface temperature to the product of the depth and the geothermal gradient. The rate of increase in temperature per unit depth in the Earth. Although the geothermal gradient varies from place to place, it averages 25 to 30°C/km [15°F/1000 ft].

ground class (DAT)

A combination of the states of different parameters. Different combinations can give the same ground class, but one combination is related to one ground class only.

ground parameter (DAT)

Corresponds to one characteristic of the ground in a given region. A ground parameter can have different states and zones can have different parameters. Common parameters include Lithology, Overburden, Water Content and Inflow, and Faulting.

guide shoe

A tapered, often bullet-nosed piece of equipment often found on the bottom of a casing string. The device guides the casing toward the center of the hole and minimizes problems associated with hitting rock ledges or washouts in the wellbore as the casing is lowered into the well. The outer portions of the guide shoe are made from steel, generally matching the casing in size and threads, if not steel grade. The inside (including the taper) is generally made of cement or thermoplastic, since this material must be drilled out if the well is to be deepened beyond the casing point. It differs from a float shoe in that it lacks a check valve.

heavy pipe

An operating condition during an operation in which the force resulting from the weight of the pipe or tubing string is greater than the wellhead pressure and the buoyancy forces acting to eject the string from the wellbore. In the heavy-pipe condition, the string will drop into the wellbore if the gripping force is lost.

heavyweight drillpipe (HWDP)

A type of drillpipe whose walls are thicker and collars are longer than conventional drillpipe. HWDP tends to be stronger and has higher tensile strength than conventional drillpipe, so it is placed near the top of a long drillstring for additional support.

hydraulic fracturing

The process of pumping into a closed wellbore with powerful hydraulic pumps to create enough downhole pressure to crack or fracture the formation. This allows injection of proppant into the formation, thereby creating a plane of high-permeability sand through which fluids can flow. The proppant remains in place once the hydraulic pressure is removed and thereby props open the fracture and enhances flow into the wellbore.

hydraulic packer

A type of packer used predominantly in production applications. A hydraulic packer typically is set using hydraulic pressure applied through the tubing string rather than mechanical force applied by manipulating the tubing string. Figure A-16 shows the placement of a hydraulic packer relative to the other fracturing equipment. Also, see the related, but distinct concept of a packer.

hydrogen sulfide (H2S)

An extraordinarily poisonous gas with a molecular formula of H2S. H2S is hazardous to workers and a few seconds of exposure at relatively low concentrations can

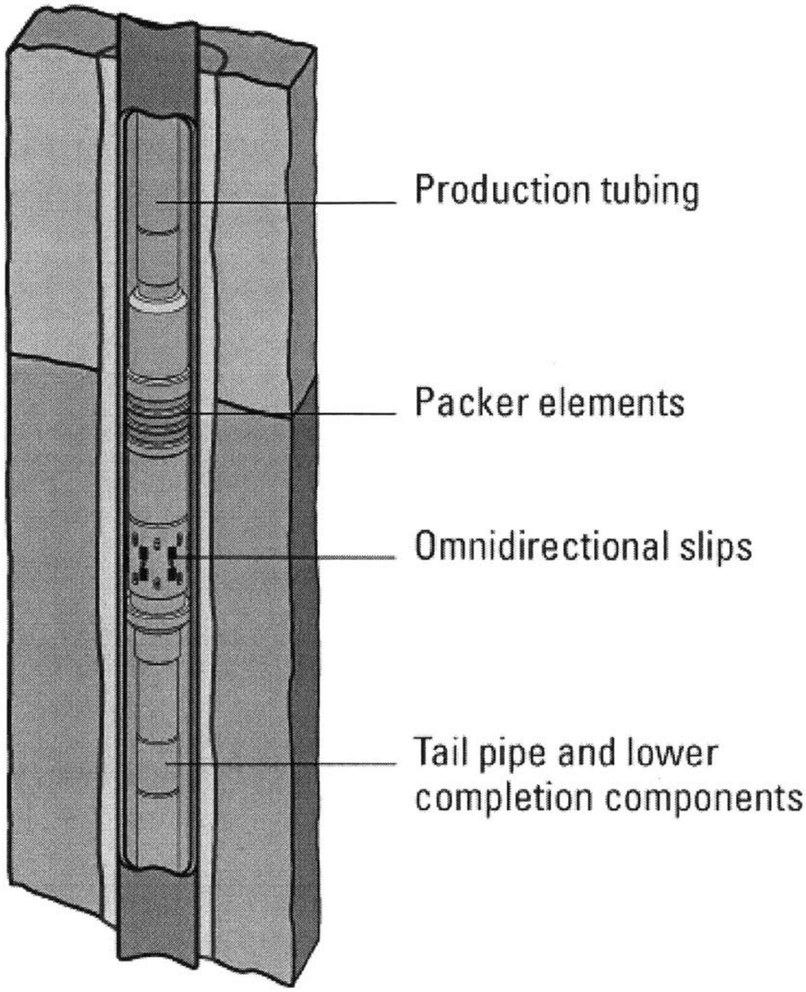


Figure A-16: Hydraulic packer. There are several types of packer in common use in oil and gas well completions. In each case, the principal function is to isolate the annulus from the tubing conduit to enable controlled production. Setting the packer hydraulically eliminates the need to manipulate the tubing string, a significant advantage during the well-completion process.

be lethal, but exposure to lower concentrations can also be harmful. The effect of H2S depends on duration, frequency and intensity of exposure as well as the susceptibility of the individual. Hydrogen sulfide is a serious and potentially lethal hazard, so awareness, detection and monitoring of H2S is essential. Since hydrogen sulfide gas is present in some subsurface formations, drilling and other operational crews must be prepared to use detection equipment, personal protective equipment, proper training and contingency procedures in H2S-prone areas. Hydrogen sulfide is produced during the decomposition of organic matter and occurs with hydrocarbons in some areas. It enters drilling mud from subsurface formations and can also be generated by sulfate-reducing bacteria in stored muds. H2S can cause sulfide-stress-corrosion cracking of metals. Because it is corrosive, H2S production may require costly special production equipment such as stainless steel tubing.

in situ

In the original location or position, such as a large outcrop that has not been disturbed by faults or landslides. Tests can be performed "in situ" in a reservoir to determine its pressure and temperature.

jar

A mechanical device used downhole to deliver an impact load to another downhole component, especially when that component is stuck. There are two primary types, hydraulic and mechanical jars. While their respective designs are quite different, their operation is similar. Energy is stored in the drillstring and suddenly released by the jar when it fires. Jars can be designed to strike up, down, or both. In the case of jarring up above a stuck bottomhole assembly, the driller slowly pulls up on the drillstring but the BHA does not move. Since the top of the drillstring is moving up, this means that the drillstring itself is stretching and storing energy. When the jars reach their firing point, they suddenly allow one section of the jar to move axially relative to a second, being pulled up rapidly in much the same way that one end of a stretched spring moves when released. After a few inches of movement, this moving section slams into a steel shoulder, imparting an impact load. In addition to the mechanical and hydraulic versions, jars are classified as drilling jars or fishing jars. The operation of the two types is similar, and both deliver approximately the same impact blow, but the drilling jar is built such that it can better withstand the rotary and vibrational loading associated with drilling. Figure A-17 details the subcomponents of a hydraulic jar.

kelly

A long square or hexagonal steel bar with a hole drilled through the middle for a fluid path. The kelly is used to transmit rotary motion from the rotary table or kelly bushing to the drillstring, while allowing the drillstring to be lowered or raised during rotation. The kelly goes through the kelly bushing, which is driven by the rotary table. The kelly bushing has an inside profile matching the kelly's outside profile (either square or hexagonal), but with slightly larger dimensions so that the kelly can freely move up and down inside. Figure A-18 gives three views of a typical kelly.

kelly bushing

An adapter that serves to connect the rotary table to the kelly. The kelly bushing has an inside diameter profile that matches that of the kelly, usually square or hexagonal. It is connected to the rotary table by four large steel pins that fit into mating holes in the rotary table. The rotary motion from the rotary table is transmitted to the bushing through the pins, and then to the kelly itself through the square or hexagonal flat surfaces between the kelly and the kelly bushing. The kelly then turns the entire drillstring because it is screwed into the top of the drillstring itself. Depth measurements are commonly referenced to the KB, such as 8327 ft KB, meaning 8327 feet below the kelly bushing.

landing collar

A component installed near the bottom of the casing string on which the cement plugs land during the primary cementing operation. The internal components of the landing collar are generally fabricated from plastics, cement and other drillable materials.

leakoff

The magnitude of pressure exerted on a formation that causes fluid to be forced

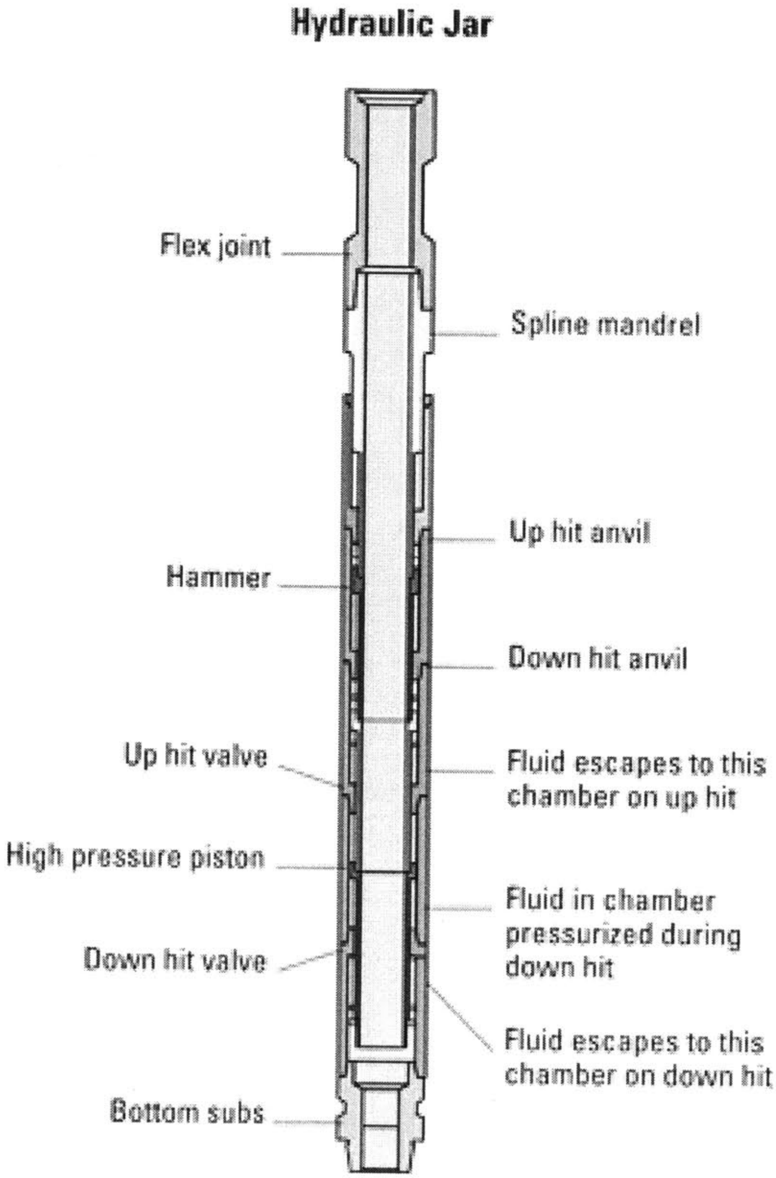


Figure A-17: Jar. This hydraulic jar can be used to free stuck downhole equipment.

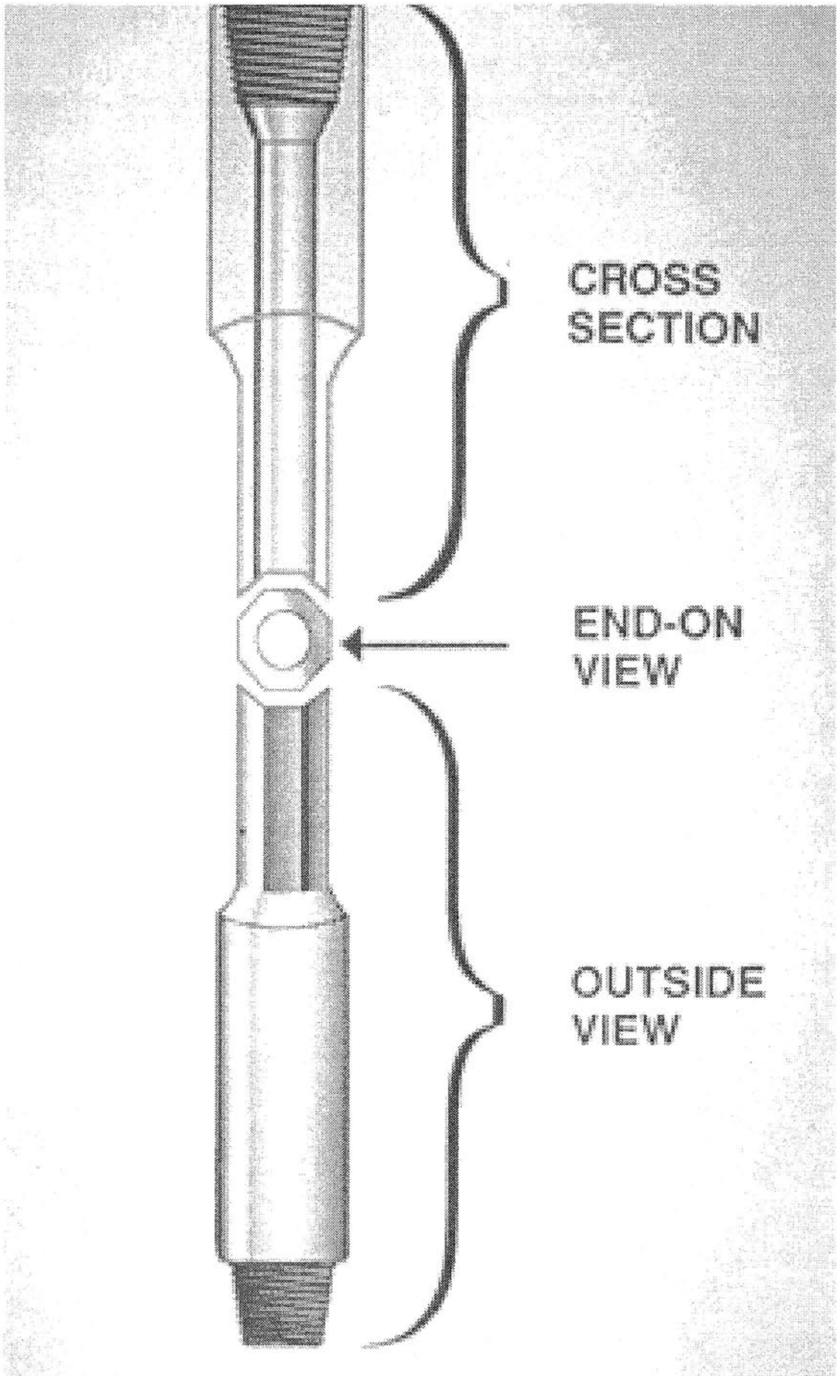


Figure A-18: Kelly. The kelly transfers rotary motion from the rotary table or kelly bushing to the drillstring. The upper (cross-sectional) diagram shows the interior fluid path. The middle (end-on) diagram shows the hexagonal cross section. The lower (outside) diagram shows the outside view of the kelly.

into the formation. The fluid may be flowing into the pore spaces of the rock or into cracks opened and propagated into the formation by the fluid pressure. This term is normally associated with a test to determine the strength of the rock, commonly called a pressure integrity test (PIT) or a leakoff test (LOT). During the test, a real-time plot of injected fluid versus fluid pressure is plotted. The initial stable portion of this plot for most wellbores is a straight line, within the limits of the measurements. The leakoff is the point of permanent deflection from that straight portion. The well designer must then either adjust plans for the well to this leakoff pressure, or if the design is sufficiently conservative, proceed as planned.

leakoff test

A test to determine the strength or fracture pressure of the open formation, usually conducted immediately after drilling below a new casing shoe. During the test, the well is shut in and fluid is pumped into the wellbore to gradually increase the pressure that the formation experiences. At some pressure, fluid will enter the formation, or leak off, either moving through permeable paths in the rock or by creating a space by fracturing the rock. The results of the leakoff test dictate the maximum pressure or mud weight that may be applied to the well during drilling operations. To maintain a small safety factor to permit safe well control operations, the maximum operating pressure is usually slightly below the leakoff test result.

liner

Any casing string that does not extend to the top of the wellbore, but instead is anchored or suspended from inside the bottom of the previous casing string. There is no difference between the casing joints themselves. The advantage to the well designer of a liner is a substantial savings in steel, and therefore capital costs. To save casing, however, additional tools and risk are involved. The well designer must trade off the additional tools, complexities and risks against the potential capital savings when deciding whether to design for a liner or a casing string that goes all the way to the top of the well (a "long string"). The liner can be fitted with special components so that it can be connected to the surface at a later time if need be. Many conventional well designs include a production liner set across the reservoir interval.

liner hanger

A device used to attach or hang liners from the internal wall of a previous casing string.

lithology

The macroscopic nature of the mineral content, grain size, texture and color of rocks.

log

The measurement versus depth or time, or both, of one or more physical quantities in or around a well. The term comes from the word "log" used in the sense of a record or a note. Wireline logs are taken downhole, transmitted through a wireline to surface and recorded there. Measurements-while-drilling (MWD) and logging while drilling (LWD) logs are also taken downhole. They are either transmitted to surface by mud pulses, or else recorded downhole and retrieved later when the instrument is brought to surface. Mud logs that describe samples of drilled cuttings are taken and recorded on surface.

logging run

An operation in which a logging tool is lowered into a borehole and then retrieved from the hole while recording measurements. The term is used in three different ways. First, the term refers to logging operations performed at different times during the drilling of a well. For example, Run 3 would be the third time logs had been recorded in that well. Second, the term refers to the number of times a particular log has been run in the well. Third, the term refers to different runs performed during the same logging operation. For example, resistivity and nuclear logs may be combined in one tool string and recorded during the first run, while acoustic and nuclear magnetic resonance logs may be recorded during the second run.

logging tool

The downhole hardware needed to make a log. The term is often shortened to simply "tool." Measurements-while-drilling (MWD) logging tools, in some cases known as logging while drilling (LWD) tools, are drill collars into which the necessary sensors and electronics have been built. The total length of a tool string may range from 10 to 100 ft [3 to 30 m] or more. Flexible joints are added in long tool strings to ease passage in the borehole, and to allow different sections to be centralized or eccentralized. If the total length is very long, it is often preferable to make two or more logging runs with shorter tool strings.

logging while drilling (LWD)

The measurement of formation properties during the excavation of the hole, or shortly thereafter, through the use of tools integrated into the bottomhole assembly. LWD, while sometimes risky and expensive, has the advantage of measuring properties of a formation before drilling fluids invade deeply. Further, many wellbores prove to be difficult or even impossible to measure with conventional wireline tools, especially highly deviated wells. In these situations, the LWD measurement ensures that some measurement of the subsurface is captured in the event that wireline operations are not possible. Timely LWD data can also be used to guide well placement so that the wellbore remains within the zone of interest.

make up

To tighten threaded connections, to connect tools or tubulars by assembling the threaded connections incorporated at either end of every tool and tubular. The threaded tool joints must be correctly identified and then torqued to the correct value to ensure a secure tool string without damaging the tool or tubular body.

Markov process

A succession of values vi= 1...n randomly generated. Each value can be chosen among a finite number of states m, where S = s1,...,sm. Probability is given by the transition probability between si and sj that is specified in the transition matrix.

mechanical jar

A type of jar that incorporates a mechanical trip or firing mechanism that activates only when the necessary tension or compression has been applied to the running string.

mode

The most commonly occurring number in a set of numbers

mud

A term that is generally synonymous with drilling fluid and that encompasses most fluids used in hydrocarbon drilling operations, especially fluids that contain significant amounts of suspended solids, emulsified water or oil. Mud includes all types of water-base, oil-base and synthetic-base drilling fluids. Drill-in, completion and workover fluids are sometimes called muds, although a fluid that is essentially free of solids is not strictly considered mud. Used to flush the borehole of cuttings produced during drilling and to support the walls of the hole prior to the setting of casing. For liquid-dominated and EGS reservoirs, muds consist of aqueous solutions or suspensions with various additives chosen to provide appropriate thermal and fluid properties (density, viscosity, corrosion resistance, thermal conductivity, etc.). For vapor-dominated reservoirs, air is often used for the drilling fluid to avoid the possibility of clogging the fine fractures associated with a vapor system.

mud cleaner

A desilter unit in which the underflow is further processed by a fine vibrating screen, mounted directly under the cones. The liquid underflow from the screens is fed back into the mud, thus conserving weighting agent and the liquid phase but at the same time returning many fine solids to the active system. Mud cleaners are used mainly with oil- and synthetic-base muds where the liquid discharge from the cone cannot be discharged, either for environmental or economic reasons. It may also be used with weighted water-base fluids to conserve barite and the liquid phase.

mud motor

A positive displacement drilling motor that uses hydraulic horsepower of the drilling fluid to drive the drill bit. Mud motors are used extensively in directional drilling operations.

nipple down

To take apart, disassemble and otherwise prepare to move the rig or blowout preventers.

nipple up

To put together, connect parts and plumbing, or otherwise make ready for use. This term is usually reserved for the installation of a blowout preventer stack.

openhole

The uncased portion of a well. All wells, at least when first drilled, have openhole sections that the well planner must contend with. Prior to running casing, the well planner must consider how the drilled rock will react to drilling fluids, pressures and mechanical actions over time. The strength of the formation must also be considered. A weak formation is likely to fracture, causing a loss of drilling mud to the formation and, in extreme cases, a loss of hydrostatic head and potential well control problems. An extremely high-pressure formation, even if not flowing, may have wellbore stability problems. Once problems become difficult to manage, casing must be set and cemented in place to isolate the formation from the rest of the wellbore. While most completions are cased, some are open, especially in horizontal or extended-reach wells where it may not be possible to cement casing efficiently.

overburden

The weight of overlying rock.

overpressure

Subsurface pressure that is abnormally high, exceeding hydrostatic pressure at a given depth. Abnormally high pore pressure can occur in areas where burial of fluid-filled sediments is so rapid that pore fluids cannot escape, so the pressure of the pore fluids increases as overburden increases. Drilling into overpressured strata can be hazardous because overpressured fluids escape rapidly, so careful preparation is made in areas of known overpressure. Figure A-19 illustrates, abstractly, the process of overpressurization.

pack off

To plug the wellbore around a drillstring. This can happen for a variety of reasons, the most common being that either the drilling fluid is not properly transporting cuttings and cavings out of the annulus or portions of the wellbore wall collapse around the drillstring. When the well packs off, there is a sudden reduction or loss of the ability to circulate, and high pump pressures follow. If prompt remedial action is not successful, an expensive episode of stuck pipe can result. The term is also used in gravel packing to describe the act of placing all the sand or gravel in the annulus.

packer

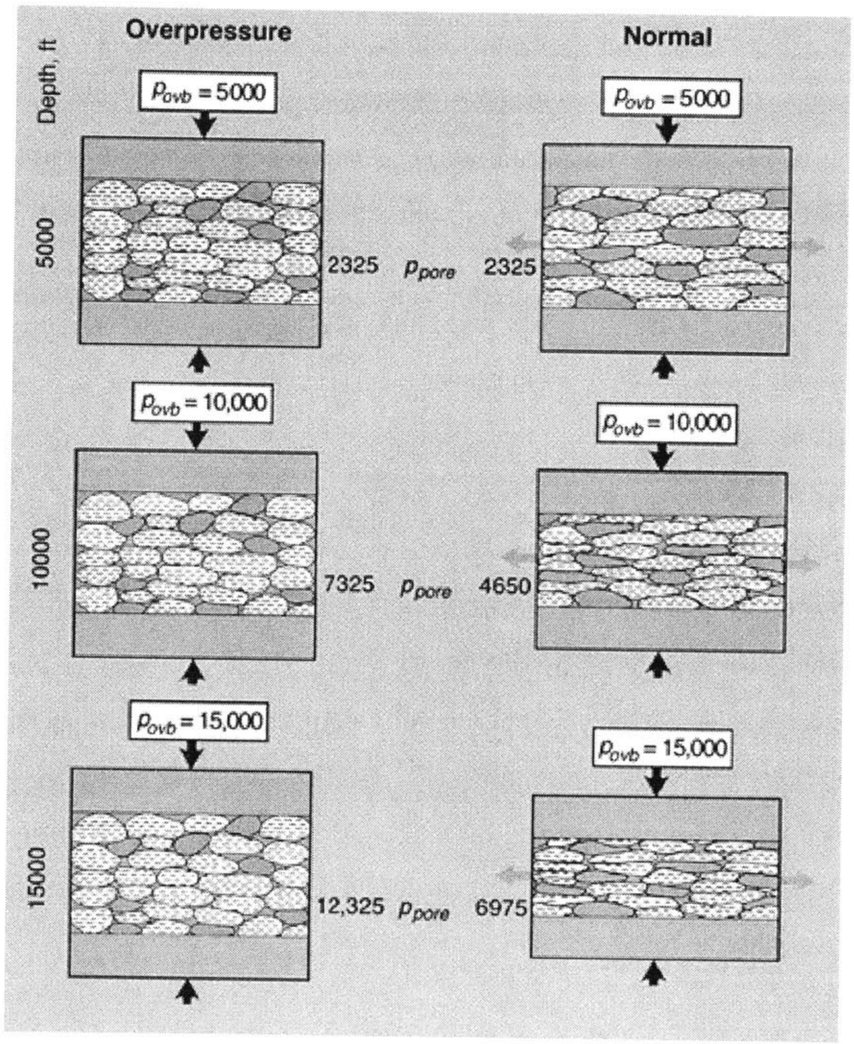


Figure A-19: Overpressure. During burial and compaction, most shales lose pore fluid continuously. Overpressure occurs when geologic burial is so rapid and permeability is so poor that the pore fluid cannot escape and supports ever-increasing stress. Povb is the overburden pressure in psi; Ppore is the pore pressure in psi.

A device that can be run into a wellbore with a smaller initial outside diameter that then expands externally to seal the wellbore. Packers employ flexible, elastomeric elements that expand. The two most common forms are the production or test packer and the inflatable packer. The expansion of the former may be accomplished by squeezing the elastomeric elements (somewhat doughnut shaped) between two plates, forcing the sides to bulge outward. The expansion of the latter is accomplished by pumping a fluid into a bladder, in much the same fashion as a balloon, but having more robust construction. Production or test packers may be set in cased holes and inflatable packers are used in open or cased holes. They may be run on wireline, pipe or coiled tubing. Some packers are designed to be removable, while others are permanent. Permanent packers are constructed of materials that are easy to drill or mill out. Packers used in almost every completion to isolate the annulus from the production conduit, enabling controlled production, injection or treatment. A typical packer assembly incorporates a means of securing the packer against the casing or liner wall, such as a slip arrangement, and a means of creating a reliable hydraulic seal to isolate the annulus, typically by means of an expandable elastomeric element. Packers are classified by application, setting method and possible retrievability. Figure A-20 shows a typical packer in relation to other components. Also, see the related, but distinct concept of a hydraulic packer.

perforated liner

A wellbore tubular in which slots or holes have been made before the string is assembled and run into the wellbore. Perforated liners are typically used in small-diameter wellbores or in sidetracks within the reservoir where there is no need for the liner to be cemented in place, as is required for zonal isolation.

permeability

The capability of a rock to allow passage of fluids through it, typically measured in darcies or millidarcies. Formations that transmit fluids readily, such as sandstones, are described as permeable and tend to have many large, well-connected pores. Impermeable formations, such as shales and siltstones, tend to be finer grained or of a mixed grain size, with smaller, fewer, or less interconnected pores. Permeability is

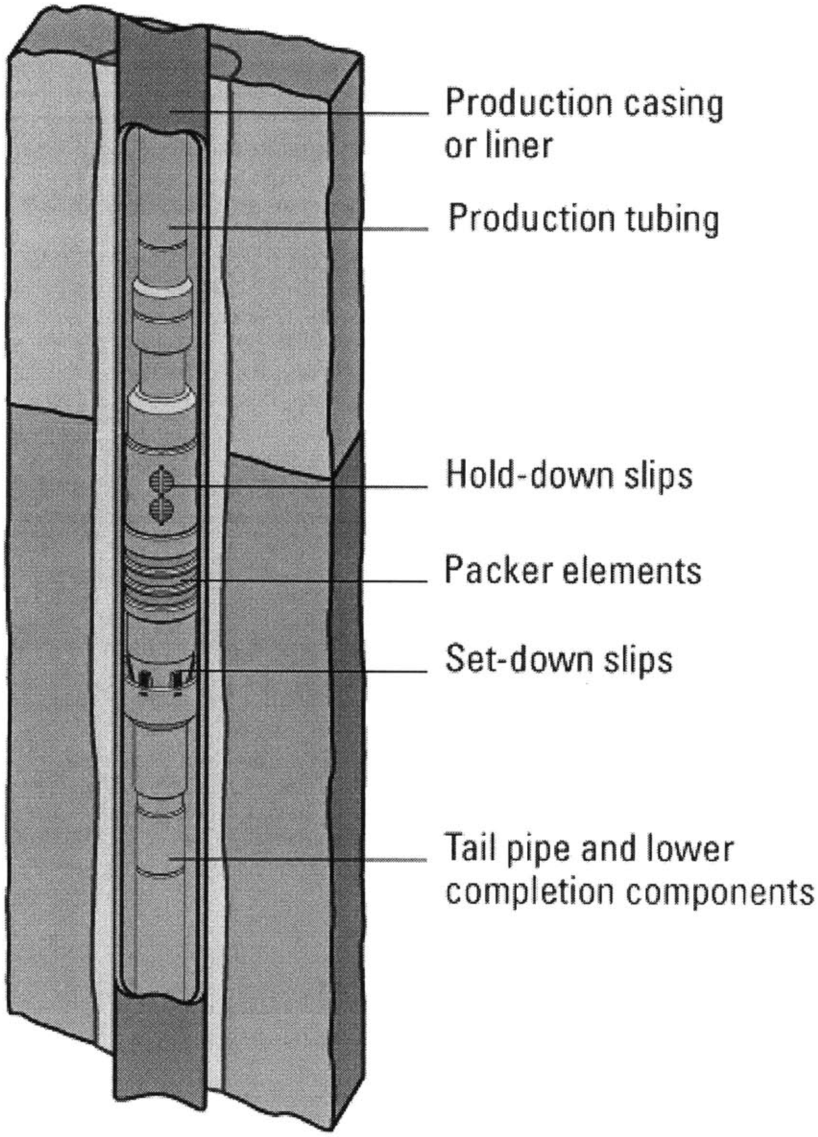


Figure A-20: Packer. There are many types and designs of packers in common use in oil and gas operations. In each case, the principal function is to isolate the annulus from the tubing conduit to enable controlled production, injection or treatment. The mechanical packer shown here is used to isolate zones during stimulation treatments.

also loosely connected to conductivity, measured in meters per second

pick-up

The depth at which the tool string is picked up off the bottom of the well during a wireline logging survey. Pick-up can be observed by an increase in cable tension and by the start of activity in the log curves. When the logging tool is lowered to the bottom of the well, it is common practice to spool in some extra cable. When the cable is pulled back out, the tool remains stationary before it is picked up off the bottom. During this time the log readings are static but the depth, which is recorded by the movement of the cable, is changing.

pore pressure

The pressure of fluids within the pores of a reservoir, usually hydrostatic pressure, or (rarely in a geothermal context) the pressure exerted by a column of water from the formation's depth to sea level. When impermeable rocks such as shales form by sediment compaction, their pore fluids cannot always escape and must then support the total overlying rock column, leading to anomalously high formation pressures.

porosity

The percentage of pore volume or void space, or that volume within rock that can contain fluids. Porosity can be generated by the development of fractures, in which case it is called fracture porosity.

pressure

The force distributed over a surface, usually measured in pounds force per square inch.

probabilistically defined

Parameters are generated following a probabilistic process.

production casing

A casing string that is set across the reservoir interval.

proppant

Small-sized particles that are mixed with hydrofracturing fluids to hold fractures open after a hydraulic fracturing treatment. Proppant materials are carefully sorted for size and shape, hardness, and chemical resistance to provide an efficient conduit for production of fluid from the reservoir to the wellbore.

ram blowout preventer

A device that can be used to quickly seal the top of the well in the event of a well control event. A ram blowout preventer (BOP) consists of two halves of a cover for the well that are split down the middle. Large-diameter hydraulic cylinders, normally retracted, force the two halves of the cover together in the middle to seal the wellbore. These covers are constructed of steel for strength and fitted with elastomer components on the sealing surfaces. The halves of the covers, formally called ram blocks, are available in a variety of configurations. In some designs, they are flat at the mating surfaces to enable them to seal over an open wellbore. Other designs have a circular cutout in the middle that corresponds to the diameter of the pipe in the hole to seal the well when pipe is in the hole. These pipe rams effectively seal a limited range of pipe diameters. Variable-bore rams are designed to seal a wider range of pipe diameters, albeit at a sacrifice of other design criteria, notably element life and hang-off weight. Still other ram blocks are fitted with a tool steel-cutting surface to enable the ram BOPs to completely shear through drillpipe, hang the drillstring off the ram blocks themselves and seal the wellbore. Obviously, such an action limits future options and is employed only as a last resort to regain pressure control of the wellbore. The various ram blocks can be changed in the ram preventers, enabling the well team to optimize BOP configuration for the particular hole section or operation in progress. Also see annular blowout preventer.

reservoir

A subsurface body of rock having sufficient porosity and permeability to store and transmit fluids. A reservoir is a critical component of a complete geothermal system.

reservoir characterization

A model of a reservoir that incorporates all the characteristics of the reservoir that are pertinent to its ability to store, transmit, and transfer heat to a working fluid. Reservoir characterization models are used to simulate the behavior of the fluids within the reservoir under different sets of circumstances and to find the optimal techniques that will maximize the production. In verb form, reservoir characterization describes the act of building a reservoir model based on its characteristics with respect to fluid flow and thermodynamics.

rotary table

The revolving or spinning section of the drillfloor that provides power to turn the drillstring in a clockwise direction (as viewed from above). The rotary motion and power are transmitted through the kelly bushing and the kelly to the drillstring. When the drillstring is rotating, the drilling crew commonly describes the operation as simply, "rotating to the right," "turning to the right," or, "rotating on bottom." Almost all rigs today have a rotary table, either as primary or backup system for rotating the drillstring. Topdrive technology, which allows continuous rotation of the drillstring, has replaced the rotary table in certain operations. A few rigs are being built today with topdrive systems only, and lack the traditional kelly system.

shaker

The primary device on a drilling rig for removing drilled solids from the mud. This vibrating sieve is simple in concept, but a bit more complicated to use efficiently. A wire-cloth screen vibrates while the drilling fluid flows over it. The liquid phase of the mud and solids smaller than the wire mesh pass through the screen, while larger solids are retained on the screen and eventually fall off the back of the device and are discarded. Smaller openings in the screen clean more solids from the whole mud, but there is a corresponding decrease in flow rate per unit area of wire cloth. Hence, screens are chosen to be as fine as possible, without dumping whole mud off the back of the shaker. It is common to use multiple, iterated shakers, with progressively increasing fineness.

shoe track

The space between the float or guide shoe and the landing or float collar. The principal function of this space is to ensure that the shoe is surrounded in high-quality cement and that any contamination that may bypass the top cement plug is safely contained within the shoe track.

spud

To start the well drilling process by removing rock, dirt and other sedimentary material with the drill bit.

stab

To place the male threads of a piece of the drillstring, such as a joint of drillpipe, into the mating female threads, prior to making up tight.

standoff

The distance between the external surface of a logging tool and the borehole wall. This distance has an important effect on the response of some logging measurements, notably induction and neutron porosity logs. For resistivity tools, the effect of standoff is taken into account in the borehole correction. In the neutron porosity tool, it is usually corrected for separately. In a smooth, regular hole, the standoff is constant and determined by the geometry of the logging tool string and the borehole. In rugose or irregular holes, standoff varies along the well.

starting probability (DAT)

The first operation in a Markovian generation consists of finding the initial state of a parameter before starting the Markov process. The user is asked to give for each state a value between 0.0 and 1.0 representing the probability of that state occurring.

stimulation

A treatment performed to restore or enhance the productivity of a geothermal reservoir. Stimulation treatments fall into two main groups, hydraulic fracturing treatments and matrix treatments. Fracturing treatments are performed above the fracture pressure of the reservoir formation and create a reservoir with highly conductive flow paths. Matrix treatments are performed below the reservoir fracture pressure and generally are designed to restore the natural permeability of the reservoir following damage to the near-wellbore area. Stimulation in hydrothermal reservoirs typically takes the form of hydraulic fracturing treatments.

stress

The force applied over an area that can result in deformation, or strain, usually described in terms of magnitude per unit of area, or intensity.

stuck

Referring to the varying degrees of inability to move or remove the drillstring from the wellbore. At one extreme, it might be possible to rotate the pipe or lower it back into the wellbore, or it might refer to an inability to move the drillstring vertically in the well, though rotation might be possible. At the other extreme, it reflects the inability to move the drillstring in any manner. Usually, even if the stuck condition starts with the possibility of limited pipe rotation or vertical movement, it will degrade to the inability to move the pipe at all.

stuck pipe

The portion of the drillstring that cannot be rotated or moved vertically.

surface casing

A large-diameter, relatively low-pressure pipe string set in shallow yet competent formations for several reasons. First, the surface casing protects fresh-water aquifers. Second, the surface casing provides minimal pressure integrity, and thus enables a diverter or perhaps even a blowout preventer (BOP) to be attached to the top of the surface casing string after it is successfully cemented in place. Third, the surface casing provides structural strength so that the remaining casing strings may be suspended at the top and inside of the surface casing.

survey

A data set measured and recorded with reference to a particular area of the Earth's surface, such as a seismic survey. To record a measurement versus depth or time, or both, of one or more physical quantities in or around a well. There is some overlap in definition with a log.

thermal conductivity

The intensive property of a material that indicates its ability to conduct heat. Heat flow is proportional to the product of the thermal conductivity and the temperature gradient.

thermal drawdown rate

The drop in temperature per unit time of a body of reservoir rock, subject to the circulation of water in a closed loop as envisioned in an EGS facility.

threadform

A particular style or type of threaded connection.

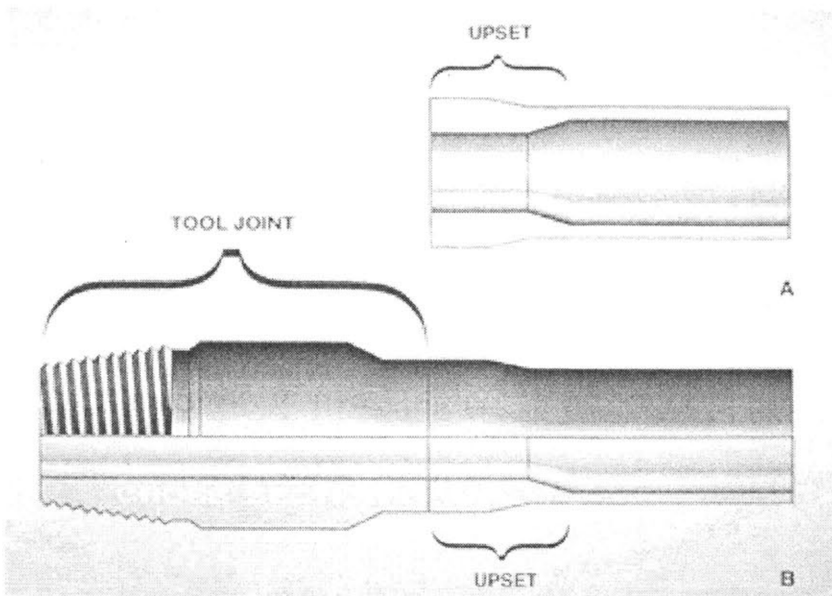


Figure A-21: Tool joint. The enlarged, threaded ends of drillpipe ensure strong connections that withstand high pressures. This diagram shows the enlargement, known as upset, and the threads at the end of the joint.

tool joint

The enlarged and threaded ends of joints of drillpipe. These components are fabricated separately from the pipe body and welded onto the pipe at a manufacturing facility. The tool joints provide high-strength, high-pressure threaded connections that are sufficiently robust to survive the rigors of drilling and numerous cycles of tightening and loosening at threads. Tool joints are usually made of steel that has been heat treated to a higher strength than the steel of the tube body. The large-diameter section of the tool joints provides a low stress area where pipe tongs are used to grip the pipe. Hence, relatively small cuts caused by the pipe tongs do not significantly impair the strength or life of the joint of drillpipe.

topdrive

A device that turns the drillstring. It consists of one or more motors (electric or hydraulic) connected with appropriate gearing to a short section of pipe called a quill, that in turn may be screwed into a saver sub or the drillstring itself. The topdrive is suspended from the hook, so the rotary mechanism is free to travel up and down

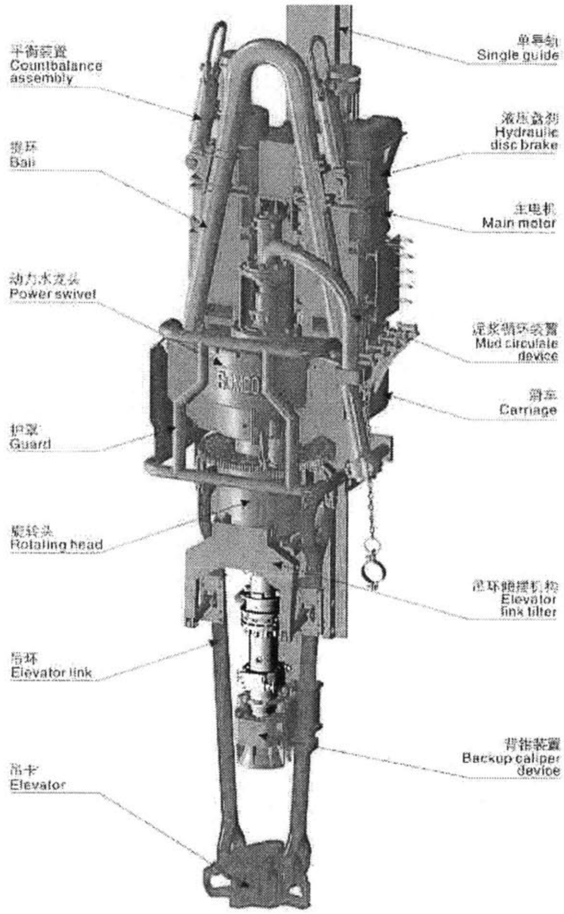


Figure A-22: Topdrive. The topdrive system is responsible for providing mechanical power to the drillstring.

the derrick. This is radically different from the more conventional rotary table and kelly method of turning the drillstring because it enables drilling to be done with three joint stands instead of single joints of pipe. It also enables the driller to quickly engage the pumps or the rotary while tripping pipe, which cannot be done easily with the kelly system. While not a panacea, modern topdrives are a major improvement to drilling rig technology and are a large contributor to the ability to drill more difficult extended-reach wellbores. In addition, the topdrive enables drillers to minimize both frequency and cost per incident of stuck pipe.

transition matrix (DAT)

The transition matrix gives the transition probabilities from state to state if a transition occurs. The rows of the matrix must have a sum equal to 1.0 because the transition probability from a state to all other states must be one.

transmissivity

The ability of a reservoir to allow the flow of fluid through a certain area, generally in the horizontal direction. The transmissivity is the product of the permeability (a property of the rock only, related to the interconnectedness and size of fractures or pores) and the thickness of the formation through which the fluid is flowing. Transmissivities in geothermal systems are very high, often having values greater than 100 darcy-meters, compared to oil and gas reservoirs where transmissivities are typically 100 to 1,000 times smaller.

trip

The complete operation of removing the drillstring from the wellbore and/or running it back in the hole. This operation is typically undertaken when the bit becomes dull or broken, and no longer drills the rock efficiently. After some preliminary preparations for the trip, the rig crew removes the drillstring 90 ft [27 m] at a time, by unscrewing every third drillpipe or drill collar connection. When the three joints are unscrewed from the rest of the drillstring, they are carefully stored upright. After the drillstring has been removed from the wellbore, the dull bit is unscrewed with the use of a bit breaker and quickly examined to determine why the bit dulled or failed. Depending on the failure mechanism, the crew might choose a different type of bit for the next section. If the bearings on the prior bit failed, but the cutting structures are still sharp and intact, the crew may opt for a faster drilling (less durable) cutting structure. Conversely, if the bit teeth are worn out but the bearings are still sealed and functioning, the crew should choose a bit with more durable (and less aggressive) cutting structures. Once the bit is chosen, it is screwed onto the bottom of the drill collars with the help of the bit breaker, the drill collars and drill pipe are run into the hole. Once on bottom, drilling commences again. The duration of this operation depends on the total depth of the well and the skill of the rig crew. A general estimate for a competent crew is that the round trip requires one hour per thousand feet of hole, plus an hour or two for handling collars and bits. At this rate, a round trip in a ten thousand-foot well might take twelve hours. A round trip for a 30,000-ft [9230 m] well might take 32 or more hours, especially if intermediate hole-cleaning operations must be undertaken.

trip gas

Gas entrained in the drilling fluid during a pipe trip, which typically results in a significant increase in gas that is circulated to surface. This increase arises from a combination of two factors: lack of circulation when the mud pumps are turned off, and swabbing effects caused by pulling the drillstring to surface. These effects may be seen following a short trip into casing or a full trip to surface.

underreaming

A method of opening up a wellbore to a larger size, often achieved by setting the drill bit below the bottom of the casing string and expanding it radially.

washout

An enlarged region of a wellbore. A washout in an openhole section is larger than the original hole size or size of the drill bit. Washout enlargement can be caused by a hole in a pressure-containing component caused by erosion, excessive bit jet velocity, soft or unconsolidated formations, in-situ rock stresses, mechanical damage by BHA components, chemical attack and swelling or weakening of shale as it contacts fresh water. Generally speaking, washouts become more severe with time. Appropriate mud types, mud additives and increased mud density can minimize washouts. A washout is relatively common where a high-velocity stream of dry gas carries abrasive sand. The severity generally decreases with sand content, velocity and liquid content.

well

A well, strictly speaking, is a vertical underground opening open at the top end with a length substantially greater than the cross-sectional dimension.

wellbore

see borehole

wellhead

The surface termination of a wellbore that incorporates facilities for installing casing hangers during the well construction phase. The wellhead also incorporates a means of hanging the production tubing and installing the systems associated with the wellhead and surface flow-control facilities in preparation for the production phase of the well.

wiper trip

An abbreviated recovery and replacement of the drillstring in the wellbore that usually includes the bit and bottomhole assembly passing by all of the openhole, or at least all of the openhole that is thought to be potentially troublesome. This trip varies from the short trip or the round trip only in its function and length. Wiper trips are commonly used when a particular zone is troublesome or if hole-cleaning efficiency is questionable.

wireline

Related to any aspect of logging that employs an electrical cable to lower tools into the borehole and to transmit data. Wireline logging is distinct from measurements-while-drilling (MWD) and mud logging. A general term used to describe well-intervention operations conducted using single-strand or multistrand wire or cable for intervention in oil or gas wells. The term commonly is used in association with electric logging and cables incorporating electrical conductors. Similarly, the term slickline is commonly used to differentiate operations performed with single-strand wire or braided lines.

wireline formation test

Test taken with a wireline formation tester. The wireline formation pressure measurement is acquired by inserting a probe into the borehole wall and performing a minidrawdown and buildup by withdrawing a small amount of formation fluid and then waiting for the pressure to build up to the formation pore pressure. This measurement can provide formation pressures along the borehole, thereby giving a measure of pressure with depth or along a horizontal borehole. The trend in formation pressure with depth provides a measure of the formation-fluid density, and a change in this trend may indicate a fluid contact. Abrupt changes in formation pressure measurements with depth indicate differential pressure depletion and demonstrate

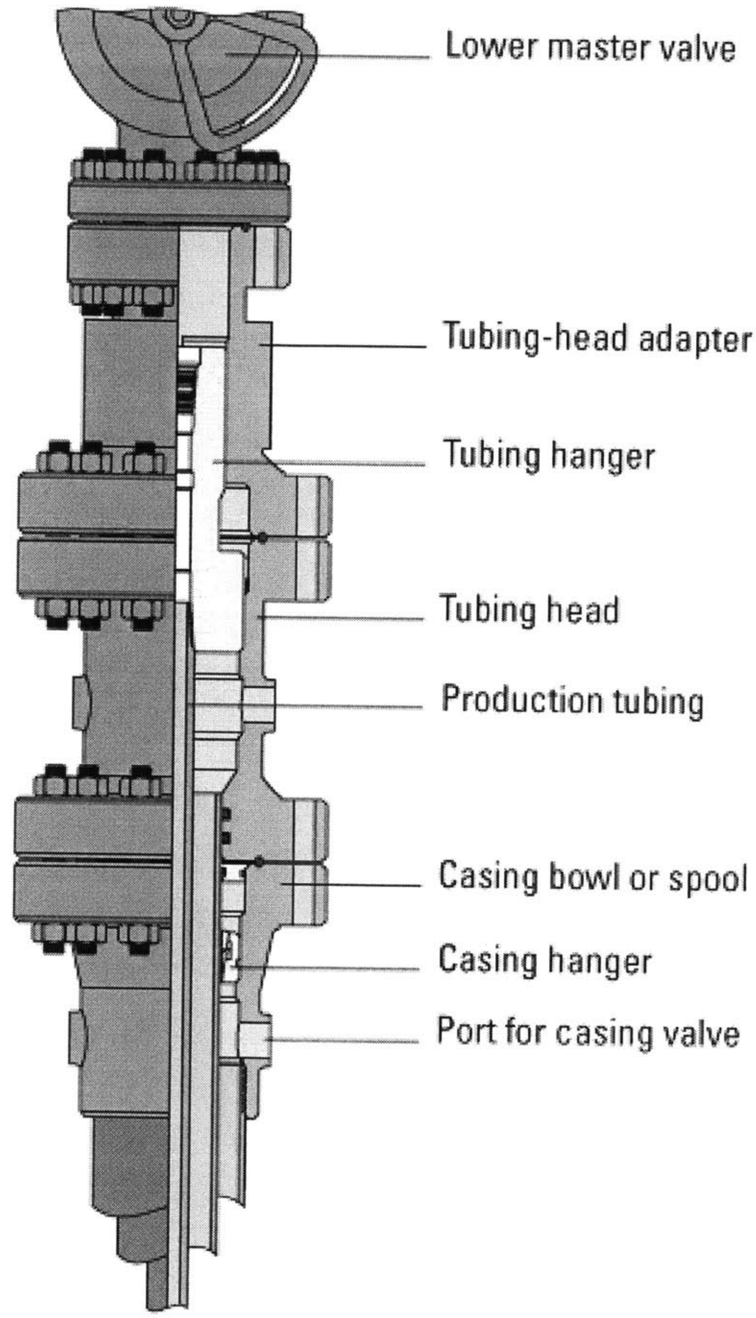


Figure A-23: Wellhead. The wellhead is assembled from, or incorporates facilities for, the upper casing and tubing hangers. This effectively provides the upper termination of the wellbore and provides a mounting position for the surface flow-control equipment barriers to vertical flow. Lateral variation in formation pressure measurements along a horizontal well or in multiple vertical wells indicate reservoir heterogeneity.

wireline log

A continuous measurement of formation properties with electrically powered instruments to infer properties and make decisions about drilling and production operations. The record of the measurements, typically a long strip of paper, is also called a log. Measurements include electrical properties (resistivity and conductivity at various frequencies), sonic properties, active and passive nuclear measurements, dimensional measurements of the wellbore, formation fluid sampling, formation pressure measurement, wireline-conveyed sidewall coring tools, and others. In wireline measurements, the logging tool (or sonde) is lowered into the open wellbore on a multiple conductor, contra-helically armored wireline. Once lowered to the bottom of the interval of interest, the measurements are taken on the way out of the wellbore. This is done in an attempt to maintain tension on the cable (which stretches) as constant as possible for depth correlation purposes. Most wireline measurements are recorded continuously even though the sonde is moving. Certain fluid sampling and pressure-measuring tools require that the sonde be stopped, increasing the chance that the sonde or the cable might become stuck. Logging while drilling (LWD) tools take measurements in much the same way as wireline-logging tools, except that the measurements are taken by a self-contained tool near the bottom of the bottomhole assembly and are recorded downward (as the well is deepened) rather than upward from the bottom of the hole (as wireline logs are recorded).

zone (DAT)

A geologic region in the area that is not precisely positioned, and thus has a probabilistic start point and length. However, a zone has the same, albeit probabilistically expressed, geological characteristics everywhere. It is thus related to a set of ground parameters and their probability of occurrence in the region.

Appendix B

Tester Report Estimation

The Tester report on geothermal energy provided detailed cost breakdowns for two of its base-case wells, a four-interval 5000m well, and a five-interval 5000m well. Although the report's cost breakdowns are not utilized for modeling purposes, they are reproduced here for completeness. Section B.1 details the inputs that went into the report's cost breakdowns, Section B.2 gives an example of how each breakdown is performed, looking at the third interval of the four-interval example, and finally Section B.3 shows the ultimate results of the cost breakdown.

B.1 MIT EGS Study Cost Breakdown Inputs

B.2 MIT EGS Study Cost Breakdown Example Snapshot

B.3 MIT EGS Study Cost Breakdown Results

Cost Information Field								
EGS 5000 m 16400 ft E Rev7 10-5/8		**12/3/2005**						
Well Configuration	**Hole Dia**	**Depths**	**Casing**		**Cost/ft**	**Interval**	**ROP**	**Bit Life**
Conductor Pipe/Line Pipe	26"bit/36"HO	80	30"0.375 Wall welded 118lb/ft		$90.00	Conductor		
Surface CSG	28"	1,250	22"0.625 Wall welded		$107.00	1 Casing	25	90
Intermediate CSG	20"	5,000	16"109lb K-55 Premium		$70.86	2 Liner	25	80
Intermediate CSG 2	14-3/4"	13,120	11-3/4"73.6lb T-95 Premium		$78.24	3 Casing	18	65
Production Zone	10-3/8"special	16,400	8-5/8"36lb K-55 slotted Butt		$29.80	4 perf Liner	15	45
Prespud and Mobilization			**Depths**	**Casing Critical psi**	**Frac Gradient psi/ft**	**Mud Shoe Pressure**		
					0.8	9.6	Csg String	
	Activity Cost		80	112 psi	64	40		
Mobilization	$132,000		1,250	570 psi	1000	624	22"0.625lb	
Mobilization Labor	$16,500		5,000	3180 psi	4000	2496	16"109lb	
Demobilization	$66,000		13,120	5920 psi	10496	6550	11-3/4"73.6lb	
Demobilization Labor	$16,500		16,400	9320 psi	13120	8187	8-5/8"36lb	
Waste Disposal & Cleanup	$30,000		0	N/A		0		
		$261,000.00						
Location Cost								6-39
Site Expense	$32,000							
Cellar	$25,000							
Drill Conductor Hole	$8,000							
Water Supply	$10,000							
Initial Mud Cost	$10,000							
Prespud Cost Total		$85,000.00						
		$346,000.00						
				Description				
Daily Operating Cost	**$1,040.65**	**$24,975.60**						
Rig Day Rate	$687.50	$16,500.00		2,000	hp	1,200,000 mast		
Fuel		$1,425.60		0.45 x hp x 0.06x cost per gal x 24		Cost Per Gallon		
Water		$400.00		Estimated				
Electric Power		$50.00		Estimated		$1.10		
Camp Expense		$200.00		Estimated				
Drilling Supervision		$1,200.00		$1000/day 1 man				
DRLG Engr & Management		$1,000.00		Estimated				
Mud Logging		$1,800.00		Current Rate				
Hole Insurance		$250.00		Estimated				
Administrative Overhead		$500.00		Estimated				
Misc Transportation		$500.00		Estimated				
Site Maintenance		$200.00		Estimated				
Waste Disposal and Cleanup		$200.00		Estimated				
Misc Services		$750.00		Estimated				

EGS 5000 m 16400 ft E Rev 7 10-5/8						
		Input Information Interval 3				
Production Casing		**14-3/4"**	**Casing**	**11-3/4" 73.6lb T-95 Premium**		**$78.24**
Depth of Interval 3		13120	Shoe Depth	13,120	Casing Length	
Interval Length		8120	Interval Length			
		ROP ft/hr	Bit Life Hrs	No.of Bits		
Bit Performance	14-3/4"bit	18.00	65.00	7		
	Hourly Rates	**Rig Time**	**Charge Time-Not Rig Time**	**Misc. Hourly Expense**	**One Time Expenses**	**Explanation of Charges and source of Information**
Delta Time Hrs		451.11				Computed Drilling Hours
Technical Changes Hrs & $						
Drilling Fluids						
Mud Cost $/Hr	$100.00	x		$45,111.11	$4000.00	Hourly Mud Expense
Mud Treatment Equip	$25.00	x	451.11	$11,277.78	$1000.00	Mud Treatment Equipment
Mud Cooling Equip	$20.00	x	451.11	$9,022.22	$1000.00	Mud Coolers
Air Service Hrs & $	$150.00		20.00	$3,000.00	$2,000.00	Air Drilling Services
D/H Tools and Times						
BHA Changes Hrs	2	14.00				Hours to Change BHA
BIT Trips Hrs		63.42				Total Interval Trip Time
BITS	$18,970.00	x			$132,790.00	14-3/4"$17,000 each
Stab, Reamers, HO		x			$26,558.00	
DRLG Tools. Jars, Shocks		x			$19,918.50	
D/H Rentals, DP, DC, Motor		x			$17,000.00	
Drill String Inspections		x			$3,000.00	
Small Tools and Supplies		x			$5,000.00	
Reaming Hrs & $	$0.00		12.00	$0.00	$4,000.00	Reaming Hrs &$
Hole Opening Hrs & $	$0.00		0.00	$0.00	$0.00	Hole Opening Hrs & $
Directional						
Dir Engr Services Hrs & $	$40.00	10.00	451.11	$18,044.44	$1,200.00	Directional Drilling Expense
Dir Tools Hrs & $	$10.00	x	451.11	$4,511.11	$4,000.00	Directional Drilling Tools
Mud Motors Hrs & $	$200.00	x	451.11	$90,222.22	$1,000.00	Mud Motor Charges
Steering/MWD Equip Hrs & $	$100.00	x	451.11	$45,111.11	$1,000.00	MWD Charges
Trouble						
Fishing Hrs & $	$10.00	0.00	0.00	$0.00	$1,000.00	Fishing Standby and Expenses
Lost Circulation Hrs & $		0.00	0.00		0.00	Lost Circulation Estimated
MISC Trouble Hrs & $		12.00				Misc Trouble Cost

EGS 5000 m 16400 ft E Rev 7 10-5/8						
End of interval						
Logging Hrs & $		18.00			$36,000.00	Logging Time and Expense
Casing Services $		x			$40,350.00	Casing Service, or Welding, and Mob.
CSG/Liner Hrs & $		48.00			$1,026,508.80	Casing Time and Cost
Casing Cementing Equipment		x			$8,000.00	
Liner Hanger and Packers		0.00			$0.00	Liner Hanger if used
Cementing Hrs & $	30% excess	22.00	$40/ft^3		$270,000.00	Cementing time, WOC and expense
End of Interval Hrs & $		12.00			$20,000.00	End of Interval
Wellhead $		8.00			$15,000.00	Well Head Cost
Welding and Heat Treat		24.00	Rental 16-3/4"		$25,000.00	Welding and Heat Treat
BOPE Hrs & $	$1,212.00	12.00	BOPE	$22,781.11	$3,000.00	BOPE Rental, Change out Time, Testing
Test and Completion			**Install 11" BOPE**			
Location Cost		x			$0.00	
Testing Coring Sampling		0.00			$0.00	
Well Testing Hrs & $		0.00			$0.00	Well Testing Expenses
Completion Hrs & $		12.00			$20,000.00	Valves
Production Tree and Valves		0.00			$84,000.00	Master Valves and exp Spool
				$249,081.11		
Total Interval Rig Hours		**706.53**	**Daily Operating**	**$735,251.60**		
					$1,772,325.30	$2,756,658.01

EGS 5000 m 16400 ft E Rev 7 10-5/8		**12/3/2005**		
BJL		**AFE Days:**	**76**	
	Descriptions of Costs			
No Entry Point		**AFE Amount**	**$6,600,809.43**	
	Tangible Drilling Costs			
	Casing	$1,577,155.80		
Cond	30"0.375 Wall Welded		$7,200.00	80 ft
Int 1	22"0.625 Wall Welded		$139,750.00	1250 ft-28"bit
Int 2	16"109lb L80 Premium		$287,897.00	5000 ft-20"bit
Int 3	11-3/4"73.6lb K-55 Premium		$1,034,508.80	13120 ft-14.75"bit
Int 4	8-5/8"40lb K-55 Slotted		$107,800.00	16400 ft-10.375"bit
	Other Well Equipment			
	Wellhead Assembly	$35,000.00		
	Production Tree and Valves	$104,000.00		
	Liner Hangers and Packers	$52,000.00		
	Total of Tangible Drilling Costs	**$1,768,155.80**		
	Intangible Drilling Costs			
ok	Drilling Engineering	$75,619.70		
ok	Direct Supervision	$90,743.64		
ok	Mobilization and Demobilization	$346,000.00		
ok	Drilling Contractor	$1,247,725.03		
	Bits, Tools, Stabilizers, Reamers etc			
	Bit Totals	$321,647.50		
Int 1	0' to 1250' Interval 28"		$43,190.00	
Int 2	1250' to 5000' Interval 20"		$53,480.00	
Int 3	5000' to 12000' Interval 14-3/4"		$132,790.00	
Int 4	12000' to 16000' Interval 10-3/8"		$92,187.50	
ok	Stabilizers, Reamers and Hole Openers	$64,329.50		
Int 1	0' to 1250' Interval 28"		$8,638.00	
Int 2	1250' to 5000' Interval 20"		$10,696.00	
Int 3	5000' to 12000' Interval 14-3/4"		$26,558.00	
Int 4	12000' to 16000' Interval 10-3/8"		$18,437.50	
EGS 5000 m 16400 ft E Rev 7 10-5/8				
	Other Drilling Tools, Jars, Shock Subs, etc	$48,247.13		
Int 1	0' to 1250' Interval 28"		$6,478.50	
Int 2	1250' to 5000' Interval 20"		$8,022.00	
Int 3	5000' to 12000' Interval 14-3/4"		$19,918.50	
Int 4	12000' to 16000' Interval 10-3/8"		$13,828.13	
	D/H Rentals DP, DC, Motors etc	$72,000.00		
	Drill String Inspections	$12,500.00		
	Small Tools, Services, Supplies	$20,000.00		
	Reaming	$7,500.00		
	Hole Opening	$ -		

	Directional Services and Equipment			
	Directional	$272,975.56		
	Directional Engineering Service		$36,451.11	
	Directional Tools		$23,191.11	
	Mud Motors		$140,222.22	
	Steering/MWD Equipment		$73,111.11	
	Trouble			
	Fishing Tools and Services	$5,000.00		
	Lost Circulation	$40,000.00		
	Misc. Trouble Cost	$ -		
	Drilling Fluids Related			
	Drilling Muds, Additives & Service	$104,227.78		
	Mud Cleaning Equipment	$25,744.44		
	Mud Coolers	$19,395.56		
	Air Drilling Services and Equipment	$45,500.00		
	Casing Cementing and EOI			
	Casing Tools and Services	$127,060.00		
	Welding and Heat Treat	$49,000.00		
	Cement and Cement Services	$554,000.00		
	Mob/Demob Cementing Equipment		$ -	
Int 1	0' to 1250' Interval 28"x 22"	Casing	$122,000.00	
Int 2	1250' to 5000' Interval 20"x 16"	Casing	$162,000.00	
Int 3	5000' to 12000' Interval 14-3/4"x 11-3/4"	Shoe to Surface	$270,000.00	
Int 4	No Cement Perforated Liner	Perforated Liner	$ -	
	Well Control Equipment			
	Blow out Preventer Rentals	$48,546.67		
Int 1	Diverter		$3,500.00	26" to 1,000'
Int 2	21-1/4"2000 Stack		$10,750.00	20" to 5,000'
Int 3	16-3/4"3000 Stack		$25,781.11	14-3/4" to 10,000'
Int 4	13-5/8"3000 Stack		$8,515.56	10-3/8" to 15,000'
Int 5	13-5/8"3000 Stack		$ -	7-7/8" to 20,000

EGS 5000 m 16400 ft E Rev 7 10-5/8			
	Logging and Testing		
ok	Mud Logging and H2S Monitoring & Equip.	$136,115.46	
	Electrical Logging	$94,000.00	
Int 1	0' to 1250' Interval		$ –
Int 2	1250' to 5000' Interval		$18,000.00
Int 3	5000' to 12000' Interval		$36,000.00
Int 4	12000' to 16000' Interval		$40,000.00
Int 5	16000' to 20000' Production Interval		$ –
	Testing, Sampling & Coring	$2,000.00	
	Well Test	$130,000.00	
	Completion Costs	$95,000.00	
	Misc Expenses		
ok	Transportation and Cranes	$37,809.85	
ok	Fuel	$107,803.44	
ok	Water and System	$30,247.88	
ok	Electric Power	$3,780.98	
	Location Cost		
ok	Camp Cost and Living Expenses	$15,123.94	
ok	Site Cleanup, Repair, Waste Disposal	$15,123.94	
	Site Maintenance	$15,123.94	
	Location Costs	$ –	
	Misc Administrative and Overhead		
	Administrative Overhead	$37,809.85	
	Well Insurance	$18,904.92	
	Miscellaneious Services	$56,714.77	
	Total Intangible Drilling Costs	$4,393,321.48	75.620 days
	Total Tangible Drilling Costs	$1,768,155.80	
	Total Tangible and Intangible Costs	$6,161,477.28	
	Contingencies 10% of Intangibles	$439,332.15	
	Total Drilling Costs	$6,600,809.43	

Appendix C

ThermaSource Reports

Sandia contacted ThermaSource Inc, a geothermal well drilling consultancy, to provide it detailed well design information and a well drilling project itinerary. Table C.1 of this Appendix is the ThermaSource-provided itinerary of the well construction process. Table C.2 is a cost itemization of the construction project. We note a small error in Table C.1: the total time requirement for the Surface Casing stage is 85 hours, not 87 as listed by ThermaSource.

C.1 Well Drilling Project Itinerary

C.2 Well Cost Itemization

ThermaSource

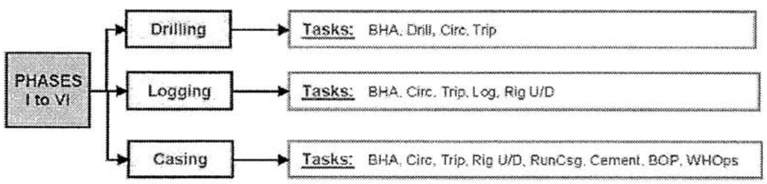
GEOTHERMAL CONSULTING AND DRILLING

TASK ANALYSIS

OPERATOR NAME: **SANDIA NATIONAL LABORATORIES**

FIELD NAME:	Clear Lake, CA	Estimator / Engineer:	Robert J. Swanson
Well Name:	20,000-ft EGS Well	Date:	August 13, 2008

Phase	Activity	Task Code	GENERAL OPERATION TASKS	Hours	Days
				3,386	141.0



Phase I: Surface			(36" Hole to 500' with 30" Casing)	180	7.5
1 Surface	**DRILLING OPERATIONS**			86	3.6
1 Surface	Drilling	BHA	1. Make up 26" bit and 36" hole opener on mud motor.	6	0.3
1 Surface	Drilling	BHA	2. Pick up 36" stabilizer and cross over to 6-5/8" HWDP.	4	0.2
1 Surface	Drilling	Drill	3. Drill and open 36" hole with motor and HWDP from 80' to 240'.	13	0.5
1 Surface	Drilling	Circ	4. Circulate	1	0.0
1 Surface	Drilling	BHA	5. Trip out of the hole and stand back 6-5/8" HWDP.	2	0.1
1 Surface	Drilling	BHA	6. Pick up (6) 11" drill collars and cross over to 6-5/8" HWDP.	8	0.3
1 Surface	Drilling	Drill	7. Drill and open 36" hole from 240' to 320'.	7	0.3
1 Surface	Drilling	Circ	8. Circulate	1	0.0
1 Surface	Drilling	BHA	9. Stand back 6-5/8" HWDP	2	0.1
1 Surface	Drilling	BHA	10. Pick up (3) 9-1/2" drill collars and cross over to 6-5/8" HWDP.	6	0.3
1 Surface	Drilling	Drill	11. Drill and open 36" hole from 320' to 500'.	15	0.6
1 Surface	Drilling	Circ	12. Circulate.	1	0.0
1 Surface	Drilling	Trip	13. Make a wiper trip to 320'.	4	0.2
1 Surface	Drilling	Circ	14. Circulate	1	0.0
1 Surface	Drilling	Trip	15. Trip out of the hole.	2	0.1
1 Surface	Drilling	BHA	16. Stand back HWDP and drill collars.	7	0.3
1 Surface	Drilling	BHA	17. Break out and lay down 36" stabilizer, mud motor, 36" hole opener and 26" bit.	6	0.3
1 Surface	**LOGGING OPERATIONS**			7	0.3
1 Surface	Logging	RigU/D	1. Rig up logging equipment.	2	0.1
1 Surface	Logging	Log	2. Run formation evaluation and caliper log.	3	0.1
1 Surface	Logging	RigU/D	3. Rig down logging equipment.	2	0.1
1 Surface	**CASING OPERATIONS**			87	3.6
1 Surface	Casing	RigU/D	1. Rig up casing running equipment.	3	0.1
1 Surface	Casing	RunCsng	2. Run 30", 1" wall, 310 ppf, X-56, Dril Quip – Quick Stab, line pipe to 500' and set	12	0.5
1 Surface	Casing	RigU/D	3. Rig up false floor for inner string cement job.	2	0.1
1 Surface	Casing	Trip	4. Pick up and run in the hole with 6-5/8" drill pipe and stab into the 30" float shoe.	2	0.1
1 Surface	Casing	RigU/D	5. Rig up cementing head on drill pipe.	1	0.0
1 Surface	Casing	Circ	6. Circulate and condition hole for cementing.	2	0.1
1 Surface	Casing	Cement	7. Mix, pump and displace cement per Table 1.	2	0.1
1 Surface	Casing	RigU/D	8. Rig down cementing equipment.	1	0.0
1 Surface	Casing	Trip	9. Trip out of the hole and stand back the 6-5/8" drill pipe.	3	0.1
1 Surface	Casing	Cement	10. Wait on cement for initial set to 500 psi compressive strength.	12	0.5
1 Surface	Casing	WH Ops	11. Slack off on casing.	1	0.0
1 Surface	Casing	WH Ops	12. Cut and lift 40" conductor.	2	0.1
1 Surface	Casing	WH Ops	13. Cut and dress 30" casing.	6	0.3
1 Surface	Casing	WH Ops	14. Weld on 30" SOW x API 30", 2000 casing head.	6	0.3

Date Printed: 8/14/2008 Tasks

ThermaSource
GEOTHERMAL CONSULTING AND DRILLING

TASK ANALYSIS

OPERATOR NAME: **SANDIA NATIONAL LABORATORIES**
FIELD NAME: Clear Lake, CA
Well Name: 20,000-ft EGS Well

Estimator / Engineer: Robert J. Swanson
Date: August 13, 2008

Phase	Activity	Task Code	GENERAL OPERATION TASKS	Hours	Days
				3,386	141.0
1 Surface	Casing	WH Ops	15. Pressure test weld to 500 psi.	1	0.0
1 Surface	Casing	BOP	16. Nipple up 30" BOP with blind ram and annular and connect to flow line.	28	1.2
1 Surface	Casing	BOP	17. Function test and pressure test BOP and 30" casing to 250 psi low and 1000 psi	3	0.1
Phase II: Intermediate 1			**(26" Hole to 5000' with 20" Casing)**	**554**	**23.1**
2 INT-1	**DRILLING OPERATIONS**			**385**	**16.0**
2 INT-1	Drilling	BHA	1. Make up 26" bit and vertical drilling BHA.	8	0.3
2 INT-1	Drilling	Trip	2. Trip in hole to the top of 20" casing shoe at 500'.	2	0.1
2 INT-1	Drilling	Drill	3. Drill out casing shoe.	2	0.1
2 INT-1	Drilling	Drill	4. Drill 26" hole from 500' to 510'.	1	0.0
2 INT-1	Drilling	Circ	5. Circulate.	1	0.0
2 INT-1	Drilling	Circ	6. Perform leak off test.	3	0.1
2 INT-1	Drilling	Drill	7. Drill 26" hole from 510' to 1250'	49	2.0
2 INT-1	Drilling	Circ	8. Circulate.	1	0.0
2 INT-1	Drilling	Trip	9. Make a wiper trip to the 30" casing shoe and back to bottom.	4	0.2
2 INT-1	Drilling	Drill	10. Drill 26" hole from 1250' to 2000'	50	2.1
2 INT-1	Drilling	Circ	11. Circulate.	1	0.0
2 INT-1	Drilling	Trip	12. Trip out of the hole for a new bit.	2	0.1
2 INT-1	Drilling	BHA	13. Stand back BHA.	4	0.2
2 INT-1	Drilling	BHA	14. Make up new 26" bit and run in the hole with BHA.	4	0.2
2 INT-1	Drilling	Trip	15. Trip in hole to 2000'	2	0.1
2 INT-1	Drilling	Drill	16. Drill 26" hole from 2000' to 2750'	50	2.1
2 INT-1	Drilling	Circ	17. Circulate.	1	0.0
2 INT-1	Drilling	Trip	18. Make a wiper trip to the 30" casing shoe and back to bottom.	4	0.2
2 INT-1	Drilling	Drill	19. Drill 26" hole from 2750' to 3500'.	50	2.1
2 INT-1	Drilling	Circ	20. Circulate.	1	0.0
2 INT-1	Drilling	Trip	21. Trip out of the hole for a new bit.	4	0.2
2 INT-1	Drilling	BHA	22. Stand back BHA.	4	0.2
2 INT-1	Drilling	BHA	23. Make up new 26" bit and run in the hole with BHA.	4	0.2
2 INT-1	Drilling	Trip	24. Trip in hole to 3500'	4	0.2
2 INT-1	Drilling	Drill	25. Drill 26" hole from 3500' to 4250'	50	2.1
2 INT-1	Drilling	Circ	26. Circulate.	1	0.0
2 INT-1	Drilling	Trip	27. Make a wiper trip to the 30" casing shoe and back to bottom.	6	0.3
2 INT-1	Drilling	Drill	28. Drill 26" hole from 4250' to 5000'	50	2.1
2 INT-1	Drilling	Circ	29. Circulate.	1	0.0
2 INT-1	Drilling	Trip	30. Make a wiper trip to the 30" casing shoe and back to bottom.	7	0.3
2 INT-1	Drilling	Circ	31. Circulate.	1	0.0
2 INT-1	Drilling	Trip	32. Trip out of the hole.	5	0.2
2 INT-1	Drilling	BHA	33. Stand back BHA.	4	0.2
2 INT-1	Drilling	BHA	34. Lay down vertical drilling motor and equipment.	4	0.2
2 INT-1	**LOGGING OPERATIONS**			**34**	**1.4**
2 INT-1	Logging	RigU/D	1. Rig up logging equipment.	1	0.0
2 INT-1	Logging	Log	2. Run formation evaluation logs and caliper log. (2 runs).	16	0.7
2 INT-1	Logging	RigU/D	3. Rig down logging equipment.	1	0.0
2 INT-1	Logging	BHA	4. Make up 26" bit on wiper trip BHA and RIH.	4	0.2
2 INT-1	Logging	Trip	5. Trip in hole to 5000'.	4	0.2
2 INT-1	Logging	Circ	6. Circulate hole clean.	1	0.0
2 INT-1	Logging	Trip	7. Trip out of hole.	4	0.2
2 INT-1	Logging	BHA	8. Stand back BHA.	3	0.1
2 INT-1	**CASING OPERATIONS**			**135**	**5.6**
2 INT-1	Casing	RigU/D	1. Rig up casing running equipment.	3	0.1

ThermaSource

GEOTHERMAL CONSULTING AND DRILLING

TASK ANALYSIS

OPERATOR NAME: **SANDIA NATIONAL LABORATORIES**

FIELD NAME: Clear Lake, CA

Well Name: 20,000-ft EGS Well

Estimator / Engineer: Robert J. Swanson

Date: August 13, 2008

Phase	Activity	Task Code	GENERAL OPERATION TASKS	Hours	Days
				3,386	141.0
2 INT-1	Casing	RunCsng	2. Run 20", 169 ppf, N-80, BTC casing to 5000' and set in slips.	36	1.5
2 INT-1	Casing	RigU/D	3. Rig up false floor for inner string cement job.	2	0.1
2 INT-1	Casing	Trip	4. Pick up and run in the hole with 6-5/8" drill pipe and stab into the 20" float shoe.	7	0.3
2 INT-1	Casing	RigU/D	5. Rig up cementing head on drill pipe.	1	0.0
2 INT-1	Casing	Circ	6. Circulate and condition hole for cementing.	2	0.1
2 INT-1	Casing	Cement	7. Mix, pump and displace cement per Table 2.	7	0.3
2 INT-1	Casing	RigU/D	8. Rig down cementing equipment.	1	0.0
2 INT-1	Casing	Trip	9. Trip out of the hole and stand back the 6-5/8" drill pipe.	5	0.2
2 INT-1	Casing	Cement	10. Wait on cement for initial set to 500 psi compressive strength.	12	0.5
2 INT-1	Casing	WH Ops	11. Slack off on casing.	1	0.0
2 INT-1	Casing	WH Ops	12. Lift BOP, rough cut 20" casing and nipple down BOP	5	0.2
2 INT-1	Casing	WH Ops	13. Cut off 30" casing head.	3	0.1
2 INT-1	Casing	WH Ops	14. Cut and dress 20" casing.	3	0.1
2 INT-1	Casing	WH Ops	15. Weld on 20" SOW x API 20-3/4", 3000 casing head.	18	0.8
2 INT-1	Casing	WH Ops	16. Pressure test weld to 1000 psi.	1	0.0
2 INT-1	Casing	BOP	17. Nipple up 20-3/4", 3000 psi BOP and connect to flow line.	18	0.8
2 INT-1	Casing	BOP	18. Function test and pressure test BOP and 20" casing to 250 psi low and 1500 psi	4	0.2
2 INT-1	Casing	BHA	19. Lay down 11" drill collars.	6	0.3
Phase III: Production Liner 1			**(17-1/2" Hole to 10,000' with 13-5/8" Casing)**	**589**	**24.5**
3 PROD-1	**DRILLING OPERATIONS**			**391**	**16.3**
3 PROD-1	Drilling	BHA	1. Make up 17-1/2" bit on vertical drilling BHA.	7	0.3
3 PROD-1	Drilling	Trip	2. Trip in hole to the top of the 20" float collar at 4960'.	5	0.2
3 PROD-1	Drilling	Drill	3. Drill out float collar, shoe track and float shoe.	3	0.1
3 PROD-1	Drilling	Drill	4. Drill 17-1/2" hole from 5000' to 5010'.	1	0.0
3 PROD-1	Drilling	Circ	5. Circulate.	1	0.0
3 PROD-1	Drilling	Circ	6. Perform leak off test.	3	0.1
3 PROD-1	Drilling	Drill	7. Drill 17-1/2" hole from 5010' to 6000'	56	2.3
3 PROD-1	Drilling	Circ	8. Circulate.	1	0.0
3 PROD-1	Drilling	Trip	9. Make a wiper trip to the 20" casing shoe and back to bottom.	2	0.1
3 PROD-1	Drilling	Drill	10. Drill 17-1/2" hole from 6000' to 7000'	56	2.3
3 PROD-1	Drilling	Circ	11. Circulate.	1	0.0
3 PROD-1	Drilling	Trip	12. Trip out of the hole for a new bit.	7	0.3
3 PROD-1	Drilling	BHA	13. Stand back BHA.	4	0.2
3 PROD-1	Drilling	BHA	14. Make up new 17-1/2" bit and run in the hole with BHA.	4	0.2
3 PROD-1	Drilling	Trip	15. Trip in hole to 7000'	7	0.3
3 PROD-1	Drilling	Drill	16. Drill 17-1/2" hole from 7000' to 8000'	56	2.3
3 PROD-1	Drilling	Circ	17. Circulate.	1	0.0
3 PROD-1	Drilling	Trip	18. Make a wiper trip to the 20" casing shoe and back to bottom.	6	0.3
3 PROD-1	Drilling	Drill	19. Drill 17-1/2" hole from 8000' to 9000'.	56	2.3
3 PROD-1	Drilling	Circ	20. Circulate.	1	0.0
3 PROD-1	Drilling	Trip	21. Trip out of the hole for a new bit.	9	0.4
3 PROD-1	Drilling	BHA	22. Stand back BHA.	4	0.2
3 PROD-1	Drilling	BHA	23. Make up new 17-1/2" bit and run in the hole with BHA.	4	0.2
3 PROD-1	Drilling	Trip	24. Trip in hole to 9000'	9	0.4
3 PROD-1	Drilling	Drill	25. Drill 17-1/2" hole from 9000' to 10,000'	56	2.3
3 PROD-1	Drilling	Circ	26. Circulate.	1	0.0
3 PROD-1	Drilling	Trip	27. Make a wiper trip to the 20" casing shoe and back to bottom.	10	0.4
3 PROD-1	Drilling	Circ	28. Circulate.	2	0.1
3 PROD-1	Drilling	Trip	29. Trip out of the hole.	10	0.4
3 PROD-1	Drilling	BHA	30. Stand back BHA.	4	0.2

ThermaSource

GEOTHERMAL CONSULTING AND DRILLING

TASK ANALYSIS

OPERATOR NAME: **SANDIA NATIONAL LABORATORIES**

FIELD NAME: Clear Lake, CA

Well Name: 20,000-ft EGS Well

Estimator / Engineer: Robert J. Swanson

Date: August 13, 2008

Phase	Activity	Task Code	GENERAL OPERATION TASKS	Hours	Days
				3,386	141.0
3 PROD-1	Drilling	BHA	31. Lay down vertical drilling motor and equipment.	4	0.2
3 PROD-1	**LOGGING OPERATIONS**			**60**	**2.5**
3 PROD-1	Logging	RigU/D	1. Rig up logging equipment.	1	0.0
3 PROD-1	Logging	Log	2. Run formation evaluation logs and caliper log. (3 runs).	30	1.3
3 PROD-1	Logging	RigU/D	3. Rig down logging equipment.	1	0.0
3 PROD-1	Logging	BHA	4. Make up 17-1/2" bit on wiper trip BHA and RIH.	4	0.2
3 PROD-1	Logging	Trip	5. Trip in hole to 10,000'.	9	0.4
3 PROD-1	Logging	Circ	6. Circulate hole clean.	2	0.1
3 PROD-1	Logging	Trip	7. Trip out of hole.	9	0.4
3 PROD-1	Logging	BHA	8. Stand back BHA.	4	0.2
3 PROD-1	**CASING OPERATIONS**			**138**	**5.8**
3 PROD-1	Casing	RigU/D	1. Rig up casing running equipment.	3	0.1
3 PROD-1	Casing	RunCsng	2. Run 5200' of 13-5/8", 88.2 ppf, P-110, BTC casing.	16	0.7
3 PROD-1	Casing	RunCsng	3. Make up liner hanger assembly to 13-5/8" casing.	2	0.1
3 PROD-1	Casing	RigU/D	4. Rig down casing running equipment.	2	0.1
3 PROD-1	Casing	RunCsng	5. Run in hole with 13-5/8" liner on 6-5/8" drill pipe to 10,000'.	12	0.5
3 PROD-1	Casing	RunCsng	6. Set liner hanger.	2	0.1
3 PROD-1	Casing	RunCsng	7. Release from running tool.	1	0.0
3 PROD-1	Casing	RigU/D	8. Rig up cementing head on drill pipe.	1	0.0
3 PROD-1	Casing	Circ	9. Circulate and condition hole for cementing.	2	0.1
3 PROD-1	Casing	Cement	10. Mix, pump and displace cement per Table 3.	8	0.3
3 PROD-1	Casing	Trip	11. Pull running tool out of liner hanger and pick up 90'.	2	0.1
3 PROD-1	Casing	Circ	12. Circulate excess cement to surface.	3	0.1
3 PROD-1	Casing	Trip	13. Trip out of the hole.	5	0.2
3 PROD-1	Casing	RunCsng	14. Lay down liner running tools.	2	0.1
3 PROD-1	Casing	BHA	15. Pick up 17-1/2" clean out BHA.	4	0.2
3 PROD-1	Casing	Trip	16. Trip in the hole to the top of cement at 4700'.	5	0.2
3 PROD-1	Casing	Cement	17. Wait on cement for initial set to 500 psi compressive strength.	6	0.3
3 PROD-1	Casing	Cement	18. Clean out cement in the 20" casing to the top of the liner hanger.	3	0.1
3 PROD-1	Casing	Circ	19. Circulate hole clean.	1	0.0
3 PROD-1	Casing	BOP	20. Pressure test the liner lap to 1000 psi surface pressure.	1	0.0
3 PROD-1	Casing	Trip	21. Trip out of the hole.	5	0.2
3 PROD-1	Casing	BHA	22. Stand back BHA.	4	0.2
3 PROD-1	Casing	BHA	23. Lay down 9-1/2" drill collars and 6-5/8" HWDP.	8	0.3
3 PROD-1	Casing	BHA	24. Lay down 6-5/8" drill pipe.	18	0.8
3 PROD-1	Casing	BHA	25. Pick up 5-1/2" HWDP and 5-1/2" drill pipe.	22	0.9
Phase IV: Production Liner 2			**(12-1/4" Hole to 17,000' with 9-5/8" Casing)**	**1,028**	**42.8**
4 PROD-2	**DRILLING OPERATIONS**			**820**	**34.2**
4 PROD-2	Drilling	BHA	1. Make up 12-1/4" clean out BHA.	4	0.2
4 PROD-2	Drilling	Trip	2. Trip in the hole to the top of the 13-5/8" liner hanger.	5	0.2
4 PROD-2	Drilling	Drill	3. Drill out pack off bushing.	2	0.1
4 PROD-2	Drilling	Circ	4. Circulate the hole clean.	2	0.1
4 PROD-2	Drilling	Trip	5. Trip in the hole to the top of the landing collar at 9880'.	5	0.2
4 PROD-2	Casing	BOP	6. Pressure test the liner to 1000 psi.	1	0.0
4 PROD-2	Drilling	Drill	7. Drill out the landing collar, 40' of cement, float collar, 80' of cement and float sh	4	0.2
4 PROD-2	Drilling	Drill	8. Drill 12-1/4" hole from 10,000' to 10,010'.	1	0.0
4 PROD-2	Drilling	Circ	9. Circulate.	2	0.1
4 PROD-2	Drilling	Circ	10. Perform leak off test.	3	0.1
4 PROD-2	Drilling	Trip	11. Trip out of hole.	10	0.4
4 PROD-2	Drilling	BHA	12. Stand back BHA.	4	0.2

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GEOTHERMAL CONSULTING AND DRILLING

TASK ANALYSIS

OPERATOR NAME: **SANDIA NATIONAL LABORATORIES**

FIELD NAME: Clear Lake, CA — Estimator / Engineer: Robert J. Swanson

Well Name: 20,000-ft EGS Well — Date: August 13, 2008

Phase	Activity	Task Code	GENERAL OPERATION TASKS	Hours	Days
				3,386	141.0
4 PROD-2	Drilling	BHA	13. Make up 12-1/4" bit on drilling BHA with vertical drilling system.	4	0.2
4 PROD-2	Drilling	Trip	14. Trip in hole to 10,010'.	10	0.4
4 PROD-2	Drilling	Drill	15. Drill 12-1/4" hole from 10,010' to 10,750.	60	2.5
4 PROD-2	Drilling	Circ	16. Circulate.	2	0.1
4 PROD-2	Drilling	Trip	17. Make a wiper trip to the 13-5/8" casing shoe.	2	0.1
4 PROD-2	Drilling	Drill	18. Drill 12-1/4" hole from 10,750' to 11,500'	60	2.5
4 PROD-2	Drilling	Circ	19. Circulate.	2	0.1
4 PROD-2	Drilling	Trip	20. Trip out of the hole for a new bit.	12	0.5
4 PROD-2	Drilling	BHA	21. Stand back BHA.	4	0.2
4 PROD-2	Drilling	BHA	22. Make up new 12-1/4" bit and run in the hole with BHA.	4	0.2
4 PROD-2	Drilling	Trip	23. Trip in hole to 11,500'	12	0.5
4 PROD-2	Drilling	Drill	24. Drill 12-1/4" hole from 11,500' to 12,250'	60	2.5
4 PROD-2	Drilling	Circ	25. Circulate.	2	0.1
4 PROD-2	Drilling	Trip	26. Make a wiper trip to the 13-5/8" casing shoe and back to bottom.	4	0.2
4 PROD-2	Drilling	Drill	27. Drill 12-1/4" hole from 12,250' to 13,000'.	60	2.5
4 PROD-2	Drilling	Circ	28. Circulate.	2	0.1
4 PROD-2	Drilling	Trip	29. Trip out of the hole for a new bit.	13	0.5
4 PROD-2	Drilling	BHA	30. Stand back BHA.	4	0.2
4 PROD-2	Drilling	BHA	31. Make up new 12-1/4" bit and run in the hole with BHA.	4	0.2
4 PROD-2	Drilling	Trip	32. Trip in hole to 13,000'	13	0.5
4 PROD-2	Drilling	Drill	33. Drill 12-1/4" hole from 13,000' to 13,750'	60	2.5
4 PROD-2	Drilling	Circ	34. Circulate.	2	0.1
4 PROD-2	Drilling	Trip	35. Make a wiper trip to the 13-5/8" casing shoe and back to bottom.	6	0.3
4 PROD-2	Drilling	Drill	36. Drill 12-1/4" hole from 13,750' to 14,500'	60	2.5
4 PROD-2	Drilling	Circ	37. Circulate.	2	0.1
4 PROD-2	Drilling	Trip	38. Trip out of the hole for a new bit.	15	0.6
4 PROD-2	Drilling	BHA	39. Stand back BHA.	4	0.2
4 PROD-2	Drilling	BHA	40. Make up new 12-1/4" bit and run in the hole with BHA.	4	0.2
4 PROD-2	Drilling	Trip	41. Trip in hole to 14,500'	15	0.6
4 PROD-2	Drilling	Drill	42. Drill 12-1/4" hole from 14,500' to 15,250'	60	2.5
4 PROD-2	Drilling	Circ	43. Circulate.	3	0.1
4 PROD-2	Drilling	Trip	44. Make a wiper trip to the 13-5/8" casing shoe and back to bottom.	8	0.3
4 PROD-2	Drilling	Drill	45. Drill 12-1/4" hole from 15,250' to 16,000'.	60	2.5
4 PROD-2	Drilling	Circ	46. Circulate.	3	0.1
4 PROD-2	Drilling	Trip	47. Trip out of the hole for a new bit.	16	0.7
4 PROD-2	Drilling	BHA	48. Stand back BHA.	4	0.2
4 PROD-2	Drilling	BHA	49. Make up new 12-1/4" bit and run in the hole with BHA.	4	0.2
4 PROD-2	Drilling	Trip	50. Trip in hole to 16,000'	16	0.7
4 PROD-2	Drilling	Drill	51. Drill 12-1/4" hole from 16,000' to 17,000'	60	2.5
4 PROD-2	Drilling	Circ	52. Circulate.	3	0.1
4 PROD-2	Drilling	Trip	53. Make a wiper trip to the 13-5/8" casing shoe and back to bottom.	10	0.4
4 PROD-2	Drilling	Circ	54. Circulate.	3	0.1
4 PROD-2	Drilling	Trip	55. Trip out of the hole.	17	0.7
4 PROD-2	Drilling	BHA	56. Stand back BHA.	4	0.2
4 PROD-2	Drilling	BHA	57. Lay down vertical drilling motor and equipment	4	0.2
4 PROD-2	**LOGGING OPERATIONS**			**95**	**4.0**
4 PROD-2	Logging	RigU/D	1. Rig up logging equipment.	1	0.0
4 PROD-2	Logging	Log	2. Run formation evaluation logs and caliper log. (3 runs).	48	2.0
4 PROD-2	Logging	RigU/D	3. Rig down logging equipment.	1	0.0
4 PROD-2	Logging	BHA	4. Make up 12-1/4" bit on wiper trip BHA and RIH.	4	0.2
4 PROD-2	Logging	Trip	5. Trip in hole to 17,000'.	17	0.7

Date Printed: 8/14/2008 — Tasks

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GEOTHERMAL CONSULTING AND DRILLING

TASK ANALYSIS

OPERATOR NAME: **SANDIA NATIONAL LABORATORIES**

FIELD NAME: Clear Lake, CA

Well Name: 20,000-ft EGS Well

Estimator / Engineer: Robert J. Swanson

Date: August 13, 2008

Phase	Activity	Task Code	GENERAL OPERATION TASKS	Hours	Days
				3,386	141.0
4 PROD-2	Logging	Circ	6. Circulate hole clean.	3	0.1
4 PROD-2	Logging	Trip	7. Trip out of hole.	17	0.7
4 PROD-2	Logging	BHA	8. Stand back BHA.	4	0.2
4 PROD-2	**CASING OPERATIONS**			**113**	**4.7**
4 PROD-2	Casing	RigU/D	1. Rig up casing running equipment.	3	0.1
4 PROD-2	Casing	RunCsng	2. Run 7200' of 9-5/8", 53.5 ppf, P-110, BTC casing.	24	1.0
4 PROD-2	Casing	RunCsng	3. Make up liner hanger assembly to 9-5/8" casing.	2	0.1
4 PROD-2	Casing	RigU/D	4. Rig down casing running equipment.	1	0.0
4 PROD-2	Casing	RunCsng	5. Run in hole with 9-5/8" liner on 5-1/2" drill pipe to 17,000'.	20	0.8
4 PROD-2	Casing	RunCsng	6. Set liner hanger.	1	0.0
4 PROD-2	Casing	RunCsng	7. Release from running tool.	1	0.0
4 PROD-2	Casing	RigU/D	8. Rig up cementing head on drill pipe.	1	0.0
4 PROD-2	Casing	Circ	9. Circulate and condition hole for cementing.	3	0.1
4 PROD-2	Casing	Cement	10. Mix, pump and displace cement per Table 4.	6	0.3
4 PROD-2	Casing	Trip	11. Pull running tool out of liner hanger and pick up 90'.	1	0.0
4 PROD-2	Casing	Circ	12. Circulate excess cement to surface.	4	0.2
4 PROD-2	Casing	Trip	13. Trip out of the hole.	10	0.4
4 PROD-2	Casing	RunCsng	14. Lay down liner running tools	2	0.1
4 PROD-2	Casing	BHA	15. Pick up 12-1/4" clean out BHA.	4	0.2
4 PROD-2	Casing	Trip	16. Trip in the hole to the top of cement at 9700'.	10	0.4
4 PROD-2	Casing	Cement	17. Wait on cement for initial set to 500 psi compressive strength.	1	0.0
4 PROD-2	Casing	Cement	18. Clean out cement in the 13-5/8" casing to the top of the liner hanger.	2	0.1
4 PROD-2	Casing	Circ	19. Circulate hole clean.	2	0.1
4 PROD-2	Casing	BOP	20. Pressure test the liner lap to 1000 psi surface pressure.	1	0.0
4 PROD-2	Casing	Trip	21. Trip out of the hole.	10	0.4
4 PROD-2	Casing	BHA	22. Stand back BHA.	4	0.2
Phase V: Production Liner 3			**(8-1/2" Hole to 20,000' with 7" Casing)**	**805**	**33.5**
5 PROD-3	**DRILLING OPERATIONS**			**472**	**19.7**
5 PROD-3	Drilling	BHA	1. Make up 8-1/2" clean out BHA.	4	0.2
5 PROD-3	Drilling	Trip	2. Trip in the hole to the top of the 9-5/8" liner hanger.	10	0.4
5 PROD-3	Drilling	Drill	3. Drill out pack off bushing.	2	0.1
5 PROD-3	Drilling	Circ	4. Circulate the hole clean.	3	0.1
5 PROD-3	Drilling	Trip	5. Trip in the hole to the top of the landing collar at 16,880'.	7	0.3
5 PROD-3	Casing	BOP	6. Pressure test the liner to 1000 psi.	1	0.0
5 PROD-3	Drilling	Drill	7. Drill out the landing collar, 40' of cement, float collar, 80' of cement and float sho	4	0.2
5 PROD-3	Drilling	Drill	8. Drill 8-1/2" hole from 17,000' to 17,010'.	1	0.0
5 PROD-3	Drilling	Circ	9. Circulate.	4	0.2
5 PROD-3	Drilling	Circ	10. Perform leak off test.	3	0.1
5 PROD-3	Drilling	Trip	11. Trip out of hole.	17	0.7
5 PROD-3	Drilling	BHA	12. Stand back BHA.	4	0.2
5 PROD-3	Drilling	BHA	13. Make up 8-1/2" bit on drilling BHA with vertical drilling system.	4	0.2
5 PROD-3	Drilling	Trip	14. Trip in hole to 17,010'.	17	0.7
5 PROD-3	Drilling	Drill	15. Drill 8-1/2" hole from 17,010' to 18,000'.	83	3.5
5 PROD-3	Drilling	Circ	16. Circulate.	4	0.2
5 PROD-3	Drilling	Trip	17. Trip out of the hole for a new bit.	18	0.8
5 PROD-3	Drilling	BHA	18. Stand back BHA.	4	0.2
5 PROD-3	Drilling	BHA	19. Make up new 8-1/2" bit and run in the hole with BHA.	4	0.2
5 PROD-3	Drilling	Trip	20. Trip in hole to 18,000'	18	0.8
5 PROD-3	Drilling	Drill	21. Drill 8-1/2" hole from 18,000' to 19,000'	84	3.5
5 PROD-3	Drilling	Circ	22. Circulate.	4	0.2

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GEOTHERMAL CONSULTING AND DRILLING

TASK ANALYSIS

OPERATOR NAME: **SANDIA NATIONAL LABORATORIES**

FIELD NAME: Clear Lake, CA — Estimator / Engineer: Robert J. Swanson

Well Name: 20,000-ft EGS Well — Date: August 13, 2008

Phase	Activity	Task Code	GENERAL OPERATION TASKS	Hours	Days
				3,386	141.0
5 PROD-3	Drilling	Trip	23. Trip out of the hole for a new bit.	19	0.8
5 PROD-3	Drilling	BHA	24. Stand back BHA.	4	0.2
5 PROD-3	Drilling	BHA	25. Make up new 8-1/2" bit and run in the hole with BHA.	4	0.2
5 PROD-3	Drilling	Trip	26. Trip in hole to 19,000'	19	0.8
5 PROD-3	Drilling	Drill	27. Drill 8-1/2" hole from 19,000' to 20,000'	84	3.5
5 PROD-3	Drilling	Circ	28. Circulate.	4	0.2
5 PROD-3	Drilling	Trip	29. Make a wiper trip to the 9-5/8" casing shoe and back to bottom.	6	0.3
5 PROD-3	Drilling	Circ	30. Circulate.	4	0.2
5 PROD-3	Drilling	Trip	31. Trip out of the hole.	20	0.8
5 PROD-3	Drilling	BHA	32. Stand back BHA.	4	0.2
5 PROD-3	Drilling	BHA	33. Lay down vertical drilling motor and equipment.	4	0.2
5 PROD-3	**LOGGING OPERATIONS**			**114**	**4.8**
5 PROD-3	Logging	RigU/D	1. Rig up logging equipment.	1	0.0
5 PROD-3	Logging	Log	2. Run formation evaluation logs and caliper log. (3 runs).	60	2.5
5 PROD-3	Logging	RigU/D	3. Rig down logging equipment.	1	0.0
5 PROD-3	Logging	BHA	4. Make up 8-1/2" bit on wiper trip BHA and RIH.	4	0.2
5 PROD-3	Logging	Trip	5. Trip in hole to 20,000'.	20	0.8
5 PROD-3	Logging	Circ	6. Circulate hole clean.	4	0.2
5 PROD-3	Logging	Trip	7. Trip out of hole.	20	0.8
5 PROD-3	Logging	BHA	8. Stand back BHA.	4	0.2
5 PROD-3	**CASING OPERATIONS**			**219**	**9.1**
5 PROD-3	Casing	RigU/D	1. Rig up casing running equipment.	3	0.1
5 PROD-3	Casing	RunCsng	2. Run 3200' of 7", 32 ppf, P-110, BTC casing.	10	0.4
5 PROD-3	Casing	RunCsng	3. Make up liner hanger assembly to 7" casing.	2	0.1
5 PROD-3	Casing	RigU/D	4. Rig down casing running equipment.	1	0.0
5 PROD-3	Casing	RunCsng	5. Run in hole with 7" liner on 5-1/2" drill pipe to 20,000'.	34	1.4
5 PROD-3	Casing	RunCsng	6. Set liner hanger.	1	0.0
5 PROD-3	Casing	RunCsng	7. Release from running tool.	1	0.0
5 PROD-3	Casing	RigU/D	8. Rig up cementing head on drill pipe.	1	0.0
5 PROD-3	Casing	Cement	9. Circulate and condition hole for cementing.	4	0.2
5 PROD-3	Casing	Cement	10. Mix, pump and displace cement per Table 5.	5	0.2
5 PROD-3	Casing	Trip	11. Pull running tool out of liner hanger and pick up 90'.	1	0.0
5 PROD-3	Casing	Circ	12. Circulate excess cement to surface.	5	0.2
5 PROD-3	Casing	Trip	13. Trip out of the hole.	17	0.7
5 PROD-3	Casing	RunCsng	14. Lay down liner running tools.	2	0.1
5 PROD-3	Casing	BHA	15. Pick up 8-1/2" clean out BHA.	4	0.2
5 PROD-3	Casing	Trip	16. Trip in the hole to the top of cement at 16,700'.	17	0.7
5 PROD-3	Casing	Cement	17. Wait on cement for initial set to 500 psi compressive strength.	1	0.0
5 PROD-3	Casing	Cement	18. Clean out cement in the 9-5/8" casing to the top of the7" liner hanger.	2	0.1
5 PROD-3	Casing	Circ	19. Circulate hole clean.	4	0.2
5 PROD-3	Casing	BOP	20. Pressure test the liner lap to 1000 psi surface pressure.	1	0.0
5 PROD-3	Casing	Trip	21. Trip out of the hole.	17	0.7
5 PROD-3	Casing	BHA	22. Stand back BHA.	4	0.2
5 PROD-3	Casing	BHA	23. Make up 6" clean out BHA.	4	0.2
5 PROD-3	Casing	BHA	24. Pick up 3500' of 3-1/2" drill pipe and cross over to 5" drill pipe.	10	0.4
5 PROD-3	Casing	Trip	25. Trip in the hole to the top of the 7" liner hanger.	17	0.7
5 PROD-3	Casing	Drill	26. Drill out pack off bushing.	3	0.1
5 PROD-3	Casing	Circ	27. Circulate the hole clean.	4	0.2
5 PROD-3	Casing	Trip	28. Trip in the hole to the top of the landing collar at 19,880'.	4	0.2
5 PROD-3	Casing	Circ	29. Circulate.	5	0.2
5 PROD-3	Casing	BOP	30. Pressure test the liner to 1000 psi.	1	0.0

Date Printed: 8/14/2008 — Tasks

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GEOTHERMAL CONSULTING AND DRILLING

TASK ANALYSIS

OPERATOR NAME: **SANDIA NATIONAL LABORATORIES**

FIELD NAME: Clear Lake, CA

Well Name: 20,000-ft EGS Well

Estimator / Engineer: Robert J. Swanson

Date: August 13, 2008

Phase	Activity	Task Code	GENERAL OPERATION TASKS	Hours	Days
				3,386	141.0
5 PROD-3	Casing	Trip	31. Trip out of hole.	20	0.8
5 PROD-3	Casing	BHA	32. Lay down 3-1/2" drill pipe.	8	0.3
5 PROD-3	Casing	BHA	33. Lay down 6" BHA.	6	0.3
Phase VI: Production Tie-Back (13-3/8" Casing)				**230**	**9.6**
6 PL1-TB	**CASING OPERATIONS**			230	9.6
6 PL1-TB	Casing	BHA	1. Pick up 13-5/8" retrievable bridge plug.	2	0.1
6 PL1-TB	Casing	Trip	2. Trip in hole on 5-1/2" drill pipe to 4850'.	10	0.4
6 PL1-TB	Casing	BOP	3. Set bridge plug inside the 13-5/8" production liner.	2	0.1
6 PL1-TB	Casing	Trip	4. Trip out of hole with plug setting tool.	5	0.2
6 PL1-TB	Casing	RigU/D	5. Rig up casing running equipment.	3	0.1
6 PL1-TB	Casing	RunCsng	6. Run 4800' of 13-3/8", 72 ppf, N-80, Vam Top casing.	15	0.6
6 PL1-TB	Casing	RunCsng	7. Stab in to tieback stem.	2	0.1
6 PL1-TB	Casing	RigU/D	8. Rig down casing running equipment.	1	0.0
6 PL1-TB	Casing	RigU/D	9. Rig up 13-3/8" cement head.	1	0.0
6 PL1-TB	Casing	Circ	10. Circulate and condition hole for cementing.	3	0.1
6 PL1-TB	Casing	Cement	11. Mix, pump and displace cement per Table 6.	8	0.3
6 PL1-TB	Casing	Cement	12. Wait on cement for initial set to 500 psi compressive strength.	12	0.5
6 PL1-TB	Casing	BOP	13. Lift BOP and rough cut 13-3/8" casing and lay down.	3	0.1
6 PL1-TB	Casing	BOP	14. Nipple down BOP.	3	0.1
6 PL1-TB	Casing	WH Ops	15. Cut of 20" casing head.	4	0.2
6 PL1-TB	Casing	WH Ops	16. Weld on 13-3/8", SOW x API 13-5/8", 3000 casing head.	18	0.8
6 PL1-TB	Casing	WH Ops	17. Install 12" x ANSI 900 Series master valve.	2	0.1
6 PL1-TB	Casing	BOP	18. Nipple up cross over spool and 20-3/4" BOP.	18	0.8
6 PL1-TB	Casing	BOP	19. Function test and pressure test BOP and 13-3/8" tieback casing to 2000 psi.	4	0.2
6 PL1-TB	Casing	BHA	20. Make up 12-1/4" clean out BHA.	4	0.2
6 PL1-TB	Casing	Trip	21. Trip in hole to the top of the float collar at 4720'.	5	0.2
6 PL1-TB	Casing	Drill	22. Drill out the float collar and clean out cement to the 13-5/8" tieback stem.	3	0.1
6 PL1-TB	Casing	Circ	23. Circulate.	1	0.0
6 PL1-TB	Casing	Trip	24. Trip in hole to the top of the retrievable bridge plug at 4850'.	1	0.0
6 PL1-TB	Casing	Circ	25. Circulate hole clean.	2	0.1
6 PL1-TB	Casing	Trip	26. Trip out of the hole.	5	0.2
6 PL1-TB	Casing	BHA	27. Lay down 12-1/4" BHA.	8	0.3
6 PL1-TB	Casing	BHA	28. Pick up bridge plug retrieval tool and make up to 5-1/2" drill pipe.	3	0.1
6 PL1-TB	Casing	Trip	29. Trip in hole to the top of the retrieval bridge plug at 4850'.	8	0.3
6 PL1-TB	Casing	BOP	30. Release bridge plug.	1	0.0
6 PL1-TB	Casing	Trip	31. Trip out of hole with retrievable bridge plug.	8	0.3
6 PL1-TB	Casing	BHA	32. Lay down bridge plug and retrieval tool.	1	0.0
6 PL1-TB	Casing	BHA	33. Lay down all drill collars.	16	0.7
6 PL1-TB	Casing	BHA	34. Lay down all drill pipe.	48	2.0

Date Printed: 8/14/2008 Tasks

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GEOTHERMAL CONSULTING AND DRILLING

Estimator / Engineer: Robert J. Swanson
August 13, 2008
OK: Cost Allocation Matches Total Estimated Cost

COST ESTIMATING DATA INPUT TABLE

SANDIA NATIONAL LABORATORIES
Clear Lake, CA
20,000-ft EGS Well

TOTAL ESTIMATED DAYS: 143
DRILLING DAYS: 92

ROUNDED-UP TOTAL COST $ 21,340,000

Acctg Code	COST CATEGORIES			Units	Quantity	Unit Cost	Total Est Cost $ 21,254,091
	EQUIPMENT RENTAL AND SERVICES					$	15,745,691
10	RIG MOBILIZATION and DEMOBILIZATION						$ -
	Mobilization			$	1	-	-
	Demobilization			$	1 .	-	-
20	CONTRACT DRILLING RIG						$ 6,224,075
	Rig Move Day Rate			$/day	0		-
	Trucks and Cranes for Rig Move			$	0		-
	Rig Operating Day Rate			$/day	143	28,000.00	4,004,000
	Top Drive Rental			$/day	143	3,200.00	457,600
	Rig Welding Services			$/day	143	700.00	100,100
	Fuel			gal/day	2,500	4.25	1,519,375
	Rig Crew Travel and Accommodations			$/day	143	1,000.00	143,000
30	PLANNING, ENGINEERING AND PROJECT MANAGEMENT						$ 747,000
	Rig Site Management			$/day	143	2,000.00	286,000
	Engineering Services			$/day	143	2,000.00	286,000
	Project Management			$/month	6	25,000.00	150,000
	Well Insurance			$	1	25,000.00	25,000
40	DRILLING FLUIDS AND SOLIDS CONTROL						$ 1,057,916
	Drilling Fluids Engineer			$/day	143	900.00	128,700
	Drilling Fluid Materials	Status	Size				
	Surface Hole	Y	*36 in*	$/bbl	2,645	7.00	18,515
	Intermediate Hole 1	Y	*26 in*	$/bbl	14,781	10.00	147,810
	Intermediate Hole 2			$/bbl			-
	Production Hole 1	Y	*17-1/2 in*	$/bbl	7,440	14.75	109,740
	Production Hole 2	Y	*12-1/4 in*	$/bbl	5,104	21.15	107,950
	Production Hole 3	Y	*8-1/2 in*	$/bbl	1,053	25.50	26,852
	Production Hole 4			$/bbl			-
	Shakers, Mud Cleaner and Centrifuge Rental			$/day	143	1,200.00	171,600
	Shaker Screens			$	50	500.00	25,000
	Mud Cooler Rental			$/day	143	750.00	107,250
	Sumpless Drilling and Cuttings Management Services			$/day	143	1,500.00	214,500
50	DIRECTIONAL DRILLING SERVICES						$ 1,392,000
	Directional Drilling Equipment			$/day	92	12,000.00	1,104,000
	Directional Drilling Personnel			$/day	144	2,000.00	288,000
60	CEMENT and SERVICES	Status	Cemented				$ 3,671,900
	Surface Casing	Y	Cemented	$/bbl	350	630.00	220,500
	Intermediate Casing 1	Y	Cemented	$/bbl	2,030	595.00	1,207,850
	Intermediate Casing 2			$/bbl			-
	Intermediate C-2 Tie-Back			$/bbl			-
	Production Liner 1	Y	Cemented	$/bbl	940	760.00	714,400
	Production L-1 Tie-Back	Y	Cemented	$/bbl	970	660.00	640,200
	Production Liner 2	Y	Cemented	$/bbl	600	920.00	552,000
	Production Liner 3	Y	Cemented	$/bbl	115	2,930.00	336,950
	Production Liner 4			$/bbl			-
70	AIR DRILLING SERVICES						$ 527,500
	Air Compressor Standby Day Rate			$/day	75	1,500.00	112,500
	Air Compressor Operating Day Rate			$/day	68	2,500.00	170,000
	Air Compressor Personnel			$/day	68	1,500.00	102,000
	Air Drilling Flow Line and Separator System Rental			$/day	143	1,000.00	143,000

Date Printed: 8/21/2008 Cost Data Input

ThermaSource
GEOTHERMAL CONSULTING AND DRILLING

Estimator / Engineer: Robert J. Swanson
August 13, 2008
OK. Cost Allocation Matches Total Estimated Cost

COST ESTIMATING DATA INPUT TABLE

SANDIA NATIONAL LABORATORIES
Clear Lake, CA
20,000-ft EGS Well

TOTAL ESTIMATED DAYS: 143
DRILLING DAYS: 92

ROUNDED-UP TOTAL COST $ 21,340,000

Acctng Code	COST CATEGORIES	Units	Quantity	Unit Cost	Total Est Cost $ 21,254,091
80	**GEOLOGIC EVALUATION AND RESERVOIR ENGINEERING**				$ 1,075,450
	Mud Logging Services	$/day	143	2,000.00	286,000
	H2S Monitoring, Testing and Training Services	$/day	143	750.00	107,250
	Wireline Services	$	5	125,000.00	625,000
	Coring Services	$/day			-
	Well Testing Services	$/day			-
	Geologic Services	$/day	143	400.00	57,200
90	**DRILLING TOOLS RENTAL AND REPAIR**				$ 473,200
	Stabilizers, Roller Reamers and Hole Openers Rental	$	92	900.00	82,800
	Rebuild Charges for Stabilizers, Roller Reamers and Hole Openers	$	1	50,000.00	50,000
	Jars, Intensifiers and Shock Subs Rental	$/day	92	800.00	73,600
	Rebuild Charges for Jars, Intensifiers and Shock Subs	$	1	40,000.00	40,000
	Drill Pipe, HWDP and Drill Collar Rental	$/day	92	150.00	13,800
	Drill Pipe Hard Banding and Repair	$	700	100.00	70,000
	Tubular Inspection Services	$/day	143	1,000.00	143,000
100	**WELL CONTROL EQUIPMENT RENTAL AND SERVICES**				$ 312,100
	BOP Rental	$/day	143	1,500.00	214,500
	BOP Inspection and Repair	$	3	10,000.00	30,000
	BOP Consumables	$	1	20,000.00	20,000
	Rotating Head Rental	$/day	86	350.00	30,100
	Rotating Head Rubbers	$	5	1,500.00	7,500
	Drill Pipe Floats	$	20	500.00	10,000
110	**RIG SITE LOGISTICS**				$ 164,450
	Communications	$/day	143	250.00	35,750
	Rig Monitoring System	$/day	143	250.00	35,750
	Rig Site Living Accommodations	$/day	143	500.00	71,500
	Potable Water and Power	$/day	143	150.00	21,450
120	**ROAD AND LOCATION CONSTRUCTION**				$ -
	Permits and Surveying	$	1	-	-
	Roads and Location Construction Costs	$	1	-	-
	Conductor and Cellar Installation	$	1	-	-
130	**TRUCKING AND TRANSPORTATION**				$ 100,100
	Equipment Transportation	$	143	500.00	71,500
	Vacuum Trucking	$			-
	Vehicle Rental	$/day	143	50.00	7,150
	Forklift and Man Lift Rental	$/day	143	150.00	21,450
140	**COMPLETION SERVICES**				$ -
	Perforating Services	$			-
	Stimulation Services	$			-
	Coiled Tubing Services	$			-
150	**FISHING TOOLS AND SERVICES**				$ -
	Daily Service	$/day			-
	Tool Rental	$/day			-
	Fishing Tool Repair	$			-

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Cost Data Input

ThermaSource
GEOTHERMAL CONSULTING AND DRILLING

Estimator / Engineer: Robert J. Swanson
August 13, 2008
OK. Cost Allocation Matches Total Estimated Cost

COST ESTIMATING DATA INPUT TABLE

SANDIA NATIONAL LABORATORIES

Clear Lake, CA
20,000-ft EGS Well

TOTAL ESTIMATED DAYS: 143
DRILLING DAYS: 92

ROUNDED-UP TOTAL COST $ 21,340,000

Acctng Code	COST CATEGORIES			Units	Quantity	Unit Cost	Total Est Cost $ 21,254,091
	MATERIALS, CONSUMABLES AND RELATED SERVICES					$	5,508,400
160	**BITS**	Status	Size				$ 784,000
	Surface Hole	Y	36 in	$	1	80,000.00	80,000
	Intermediate Hole 1	Y	26 in	$	4	85,000.00	340,000
	Intermediate Hole 2			$			-
	Production Hole 1	Y	17-1/2 in	$	3	50,000.00	150,000
	Production Hole 2	Y	12-1/4 in	$	6	25,000.00	150,000
	Production Hole 3	Y	8-1/2 in	$	4	16,000.00	64,000
	Production Hole 4			$			-
170	**CASING AND TUBING**	Status	Size				$ 4,364,400
	Conductor Pipe	Y	40 in	$/ft	50	400.00	20,000
	Surface Casing	Y	30 in	$/ft	500	300.00	150,000
	Intermediate Casing 1	Y	20 in	$/ft	5,000	190.00	950,000
	Intermediate Casing 2			$/ft	0		-
	Intermediate C-2 Tie-Back			$/ft	0		-
	Production Liner 1	Y	13-5/8 in	$/ft	5,200	216.00	1,123,200
	Production L-1 Tie-Back	Y	13-3/8 in	$/ft	4,800	235.00	1,128,000
	Production Liner 2	Y	9-5/8 in	$/ft	7,200	98.00	705,600
	Production Liner 3	Y	7 in	$/ft	3,200	68.00	217,600
	Production Liner 4			$/ft	0		-
	Casing Crews and Lay Down Machine			$	7	10,000.00	70,000
180	**CASING ACCESSORIES**						$ 187,000
	Production Liner 1 Hanger and Running Services	Y		$	1	45,000.00	45,000
	Production Liner 2 Hanger and Running Services	Y		$	1	35,000.00	35,000
	Production Liner 3 Hanger and Running Services	Y		$	1	25,000.00	25,000
	Production Liner 4 Hanger and Running Services			$			-
	Liner Adapter	6	13,657	$			-
	Centralizers			$	1	25,000.00	25,000
	Float Shoes and Float Collars			$	1	57,000.00	57,000
190	**PRODUCTION EQUIPMENT**						$ 173,000
	Surface Casing Head			$	1	20,000.00	20,000
	Intermediate Casing Head			$	1	15,000.00	15,000
	Tieback Casing Head			$	1	10,000.00	10,000
	Expansion Spool			$			-
	Master Valves			$	2	35,000.00	70,000
	Wing Valves			$	3	4,000.00	12,000
	Nuts, Studs, Flanges and Gages			$	1	10,000.00	10,000
	Wellhead Welding and Installation Services	3	57,667	$	3	12,000.00	36,000
200	**NEW CATEGORY**						$ -
							-
							-
							-
							-
							-