A SPREADSHEET FOR GEOTHERMAL DIRECT USE COST EVALUATION

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INTRODUCTION

In order to be seriously considered as an alternative in any project, an energy source must be easily characterized in terms of cost, both capital and unit energy cost. Historically, this has been a difficult hurdle for geothermal energy. Its costs vary with the depth and character of the resource, number of production and injection wells, and a host of other parameters. As a result, even in cases where developers are interested in using the geothermal, identifying its costs has been a cumbersome process. To address this problem, the Geo-Heat Center has developed a spreadsheet which allows potential users to quickly evaluate the capital cost and unit energy cost of accessing a geothermal resource.

Using resource, financing and operating inputs, the spreadsheet calculates the capital cost for production well(s), well pump(s), well head equipment, injection well(s), and connecting pipelines. These capital costs are used along with the quantity of annual energy to be supplied and financing information to produce a unit cost of energy. Unit costs for operation (maintenance and electricity) are added to arrive at a total unit cost in $ per million Btu for geothermal heat. To put this value into perspective, similar costs for an equivalently sized gas boiler plant are also calculated. These values can then be compared to determine the relative economic merit of geother-mal for any specific set of circumstances. This information is particularly useful at the conceptual stage of a project when decisions as to fuel source are typically made by the developers.

Cost data for geothermal systems was drawn primarily from past projects and vendor price data. Costs for well head piping and gas boiler equipment were taken from standard industry estimating guides (Konkel, 1987; Khashab, 1984; Lund, 1998), updated where necessary for 2001.

SYSTEM DESCRIPTIONS

The spreadsheet compares two basic approaches to producing heat: a geothermal system, and a gas boiler plant.

For the geothermal system, up to 3 production wells can be specified. Well casing is sized to accommodate a pump capable of supplying the required flow rate. Costs are included for drilling, casing, cementing and drill rig mobilization. An option is provided for open hole completion.

Wells can be equipped with production pumps at the users discretion. Pumps are assumed to be oil lubricated/lineshaft type and can be equipped with variable-speed drives. The spreadsheet calculates the total pump head (including injection pressure if applicable), bowl size, number of stages, lateral requirements, column size and length, and sums all costs.

Well head equipment includes piping, check valve and shut-off valves along with electrical connections and accessories for the motor. All of these items are assumed to be located in an enclosure.

Injection wells (up to 3) can be included in the system at the users discretion, along with a user defined casing depth. Cost components for the injection wells are similar to those described for the production wells; although, the drilling cost rates used for injection are higher than those used for production. This rate is 20% higher to allow for alternate drilling methods sometimes employed for injection wells.

Finally, piping connecting the production wells and injection wells to the building (or process) are included to complete the geothermal system. A 15% contingency is added to all major cost categories.

For the boiler plant costs are calculated for a cast iron gas-fired boiler including: boiler and burner, concrete pad, breaching to flue, gas piping, combustion air louvers, expansion tank and air fitting, air separation, relief valve and piping, feed-water assembly, boiler room piping and shut-off valves. The spreadsheet is intended to compare geothermal to other conventional methods of supplying heat. As a result, it focuses upon the heat source only. Costs necessary for interface with a specific use, such as a heat exchanger, fan coil units or distribution system are not included.

The Input and Primary Output screen appears in Figure 1.

INPUT

1. Peak Load (Btu/hr). Enter the peak heat requirement of the load to be served by the system. If the load is to be served by multiple heat sources, enter only the portion of the peak load to be served by the geothermal source.

2. Load Factor. Enter the load factor for load to be served by the system. This value is very important. It is used by the spreadsheet to determine the annual quantity of heat supplied (Load Factor * 8760 * Peak Load = Annual Energy). The load factor has a direct bearing upon the unit cost of energy. In the absence of other information, value of .15 - .22 for space heating, .18 - .28 for district heating and greenhouses, and .25 and above for industrial processes may be used as a starting point. The load factor should be the value appropriate to only the geothermal portion of the system if the load is served by multiple heat sources.

INPUT		OUTPUT	
1. Peak Load	1E+07 Btu/hr	**Required Flow**	500 gpm
2. Load Factor	0.25 decimal	**CAPITAL COSTS**	
3. Temp Drop	40 F	**Production Well**	153438 $
4. kWh cost	0.07 $/kwh	**Well pump**	54565 $
5. kW cost	1 $/kw	**Wellhead Equip.**	13120 $
6. Interest Rate	0.08 decimal	**Injection Well**	0 $
7. Loan Term	20 yrs	**Pipe Line**	11157 $
8. No. Prod Wells	1	**Total Geo Cost**	**232281** $
9. Depth	1500 Ft	**Boiler plant cost**	**83423** $
10. Temperature	180 F	**GEOTHERMAL UNIT COSTS**	$/MMbtu
11. Hard Drill %	0.6 decimal	**Unit Cap Cost**	1.08 $/MMbtu
12. Soft Drill %	0.4 decimal	**Unit Maint Cost**	0.26 $/MMbtu
13. Spec. Cap.	5 gpm/ft	**Unit Elec Cost**	0.47 $/MMbtu
14. Static level	200 ft	**Total Unit Cost**	**1.81** $/MMbtu
15. Open hole?	0 Y=1,N=0	**BOILER UNIT COSTS**	$/MMbtu
16. No. Pumps	1	**Boiler Fuel Cost**	5.33 $/MMbtu
17. No of VSD	0	**Equip Unit Cost**	0.45 $/MMbtu
18. No. Inj Wells	0	**Maint Unit Cost**	0.11 $/MMbtu
19. Inj well eff	1 decimal	**Total Unit Cost**	**5.89** $/MMbtu
20. Depth	2000 ft	**Simple Payback**	**1.66** yrs
21. Static level	200 ft		
22. Casing Depth	1000 ft		
23. Boiler Eff	0.75 decimal		
24. Nat Gas Cost	0.4 $/therm		
25. Blowout prev.	0 Y=1,N=0		

Figure 1.

3. <u>Temp. Drop (°F)</u>. Enter the value of the ΔT for which the system will be designed at peak. This value is used to calculate the peak flow requirement which influences pump size, well sizes and pumping energy requirements. Most district heating and greenhouse systems are designed for a minimum of 35°F ΔT and as high as 75°F ΔT.

4. <u>kWh Cost ($/kWh)</u>. Enter the cost for electricity which would be applicable to the system well pumps for energy (kWh). This value is used in conjunction with Input #5 to calculate the cost of pumping.

5. <u>kW Cost ($/kW)</u>. Enter the cost for electricity which would be applicable to the system well pump electrical demand. This value along with Input #4 is used in the calculation of pumping energy costs.

6. <u>Interest Rate (as decimal)</u>. Enter the value for the interest rate which is applicable to the financing of the capital cost of the project. This value along with Input #7 is used to calculate the ownership cost of the system.

7. Loan Term (yrs). Enter the value for the length of the loan term for the financing of the capital cost of the project. This value in conjunction with Input #6 is used to determine the ownership costs of the system

8. No. Prod. Wells. Enter the number of production wells to be used for the project. The maximum number of production wells the spreadsheet can accommodate is 3. Most current systems employ a single well if one is capable of meeting system flow requirements. Spare wells are generally not included in geothermal systems. A second well should be considered for peak flow requirements in excess of 500 gpm although direct use wells have been constructed to produce up to 2000 gpm in a few cases.

9. Depth (ft). Enter the depth of the production well or wells. The spreadsheet assumes that if multiple wells are used, that all are the same depth. Cost factors used by the spreadsheet are limited to depths of 3000 ft.

10. Temperature (°F). Enter the temperature of the fluid produced by the production well(s). The temperature is used in the calculation of pump thermal expansion and cost.

11. Hard Drill % (as decimal). Enter the fraction of the well drilling which is expected to be associated with hard rock. The spreadsheet applies two different costs to drilling: one for soft and one for hard drilling. Inputs #11 and #12 must sum to a total of 1.0. A reasonable value for many western resource areas would be 60% hard drilling and 40% soft drilling.

12. Soft Drill % (as decimal). Enter the fraction of the well drilling depth which is expected to be associated with soft materials. The spreadsheet applies two different costs to drilling: one for soft conditions and one for hard rock drilling. Inputs #11 and #12 must sum to a total of 1.0.

13. Spec. Cap. (gpm/ft). Enter the value for the production well(s) which is appropriate to the peak flow rate. Specific capacity is the peak flow for the well divided by the drawdown (static water level - pumping water level). The value is used to determine the depth required for the pump setting and the pump housing portion of the casing. Values for a specific capacity for existing direct use wells vary over a wide range. For wells producing from fractured basalt, values range from 3 to 20 gpm/ft. Much less data is available for wells producing from sand and gravel type sequences; but, values for these applications would likely be less than for fractured basalt.

14. Static Level (ft). Enter the production well static water level. This value is used in conjunction with Input #13 for calculating pump setting depth.

15. Open Hole. If open hole completion is to be used, enter a 1. If the well is to use full depth casing, enter a 0. If open hole completion is chosen, the spreadsheet assumes that no casing is installed below the pump housing portion of the well. Selecting open hole completion reduces the production well costs. Open hole completion is frequently used for wells

completed in competent rock formations. It is not appropriate for wells completed in sand and gravel or sandstone formations.

16. No. Pumps. Enter the number of production well pumps to be used in the system. The spreadsheet calculates pump costs assuming the use of enclosed lineshaft turbine pumps.

17. No. VSDs. Enter the number of variable speed drives to be used in the system. One or all of the well pumps can be equipped with a drive. The spreadsheet calculates costs assuming the use of electronic variable frequency drives. Space heating applications generally benefit from the use of a drive to reduce annual pumping energy. Industrial process and other high load factor applications may not require a drive.

18. No. Inj. Wells. The spreadsheet can accommodate up to 3 injection wells for a system. Entering a zero for the number of injection wells simulates the use of surface disposal.

19. Inj. Well Eff. This value, entered as a decimal, is used to correct the specific capacity (entered for the production wells) to injection conditions. This factor is included in the input to account for the fact that in many installations, injection wells have been found to be less capable of accepting fluid than the production wells are at producing fluid from the aquifer. The efficiency value is used in the calculation of injection pressure requirements. Injection Specific Capacity = Production Specific Capacity * Injection Well Efficiency.

20. Depth (ft). Enter the depth of the injection wells. If multiple injection wells are specified, the spreadsheet assumes that all are the same depth. In many jurisdictions, injection must be into the same aquifer as production. As a result, injection well depth must be at least to the top of the producing aquifer.

21. Static Level (ft). Enter the injection well static water level in feet. This value in conjunction with Input #19 is used to determine required injection pressure.

22. Casing Depth (ft). Enter the depth to which casing will be installed in the injection well. A conservative approach would be to assume that the casing depth is equal to the well depth.

23. Boiler Eff. (as decimal). Enter the value for the overall boiler plant efficiency.

24. Nat. Gas Cost ($/therm). Enter the unit cost of natural gas appropriate to the project. Most utilities price natural gas on a per therm basis with a therm equal to 100,000 Btu. The value is also equal to the older "100 ft^3" or CCF unit.

25. Blowout Preventer. In most states, wells penetrating areas of high temperature (160 - 180°F and above) will require the use of a blowout prevention device. Enter 1 for the cost of this equipment or a 0 if the device is not required.

PRIMARY OUTPUT

1. Required Flow (gpm). This value is the flow rate required to meet the peak load specified (Input #1) at the temperature drop specified (Input #3). If multiple production wells are specified, this value is divided equally among the multiple wells.

2. Production Well(s). This is the capital cost calculated by the spreadsheet for the production well or wells. The basic procedure the spreadsheet use is as follows. The required flow rate is divided equally among the specified number of production wells. A pump size is determined from the flow rate. A casing size (for the upper portion of the well) is calculated from the pump bowl size. A casing size for the lower portion of the well is calculated based on the flow rate. Pump housing casing depth is determined from the static water level plus the drawdown (at the required flow rate) plus an additional 40 ft. Drilling costs are based on hole sizes of 2 inches greater than the casing sizes. Drilling costs are divided into hard and soft values on a $ per inch diameter per foot of depth basis, and are adjusted according to whether or not open hole completion is specified. Cement costs are based on casing length. Rig mobilization is entered at a flat value of $2500. After the individual costs are summed, a 15% contingency factor is added.

3. Well Pump(s). This is the capital cost for the production well pump(s) specified. The procedure for sizing the pump is as follows. The required flow rate is divided equally among the number of pumps specified. The pump bowl size is determined by the flow rate. The total pump head is determined from the sum of the static water level, drawdown, an assumed 40 psi well head pressure, a 5 ft allowance for pump column friction and the calculated injection pressure. The number of stages required is based on the total head. The bowl assembly cost is based upon the size and number of stages. In addition, a cost allowance for lateral (to accommodate thermal expansion) is added. Column size is calculated based on the flow rate. Column length is based upon the static water level plus the drawdown (at the specified flow) plus 20 ft. The cost of a well head pedestal is added. The motor horsepower is calculated from the required flow, total head and the calculated pump efficiency. This is corrected to a nominal motor horsepower for motor pricing. These values are summed and increased by a 15% contingency factor to arrive at the pump cost appearing in the output.

4. Wellhead Equipment. This figure includes the necessary well head mechanical and electrical equipment along with an enclosure for weather protection. If a variable speed drive is specified, this item is included in the well head equipment.

5. Injection Well. The injection well costs are calculated in the same general manner as that described above for production wells. Injection well size is based upon the injection flow rate (required production flow ÷ number of injections wells).

6. Pipeline. This is the cost of piping the geothermal fluid from the production wells to the facility and from the facility to the injection well. An allowance of 300 ft of pipe for both purposes is included in the spreadsheet. Costs are based upon the use of buried pre-insulated ductile iron material. Pipeline lengths are increased when multiple wells are employed.

7. Total Geothermal Cost. This is the sum of the individual cost items described above. It is the total cost of access to the geothermal resource.

8. Boiler Plant Cost. This value is the cost of gas-fired boiler plant sized to meet the peak load specified in Input #1. The items included are: boiler and burner, concrete pad, breeching to flue, gas piping, combustion air louvers, expansion tank and air fitting, air separator, relief valve and piping, feed-water assembly, boiler room piping, and shut off valves.

9. Unit Capital Cost. This value for the geothermal system is determined by calculating the annual cost of the system based on a 20-year term at the interest rate specified in Input #6 and dividing this value by the annual energy supplied (in million Btu). The annual energy supplied is based upon: (peak load * 8760 * load factor/1,000,000.

10. Unit Maintenance Cost. This value is the annualized cost of maintaining the geothermal system. It is comprised primarily of production well pump maintenance. Pump maintenance is based upon overhauls of the pump bowl assembly at 5-year intervals at a cost of 60% of capital cost. Pump replacement is assumed at 15 years. In addition, maintenance of the well head equipment is allowed for at a rate of 1.5% of capital cost.

11. Unit Electrical Cost. This value is the cost of pumping energy. It is based on the electrical cost input values (#4 and #5), and the pump efficiency and horsepower calculations made by the spreadsheet. The cost values shown assume a 12-month demand ratchet in the electric rate.

12. Total Unit Cost. This value is the sum of the 3 individual unit cost items for geothermal. This unit cost assumes a 20-year system life. In this regard, the cost is conservative in that most direct use systems have useful lives well in excess of 20 years.

13. Boiler Fuel Cost. This value is the cost of gas heat attributable to the cost of fuel and boiler plant efficiency.

14. Equipment Unit Cost. This value corresponds to the Unit Capital Cost for the geothermal system. It is the annualized cost of the boiler plant divided by the annual quantity of heat supplied.

15. Maintenance Unit Cost. This value is the annual cost of maintenance on the boiler plant divided by the annual quantity of heat supplied.

16. Total Unit Cost. This value is the sum of the 3 unit cost items above. It is the total unit cost for boiler supplied heat and directly corresponds to the total unit cost for geothermal.

17. Simple Payback. This value compares the difference in unit costs to the difference in capital cost. It is calculated by subtracting the boiler capital cost from the geothermal capital cost and dividing by the difference in unit costs times the annual energy supplied.

SECONDARY OUTPUT

The secondary output is divided into 3 columns, one for each of the possible wells (production and injection) which the spreadsheet can accommodate. Each of the 3 columns is identical with the exception of the boiler equipment cost calculations appearing at the bottom of column 1.

Required Flow. The peak required flow (Primary Output) is divided by the number of wells specified in the input. The result appears here. If only a single production well is specified, this value will be equal to the required flow value appearing in the Primary Output.

Diameter Upper. This is the required nominal casing diameter to accommodate the pump necessary to produce the required flow rate.

Diameter Lower. This is the nominal casing size required for the lower portion of the well based on the required flow rate.

Depth Upper. This is the depth to which the upper casing size must be installed. It is based upon the static water level plus the drawdown plus 40 ft.

Injection Head. This is the value of the injection pump head which will be imposed on the system. It is added to the production well pump head. It is calculated by multiplying the input specific capacity by the input injection well efficiency and using this value along with the required flow to calculate an injection water level rise. Subtracting the injection well static water level from this value results in the net injection head (if any) required at the surface at the peak flow conditions. If the calculation yields a negative number (indicating a water level below the ground surface), the spreadsheet returns a 0 for injection head.

TDH. Total dynamic head for the well pump is the sum of drawdown + surface pressure (assumed at 90 ft) + static water level + column friction (assumed at 10 ft) + injection head. Drawdown is calculated by dividing the required flow by the specific capacity specified in the input.

Pump Efficiency. Pump efficiency is calculated using an equation which relates flow rate to efficiency. This equation was developed from manufacturer's data for lineshaft pumps.

Motor Efficiency 1. The spreadsheet calculates the efficiencies related to the well pump drive. The motor efficiency, is the calculated efficiency of an electric motor sized for the application. This value is calculated using a formula incorporating values from manufacturer's data. If no variable frequency drive is specified in the input, this value is used as the basis for pump electrical consumption.

Drive Efficiency. If a variable frequency drive is specified in the input, the value for the motor efficiency calculated above is multiplied by 0.93 to arrive at a combined motor and drive efficiency.

Pump Column Diameter. Based on the required flow rate, the spreadsheet selects a column pipe diameter. Available sizes are 8", 6", 5" and 4" nominal pipe size.

Pump Horsepower. Pump horsepower is calculated based on the required flow rate, TDH, and efficiency calculated above. This is the brake horsepower for well #1. If more than 1 well is specified, a separate horsepower is calculated for each well pump based on individual flow rates and pump heads.

Pump kW. This is the calculated electrical input required for the well pump. It is based on the pump horsepower and the drive efficiency calculated above.

Column Length. This is the distance between the well head (ground surface) and the top of the pump. It is calculated by adding the static water level + drawdown + 25 ft. This value is used in the calculation of the pump cost.

Line Size. This is the nominal size of the buried pipeline connecting the well head to the building or process which will be using the geothermal fluid.

Stages. The number of stages required in the production well pump to meet the required flow and calculated TDH. The calculation is based upon manufacturer's information on pump performance.

Pump Cost. This is the calculated cost of the pump (bowl assembly only). It excludes cost for accommodating additional lateral (discussed below).

Lateral. This is the calculated cost for accommodating thermal expansion of the well pump shaft and column shaft. There are basically two methods of accommodating lateral. For relatively shallow pump settings and/or operation in low temperature water, the relatively small expansion can be accommodated by machining the bowls (impeller housings). For deep settings and/or operation in higher temperature wells, it is necessary to use extra lateral bowls (housings, specially cast for this purpose). The second approach is much more expensive. The spreadsheet calculates the amount of shaft expansion and determines which approach is required. It then calculates the cost associated with the lateral allowance.

Wellhead. This is the cost for the fitting which supports the motor and anchors the column to the surface. It also includes the fittings for adjusting tension on the shaft enclosing tube and admitting lubricating oil to the column shaft bearings.

Column Cost. The cost of the column is based on the use of enclosed lineshaft. Total cost is based on the column length calculated above and manufacturer's cost data for threaded material with 10 ft bearing spacing.

Motor Size. Motor size is based on the horsepower calculated above.

Motor Cost. Motor cost is based on 3, 460 v, vertical, hollow shaft induction motor with TEFC enclosure.

Total Pump Cost. This value is the sum of the pump, lateral, column, well head and motor costs calculated above plus the pump installation cost calculated below.

VSD Cost. If a variable speed drive is specified in the input, this is the calculated cost of the drive. Calculations are based on the use of a pulse-width modulation-type variable frequency drive.

Wellhead Electrical. The value shown indicates costs for electrical equipment necessary to accommodate the operation of the pump. Included are: disconnect switch, starter, and motor connection hardware. In addition, a flat $400 is included for lighting and miscellaneous electrical connections. Starter and disconnect sizing is based upon calculated motor horsepower.

Wellhead Mechanical. The value shown is the cost for miscellaneous mechanical equipment required to connect the piping to the well head. Included are: 1 gate valve, 1 check valve, 10 ft bare steel pipe, 5 flanges and 3 elbows. Costs are calculated for nominal 4", 6" and 8" pipe sizes, and the cost applied is determined by flow rate.

Wellhead Enclosure. A flat $2500 is included for a well head enclosure building.

Pump Installation. The cost for the pump installation is based upon the length of pump column calculated above. If the length of the column exceeds 150 ft, a value of $2240 is used. For column length less than 150 ft, $1120 is used.

Total Wellhead Equipment. This value is the sum of the variable-speed drive, wellhead electrical, wellhead mechanical and wellhead enclosure costs calculated above. If no production well pump is specified, only values for wellhead mechanical and wellhead enclosure are included.

Lines. The cost shown is that associated with the pipelines which deliver geothermal fluid from the production well to the building or process. Line size is based upon the required flow rate. Pre-insulated ductile iron material is assumed and an allowance of 300 ft of production lines is included.

Upper Drilling. This is the cost of drilling the upper portion of the well (pump housing). The depth of this interval is based on the "depth upper" calculation above. Diameter is based upon the upper casing size plus 2 inches. Drilling costs for this and all subsequent calculations are evaluated according to drilling conditions and depth. Drilling conditions are characterized as either hard or soft conditions. Four different depth related costs are used. Costs employed in spreadsheet calculations are summarized in the table below.

Spreadsheet Drilling Costs Assumptions[1]
(All values in $ per inch diameter per foot depth)

Depth (ft)	Hard Drilling	Soft Drilling
<500	5.00	1.80
500 - 1200	6.25	3.00
1201 - 2000	9.00	4.75
2001 - 3000	11.00	8.50

[1] From Culver, 1994–updated

The spreadsheet uses the input values for percent hard and soft drilling to determine final costs.

Depth 1 Depth 2 Depth 3 Depth 4	The spreadsheet uses these values to determine the quantity of drilling to occur in each of the 4 depth cost categories. A negative value in any depth category is interpreted as a 0. Depth 1 is the depth which remains after the "upper drilling" value is deducted.
Cost 1 Cost 2 Cost 3 Cost 4	The values shown appropriate these headings use the drilling costs associated with each of the depth categories. Only drilling is included. Casing, cement and other costs associated with the well are calculated separately below.

Blowout Preventer. In many jurisdictions, a rig constructing a well penetrating an interval expected to be above a certain temperature, may be required to be equipped with a blowout prevention device. These tools are often rented by the driller.

Casing Upper. The cost shown is that associated with the cost of the casing in the upper (pump housing) portion of the well. The casing cost is based on a value of $1.00 per inch of diameter per foot of length. Diameter is based on the "casing upper" calculation above.

Casing Lower. The cost shown is that associated with the cost of casing for the lower portion (below the pump housing) of the well. Size is based on the "casing lower" calculation above. If the user selects open hole completion in the input, the value for the casing lower would be 0.

Well Cost. This value is the total of the upper drilling, Cost 1, Cost 2, Cost 3, Cost 4, casing upper and casing lower calculations above.

Cement Cost. This is the cost of the cement placed between the casing and the borehole wall. The cost is based on the length of casing installed and a cement cost of $11 per sack.

Mobilization/De-mobilization. A flat value for mob/de-mob of the drilling rig is included at $2500. This figure is heavily influenced by the distance to the drilling site, and the size of the rig and equipment included and the nature of the site. The figure used would be appropriate to a local driller and a site requiring minimal preparation. For greater distance, a higher value should be used.

Cement Install. Assumes a cost of 10 times the cement material cost. The method used for the cementing and the casing depth both heavily influence the cement installation cost.

Total Production Well. The value shown is the sum of the well cost, cement and mob/de-mob calculations above. This value together with a 15% contingency factor appears in the primary output as the production well cost. If more than one production well is specified in the input, the value shown in the output is the sum of the total production well values for the number of wells specified.

Injection Lines. The value displayed is the nominal size for the buried lines which transport the geothermal fluid from the building or process to the injection well. The spreadsheet calculates the flow to the injection well(s) and determines which nominal size (10", 8", 6", 4", 3") is appropriate. The total system flow rate is divided equally among the number of injection wells specified.

Injection Flow. The total system flow rate is divided equally among the number of injection wells specified in the input. The value shown is the result.

Injection Well Diameter. The spreadsheet decides between two injection well casing diameters based on injection flow rate. For flows greater than 400 gpm, an 8" casing is used. For flows less than 400 gpm, a 6" casing is used.

Depth 1 Depth 2 Depth 3 Depth 4 Cost 1 Cost 2 Cost 3 Cost 4	The spreadsheet uses the same procedure for calculating the cost of the injection well as for the production well described above. The major departure from that procedure is in the unit cost drilling. For the injection well cost calculation, the unit costs are increased by a factor of 25% to allow for increased cost of alternative drilling methods sometimes used for injection. The 25% is added in the well cost calculation below.

Casing. Injection well casing is priced on the same basis as the casing for the production well described above.

Well Cost. The value shown is the sum of the Cost 1, Cost 2, Cost 3, Cost 4 and casing cost calculations above.

Cement. The cost for cement is based on 0.2 sacks per foot of casing and a cement cost of $11 per sack.

Cement Install. Assumes a cost of 10 times the cement material cost. Cementing method heavily influences cost.

Total Injection Well. This value is the sum of the well cost calculations above. This value along with a 15% contingency factor appears in the primary output on the injection well cost. If more than 1 injection well is specified in the input, the total injection well values for the number of wells specified are summed to arrive at the injection well figure in the primary output.

Lines. This is the cost for the buried pipeline to deliver the geothermal fluid from the building or process to the injection well. It is calculated in the same way as the production lines described above.

Injection Lines Total. This the total of the "Lines" value for the number of injection wells specified in the input. If only 1 injection well is specified, the value will be equal to the lines value immediately above.

Unit Power Cost. The value shown is the unit cost of pumping the geothermal fluid in $\$/10^6$ Btu based on the electrical energy rate specified in the input. The unit cost of pumping attributable to the demand rate is calculated separately. This cost is calculated according to the following:

> ((1,000,000/peak load)* pump kW * $/kWh)/0.8). The 0.8 value is to adjust the unit cost for lower efficiency which occurs at off-peak conditions.

Unit Demand Cost. This is the cost of pumping associated with the electric demand rate. The calculation assumes a 12-month ratchet and is based upon the demand charge specified in the input. It is calculated according to the following:

> (pump kW * 12-mo/year * demand rate $/kW)/(8760 * load factor * peak load/1,000,000)

Annual Maintenance. The cost for maintenance is based upon: 1% of the capital cost of the wellhead equipment and well pump overhaul at 5-year intervals (at 60% of bowl assembly cost), pump replacement at 15-year intervals (including replacement of 25% of the pump column).

Annual Maintenance Cost. This value is calculated by dividing the Annual Maintenance value by the annual quantity of energy supplied by the system.

Boiler Equipment Cost. Boiler plant costs are based on the costs for: cast iron boiler and burner, concrete pad, breeching to flue, gas piping, combustion air louvers, expansion tank and air fittings, air separator, relief valve and piping, feed-water assembly, boiler room piping and shut-off valves. These cost were based on data from Konkel, 2201.

Inflator. This is the multiplier used to inflate prices from the last update of the spreadsheet 1998 to 2001 values. A different value can be added to make future updates.

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