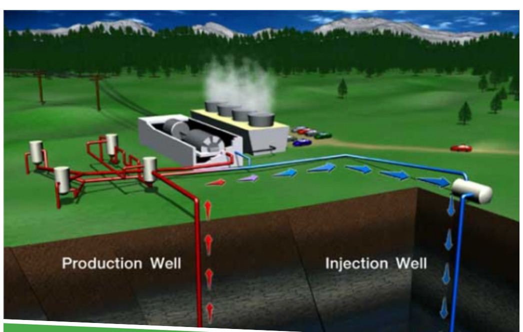

Revised Final (R1) Report

An Assessment of the Economic Viability of Selected Geothermal Resources in British Columbia
Geoscience BC Report 2015-11

March 31, 2016
KWL File No. 2692.006-300

Submitted by:

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GeothermEx
A Schlumberger Company

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Executive Summary

Kerr Wood Leidal Associates Ltd. (KWL), with its partner GeothermEx Inc. was retained by Geoscience BC in January 2015 to provide an assessment of the economic viability of geothermal energy in British Columbia for electrical power development. More specifically, the scope of this assignment comprised the research and compilation of data on 18 specified geothermal sites, and the technical and economic assessment of those sites deemed 'favourable'. The general location of these 18 sites is shown on Figure E1-1 entitled 'Potential Geothermal Sites'.

In March 2016, the assignment was expanded to include a sensitivity analysis of drilling costs (at 50% and 150% of base drilling costs) for two of those specified sites, namely Pebble Creek and Sloquet Creek.

Estimates of the levelized cost of electricity for the nine favourable sites (plus Jedney Area, and Clarke Lake at 5 MW) were calculated using the specified *Geothermal Electricity Technology Evaluation Model* (*GETEM*). Table E1-1 summarizes both the volumetric assessment and the economic analysis for these sites.

Observations and conclusions are:

1. Planning-level and Technical Nature of Assignment:
    a. It is not within the scope of this assignment to comment on policy issues;
    b. There have been various estimates of the potential for geothermal power in British Columbia.[1, 2] This study was directed in the RFP to assess 18 specified sites and carry out a volumetric assessment and economic analysis on the 'favourable' sites within those 18 sites. These favourable sites are estimated to have a combined potential of under 400 MW;
    c. This is a planning-level study which uses publicly available information only. While it is informed by direction and comments from Geoscience BC and the Technical Advisory Committee, consultation with interested parties (e.g., geothermal proponents, individuals/groups, municipalities) was not part of the approved scope. Fieldwork and exploration activities were also not part of the scope; and
    d. It should be kept in mind, as noted in the description of the GETEM in Appendix U, that "the model is intended to provide representative estimates of cost and performance for geothermal produced from scenarios defined by a user, not as a tool for assessing specific projects or sites". Project proponents may have detailed information obtained through specific exploration and other activities at a particular site. This information is generally proprietary and could include exploration results for the geothermal resource, the development of innovative technologies, and detailed route investigations for a power line to connect the plant to the electrical grid. This in-depth knowledge could potentially result in a different cost of electricity than the cost produced by GETEM. Canoe Creek (also known as Canoe Reach), Lakelse Lake, Meager Creek and Pebble Creek have geothermal proponents/developers. For example, Borealis GeoPower has carried out a number of exploration and project development activities on its Canoe Creek geothermal permit area in the last few years. They may have detailed information that would reflect in their calculations of the levelized cost of electricity.

[1] The Canadian Geothermal Energy Association (CanGEA) stated in their BC Geothermal Resource Estimates Key Findings: "The most conservative view of the technical potential of geothermal power from hot sedimentary aquifers in British Columbia is 5700 MW of 'indicated resources'.

[2] The total energy potential of the 16 top geothermal prospects in British Columbia is 4000 MW, derived from "High-Temperature Geothermal Energy – Why No Canadian Development? By Mory Ghomshei, Stephen Mak and John Meech, 2014.

2. Levelized Cost of Electricity

   a. This revised report corrects the values in the depreciation schedule which is an input to GETEM. The resulting LCOEs for the favourable sites are materially different from the LCOEs previously presented;

   b. Based on the GETEM analysis, the LCOE from Table 6-1 for the favourable sites at a 5% discount rate ranges from 11.5 CAD¢/kWh for Pebble Creek to 29.7 CAD¢/kWh for Clarke Lake. The LCOE for the Jedney Area and for Clarke Lake at 5 MW (both added at the direction of Geoscience BC) are 39.8 CAD¢/kWh and 33.2 CAD¢/kWh respectively. A geothermal supply curve reflecting these results for the favourable sites is shown in Figure 7-1;

   c. Although GETEM is a complex tool and US-focused, it has the capability to permit the input of specific values reflecting British Columbia conditions. Where sufficient information was available to estimate specific parameters (such as costs for power lines and roads), these parameters were included as input to GETEM. Otherwise, default parameters, internal to the GETEM program, were used; and

   d. The cost of drilling wells during the various phases of a geothermal project has a significant impact on the LCOE, as demonstrated by sensitivity analysis of drilling costs for Pebble Creek and Sloquet Creek (Table 6-4). The LCOEs for Pebble Creek (with a base LCOE of 11.5 CAD ¢/kWh) are 7.8 and 15.2 CAD ¢/kWh, reflecting drilling costs of 50% and 150% of base case, respectively. Similarly, the LCOEs for Sloquet Creek (with a base LCOE of 21.8 CAD ¢/kWh) are 15.7 and 27.7 CAD ¢/kWh, reflecting drilling costs of 50% and 150% of base case, respectively.

3. Market Opportunities for Geothermal Power

   A graphical representation of the LCOE versus capacity of each site, including the parameters of BC Hydro's SOP is shown in Figure 7-2. Observations on potential market opportunities for geothermal power from the research carried out and from Figure 7-2 include:

   a. At present there are no BC Hydro calls for power from independent power producers;

   b. BC Hydro's SOP presents an opportunity for those sites with a capacity of less than 15 MW;

   c. As of June 2015, the price of power under BC Hydro's SOP is approximately $100/MWh. Meager Creek and Pebble Creek are the only projects close to this threshold. However, they are greater than 15 MW;

   d. Mt. Cayley, Meager Creek and Pebble Creek are not eligible for SOP and require alternative procurement processes;

   e. There may be opportunities for agreements with major industrial facilities (e.g., gas processing plants, pulp mills, mines) to supply electricity connected directly from geothermal resources (the use of BC Hydro and Fortis BC transmission systems for this purpose is not permitted as there is no retail access); and

   f. There may be opportunities for bi-lateral agreements with BC Hydro for geothermal power over the threshold for the SOP in specific BC Hydro regions of the province.

4. Power Lines (and associated equipment) and Access Roads

   Power line routing: maps and other office studies were used to determine the preliminary routing of the power line from the geothermal generating site to the appropriate interconnection point on the electrical grid (BC Hydro, Fortis BC, or private owner). More detailed studies would involve field reconnaissance and surveys;

   a. Costs of power lines and access roads: appropriate voltage levels, and the costs of both power lines (transmission and distribution as appropriate) and access roads were generally developed from information and guidance contained in “Road and Power Line Estimating using GIS”, a publically available document developed with and for BC Hydro. These costs were then input into GETEM; and
   b. Interconnections: An interconnection of a power line from a geothermal generating site to a power line owned by a private company will require negotiations with and the approval of that private company. No allowance has been made for the cost of using the private power line.

5. Clarke Lake at 5 MW
   a. A GETEM analysis was carried out for Clarke Lake with a capacity of 5 MW at the request of Geoscience BC. A generating plant of this size and proximity to the BC Hydro distribution system near Fort Nelson requires only a distribution line. This is reflected in the LCOE from GETEM; and
   b. However, there is a strategic question here for BC Hydro centred on the possibility of additional future generating plants each with a capacity in the order of 5 MW. This could require a collecting substation and a 138 kV line from that collecting substation. This is beyond the scope of this assignment.

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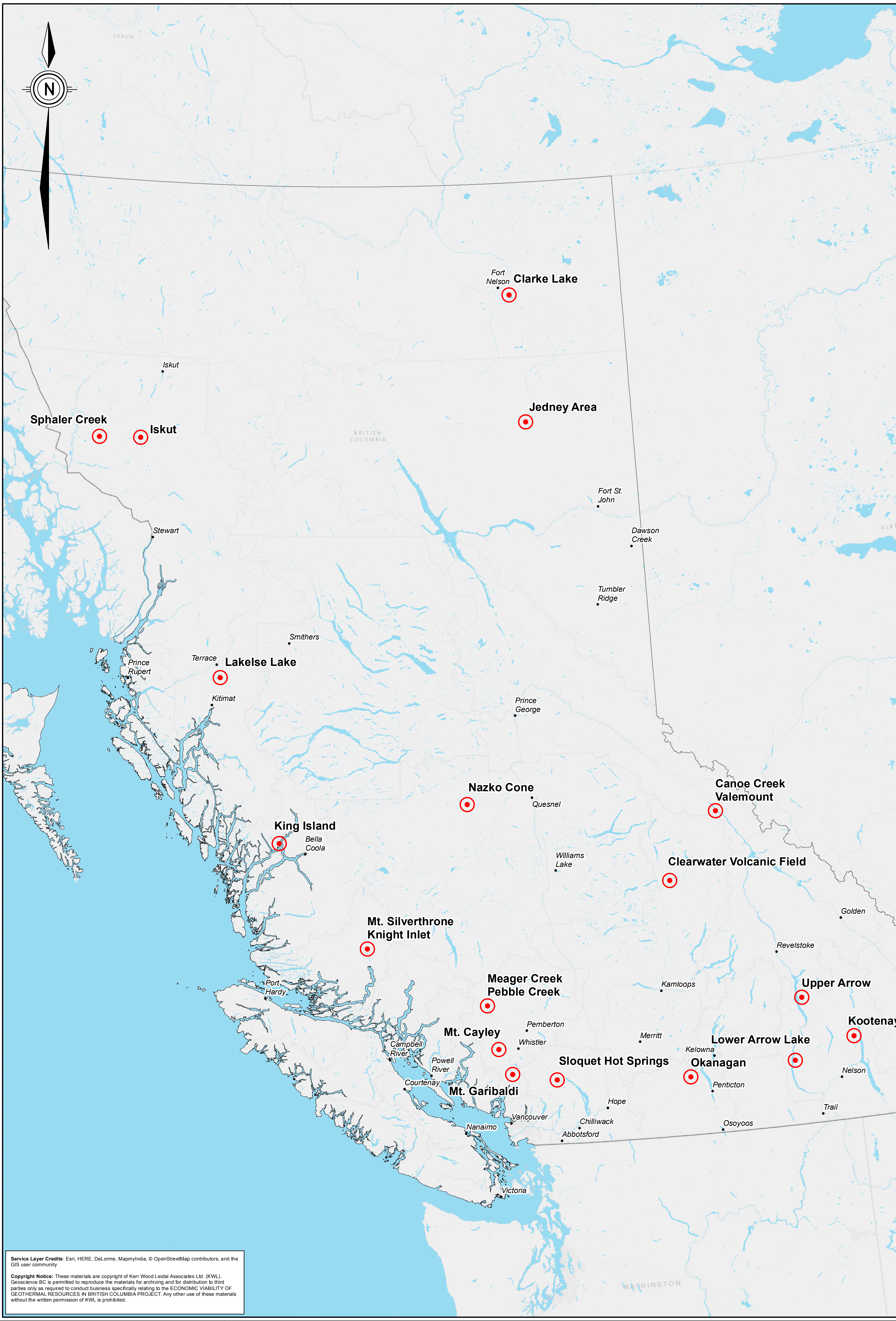

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consulting engineers

Geoscience BC

Project No.	Date
2692-004	April 30, 2015

100 0 100
Kilometers

Potential Geothermal Sites

Figure E1-1

Table E1-1: Results of Volumetric Assessment and Economic (GETEM) Analysis

Geothermal Prospect Site/Area	Plant Type	Initial MW estimate (GDDM)	MW (gross) at 90% probability from Vol.Est.	MW (net) : Parasitic = 10% for Flash 25% for Binary	Levelized Cost of Electricity* (CAN¢/kWh) Discount Rate 5%
Canoe Creek – Valemount	Flash	15	14.3	12.9	26.8
Clarke Lake	Binary	34	18.4	13.8	29.7
Clarke Lake (5 MW scenario)	Binary	5	-	3.8	33.2
Jedney Area	Binary	15	12.2	9.2	39.8
Kootenay	Binary	20	19.9	14.9	22.8
Lakelse Lake	Binary	20	19.6	14.7	23.4
Lower Arrow Lake	Binary	20	19.6	14.7	23.7
Meager Creek (Pebble Creek volume assumed equivalent)**	Flash	100-200 total (50-100 ea)	198.0 combined (99.0 ea)	178.2 combined 89.1 (ea)	11.7
Mt. Cayley	Binary	50	40.7	30.5	17.3
Okanagan	Binary	20	18.3	13.7	24.1
Sloquet Creek	Binary	10	10	7.5	21.8

* These LCOEs have been revised from the previous versions of this report to correct the values used for the depreciation schedule in GETEM (Lines 32 to 37 of Table V-1)

** Pebble Creek transmission and infrastructure costs are significantly less than those at Meager Creek, resulting in a lower LCOE value for Pebble Creek (11.5 CAN¢/kWh).

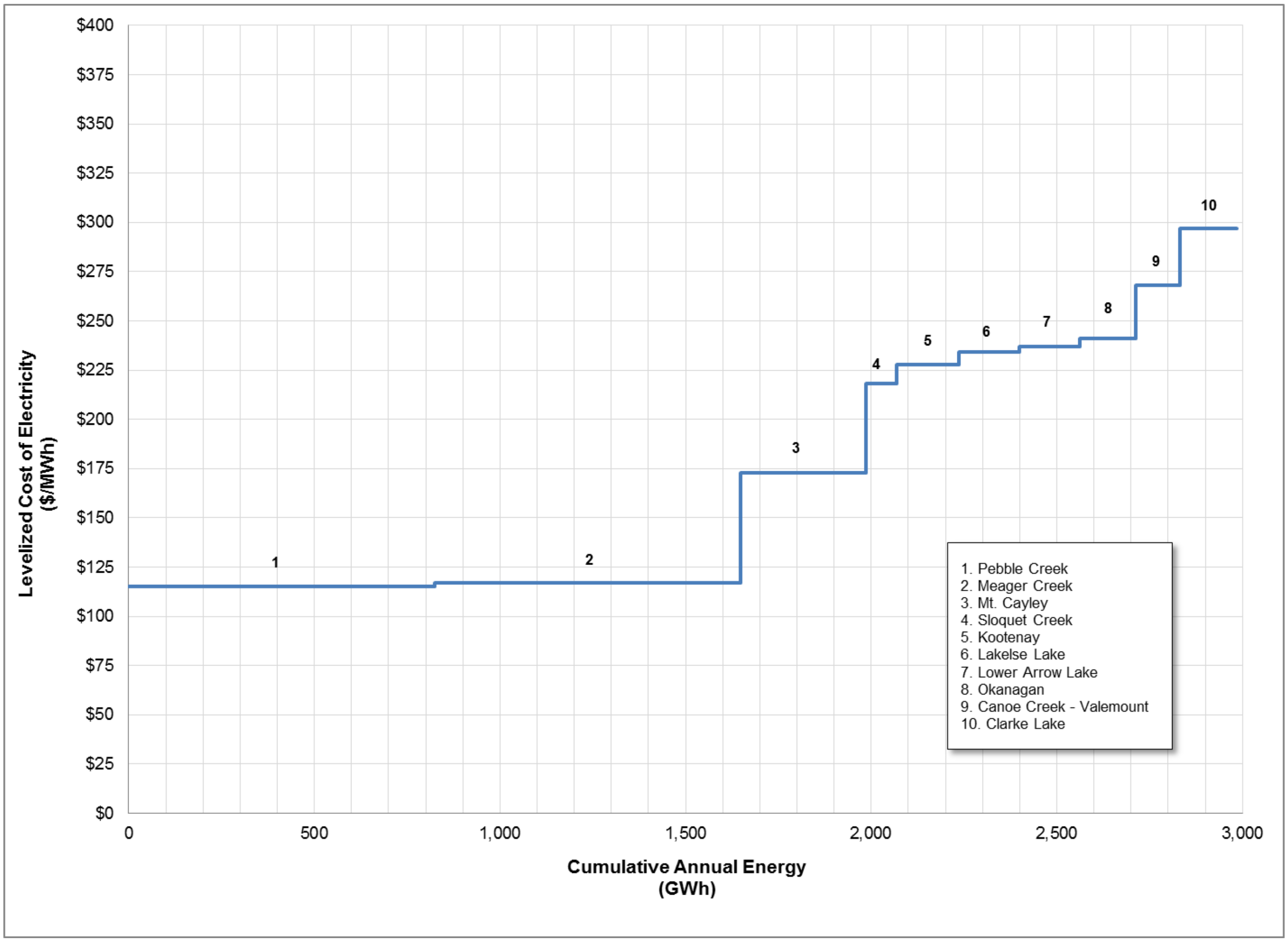

Figure E1-2: Geothermal Supply Curve for Favourable Sites

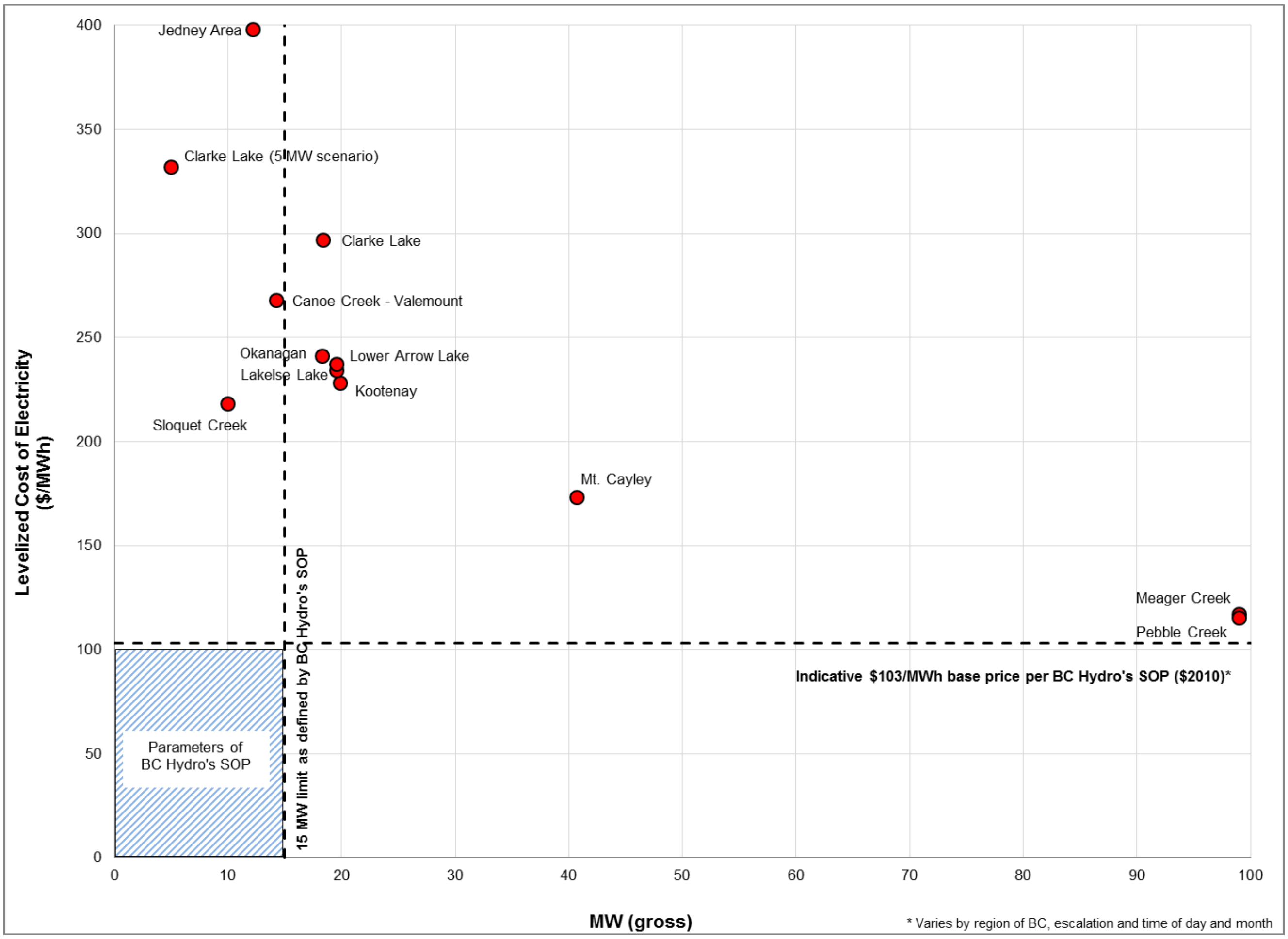

Figure E1-3: Geothermal Sites – LCOE vs Capacity

1. Introduction and Background

Geothermal energy is defined as heat from the Earth. Geothermal energy systems draw on that natural heat to drive conventional power generation technologies.[3] The electricity produced is generally viewed as a clean, renewable and sustainable form of energy. It also represents a base-load source of electricity. It is used in over 70 countries to generate electricity with a total installed capacity of more than 12,000 MW worldwide. Although there has been geothermal exploration activity in various parts of British Columbia for a number of years, there is currently no electricity produced in British Columbia from geothermal sources.[4]

Kerr Wood Leidal Associates Ltd. (KWL), with its partner GeothermEx Inc. was retained by Geoscience BC in January 2015 to provide an assessment of the economic viability of geothermal energy in British Columbia for electrical power development. More specifically, the scope of this assignment comprised the research and compilation of data on 18 specified geothermal sites, and the technical and economic assessment of those sites deemed 'favourable'.

In March 2016, the assignment was expanded to include a sensitivity analysis of drilling costs (at 50% and 150% of base drilling costs) for two of those specified sites, namely Pebble Creek and Sloquet Creek, and brief comments on "Project Life" and "Annual Rate of Decline" as originally modelled.

This report provides the results of that assessment. It is organized as follows:

- Executive Summary: a concise summary of the results;
- Introduction and Background: a brief introduction to the assignment;
- Project Approach and Methodology: a listing and description of the key tasks and a project schematic;
- Data Compilation: research and presentation of information under specified categories;
- Threshold Criteria/Favourability Analysis: a methodology to determine which sites are deemed 'favourable';
- Volumetric Assessment: estimates of geothermal energy reserves for favourable sites;
- Economic Analysis: estimates of the levelized cost of electricity (LCOE) for favourable sites, together with the above noted sensitivity analysis;
- Observations and Conclusions: observations on the results, and conclusions; and
- Appendices.

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[3] Typically, three geothermal power plant technologies are used to convert hydrothermal fluids to electricity: dry steam, flash steam and binary cycle. The type of conversion used (selected in development) depends on the state of the fluid (steam or water) and its temperature. A binary cycle power plant is a type of geothermal power plant that allows cooler geothermal reservoirs to be used (when compared to the temperatures required for dry steam and flash steam plants). With flash steam plants, water originating at reservoir temperatures greater than about 180 °C is produced through self-flowing wells as a steam-water mixture, supplying steam to generation equipment at the surface. With binary cycle geothermal power plants, pumps are used to pump hot water from a geothermal well through a heat exchanger, and the cooled water is returned to the underground reservoir. A second fluid with a low boiling point is pumped through the heat exchanger, where it is vapourized and then directed through a turbine. The vapour exiting the turbine is then condensed by cold air radiators or cold water and cycled back through the heat exchanger.

[4] Geothermal heat pumps, also known as ground source heat pumps or geoexchange systems, are used to heat and cool homes, commercial buildings, etc. Heat from the ground (or in some cases, groundwater) is used for heating in winter, and in summer the ground can be used as a "heat sink" for heat removed from the building. This report does not consider geoexchange systems.

2. Project Approach and Methodology

Our approach to this project, as defined in Geoscience BC's Request for Proposals (RFP) dated November 24, 2014 and entitled '*Economic Viability of Geothermal Resources in British Columbia'*, comprised the following tasks as shown in Figure 2-1 entitled *Project Schematic*:

1. **Data Compilation**: carry out research using publicly available information sources and provide relevant data to complete the Geothermal Development Decision Matrix (GDDM) for each of the 18 specified sites;
2. **Threshold Criteria/Favourability Analysis**: Using the information compiled in the GDDMs for each of the 18 sites, develop a methodology to determine which of the sites are 'favourable' (and by extension which ones are 'unfavourable');
3. **Volumetric Assessment**: estimate the energy generation potential of the "favourable" sites using the geothermal assessment methodology of the US Geological Survey (USGS) (Williams et al 2008), or equivalent; and
4. **Economic Analysis**: calculate the LCOE of the "favourable" sites using the Geothermal Electricity Technology Evaluation Model (GETEM) developed by the National Renewable Energy Laboratory (NREL), or equivalent.
5. **Report**: prepare draft report, receive and incorporate relevant comments and submit the final report to Geoscience BC.

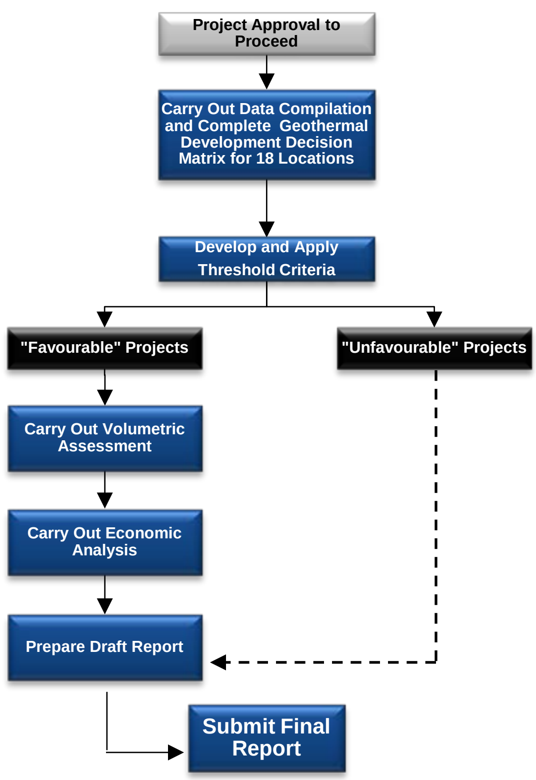


Figure 2-1: Project Schematic

3. Data Compilation

3.1 Potential Sites and Geothermal Development Decision Matrix

KWL was directed to focus this assignment on the evaluation of 18 specified sites in British Columbia. These sites were regarded as having potential for geothermal energy. The location of these 18 sites was reviewed with and confirmed by Geoscience BC. The general location of these 18 sites is shown on Figure E1-1 entitled 'Potential Geothermal Sites' and the location coordinates are provided in Table 3-1. (Note that Table 3-1 provides information separately for Meager Creek and Pebble Creek and therefore the table totals 19 sites.)

Two maps were developed for each of the 18 sites, namely:

- A regional topographic map, showing:
  - population centres, roads, and other facilities;
  - land tenures in the area, including parks;
  - the potential geothermal plant location;
  - relevant existing electrical system infrastructure; and
  - the proposed transmission line routing, voltage and point of interconnection to that infrastructure;
- A geologic strata map.

Data on each of these 18 sites was compiled from research using publicly available information (fieldwork was not part of the scope of this assignment). This research was carried out using a variety of sources. These sources are listed in Appendix A entitled '*Reference Materials/Sources for Data Compilation*'. Note that confidential developer information was not used.

This data for each site was compiled and reported under appropriate categories in a spreadsheet format entitled 'Geothermal Development Decision Matrix'. The categories that KWL was directed to use are shown in Table 3-2 entitled 'GDDM – Specified Categories and Sub-categories for Data Compilation'. The presentation of data in a consistent format for all 18 sites assists in comparing the potential sites.

The GDDM, topographic map and geologic map for each site are presented in the respective Appendix (Appendix B to Appendix S inclusive).

Table 3-1: Potential Geothermal Site Coordinates

Geothermal Site	Latitude	Longitude	UTM X (m E)	UTM Y (m N)
Canoe Creek – Valemount	52.673325	-119.056345	360966.462	5837915.971
Clarke Lake	58.721628	-122.531644	527124.861	6509150.560
Clearwater Volcanic Field	51.924406	-120.026145	704478.542	5756809.475
Iskut	57.064719	-130.355234	417818.507	6325405.963
Jedney Area	57.262861	-122.245747	545495.188	6346898.892
King Island	52.498855	-127.290420	616050.110	5817898.367
Kootenay	49.734076	-116.914369	506170.707	5509068.256
Lakelse Lake	54.322493	-128.539906	529925.267	6019500.958
Lower Arrow Lake	49.744664	-118.082239	422029.852	5510803.919
Meager Creek	50.566909	-123.512111	463731.973	5601790.518
Pebble Creek	50.667800	-123.470425	466755.385	5612989.614
Mt. Cayley	50.101612	-123.362587	474069.291	5549991.436
Mt. Garibaldi	49.807771	-123.105309	492422.763	5517263.479
Mt. Silverthrone – Knight Inlet	51.296153	-125.641864	315818.262	5686073.825
Nazko Cone	52.927207	-123.740111	450247.756	5864429.345
Okanagan	49.665530	-119.949552	287166.525	5505621.550
Sloquet Hot Springs	49.736758	-122.303431	550192.909	5509595.749
Sphaler Creek	57.047496	-131.196583	366745.601	6324816.784
Upper Arrow	50.429098	-117.840702	440287.707	5586679.251

Table 3-2: GDDM – Specified Categories and Sub-categories for Data Compilation[5]

Category		Sub-category
A	Reservoir Potential	• Size/Potential/Type • Temperature/Water and Gas Chemistry/Mineral Indicators • Surface Flow Rates and Reservoir Recharge • 3D Permeability (heat exchange potential) • Recent Magmatism • Structural Setting • Geophysics
B	Exploration Uncertainty (Risk)	• Degree of Identification of Resources/Reserves • Likelihood of Covering Reservoir with Concession • Expected Authorisation Date • Specific Timing of Exploration • Degree of Previous Exploration • Surface Operational Capacity (enough stable area for drilling and a plant?) • Exploration to Exploitation: a summary rating of Exploration Uncertainty (risk) on a Scale of Difficult (high risk) through medium (moderate risk) to Easy (low risk)

[5] There was no Category G in the scope of work from Geoscience BC. It has been excluded for consistency.

Category		Sub-category
C	Environmental Issues	• Protected Areas • Endangered Species • Geothermal Surface Features • Other
D	Geothermal Area – Bidding and/or Type of Land Holding (private/government/lease, etc.)	• Bidding Area • Other Claim Rights (mining and/or oil)
E	Market	• Main Electricity Consumers (direct sales and/or government) • Time Limits? (business agreements, operating/ generating – by deadlines?
F	Transmission Line Infrastructure	• State of the Infrastructure • Transmission Route (distance, terrain, and cost)
H	Community Issues	• Indigenous Law and Indigenous Development Areas • Community Action • Surface Rights • Tourism
I	Water Rights	• Availability (e.g., 'air-cooled required') • Availability for Drilling
J	Engineering	• Plant Location and Design • Construction Issues • Transportation Issues • Architectural Issues • Special Construction Issues
K	Non-electrical Infrastructure (Roads and Habitation)	• Nearest Large Community > 50,000 • Nearest Community • Nearest Road and Condition • Current Access Conditions (restrictions) • Terrain and Distance Factor for Road Building
L	Finance	• General Power Prices • Market Price ($/MWh) • Green Power Premium ($/MWh) • Capacity Price ($/kW) • Is there a higher price for base load power? • Estimated Size of Resource • Are there any green power incentives? • Grants • Tax Holidays • Tax Relief • Loan Guarantees • Royalties/Fees • General Idea of Royalties • Private Land Owner or Government Land • Tax Rate in the Country • Transmission Tariffs

Category		Sub-category
M	Maps	• Regional topographic map showing population centres, roads and other infrastructure including electrical grid and nearest sub-station and/or generating station • Regional map showing land tenure in area – geothermal concessions, mining concessions, private land holdings, public or national lands (parks) • Regional geological map • Detailed geological map of the immediate area of the concessions
N	Other Issues and Considerations	

3.2 Exploration Uncertainty

"*The resource risk (or exploration risk) reflects both the difficulty of estimating the resource capacity of a geothermal field and the costs associated with its development.*"[6]

GDDMs completed for each of the 18 sites contain information on Category B (Exploration Uncertainty), together with the sub-categories as shown in Table 3-2. The "Exploration to Exploitation" summary rating in this category represents to a large degree professional judgement on the relative measure of risks between the sites. This rating is included as one of the differentiating criteria in the Favourable Analysis (Section 4).

Insights into the measure/level of resource risk (independent of other geothermal resources) can be gleaned from use of Figure 3-1 entitled *Resource Risk*. This figure illustrates the project/resource risk and cumulative costs for each geothermal site depending on the development phase of that potential site.

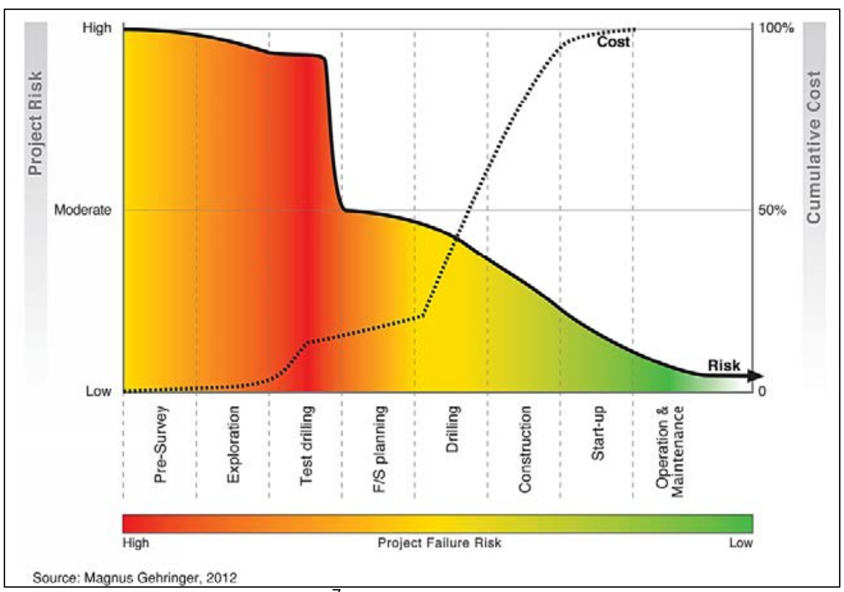


Figure 3-1: Resource Risk[7]

[6] Source: Geothermal Handbook: Planning and Financing Power Generation, 2012. The World Bank.
[7] Adapted from Geothermal Handbook: Planning and Financing Power Generation, 2012. The World Bank.

This figure is divided into a series of development phases along the x axis before the operation and maintenance phase begins. Using professional judgement and information from the GDDMs, the appropriate development phase for each potential site can be ascertained, allowing an estimate of the degree of project/resource risk (low to high) and cumulative costs (0 to 100%) to be made for each site.

Recognising that full-diameter test wells have not been drilled for the majority of the sites, most of the sites fall into the Pre-survey or Exploration phase (except for Meager/Pebble Creeks).

Table 3-3 entitled *Geothermal Resource Exploration Uncertainty* summarises the project/resource risk for each site.

Table 3-3: Geothermal Resource Exploration Uncertainty

Geothermal Site	Development Phase	Project Risk	Cumulative Cost
Canoe Creek – Valemount	Exploration	High	<5%
Clarke Lake	Exploration	High	<5%
Clearwater Volcanic Field	Pre-Survey	High	0%
Iskut	Pre-Survey	High	0%
Jedney Area	Exploration	High	<5%
King Island	Pre-Survey	High	0%
Kootenay	Pre-Survey	High	<5%
Lakelse Lake	Exploration	High	<5%
Lower Arrow Lake	Pre-Survey	High	0%
Meager Creek	Test Drilling	High-Moderate	~15%
Pebble Creek	Test Drilling	High	~10%
Mt. Cayley	Exploration	High	<5%
Mt. Garibaldi	Pre-Survey	High	0%
Mt. Silverthrone – Knight Inlet	Pre-Survey	High	0%
Nazko Cone	Exploration	High	<5%
Okanagan	Exploration	High	<5%
Sloquet Hot Springs	Exploration	High	<5%
Sphaler Creek	Pre-Survey	High	0%
Upper Arrow	Pre-Survey	High	0%

4. Favourability Analysis

This section describes the methodology developed to determine which of the 18 sites are 'favourable' (and which ones are 'unfavourable'). The Volumetric Assessment and Economic Analysis were then carried out on the favourable sites.

4.1 Differentiating Criteria

Data provided under selected categories from the Geothermal Development Decision Matrix are consolidated and used as differentiating criteria to evaluate each of the 18 sites.

These consolidated threshold criteria are:

- reservoir potential;
- exploration uncertainty (risk);
- environmental issues;
- transmission line infrastructure;
- community issues; and
- non-electrical infrastructure (roads and habitation).

The criteria above are all assigned an equal weighting. The ratings/scores for each of the 18 sites evaluated against each of the above-noted criteria are represented by coloured balls and numerical scores, as follows:[8]

Table 4-1: Rating/Scoring System

Rating	Score	Description
⊙	+1	**Positive/Good**: promising, no apparent key issues that would affect project development
⊙	0	**Neutral**: some residual issues exist which may be able to be resolved or mitigated upon further investigation
○	-1	**Negative**: key issues exist which may be difficult or impossible to mitigate and which would impact project development
☐○	N/A	**Major Barriers**: Any potential major barrier ('show-stopper') such as severe technical (e.g. extreme slopes) and intractable social or environmental constraints (e.g., parks and protected areas), or lengthy transmission lines with attendant high costs are shown by placing a square box around the relevant coloured ball.

Before applying this rating/scoring system to each of the 18 sites, it must be recognized that this is a screening-level tool to aid in the favourability decision. It required the professional judgement of the respective members of the project team, along with input from and dialogue with Geoscience BC and members of the Technical Advisory Committee, in the determination, consistency of application and analysis of the ratings/scores. Notwithstanding the screening-level nature of this analysis, it was possible to make a reasonable determination of which sites could be deemed favourable for the purposes of this study.

A summary of the overall ratings/scores for the 18 sites is presented in Table 4-2 entitled 'Summary of Overall Ratings/Scores'.

[8] The coloured balls can also be distinguished if the document is printed in black and white.

Table 4-2: Summary of Overall Ratings/Scores[9]

Geothermal Site	Criteria Rating						Conclusions	
	Reservoir Potential	Exploration Uncertainty (Risk)	Environmental Issues	Transmission Line Infrastructure	Community Issues	Non-electrical Infrastructure (roads and habitation)	Summary Rating / Score	Favourable √ Unfavourable X
Canoe Creek - Valemount (15 MW)	◉	◉	⊙	⊙	◉	◉	◉ / +4	√
Clarke Lake (34 MW)	◉	⊙	⊙	◉	◉	◉	◉ / +4	√
Clearwater Volcanic Field (10 MW)	◉	○	○	⊙	⊙	◉	○ / +0	X
Iskut (10 MW)	◉	○	⊙	⊙	◉	⊙	⊙ / +1	X
Jedney Area (15 MW)	◉	⊙	⊙	○	◉	◉	⊙ / +2	X
King Island (20 MW)	◉	○	⊙	$\boxed{\bigcirc}$	◉	○	$\boxed{\bigcirc}$	X
Kootenay (20 MW)	◉	⊙	◉	◉	◉	◉	◉ / +5	√
Lakelse Lake (20 MW)	◉	◉	⊙	◉	◉	◉	◉ / +5	√
Lower Arrow Lake (20 MW)	◉	⊙	◉	◉	⊙	◉	◉ / +4	√
Meager Creek-Pebble Creek (50 - 100 MW each)	◉	◉	◉	◉	⊙	⊙	◉ / +4	√
Mt. Cayley (50 MW)	◉	⊙	⊙	◉	◉	◉	◉ / +4	√
Mt. Garibaldi (50 MW)	◉	○	⊙	◉	⊙	◉	⊙ / +2	X
Mt. Silverthrone - Knight Inlet (50 MW)	◉	○	○	$\boxed{\bigcirc}$	⊙	○	$\boxed{\bigcirc}$	X
Nazko Cone (10 MW)	◉	⊙	◉	$\boxed{\bigcirc}$	⊙	⊙	$\boxed{\bigcirc}$	X
Okanagan (20 MW)	◉	⊙	⊙	◉	⊙	◉	◉ / +3	√
Sloquet Hot Springs (10 MW)	◉	⊙	⊙	◉	⊙	◉	◉ / +3	√
Sphaler Creek (10 MW)	◉	○	⊙	$\boxed{\bigcirc}$	⊙	○	$\boxed{\bigcirc}$	X
Upper Arrow (20 MW)	◉	⊙	⊙	⊙	⊙	⊙	⊙ / +1	X

[9] The MW values in the first column are as estimated in the preliminary GDDM review. For favourable sites, the MW estimates were later revised in the Volumetric Assessment phase of this study.

4.2 Discussion

The rationale for the summary rating/score for each of the 18 sites and the conclusions as to whether each site is 'favourable' or 'unfavourable' are provided below.

1. All sites with a summary score of +3, +4 or +5 are 'favourable';
2. All sites with a summary score of +0, +1 or +2 are 'unfavourable'; and
3. Major Barriers: Lengthy transmission lines are required to connect the following geothermal sites to the integrated system grid (except King Island, as Bella Coola is a non-integrated area).

These four geothermal sites in Table 4-3 are therefore 'unfavourable'. A summary score is not relevant.

Table 4-3: Major Barriers[10]

Site	Capacity MW	Transmission Line Voltage kV	Transmission Line Length km	Comments
King Island	20	69	61	• Transmission line routing along steep terrain on Labouchere Channel and North Bentinck Arm to Bella Coola • Requires transformation to 25 kV at Bella Coola • Requires 69 kV submarine cable across Labouchere Channel • Proposed geothermal site location accessible by water or helicopter (no road access) only • There is limited electrical demand/load in Bella Coola • Project would have no access to the BC Hydro grid as Bella Coola is not integrated with the grid • Potential environmental issues
Mt. Silverthrone-Knight Inlet	50	138	165	• Long transmission line with attendant costs • Requires three submarine cables • Requires water (barge) access • Potential environmental issues
Nazko Cone	10	69	97	• Long transmission line with attendant costs • Small plant
Sphaler Creek	10	287	74	• Long transmission line with attendant costs • Although the transmission line could be built at a lower voltage, 287 kV was chosen to provide for additional geothermal or other projects in the area • Small plant

[10] The MW values in the Capacity column are as estimated in the preliminary GDDM review.

4.3 Favourability Conclusions

Table 4-4 provides a listing of the favourable sites. A volumetric assessment and an economic analysis have been carried out on each of these sites.

Table 4-4: Favourable Sites

Site	Initial Volume Estimate (MW)
Canoe Creek – Valemount	15
Clarke Lake	34
Kootenay	20
Lakelse Lake	20
Lower Arrow Lake	20
Meager Creek – Pebble Creek	100-200*
Mt. Cayley	50
Okanagan	20
Sloquet Hot Springs	10
Total	289-389

* 50 to 100 MW at each location

Geoscience BC subsequently directed that the following two additions be made to the scope of the assignment:

1. A volumetric assessment and an economic analysis were to be carried out on Jedney Area (it was unfavourable; and
2. An economic analysis was to be carried out for Clarke Lake assuming a generation capacity of 5 MW.

5. Volumetric Assessment

Estimates of energy reserves for the nine favourable sites (plus Jedney Area) were developed using a methodology/volumetric reserve estimation approach introduced by the US Geological Survey, modified to account for uncertainties in some input parameters by using a probabilistic basis (Monte Carlo simulation). A description of this methodology published as Appendix III of the California Energy Commission's *Pier Report* (GeothermEx, 2004) is included in Appendix T. The website link for this methodology is http://www.energy.ca.gov/reports/500-04-051.PDF

A one-page summary entitled *Estimation of Geothermal Energy Resource* is provided for each site in Figures 5-1 to 5-10.

SUMMARY OF INPUT PARAMETERS

Variable Parameters	Minimum	Most Likely	Maximum
Reservoir Area (sq. km)	1.04	2.0	3.11
Reservoir Thickness (m)	800	1100	1700
Rock Porosity	0.03		0.07
Reservoir Temperature (°C)	190	210	230
Recovery Factor	0.05		0.20

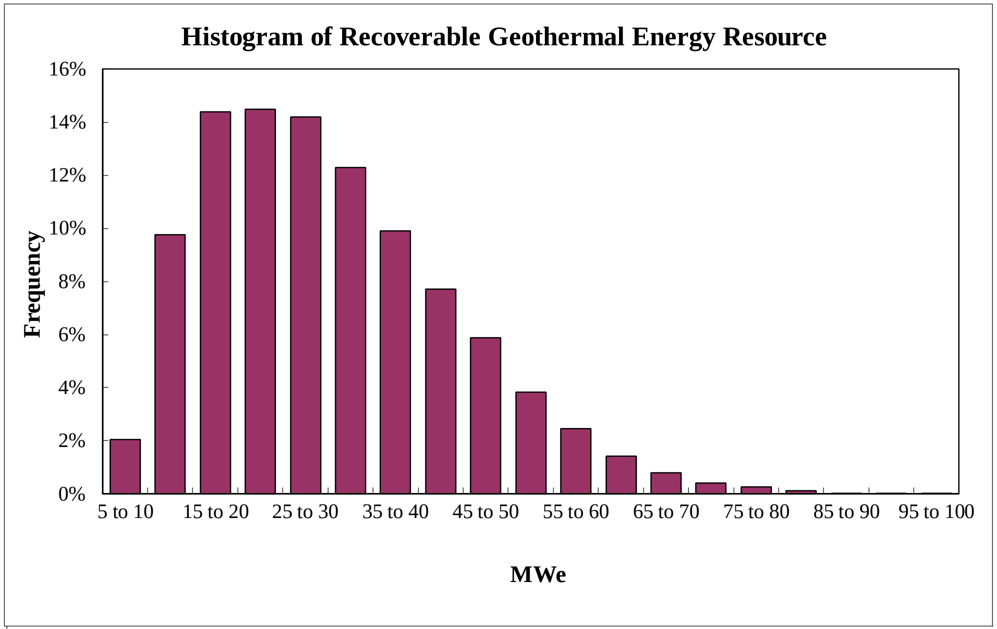
Fixed Parameters		
Rock Volumetric Heat Capacity	2613	kJ/cu. m°C
Rejection Temperature	15	°C
Utilization Factor	0.45	
Plant Capacity Factor	0.90	
Power Plant Life	20	years

RESULTS

	Statistics		
	MW	MW/sq. km	Recovery Efficiency
Mean	30.3	14.7	1.33%
Std. Deviation	13.7	5.7	0.46%
Minimum (90% prob.)	**14.3**	7.4	0.69%
Median (50% prob.)	**28.3**	14.3	1.32%
Most-likely (Modal)	**21.4**	12.6	1.59%

Canoe Creek - Valemount

Estimation of Geothermal Energy Resource



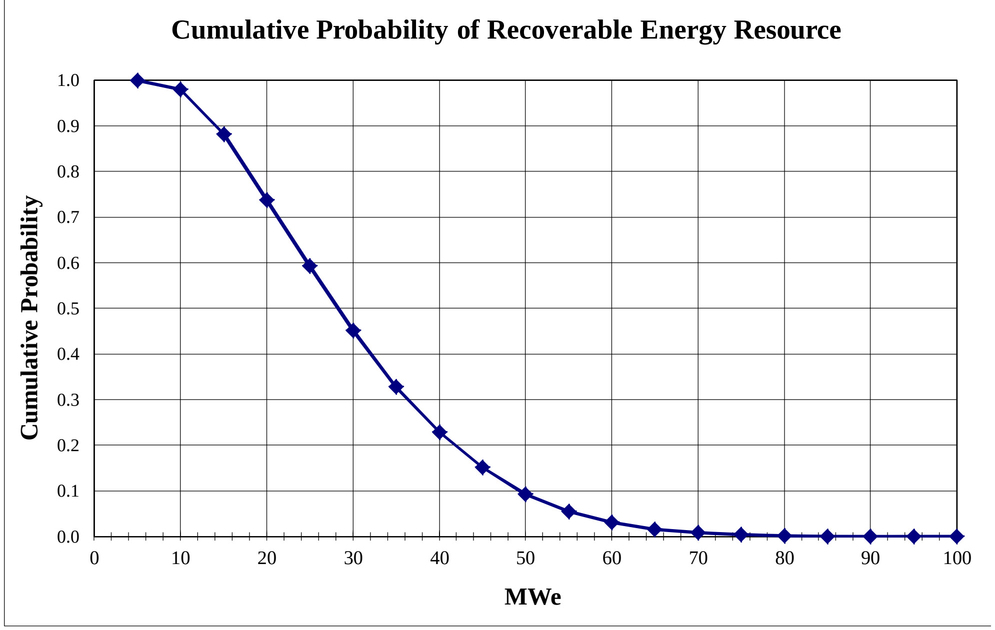


Figure 5-1: Canoe Creek - Valemount Estimation of Geothermal Energy Resources

SUMMARY OF INPUT PARAMETERS

Variable Parameters	**Minimum**	**Most Likely**	**Maximum**
Reservoir Area (sq. km)	15.00	30.00	45.00
Reservoir Thickness (m)	100	200	250
Rock Porosity	0.03		0.07
Reservoir Temperature (°C)	130	160	190
Recovery Factor	0.05		0.20

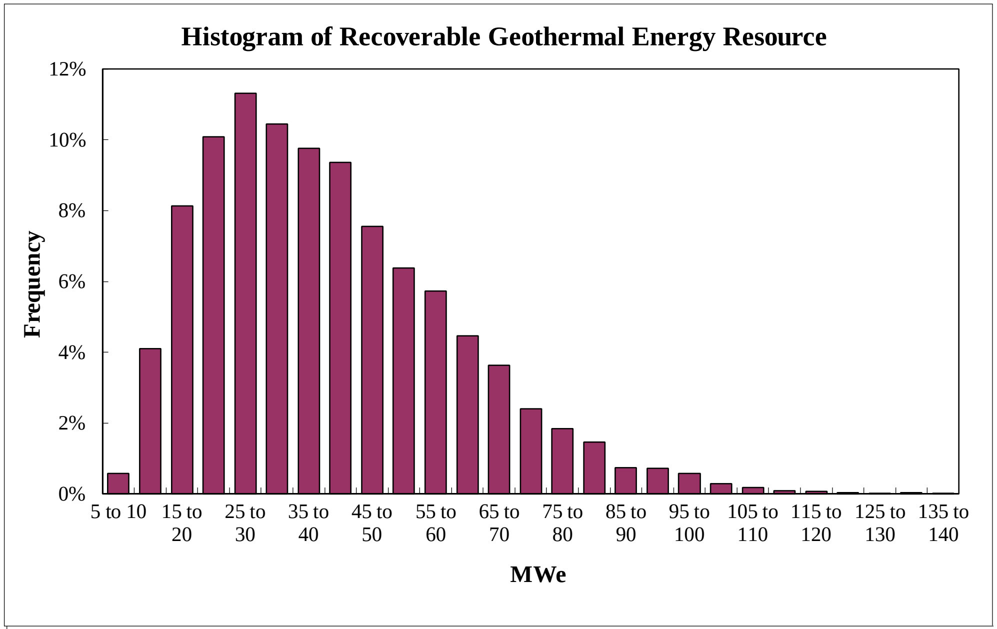
Fixed Parameters		
Rock Volumetric Heat Capacity	2613	kJ/cu. m°C
Rejection Temperature	15	°C
Utilization Factor	0.45	
Plant Capacity Factor	0.90	
Power Plant Life	20	years

RESULTS

Statistics			
	MW	**MW/sq. km**	**Recovery Efficiency**
Mean	40.8	1.4	1.07%
Std. Deviation	19.5	0.6	0.38%
Minimum (90% prob.)	**18.4**	0.7	0.55%
Median (50% prob.)	**37.4**	1.3	1.07%
Most-likely (Modal)	**29.1**	0.9	1.19%

Clarke Lake

Estimation of Geothermal Energy Resource



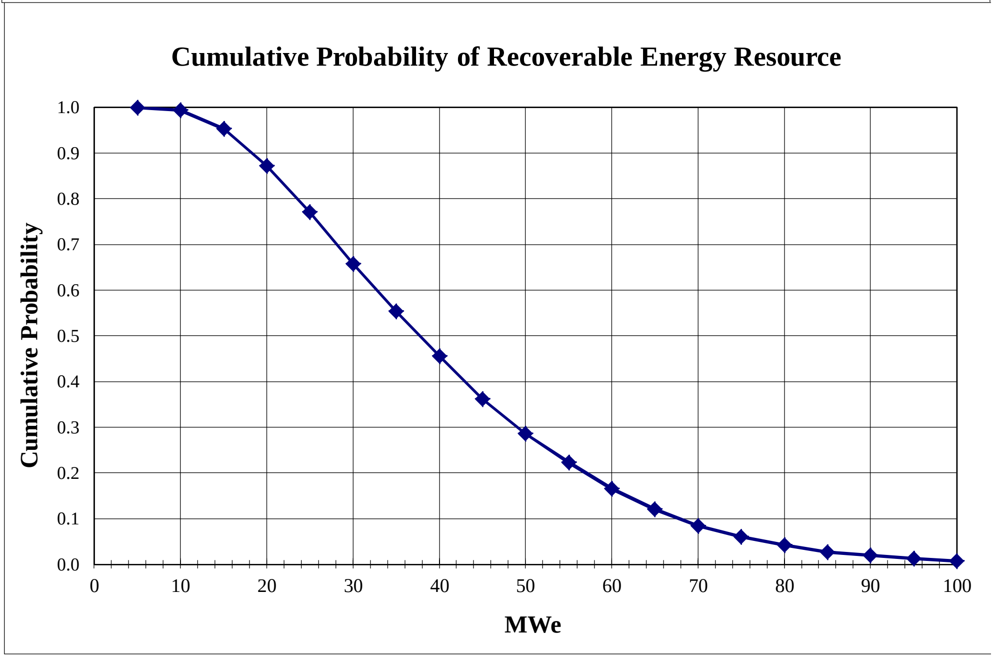


Figure 5-2: Clarke Lake Estimation of Geothermal Energy Resources

SUMMARY OF INPUT PARAMETERS

Variable Parameters	**Minimum**	**Most Likely**	**Maximum**
Reservoir Area (sq. km)	10.00	20.00	30.00
Reservoir Thickness (m)	100	200	250
Rock Porosity	0.03		0.07
Reservoir Temperature (°C)	130	160	190
Recovery Factor	0.05		0.20

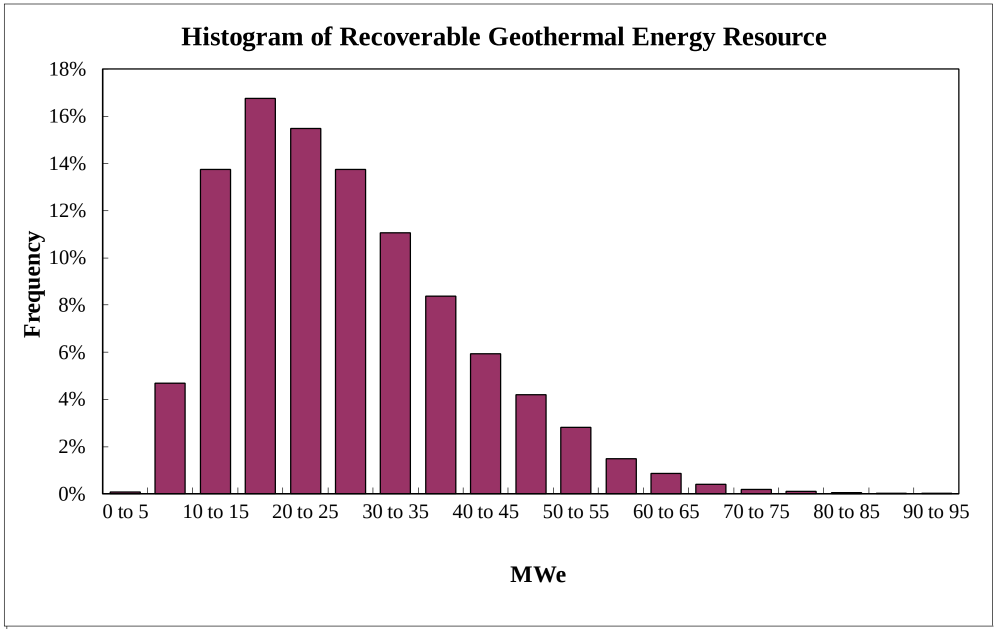
Fixed Parameters		
Rock Volumetric Heat Capacity	2613	kJ/cu. m°C
Rejection Temperature	15	°C
Utilization Factor	0.45	
Plant Capacity Factor	0.90	
Power Plant Life	20	years

RESULTS

Statistics			
	MW	**MW/sq. km**	**Recovery Efficiency**
Mean	26.9	1.3	1.07%
Std. Deviation	12.9	0.6	0.38%
Minimum (90% prob.)	**12.2**	0.7	0.55%
Median (50% prob.)	**24.7**	1.3	1.06%
Most-likely (Modal)	**18.9**	0.8	0.65%

Jedney Area

Estimation of Geothermal Energy Resource



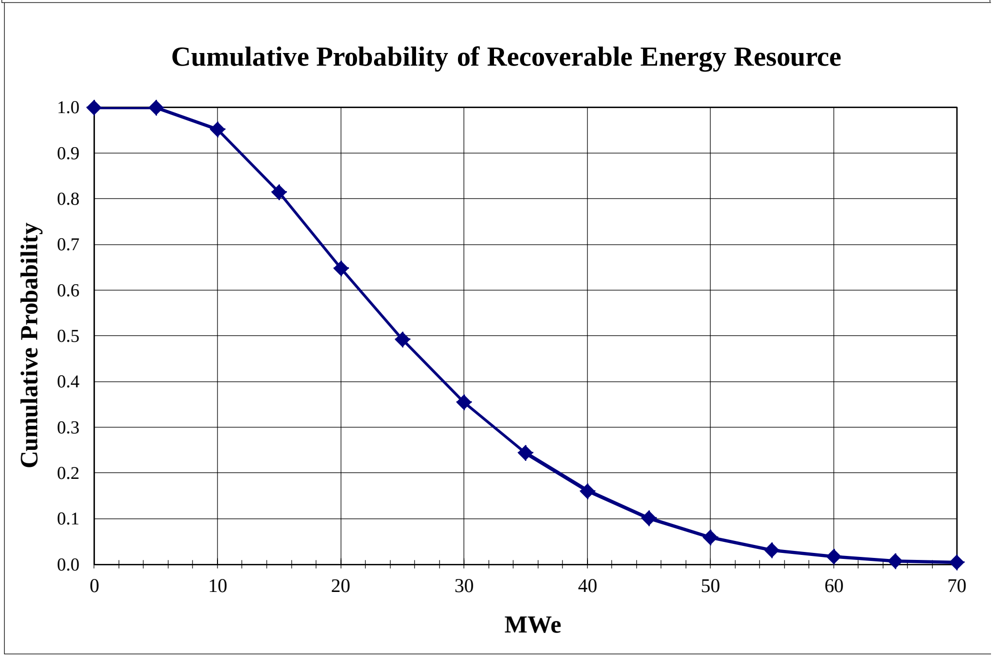


Figure 5-3: Jedney Area Estimation of Geothermal Energy Resources

SUMMARY OF INPUT PARAMETERS

Variable Parameters	**Minimum**	**Most Likely**	**Maximum**
Reservoir Area (sq. km)	2.00	5.00	10.00
Reservoir Thickness (m)	800	1100	1700
Rock Porosity	0.03		0.07
Reservoir Temperature (°C)	125	155	185
Recovery Factor	0.05		0.20

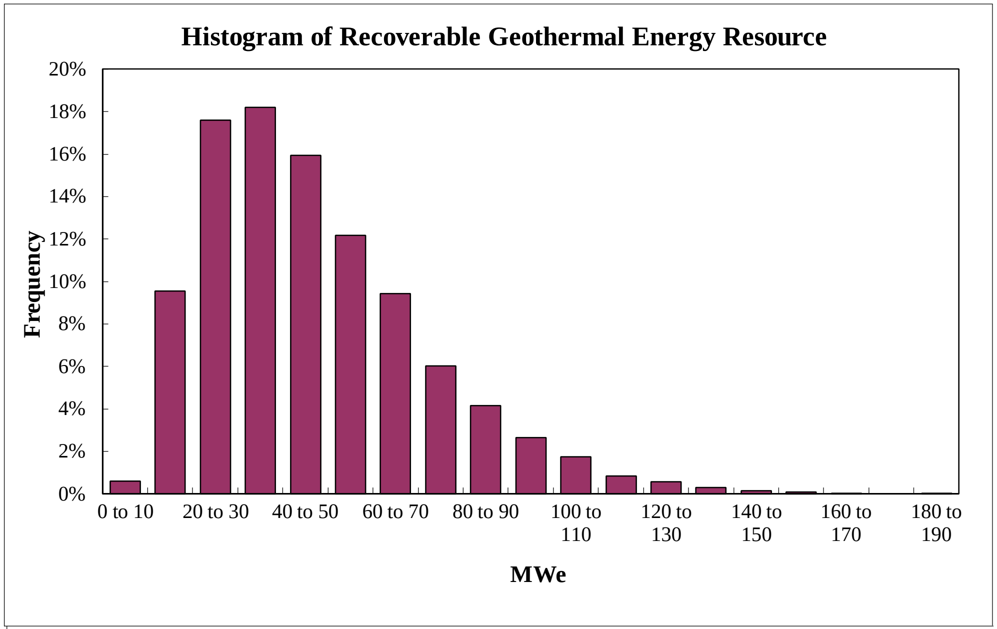
Fixed Parameters		
Rock Volumetric Heat Capacity	2613	kJ/cu. m°C
Rejection Temperature	15	°C
Utilization Factor	0.45	
Plant Capacity Factor	0.90	
Power Plant Life	20	years

RESULTS

Statistics			
	MW	**MW/sq. km**	**Recovery Efficiency**
Mean	47.1	8.3	1.04%
Std. Deviation	24.5	3.5	0.37%
Minimum (90% prob.)	**19.9**	4.1	0.54%
Median (50% prob.)	**42.2**	8.0	1.04%
Most-likely (Modal)	**27.5**	7.9	1.25%

Kootenay

Estimation of Geothermal Energy Resource



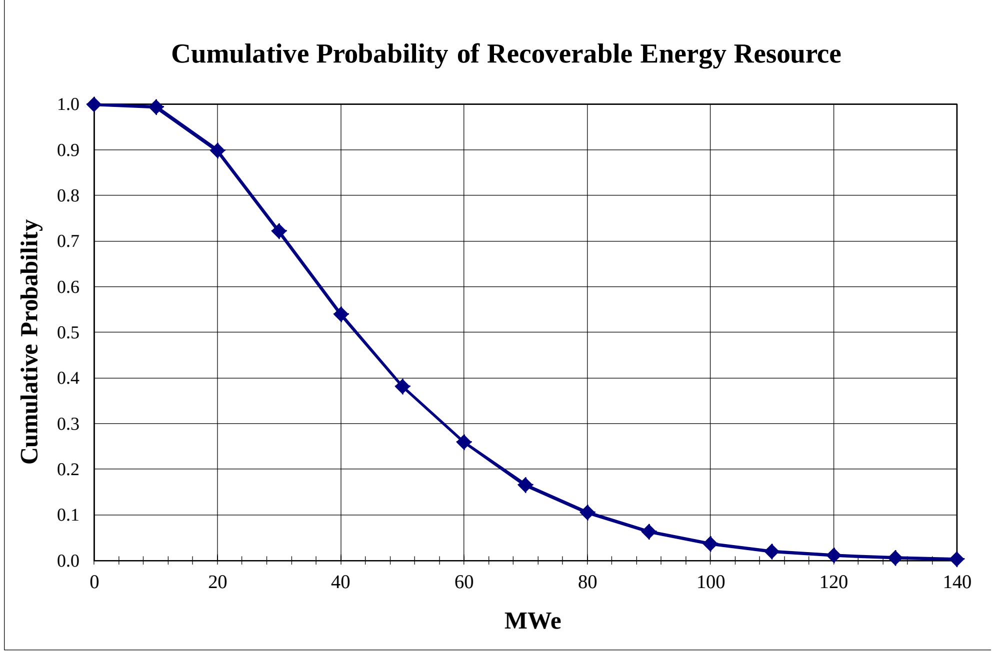


Figure 5-4: Kootenay Estimation of Geothermal Energy Resources

SUMMARY OF INPUT PARAMETERS

Variable Parameters	Minimum	Most Likely	Maximum
Reservoir Area (sq. km)	3.00	5.00	7.00
Reservoir Thickness (m)	800	1100	1700
Rock Porosity	0.03		0.07
Reservoir Temperature (°C)	125	155	185
Recovery Factor	0.05		0.20

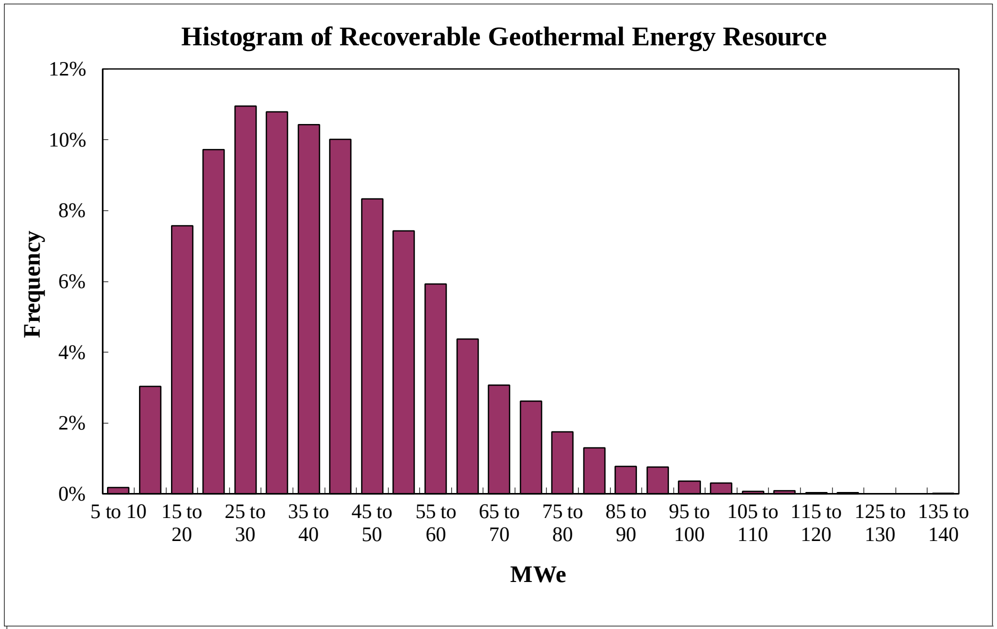
Fixed Parameters		
Rock Volumetric Heat Capacity	2613	kJ/cu. m°C
Rejection Temperature	15	°C
Utilization Factor	0.45	
Plant Capacity Factor	0.90	
Power Plant Life	20	years

RESULTS

Statistics	MW	MW/sq. km	Recovery Efficiency
Mean	41.4	8.3	1.04%
Std. Deviation	18.6	3.4	0.37%
Minimum (90% prob.)	**19.6**	4.1	0.54%
Median (50% prob.)	**38.7**	7.9	1.03%
Most-likely (Modal)	**30.1**	5.4	1.32%

Lakelse Lake

Estimation of Geothermal Energy Resource



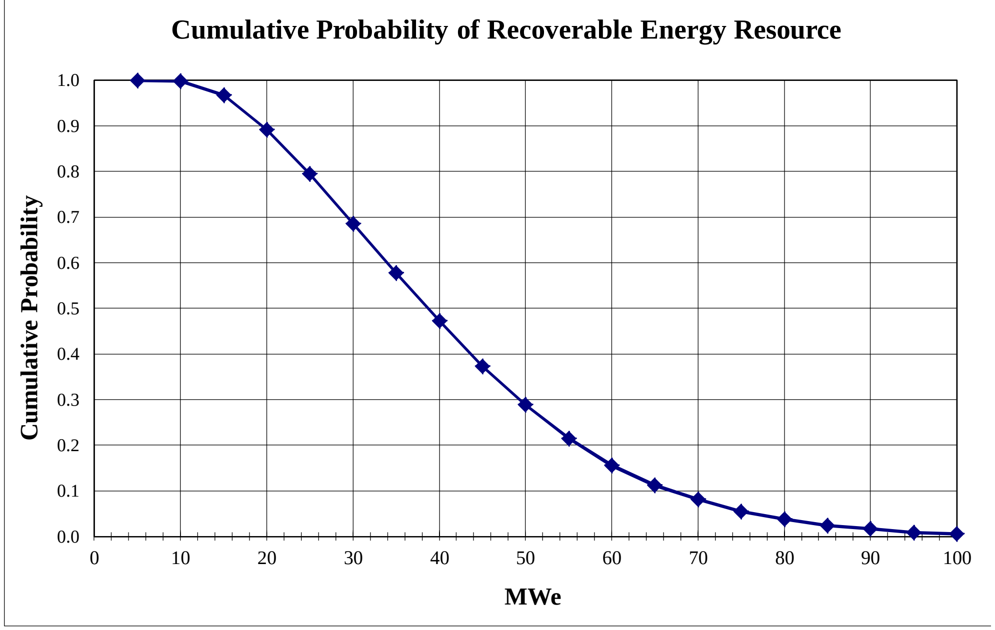


Figure 5-5: Lakelse Lake Estimation of Geothermal Energy Resources

SUMMARY OF INPUT PARAMETERS

Variable Parameters	**Minimum**	**Most Likely**	**Maximum**
Reservoir Area (sq. km)	3.00	5.00	7.00
Reservoir Thickness (m)	800	1100	1700
Rock Porosity	0.03		0.07
Reservoir Temperature (°C)	125	155	185
Recovery Factor	0.05		0.20

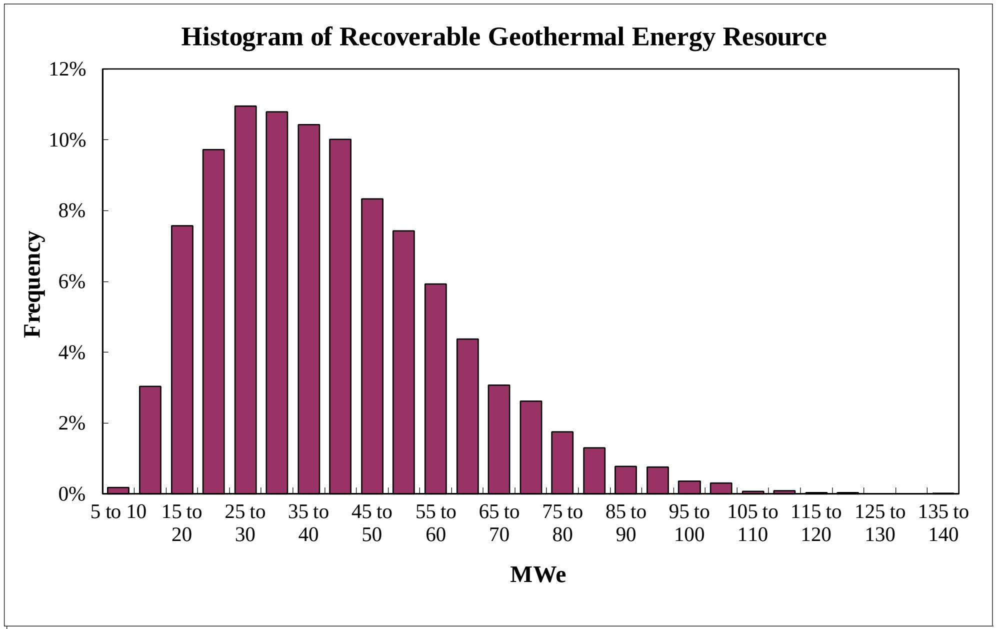
Fixed Parameters		
Rock Volumetric Heat Capacity	2613	kJ/cu. m°C
Rejection Temperature	15	°C
Utilization Factor	0.45	
Plant Capacity Factor	0.90	
Power Plant Life	20	years

RESULTS

Statistics			
	MW	**MW/sq. km**	**Recovery Efficiency**
Mean	41.4	8.3	1.04%
Std. Deviation	18.6	3.4	0.37%
Minimum (90% prob.)	**19.6**	4.1	0.54%
Median (50% prob.)	**38.7**	7.9	1.03%
Most-likely (Modal)	**30.1**	5.4	1.32%

Lower Arrow Lake

Estimation of Geothermal Energy Resource



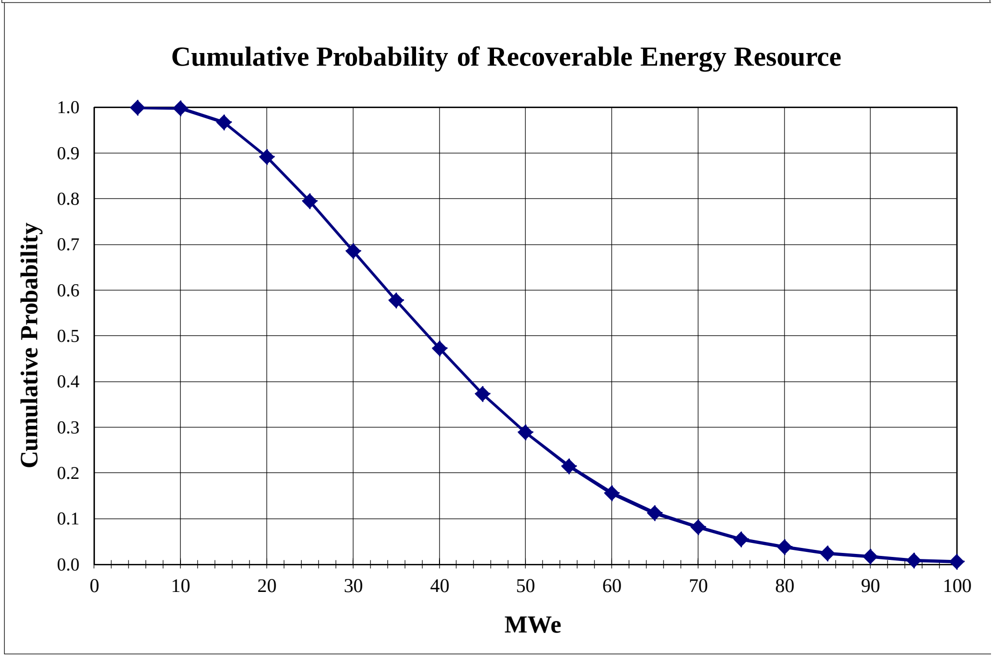


Figure 5-6: Lower Arrow Lake Estimation of Geothermal Energy Resources

SUMMARY OF INPUT PARAMETERS

Variable Parameters	Minimum	Most Likely	Maximum
Reservoir Area (sq. km)	3.00	6.00	9.00
Reservoir Thickness (m)	1500	2500	3500
Rock Porosity	0.03		0.07
Reservoir Temperature (°C)	180	230	280
Recovery Factor	0.05		0.20

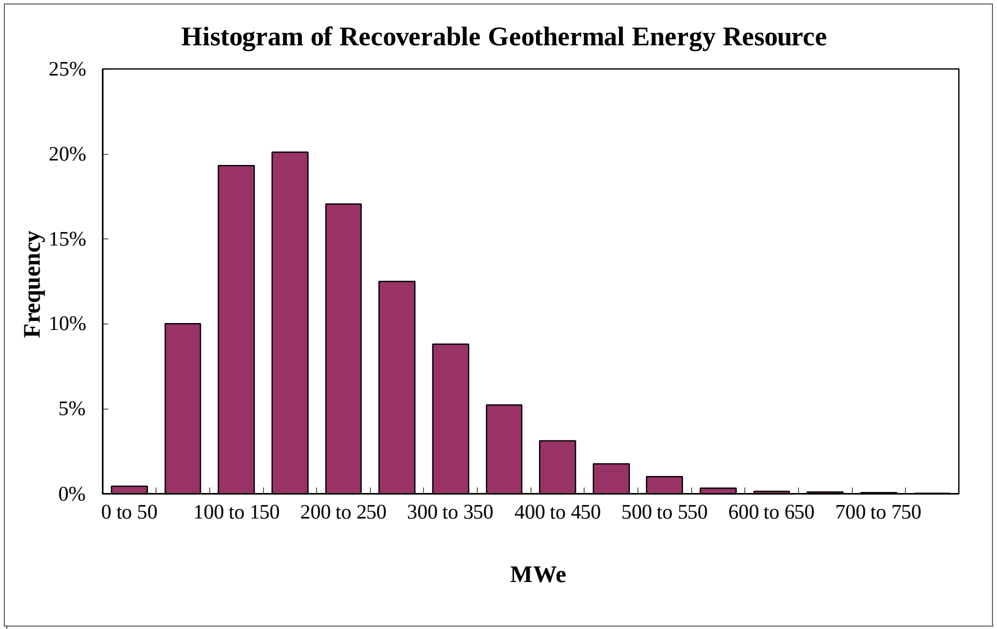
Fixed Parameters		
Rock Volumetric Heat Capacity	2613	kJ/cu. m°C
Rejection Temperature	15	°C
Utilization Factor	0.45	
Plant Capacity Factor	0.90	
Power Plant Life	20	years

RESULTS

Statistics			
	MW	MW/sq. km	Recovery Efficiency
Mean	218.7	36.5	1.42%
Std. Deviation	105.9	15.5	0.50%
Minimum (90% prob.)	**99.0**	17.7	0.75%
Median (50% prob.)	**200.4**	34.7	1.41%
Most-likely (Modal)	**158.5**	23.5	1.37%

Meager Creek (Pebble Creek assumed equivalent)

Estimation of Geothermal Energy Resource



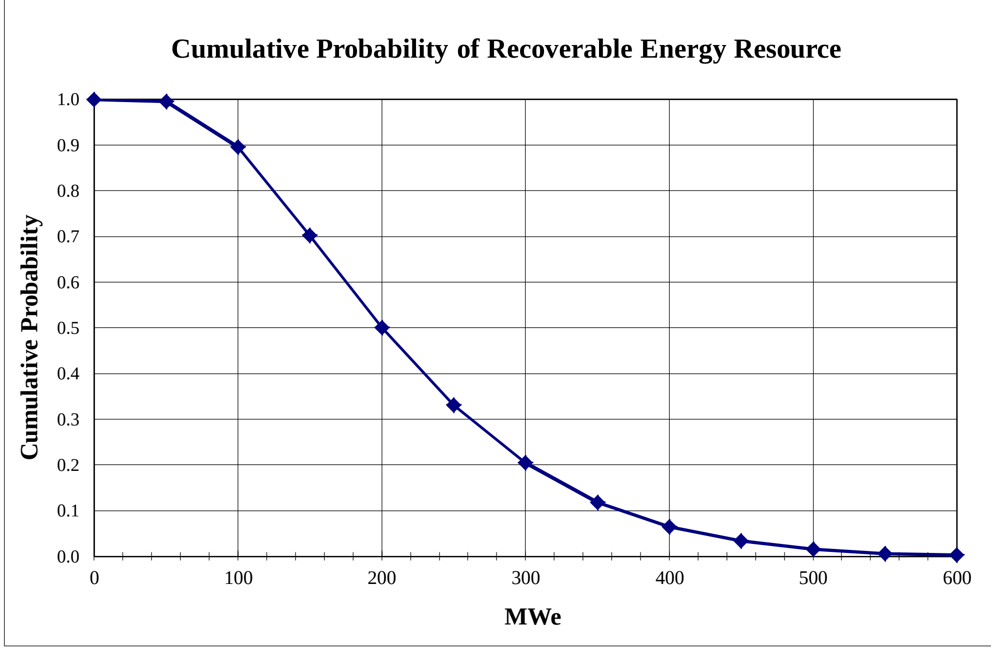


Figure 5-7: Meager Creek Estimation of Geothermal Energy Resources

SUMMARY OF INPUT PARAMETERS

Variable Parameters	**Minimum**	**Most Likely**	**Maximum**
Reservoir Area (sq. km)	2.00	4.00	6.00
Reservoir Thickness (m)	1500	2500	3500
Rock Porosity	0.03		0.07
Reservoir Temperature (°C)	150	175	200
Recovery Factor	0.05		0.20

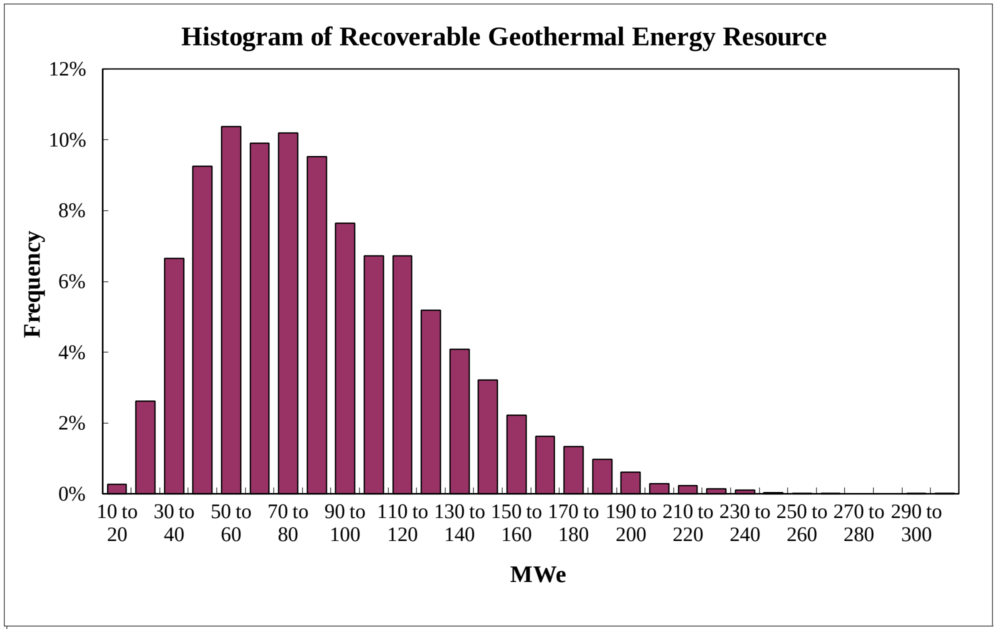
Fixed Parameters		
Rock Volumetric Heat Capacity	2613	kJ/cu. m°C
Rejection Temperature	15	°C
Utilization Factor	0.45	
Plant Capacity Factor	0.90	
Power Plant Life	20	years

RESULTS

	Statistics		
	MW	**MW/sq. km**	**Recovery Efficiency**
Mean	87.2	21.9	1.15%
Std. Deviation	40.1	8.8	0.40%
Minimum (90% prob.)	**40.7**	11.0	0.60%
Median (50% prob.)	**80.9**	21.0	1.15%
Most-likely (Modal)	**64.0**	16.1	1.34%

Mt. Cayley

Estimation of Geothermal Energy Resource



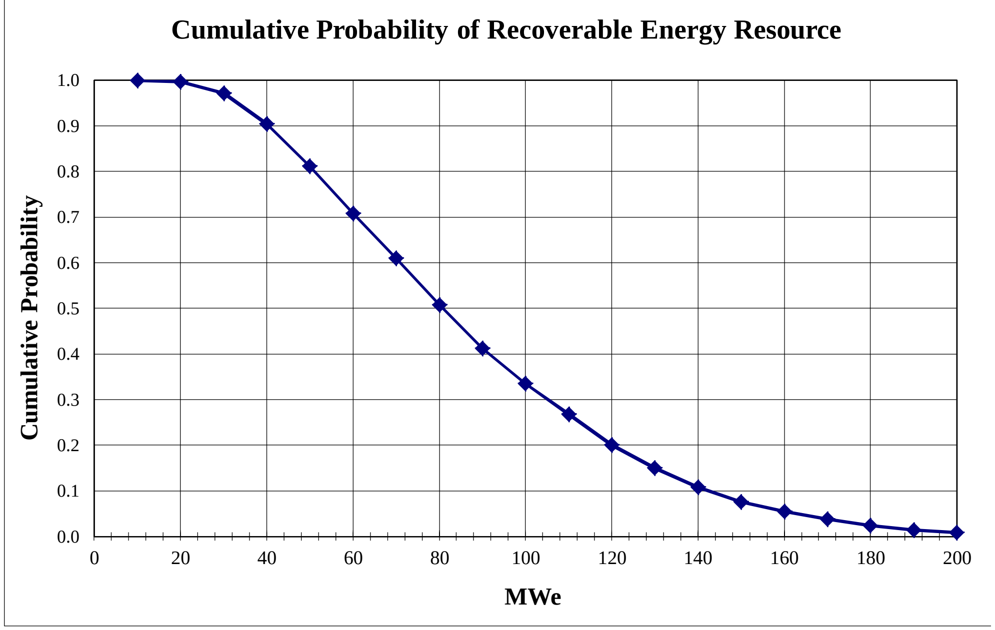


Figure 5-8: Mt. Cayley Estimation of Geothermal Energy Resources

SUMMARY OF INPUT PARAMETERS

Variable Parameters	**Minimum**	**Most Likely**	**Maximum**
Reservoir Area (sq. km)	50.00	100.00	150.00
Reservoir Thickness (m)	30	60	90
Rock Porosity	0.03		0.07
Reservoir Temperature (°C)	125	155	185
Recovery Factor	0.05		0.20

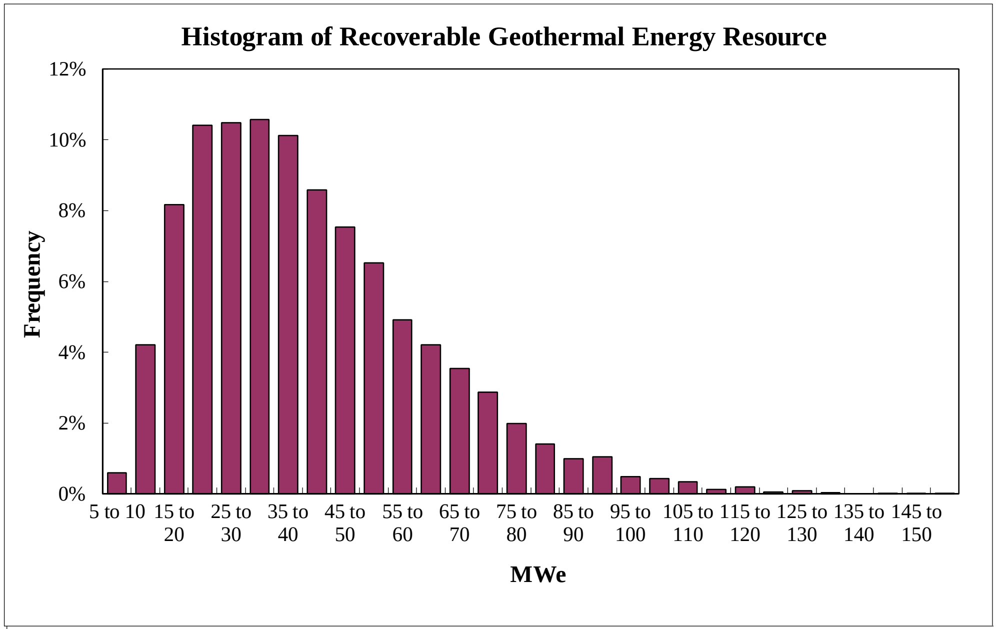
Fixed Parameters		
Rock Volumetric Heat Capacity	2613	kJ/cu. m°C
Rejection Temperature	15	°C
Utilization Factor	0.45	
Plant Capacity Factor	0.90	
Power Plant Life	20	years

RESULTS

Statistics			
	MW	**MW/sq. km**	**Recovery Efficiency**
Mean	41.5	0.4	1.04%
Std. Deviation	20.7	0.2	0.37%
Minimum (90% prob.)	**18.3**	0.2	0.54%
Median (50% prob.)	**37.7**	0.4	1.04%
Most-likely (Modal)	**31.0**	0.3	0.55%

Okanagan

Estimation of Geothermal Energy Resource



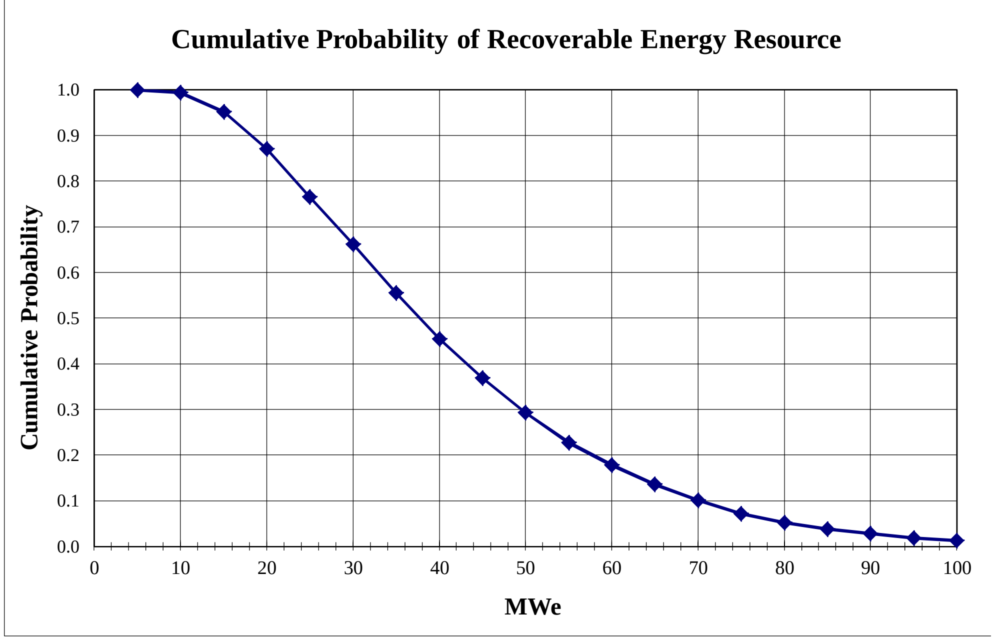


Figure 5-9: Okanagan Estimation of Geothermal Energy Resources

SUMMARY OF INPUT PARAMETERS

Variable Parameters	Minimum	Most Likely	Maximum
Reservoir Area (sq. km)	1.04	2.0	3.11
Reservoir Thickness (m)	800	1100	1700
Rock Porosity	0.03		0.07
Reservoir Temperature (°C)	150	175	200
Recovery Factor	0.05		0.20

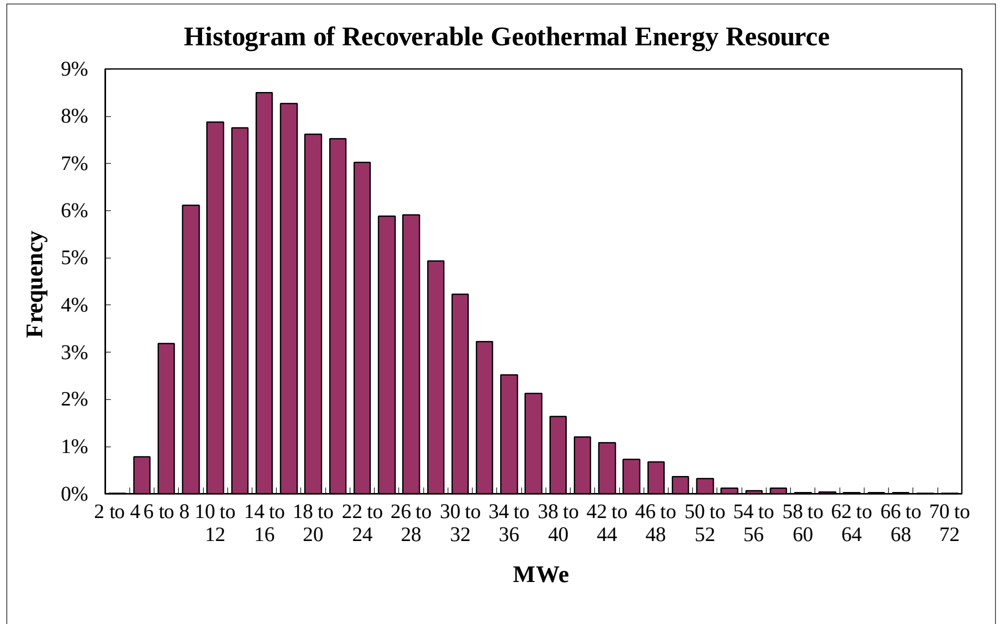
Fixed Parameters		
Rock Volumetric Heat Capacity	2613	kJ/cu. m°C
Rejection Temperature	15	°C
Utilization Factor	0.45	
Plant Capacity Factor	0.90	
Power Plant Life	20	years

RESULTS

Statistics			
	MW	MW/sq. km	Recovery Efficiency
Mean	21.4	10.4	1.14%
Std. Deviation	9.8	4.2	0.40%
Minimum (90% prob.)	**10.0**	5.2	0.59%
Median (50% prob.)	**20.0**	10.1	1.14%
Most-likely (Modal)	**15.0**	9.0	0.54%

Sloquet Creek

Estimation of Geothermal Energy Resource



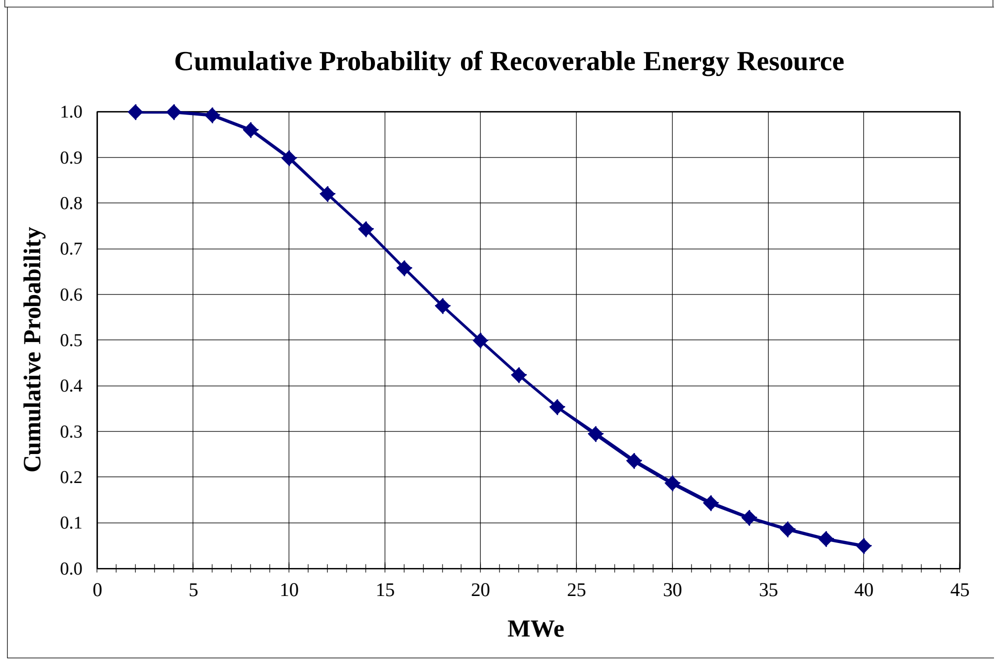


Figure 5-10: Sloquet Creek Estimation of Geothermal Energy Resources

6. Economic Analysis

6.1 Summary Results of Economic Analysis

Estimates of the levelized cost of electricity for the nine favourable sites (plus the Jedney Area, and Clarke Lake at 5 MW) were calculated using the specified Geothermal Electricity Technology Evaluation Model (GETEM). A description of this model is included as Appendix U. Table 6-1 summarizes both the volumetric assessment and the economic analysis for these sites.

6.2 GETEM Input Parameters

GETEM input parameters and assumptions are provided in Appendix V. Further comments on these inputs and assumptions are:

1. GETEM requires all costs to be in US dollars. Accordingly, a conversion factor of one Canadian dollar equals 0.82 US dollars (as of April 28, 2015) was used;
2. Power line details including voltage level, routing from the geothermal generation site to the appropriate point of interconnection to the electrical grid (BC Hydro, FortisBC or private owner) and costs were developed and included in the model. The access road and power line costs (either transmission or distribution voltage) were generally ascertained based on information and guidance contained in "*Road and Power Line Estimating Using GIS*", a publically available document developed with and for BC Hydro.[11] Power line costs, station costs (including interconnection and any transformation) as well as step-up transformer costs and other related electrical facility costs at the generating station are included;
3. Accelerated depreciation rates pursuant to Revenue Canada's CCA Class 43.2 schedule (as of April 2015) have been used;
4. No royalty costs have been included since royalty rates have not yet been determined in BC;
5. GETEM runs used a 5% discount rate as directed by Geoscience BC;
6. The number and costs of wells for each site in the GETEM economic analysis have been summarized and are presented in Table 6-2;
7. The capital costs of the main components of a geothermal generating station are summarized for each site and presented in Table 6-3. These components are:
    a. power line costs (as noted above);
    b. road building costs (as noted above), recognizing that Meager Creek requires significant access road construction due to the Capricorn Creek landslide;
    c. permitting and leasing costs are derived from legislation, along with an allowance to cover environmental studies, public consultation, First Nations engagement, and regulatory review and licencing; and
    d. costs of resource exploration, resource confirmation, resource development, and power plant.

    These capital costs are expressed as a sum and are also presented as a total cost per gross kilowatt installed.

[11] Published as Appendix B to BC Hydro's Resource Options Mapping Update. BC Hydro is revising this information and the updated data was used in this study.

8. Project Life

   A project life of 20 years was assumed in the GETEM runs. As noted on line 10 of Table V-1, this assumption was made to maintain consistency with the project lives assumed for the volumetric assessments of megawatt (MW) capacity based on heat in place (see Section 5 entitled Volumetric Assessment), as well as being reflective of anticipated terms of Power Purchase Agreements in BC. The default value of project life suggested in the GETEM documentation is 30 years. However, geothermal project economics are commonly evaluated in the range of 20 to 30 years, depending on the circumstances of the project concerned. If the volumetric assessments had assumed 30-year project lives (that is, if the amount of heat in place were to be produced at a constant MW output over 30 years instead of 20 years), the estimates of MW capacity would have been lower.

9. Annual Rate of Decline

   The GETEM parameter to take account of thermal drawdown is the Annual Rate of Decline (line 103 of Table V-1), expressed as a percentage of the resource temperature. In the GETEM runs for this study, the default value of 0.3% for this parameter has been used. For geothermal resource temperatures in the range of 150 °C to 200 °C, this works out to a decline of about 0.5 °C per year, which is typical for well-managed geothermal projects. Historically, some geothermal projects have exhibited much higher rates of thermal drawdown, especially in the early years of project life. However, in these cases, the operators typically take remedial action (such as a reconfiguration of the injection strategy) to bring thermal drawdown into a more manageable range. In addition, there are other examples of geothermal projects that show essentially no thermal drawdown over many years, especially if the amount of installed plant capacity is small in comparison to the resource capacity. For these reasons, the default value of 0.3% was deemed reasonable for the purpose of this assessment.

Table 6-1: Results of Volumetric Assessment and Economic (GETEM) Analysis

Geothermal Prospect Site/Area	Plant Type	Initial MW estimate (GDDM)	MW (gross) at 90% probability from Vol.Est.	MW (net) : Parasitic = 10% for Flash 25% for Binary	Levelized Cost of Electricity* (CAN¢/kWh) Discount Rate 5%
Canoe Creek – Valemount	Flash	15	14.3	12.9	26.8
Clarke Lake	Binary	34	18.4	13.8	29.7
Clarke Lake (5 MW scenario)	Binary	5	-	3.8	33.2
Jedney Area	Binary	15	12.2	9.2	39.8
Kootenay	Binary	20	19.9	14.9	22.8
Lakelse Lake	Binary	20	19.6	14.7	23.4
Lower Arrow Lake	Binary	20	19.6	14.7	23.7
Meager Creek (Pebble Creek volume assumed equivalent)**	Flash	100-200 total (50-100 ea)	198.0 combined (99.0 ea)	178.2 combined 89.1 (ea)	11.7
Mt. Cayley	Binary	50	40.7	30.5	17.3
Okanagan	Binary	20	18.3	13.7	24.1
Sloquet Creek	Binary	10	10	7.5	21.8

* These LCOEs have been revised from the previous versions of this report to correct the values used for the depreciation schedule in GETEM (Lines 32 to 37 of Table V-1)

** Pebble Creek transmission and infrastructure costs are significantly less than those at Meager Creek, resulting in a lower LCOE value for Pebble Creek (11.5 CAN¢/kWh).

Table 6-2: Number and Cost of Wells in GETEM Economic Analysis (2015 $)

Project Name	Meager Creek	Pebble Creek	Mt. Cayley	L. Arrow	Okanagan	Kootenay	Lakelse Lake	Clarke Lake	Canoe Creek	Jedney	Sloquet Creek	Clarke Lake
Approximate Capacity (Gross MW)	100	100	40	20	20	20	20	20	15	15	10	5
Project Type	Flash	Flash	Binary	Binary	Binary	Binary	Binary	Binary - Deep Sedimentary	Flash	Binary - Deep Sedimentary	Binary	Binary - Deep Sedimentary
Number of Wells												
Exploration Phase (Slim Holes)	4	4	3	3	3	3	3	3	2	2	2	1
Confirmation Phase (Full-Diameter Wells)												
# Successful Confirmation Wells	3	3	2	2	2	2	2	2	1	1	1	1
Calculated MW Capacity per Production Well (Confirmation Wells Only)	4.5	4.5	5.0	4.0	4.0	4.0	4.1	4.6	4.5	4.6	4.9	4.1
# Successful Wells Required to Confirm 25% of Production Capacity	5.0	5.0	1.5	0.9	0.9	0.9	0.9	0.8	0.7	0.5	0.4	0.2
Total # Confirmation Wells Drilled	7.0	7.0	5.3	5.3	5.3	5.3	5.3	5.3	3.7	3.7	3.7	1.7
Development Phase (Full-Diameter Wells)												
# Successful Production Wells Drilled in Development Phase	9.8	9.8	4.1	1.6	1.4	1.7	1.6	1.0	1.3	1.0	0.5	0.0
Cumulative Full-diameter Production Wells Drilled (Confirmation + Development)	12.8	12.8	6.1	3.6	3.4	3.7	3.6	3.0	2.3	2.0	1.5	1.0
# Injection Wells Drilled	9.6	9.6	6.1	3.6	3.4	3.7	3.6	3.0	1.7	2.0	1.5	0.9
# Spare Production Wells	1	1	1	1	1	1	1	1	1	1	1	1
# Dry Holes	3.9	3.9	2.1	1.1	1.0	1.1	1.0	0.8	0.6	0.6	0.4	0.2
Total Development Wells	27.3	27.3	15.3	9.3	8.8	9.5	9.2	7.8	5.6	5.6	4.4	3.1
Injector/Producer Ratio - cumulative	0.75	0.75	1	1	1	1	1	1	0.75	1	1	1
Depth of Full-Diameter Wells (meters)	2,500	2,500	1,250	1,250	1,250	1,250	1,250	2,000	2,500	2,000	1,250	2,000
Cost of Wells (US $) per Well												
Exploration phase (Slim Hole = 0.6 X Full-Diameter Well in Development Phase)	$4,911,719	$4,911,719	$2,470,512	$2,470,512	$2,470,512	$2,470,512	$2,470,512	$3,936,221	$4,911,719	$3,936,221	$2,470,512	$3,936,221
Confirmation phase (1.2 X Full-Diameter Well in Development Phase)	$9,823,438	$9,823,438	$4,941,024	$4,941,024	$4,941,024	$4,941,024	$4,941,024	$7,872,443	$9,823,438	$7,872,443	$4,941,024	$7,872,443
Development phase (Full-diameter well)	$8,186,198	$8,186,198	$4,117,520	$4,117,520	$4,117,520	$4,117,520	$4,117,520	$6,560,369	$8,186,198	$6,560,369	$4,117,520	$6,560,369
Cost of Wells (CAN $) per Well												
Exploration phase (Slim Hole = 0.6 X Full-Diameter Well in Development Phase)	$5,989,841	$5,989,841	$3,012,789	$3,012,789	$3,012,789	$3,012,789	$3,012,789	$4,800,222	$5,989,841	$4,800,222	$3,012,789	$4,800,222
Confirmation phase (1.2 X Full-Diameter Well in Development Phase)	$11,979,682	$11,979,682	$6,025,579	$6,025,579	$6,025,579	$6,025,579	$6,025,579	$9,600,444	$11,979,682	$9,600,444	$6,025,579	$9,600,444
Development phase (Full-diameter well)	$9,983,068	$9,983,068	$5,021,316	$5,021,316	$5,021,316	$5,021,316	$5,021,316	$8,000,370	$9,983,068	$8,000,370	$5,021,316	$8,000,370

Legend
User input parameter
Calculated by GETEM model

\\Libra25.burnaby.kerrwoodleidal.org\2000-2999\2600-2699\2692-004\300-Report\Report\20150611FINAL\Tables\[2015-06-04_BC_geothermalassessment-KWLFormat.xlsx]Number & Cost of Wells

Table 6-3: Estimated Capital Costs for Favourable Sites

Geothermal Prospect Area/Site	Transmission-Line Costs (incl. Substations) (million CAD$ 2015)	Road-Building Costs (million CAD$ 2015)	Permitting & Leasing Costs† (million CAD$ 2015)	Resource Exploration Costs** (million CAD$ 2015)	Resource Confirmation Costs†† (million CAD$ 2015)	Resource Development Costs*** (million CAD$ 2015)	Power Plant Costs (million CAD$ 2015)	Total Capital Costs (million CAD$ 2015)	Total Cost per Gross kW Installed (CAD$ 2015)
Canoe Creek – Valemount	$16.4	-	$0.5	$13.0	$45.2	$50.7	$43.8	$169.6	$11,900
Clarke Lake	$14.4	-	$0.5	$15.9	$52.6	$54.0	$67.3	$204.7	$11,100
Clarke Lake (5 MW scenario)	$1.5	-	$0.5	$5.3	$16.5	$19.6	$19.3	$62.8	$12,600
Jedney Area	$34.5	-	$0.5	$10.6	$36.3	$42.1	$45.3	$169.3	$13,900
Kootenay	$10.2	-	$0.5	$10.6	$33.1	$45.7	$72.7	$172.8	$8,700
Lakelse Lake	$12.2	-	$0.5	$10.6	$33.1	$44.5	$72.1	$173.0	$8,800
Lower Arrow Lake	$13.7	-	$0.5	$10.6	$33.1	$44.9	$71.6	$174.4	$8,900
Meager Creek	$13.2	$1.0	$0.5	$30.0	$85.9	$262.9	$172.5	$566.0	$5,700
Mt. Cayley	$30.6	-	$0.5	$10.6	$33.1	$79.8	$110.0	$264.7	$6,500
Pebble Creek	$6.8	$0.5	$0.5	$28.0	$85.9	$262.9	172.5	557.1	$5,600
Okanagan	$12.3	-	$0.5	$10.6	$33.1	$41.5	$67.0	$165.1	$9,000
Sloquet Creek	$2.1	-	$0.5	$7.0	$22.9	$21.0	$28.6	$82.1	$8,200

* Also includes the Jedney Area, and Clarke Lake at 5 MW
† Permitting and leasing costs are for entire project life, including environmental studies.
** Resource Exploration Costs comprise primarily slim-hole drilling costs, as well as costs for geological, geochemical, and geophysical studies.
†† Resource Confirmation Costs include confirmation drilling and well testing costs.
*** Resource Development Costs comprise wells drilled between resource confirmation and plant start-up, as well as production and injection pipelines in the wellfield.

6.3 Drilling Costs and Sensitivity Analysis

As shown in Table 6-2, the cost of drilling wells for all phases (exploration, confirmation, and development) of a geothermal project is substantial. Appendix U provides a narrative on the general drilling cost methodology inherent in the use of GETEM (Page 4 of Appendix U), as well as a description of the methodology for the calculation of drilling costs for each of the above noted phases (Pages 14 to 16 inclusive of Appendix U). However the following should be kept in mind:

- GETEM is based on drilling cost information from existing geothermal projects and is US-focused. Since there are no geothermal projects in service in Canada, no Canadian information is included in the database; and
- The potential exists at the current time for lower drilling costs as a result of the decline in oil prices over the past year or so. It is however not readily apparent that this trend will carry forward in the long term. Since this assessment has such a long-term perspective, it would not be prudent to base the results on what may be a shorter-term anomaly in oil prices and resulting drilling costs. Rather, a sensitivity analysis around drilling costs would provide further insight into the effect of drilling cost on the LCOEs.

Accordingly, additional GETEM runs were carried out reflecting drilling costs at 50% and 150% of the original drilling estimates for two projects. The two projects for these sensitivity runs were selected to represent the best large project and the best small project, where 'best' means the project with the lowest LCOE, 'large' means 50 MW or larger, and 'small' means 20 MW or smaller. The two projects selected on this basis were Pebble Creek (best large project) and Sloquet Creek (best small project).

The changes in drilling costs for these sensitivity runs were made by multiplying the 'User Adjustment to Production Well Cost' in Line 87 of Table V-1 and the 'User Adjustment to Injection Well Cost' in Line 88 of Table V-1 by factors of 0.5 and 1.5 (representing drilling costs at 50% and 150% respectively).

The resulting LCOEs for both Pebble Creek and Sloquet Creek for the drilling cost sensitivities (with the base case included for ease of reference) are shown below in Table 6-4.

Table 6-4: Sensitivity Analysis for Drilling Costs

	LCOE (CAN ¢/kWh)		
Project	**Base Case**	**Drilling Costs at 50% of Base Case**	**Drilling Costs at 150% of Base Case**
Pebble Creek	11.5	7.8	15.2
Sloquet Creek	21.8	15.7	27.7

7. Observations and Conclusions

Observations and conclusions are:

1. Planning-level and Technical Nature of Assignment:
   a. It is not within the scope of this assignment to comment on policy issues;
   b. There have been various estimates of the potential for geothermal power in British Columbia.[12], [13] This study was directed in the RFP to assess 18 specified sites and carry out a volumetric assessment and economic analysis on the 'favourable' sites within those 18 sites. These favourable sites are estimated to have a combined potential of under 400 MW;
   c. This is a planning-level study which uses publicly available information only. While it is informed by direction and comments from Geoscience BC and the Technical Advisory Committee, consultation with interested parties (e.g., geothermal proponents, individuals/groups, municipalities) was not part of the approved scope. Fieldwork and exploration activities were also not part of the scope; and
   d. It should be kept in mind, as noted in the description of the GETEM in Appendix U, that "the model is intended to provide representative estimates of cost and performance for geothermal produced from scenarios defined by a user, not as a tool for assessing specific projects or sites". Project proponents may have detailed information obtained through specific exploration and other activities at a particular site. This information is generally proprietary and could include exploration results for the geothermal resource, the development of innovative technologies, and detailed route investigations for a power line to connect the plant to the electrical grid. This in-depth knowledge could potentially result in a different cost of electricity than the cost produced by GETEM. Canoe Creek (also known as Canoe Reach), Lakelse Lake, Meager Creek and Pebble Creek have geothermal proponents/developers. For example, Borealis GeoPower has carried out a number of exploration and project development activities on its Canoe Creek geothermal permit area in the last few years. They may have detailed information that would reflect in their calculations of the levelized cost of electricity.
2. Levelized Cost of Electricity
   a. This revised report corrects the values in the depreciation schedule which is an input to GETEM. The resulting LCOEs for the favourable sites are materially different from the LCOEs previously presented;
   b. Based on the GETEM analysis, the LCOE from Table 6-1 for the favourable sites at a 5% discount rate ranges from 11.5 CAD¢/kWh for Pebble Creek to 29.7 CAD¢/kWh for Clarke Lake. The LCOE for the Jedney Area and for Clarke Lake at 5 MW (both added at the direction of Geoscience BC) are 39.8 CAD¢/kWh and 33.2 CAD¢/kWh respectively. A geothermal supply curve reflecting these results for the favourable sites is shown in Figure 7-1; and

[12] The Canadian Geothermal Energy Association (CanGEA) stated in their BC Geothermal Resource Estimates Key Findings: "The most conservative view of the technical potential of geothermal power from hot sedimentary aquifers in British Columbia is 5700 MW of 'indicated resources'.

[13] The total energy potential of the 16 top geothermal prospects in British Columbia is 4000 MW, derived from "High-Temperature Geothermal Energy – Why No Canadian Development? By Mory Ghomshei, Stephen Mak and John Meech, 2014.

c. Although GETEM is a complex tool and US-focused, it has the capability to permit the input of specific values reflecting British Columbia conditions. Where sufficient information was available to estimate specific parameters (such as costs for power lines and roads), these parameters were included as input to GETEM. Otherwise, default parameters, internal to the GETEM program, were used.

d. The cost of drilling wells during the various phases of a geothermal project has a significant impact on the LCOE, as demonstrated by sensitivity analysis of drilling costs for Pebble Creek and Sloquet Creek (Table 6-4). The LCOEs for Pebble Creek (with a base LCOE of 11.5 CAD ¢/kWh) are 7.8 and 15.2 CAD ¢/kWh, reflecting drilling costs of 50% and 150% of base case, respectively. Similarly, the LCOEs for Sloquet Creek (with a base LCOE of 21.8 CAD ¢/kWh) are 15.7 and 27.7 CAD ¢/kWh, reflecting drilling costs of 50% and 150% of base case, respectively.

3. Market Opportunities for Geothermal Power

   A graphical representation of the LCOE versus capacity of each site, including the parameters of BC Hydro's SOP is shown in Figure 7-2. Observations on potential market opportunities for geothermal power from the research carried out and from Figure 7-2 include:

   a. At present there are no BC Hydro calls for power from independent power producers;
   b. BC Hydro's SOP presents an opportunity for those sites with a capacity of less than 15 MW;
   c. As of June 2015, the price of power under BC Hydro's SOP is approximately $100/MWh. Meager Creek and Pebble Creek are the only projects close to this threshold. However, they are greater than 15 MW;
   d. Mt. Cayley, Meager Creek and Pebble Creek are not eligible for SOP and require alternative procurement processes;
   e. There may be opportunities for agreements with major industrial facilities (e.g., gas processing plants, pulp mills, mines) to supply electricity connected directly from geothermal resources (the use of BC Hydro and Fortis BC transmission systems for this purpose is not permitted as there is no retail access); and
   f. There may be opportunities for bi-lateral agreements with BC Hydro for geothermal power over the threshold for the SOP in specific BC Hydro regions of the province.

4. Power Lines (and associated equipment) and Access Roads

   a. Power line routing: maps and other office studies were used to determine the preliminary routing of the power line from the geothermal generating site to the appropriate interconnection point on the electrical grid (BC Hydro, Fortis BC, or private owner). More detailed studies would involve field reconnaissance and surveys;
   b. Costs of power lines and access roads: appropriate voltage levels, and the costs of both power lines (transmission and distribution as appropriate) and access roads were generally developed from information and guidance contained in "*Road and Power Line Estimating using GIS*", a publically available document developed with and for BC Hydro. These costs were then input into GETEM; and
   c. Interconnections: An interconnection of a power line from a geothermal generating site to a power line owned by a private company will require negotiations with and the approval of that private company. No allowance has been made for the cost of using the private power line.

5. Clarke Lake at 5 MW

   a. A GETEM analysis was carried out for Clarke Lake with a capacity of 5 MW at the request of Geoscience BC. A generating plant of this size and proximity to the BC Hydro distribution system near Fort Nelson requires only a distribution line. This is reflected in the LCOE from GETEM.

   b. However, there is a strategic question here for BC Hydro centred on the possibility of additional future generating plants each with a capacity in the order of 5 MW. This could require a collecting substation and a 138 kV line from that collecting substation. This is beyond the scope of this assignment.

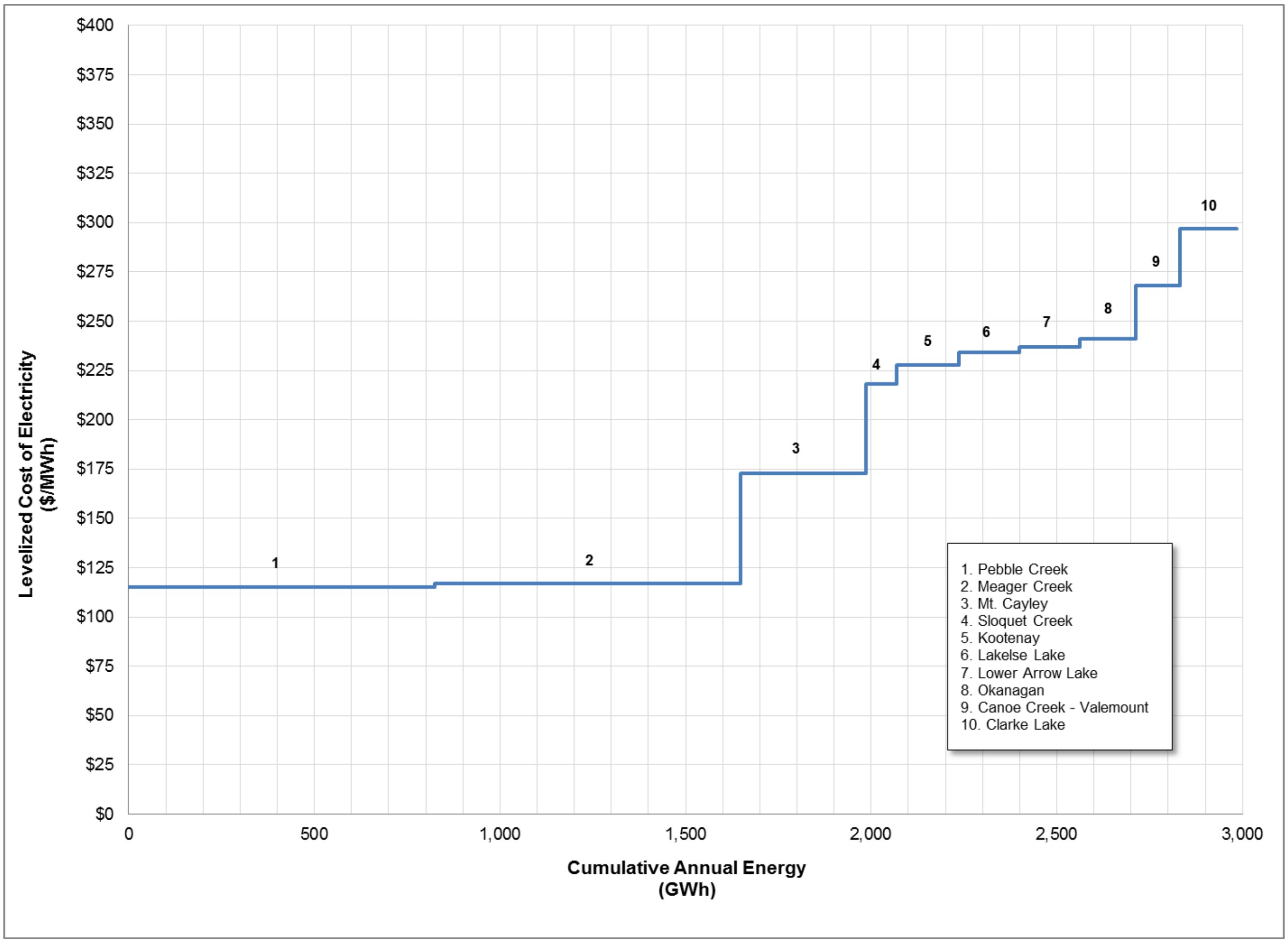


Figure 7-1: Geothermal Supply Curve for Favourable Sites

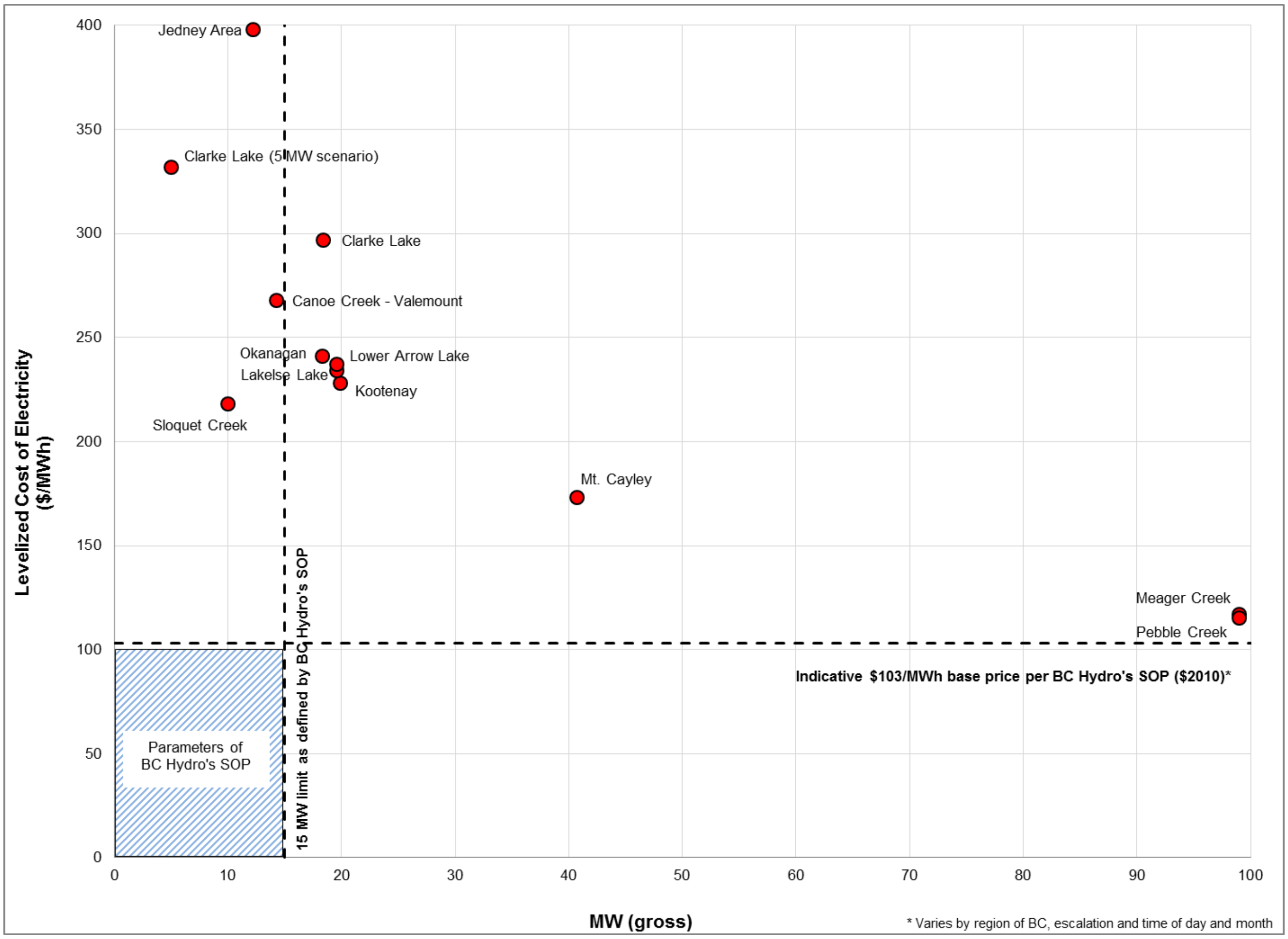


Figure 7-2: Geothermal Sites – LCOE vs Capacity

8. Report Submission

A listing of the key tasks in this study is shown in Table 8-1, along with the identification of the company (KWL or GeothermEx) having the lead responsibility for that task (shown as 'R'). Input to and support for a task are indicated by an 'S'. The names and signatures of the key contributors for each company at the end of this section signify responsibility for the tasks noted as 'R'.[14]

Table 8-1: Responsibility Matrix

Task	KWL	GeothermEx
Data Compilation		
A – Reservoir Potential	-	R
B – Exploration Uncertainty (Risk)	-	R
C – Environmental Issues	R	S
D – Geothermal Area	R	S
E – Market	R	S
F – Transmission Line Infrastructure	R	S
H – Community Issues	R	S
I – Water Rights	R	S
J – Engineering	R	S
K – Non-electrical Infrastructure	R	S
L – Finance	R	S
M – Maps	R	S
N – Other Issues and Considerations	R	S
Favourability Analysis	R	S
Volumetric Assessment	S	R
Economic Analysis	S[15]	R
Report	R	S
R = Responsible S = Support		

[14] Recognizing that overall responsibility rests with KWL
[15] KWL provided input to GETEM for parameters reflecting British Columbia's conditions (e.g., transmission voltages and costs)

KERR WOOD LEIDAL ASSOCIATES LTD.

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Revision History

Revision #	Date	Status	Revision	Author	Reviewer
1	June 29, 2015	Final	Revised for final submission to Geoscience BC	JB/TAS	RJM
2	October 2, 2015	Revised Final	Revised to mainly include updated tables to reflect Lakelse Lake project life of 20 years, and deletion of duplication of permitting and leasing costs in the estimated capital costs for favourable sites.	TAS	JB/A. Falconer Thomas
3	March 31, 2016	Revised Final (R1)	Revised to reflect minor revisions, to correct the values for the depreciation schedule as input into GETEM, to present sensitivity analysis with respect to drilling costs, and to provide brief comments on project life and annual rate of decline.	JL/JB	RJM

OQM | Organizational Quality Management Program

KERR WOOD LEIDAL
consulting engineers

Appendix A

Reference Materials/Sources for Data Compilation

Appendix A

Reference Materials/Sources for Data Compilation

Category A: Reservoir Potential and Category B: Exploration Uncertainty (Risk)

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Appendix T

California Energy Commission: Public Interest Energy Research (PIER) Report New Geothermal Site Identification and Qualification, Appendix III

CALIFORNIA
ENERGY
COMMISSION

NEW GEOTHERMAL SITE IDENTIFICATION AND QUALIFICATION

CONSULTANT REPORT

Prepared For:

California Energy Commission
Public Interest Energy Research Program

Prepared By:

GeothermEx, Inc.

APRIL 2004

P500-04-051

Arnold Schwarzenegger, *Governor*

Appendix III
Methodology of Estimating Generation Capacities
(Geothermal Energy Reserves)

APPENDIX III

METHODOLOGY OF ESTIMATING GENERATION CAPACITIES (GEOTHERMAL ENERGY RESERVES)

1. THEORETICAL BASIS OF THE ESTIMATION METHOD

1.1 Introduction

To estimate energy reserves in the various project areas, we have used a methodology that has been used by GeothermEx over the past two decades. This methodology is a volumetric reserve estimation approach introduced by the U.S. Geological Survey (ref: USGSC790), modified to account for uncertainties in some input parameters by using a probabilistic basis (Monte Carlo simulation).

This technique to estimate reserves is based on a volumetric calculation of the heat-in-place at each project area, with reasonable assumptions made about:

- the percentage of that heat that can be expected to be recovered at the surface; and
- the efficiency of converting that heat to electrical energy.

As explained below, the heat-in-place calculation takes into account only a volume of rock and water that is reasonably likely to contain adequate permeability and temperature for the generation of electricity using contemporary technology. Hot rock that is deeper than likely to be economically drillable in a contemporary commercial project is not included.

The term "reserves" as used herein is analogous to the "geothermal reserve(s)" of USGSC790 (p.4), and different from the overall "geothermal resource," which includes all heat underground. In USGSC790 the concept of "resource" is further subdivided into "inaccessible" (very deep) and "accessible" (likely to be drillable in the 'foreseeable' future), and "accessible" resource is further subdivided into "residual" (too deep for present economics) and "useful" (perhaps drillable at currently acceptable cost). Finally "useful" is subdivided into "subeconomic" (probably too deep, especially if the resource temperature is not very high, or displaying inadequate permeability), and "economic" (considered likely to be viable).

In USGSC790 (p.4) the term "geothermal reserve" is defined as "that part of the geothermal resource that is identified and also can be extracted legally at a cost competitive with other commercial energy sources at present." It must be emphasized that an estimate of reserves using the volumetric method does not imply any guarantee that a given level of power generation can be achieved. Before a given level of generation can be realized, wells capable of extracting the heat from the rock by commercial production of geothermal fluid must be drilled and tested. This is the only way to unequivocally establish the presence of commercially viable reserves and demonstrate the desired generating capacity of each locally defined resource.

1.2 Calculation of Generation Capacity

In the GeothermEx method, the maximum sustainable generation (power plant) capacity (E) is given by:

$$E = V\, C_v(T-T_o)\cdot R/F/L \qquad (1.1)$$

where V = volume of the reservoir,

C_v = volumetric specific heat of the reservoir,

T = average temperature of the reservoir,

T_o = rejection temperature (equivalent to the average annual ambient temperature),

R = overall recovery efficiency (the fraction of thermal energy in-place in the reservoir that is converted to electrical energy at the power plant),

F = power plant capacity factor (the fraction of time the plant produces power on an annual basis), and

L = power plant life.

The parameter R can be determined as follows:

$$R = \frac{W \cdot r \cdot e}{C_f \cdot (T - T_o)} \qquad (1.2)$$

where r = recovery factor (the fraction of thermal energy in-place that is recoverable as thermal energy at the surface),

C_f = specific heat of reservoir fluid,

W = maximum available thermodynamic work from the produced fluid, and

e = utilization factor to account for mechanical and other losses that occur in a real power cycle.

The parameter C_v in (1.1) is given by:

$$C_v = \rho_r\, C_r\, (1-\varphi) + \rho_f\, C_f\, \varphi \qquad (1.3)$$

where ρ_r = density of rock matrix,

C_r = specific heat of rock matrix,

ρ_f = density of reservoir fluid, and

φ = reservoir porosity.

The parameter W in (1.2) is derived from the First and Second Laws of Thermodynamics as follows:

$$dW = dq\ (1 - T_o / T) \qquad (1.4)$$

and

$$dq = C_f\, dT \qquad (1.5)$$

where q represents thermal energy and T represents absolute temperature.

2. ASSIGNMENT OF PARAMETERS FOR GENERATION ESTIMATES

In the Monte Carlo simulation method of calculating reserves, some parameters in equations 1.1 to 1.3 are assigned fixed values, and others are assigned ranges of values believed to be likely, on the basis of available information about the resource. These ranges may include only a minimum (Min) and a maximum (Max), or may also include a most-likely (Mlk) value.

The Monte Carlo method proceeds by calculating a large number of generation estimates (for this project, 10,000 estimates). Each time the calculation is done, each uncertain parameter is assigned a random value within the span of Min and Max, or a random value within a triangular probability distribution that is defined by Min, Mlk and Max. The results of the multiple generation estimates are then compiled to obtain an overall Minimum Generation Capacity Estimate (here defined as the capacity value with a cumulative probability of more than 90%; i.e. 90% of estimates will be equal to or greater than this value), and a Most-likely Generation Capacity Estimate (here defined as the modal generation capacity; i.e. the most-frequently estimated value). The mean (average) of the estimated values is also recorded, as well as the standard deviation of the mean.

2.1 Parameters Assigned a Statistical Uncertainty

2.1.1 Reservoir Temperature (T)

If there is deep drilling, testing and/or production data, this information is used to estimate minimum, maximum and most-likely average temperatures for the hydrothermal system within the likely reservoir volume. There is a certain amount of feed-back between this process and the process of defining the thickness and area of the reservoir, to insure that the temperature values and volumetric parameters are compatible.

If the amount of down-hole temperature information is limited (usually the case if there is no developed geothermal field), then temperature estimates are chosen from the chemical and isotope geothermometers and from such drilling data as may be available. In most cases, the geothermometers provide at least two temperature estimates: the maximum temperature that is likely to be present in the hydrothermal system, and a minimum temperature that reflects the latest full or partial chemical equilibration between hot water and hot rock, usually in the shallowest part of the hydrothermal system. A most-likely average temperature is estimated from the minimum and maximum, from a third chemical temperature if suitable, or from drilling data. Explanations for the choice of minimum, maximum and most-likely average temperature are included with the reservoir physical properties of each project area.

Prospect areas where there are no deep drilling data <u>and</u> no chemical data (the thermal anomaly is blind and/or there are no chemical data) present a special problem for both the thickness of the reservoir (as discussed below) and for temperature. In all such cases there is a thermal anomaly that is indicated by shallow temperature gradient drilling (generally to 300 or 500 ft), and sometimes also by ID (Intermediate-Depth) slim-hole drilling (to about 2,000 ft). Elevated gradients in multiple holes can establish the approximate surface area of an anomaly (see more below), but otherwise they indicate only the rate of temperature increase moving downwards. Temperature gradients do not indicate at what (greater) depth and temperature a reservoir is present.

In these cases:

- If there is some indication that a hot aquifer has been reached in some holes, and a likely minimum temperature can be inferred, then that temperature is used as the minimum average (such as 250°F at the Aurora, Nevada, project AUR00). If there are insufficient data to indicate even a likely minimum temperature, then the default minimum average temperature that is used is 225°F, which is the lowest average production zone temperature at 11 geothermal fields in Nevada, with no known or suspected volcanic heat source, that are actually in commercial production or extensively drilled (part A of Table III-1[1]; Wabuska project).

- The default maximum average that is assigned is 440°F, which is the highest average permeable zone temperature at the same set of 11 geothermal fields (part A of Table III-1; Dixie Valley project).

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[1] Temperatures from Table III-1 are herein rounded to the nearest 5°F.

- The default most-likely average reservoir temperature that is assigned is 345°F, which is the average of the 11 geothermal fields (part A of Table III-1).

In all of these cases we have based the averages on well-known fields without volcanic heat sources because few, if any, of the new fields being estimated are likely to have a volcanic heat source. Exceptions are handled as individual cases.

2.1.2 Reservoir Thickness (factor of V)

Reservoir volume (see Section 1.2 of this appendix) is calculated as the product of reservoir thickness and reservoir area, which are each separately assigned a statistical uncertainty. The database of geothermal project areas also includes (among reservoir properties) the depth to top of reservoir. This parameter is not used for the actual reserves calculation, but it is documented because it provides a guideline for required minimum drilling depths.

The top, bottom and corresponding thickness of the reservoir (all assumed to be average values) are based on drilling data if available. Typically, the thickness value is adjusted by adding 500 ft, to allow for the probability that the deepest permeable zones reached by drilling will be mining the heat and fluid from another 500 ft below[2]. This adjustment may be omitted, however, if there is evidence that the commercial reservoir zone overlies a temperature inversion.

Often, the top is reasonably well-established but the bottom is uncertain because deeper drilling has not been done at all, or has not been done in enough wells to support a very confident estimate.

If the depth to bottom or depths to both top and bottom are unknown, then default average thickness values are applied, based on the thicknesses of permeable intervals in the 11 geothermal fields of Table III-1: the minimum permeable thickness is 2000 ft, the maximum is 5,000 ft, and the average is 3,000 ft. As with the data from drilling, these values are adjusted by adding 500 ft, to allow for the probability that heat and some fluid can be mined from below the principal zone of permeability. Therefore, the minimum reservoir thickness that is assigned is 2,500 ft (0.8 km), the maximum reservoir thickness that is assigned is 5,500 ft (1.7 km), and the adjusted average, 3,500 ft (1.1 km) is used for the most-likely value.

Corresponding thicknesses in Circular 790 were 30% to 50% greater (1 km, 2.5 km and 1.5 km). The more conservative thickness values used herein are justified by three

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[2] This 500 ft interval is seen as an integral part of the "reservoir" and of the initial "reserves," and is not a "recharge" or "resupply" increment, since thermal recharge (or resupply) is not included in the heat-in-place calculation.

observations. First, they are supported by the data in Table III-1 (largely obtained since 1979). Second, most field developments since 1979 have succeeded in developing only a fraction of the reserves estimated in Circular 790. Third, drilling costs have a practical limit on the commercial viability of development, particularly for moderate-temperature resources. In Circular 790 the heat reserves were calculated to a standard depth of 3 km (9,800 ft), but this depth is likely to exceed the limits of practical commercial viability for heat extraction if the resource temperature is less than the average 345°F.

2.1.3 Reservoir Area (factor of V)

If there is actual evidence concerning the reservoir area, from temperature contours based on deep well logs or from temperature gradients in shallower wells, this information is used to pick the minimum, maximum and most-likely areas. Hot spring locations and temperatures are used to guide the estimates, knowing, however, that a hot spring represents the outflow from a hydrothermal system which may be horizontally displaced from the principal area of the deep reservoir, at distances of several miles or more.

If downhole information is very limited, and the existence of a reservoir is implied only by the presence of a hot spring, then the most-likely area is considered to be 0.8 square miles, which is very close to a circle of one-half mile radius (0.79 square miles or 2.03 square km). The minimum is taken as one-half of this, or 0.4 square miles (1.04 sq km), and the maximum assigned area is 1.2 square miles (3.11 sq km). These values are nearly equal to the 1, 2 and 3 square km areas assigned in Circular 790.

It is reasonable to relate the minimum, most-likely and maximum areas using simple multiples of the minimum area (1, 2 and 3), instead of expanding the radius of a minimum circle by some multiple, because most geothermal reservoirs that are heated by deep circulation in a tectonic regime (the dominant type in Nevada) tend to be elongated in one direction, rather than circular in shape. Sometimes the elongation is extreme, as at Empire (San Emidio), Nevada (project EMP00). In fact, the real shape of the default most-likely area of 0.8 square miles is likely to be closer to a rectangle or elongate oval, with an aspect ratio somewhere between 5:1 and 1.5:1, than to a circle.

In areas where two or more hot springs or wells are present and it is believed that a continuous reservoir volume or heat anomaly is likely to connect them, but the boundaries of the thermal anomaly remain uncertain, the most-likely value is the area encompassed by the springs and wells to a distance of 0.5 mile radius around the outer-most points[3]. The minimum area is one-half of the most-likely area, and the maximum is 1.5 times the most-likely area.

[3] For example, if two points are separated by 2 miles, then the most-likely area is calculated as a rectangle with rounded corners (r = 0.5 mile) that is three miles long (0.5 + 2.0 + 0.5) and one mile wide (0.5 + 0.5), or 3 square miles, minus 0.05 square mile at each corner. The total area is thus 2.8 square miles.

2.1.4 Porosity (φ)

Unless there is a compelling reason to apply other values, a default minimum porosity of 3.0% and a default maximum porosity of 7.0% are used, without a most-likely value. Reservoirs known or likely to reside in sedimentary rocks with significant inter-granular porosity (as in the Imperial Valley of California) are assigned a range of 10% to 20%. Porosity has very little effect on the overall outcome of the generation capacity estimate, because it represents only the small fraction of the overall reservoir volume that is occupied by water instead of rock. Water has a smaller heat capacity than rock, so a higher porosity translates into less heat in place.

2.1.5 Recovery Factor (r)

In Circular 790, the U.S.G.S. used a recovery factor of 0.25 for reserves estimates of individual hydrothermal convection systems. Based on our assessment of more than 100 geothermal sites around the world, we have found it more realistic to apply a recovery factor in the range of 0.05 (Min) to 0.2 (Max) without application of a most-likely value. These values are assigned herein as default values. For a specific site that is reasonably well-known, this range is adjusted based on an integrated analysis of the available exploration, drill and production data. For example, at the reservoirs in sedimentary rocks of the Imperial Valley of California the Min value is adjusted to 0.10 (Min), because the reservoir fluids in these sedimentary systems are considered less likely than elsewhere to short-circuit through specific fractures.

2.2 Parameters Assigned a Fixed Value

2.2.1 Rock Volumetric Heat Capacity (C_r)

A default average value of 39 BTU/cu.ft °F (2,613 kJ/m^3°C) is used, based on data for heat capacities in a variety of rocks at 350°F in Prats, 1982 (Pra82a) and an average crustal density of 168.6 lb/cu.ft (2.7 gm/cc). The heat capacity used herein is slightly lower than the value of 2,700 kJ/m^3°C (c.40 BTU/cu.ft °F) used in Circular 790. Differences of heat capacity between different types of well-consolidated rock are fairly small, and much smaller than other uncertainties in the generation estimate.

2.2.2 Rejection Temperature (T_0)

A default value of 59°F (15°C) is applied, unless there is specific knowledge of the local mean annual air temperature.

2.2.3 Utilization Factor (e)

Utilization factor (e) represents the efficiency of power generation at a given power plant in converting theoretically available work to actual electrical energy. The value of e can vary considerably, from about 0.2 to about 0.5, depending on many factors that include the efficiency of the basic power plant design, the resource temperature, the concentration of dissolved gases in the reservoir fluid, and the condition of plant maintenance. For example, the value of an air-cooled binary plant will be lower than a water-cooled binary plant. The exact efficiency of a given plant is often difficult to determine without a detailed knowledge of historical plant and resource performance, and the efficiency of a proposed plant (not yet in operation) is subject to the claims of manufacturers and designers that may be less than fully documented. In addition, the efficiency of a plant may change with time during operations. General examples are included in Circular 790.

Because of these uncertainties, a default value of e is applied. Circular 790 used a value of 0.4, but we believe that advances in plant efficiency since the publication of Circular 790 justify a default value of 0.45, which is used herein.

2.2.4 Plant Capacity Factor (F)

A value of 0.90 is used, which is reasonably typical of modern geothermal plants that are well-maintained and operated.

2.2.5 Power plant life (L)

All cases herein assume a power plant (and project) life of 30 years.

Table III-1: Physical characteristics of producing geothermal fields

A. Areas with no volcanic heat source

Project ID	Name	Depths of Major Permeable Zones (ft)[1] min	max	Thickness(ft)[2]	Temperature (°F) (initial conditions) min	max	avg[3]	
BEO00	Beowawe	6700	9600	2900	420	420	420	Excludes shallower and narrower outflow zone to hot spring area
BRA00	Brady's Hot Springs	1000	5500	4500	340	390	365	Excludes shallow, cooler injection area to the north
DES00	Desert Peak	2500	4200	1700	390	419	405	
DIX00	Dixie Valley	5600	9500	3900	402	478	440	
EMP00	Empire	1700	3700	2000	305	306	306	Max assumed 2000 ft below Min (no deep drilling in central zone)
FIS00	Fish Lake Valley	5000	10000	5000	360	390	375	Not yet producing but conditions reasonably well-defined
HON01-03	Honey Lake - all projects	1300	5300	4000	223	250	237	
RYE01	Rye Patch - Humb. District (Rye Patch)	1900	4000	2100	260	405	333	Not yet producing but conditions reasonably well-defined
SOD00	Soda Lake	1000	4000	3000	360	375	368	
STI01-02	Stillwater	1000	3000	2000	320	360	340	
WAB00	Wabuska	2000	4000	2000	220	227	224	Max assumed 2000 ft below Min (no deep drilling done)
	Average of 11 resources	***2700***	***5709***	***3009***	***327***	***365***	***346***	
	Standard Deviation	***1966***	***2532***	***1111***	***66***	***72***	***66***	
	Median			***2900***			***365***	

B. Areas with identified or possible volcanic heat source

Project ID	Name	Production Zone Temperature (°F) (initial conditions) min	max	avg
COS00	Coso	392	650	521
LVC00	Long Valley - Casa Diablo (Mammoth Pacific Field)	320	355	338
STE01-03	Steamboat H.S. - all Lower Steamboat projects	320	340	330
STE04	Steamboat H.S. - Yankee/Caithness project	434	480	457

1. Production zones and permeable hot injection zones (significantly shallower or cooler injection zones not included).
2. This thickness is the simple difference between min and max depth and may not be equal to the most-likely reservoir average thickness used in the calculation of the project's estimated generation capacity.
3. This average is the simple mean between the min and max and may not be equal to the most-likely reservoir average temperature used in the calculation of the project's estimated generation capacity.

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Appendix U

GETEM – Geothermal Electricity Technology Evaluation Model

GETEM -Geothermal Electricity Technology Evaluation Model

General Information:

GETEM has been developed as an Excel spreadsheet. It is recommended that a User save a 'clean' version of the model upon receipt.The most current version of the model is '***Beta Version of GETEM 2012-08-29.xlsm***'. This version of the model was developed in the Office 2007 Excel. Attempts to get the model to run in an earlier version of Excel (Office 2003) have not been successful because the model now utilizes some functions that were not available in the earlier versions of Excel.

Appendix 1 has some general instructions regarding getting the macros to work. If the macros are not enabled, or do not function, the model can still be used – the User will have to manually change inputs or variables to determine the cost of electricity.

Several of the worksheets are password protected. That is done primarily for the User's benefit, but also to maintain some control over the content of the model.

This document is intended to provide some basic information specific to the input to the current model configuration. Although the model has changed significantly for the earliest versions, the manuals that were written for those early versions are still relevant. It is suggested/recommended that a User peruse those manuals (they can be downloaded from the DOE Geothermal Technologies Program web site) to gain some insight as to why the model was developed and some basics as to how it works.

Background:

GETEM was originally developed for the Department of Energy's Geothermal Technologies Program (GTP) to provide both a method for quantifying the power generation cost from geothermal energy, and a means of assessing how technology advances might impact those generation costs. Generation cost is determined as the Levelized-Cost-of-Electricity (LCOE). The model is intended to provide representative estimates of cost and performance for geothermal produced from scenarios defined by a User, and not as a tool for assessing specific projects or sites. In its current form it is amenable to a project specific evaluation; however its intended purpose remains the more generic assessment of geothermal power production.

Updated Version of GETEM:

The DOE is currently reviewing and updating the methods used by GETEM to calculate both capital costs and the LCOE. The August 2012 beta version of the model contains some of the revisions that have been made; others are either in progress or will be done in the near future. Currently the model's methods of predicting well costs are under review, and a review of the power plant cost estimates is planned.

The August 2012 version of the model includes changes to how the model determines the LCOE. Previous version of the model used a Fixed Charge Rate that was applied to the project capital costs to determine the annual revenues needed for those costs associated with capital. The FCR method has been retained, and an alternative method integrated into the model that uses an approach being developed within the DOE Energy Efficiency and Renewable Energy

(EERE) programs. This EERE Approach replicates a discounted cash flow sheet. This alternative methodology is currently being used by the DOE GTP. Again, a User has the option of using either method. The model also contains a Discounted Cash Flow sheet (***DCF***) that can also be used to determine the LCOE. The discounted cash flow requires the User utilize macros to determine the LCOE, and the resulting value is not reported in the results. This method was integrated into the model primarily as a check during the integration of the EERE approach, and has been retained.

Incorporating the EERE approach into GETEM allows:

- The project life to be varied (it is fixed at 30 years with the FCR method)
- Varying discount rates (costs of money) to be applied to each phase of the project
- The durations of each project phase to be changed.

The model's depiction of the Exploration and Confirmation phases has also changed. The changes allow for both exploration and confirmation work to be done at multiple sites, which is believed to better depict what actually occurs, ie. developers must consider and explore multiple locations in developing a successful site.

The model has also been modified so that costs associated with permitting, leasing and taxes/insurance are identified separately. The User must provide sufficient input to determine those costs.

<u>General Layout:</u>

The main interface with the model remains via the ***INPUT*** sheet where the a User defines the scenario to be evaluated. The model input is generally arranged by the phases of a geothermal project. The layout on the ***INPUT*** sheet is summarized here:

- Economic Parameters
- Exploration
- Confirmation
- Well Field Development
- Reservoir Definitions
- Operation and Maintenance
- Power Plant

The model output is now provided primarily on the ***SUMMARY*** sheet, which has the same layout as the ***INPUT*** sheet. Information on both sheets is 'grouped' so that it can be expanded or collapsed as the User desires.

At the top of the ***INPUT*** and ***SUMMARY*** sheets is a block of cells that identify the scenario being evaluated, and display both the LCOE and the power sales; these values update as the input is changed. Input and output are for both a Reference Scenario and an Improved Scenario. The User defines the Reference Scenario and then inputs a multiplier that is applied to a particular input parameter to represent a technology change for the Improved Scenario. For instance if the cost to drill a production well was $1,000,000 for the Reference Scenario and one wanted to see what the impact on LCOE from reducing that cost by 20%, one would input a multiplier of

0.8 in the appropriate cell, and the effect of having $800,000 production wells on the LCOE would be displayed at the top of the ***INPUT*** sheet, as well as on the ***SUMMARY*** sheet.

Again results are summarized in the ***SUMMARY*** sheet. If the FCR method is used to calculate the LCOE, they maybe found the ***Binary Output*** and ***Flash Output*** sheets as well (both of these sheets are typically hidden). If the EERE Approach is used to determine the LCOE, the ***EERE COE*** sheet will also have a summary of the different contributors to the LCOE, as wells as their capital costs.

Note that one cannot evaluate both a binary and flash conversion system simultaneously and view the results on these Output sheets; the model cannot perform concurrent calculations for both conversion systems. Nor does the model allow for the simultaneous assessment of both hydrothermal and EGS resources.

The model includes an ***Error-Warnings*** sheet that summarizes potential issues associated with the input provided by the User. A count of the number of Errors and Warning Messages is given at the top of the ***SUMMARY*** and ***INPUT*** sheets. If one goes to the ***Error-Warnings*** sheet, a message will be displayed for any current error/warnings and a link provided to that section of the ***Input*** sheet containing the input in question. The User should check and confirm that there is not an error associated with the input before proceeding.

In addition to these sheets, 6 others will typically be present. The ***GETEM – Read Me*** sheet contains general information about the model. The ***Tables*** has the Producer Price Indices that are used by the model. One can update these as desired; this sheet is protected, but not password protected. Note that the power plant cost estimates are based on 2002 $ and updated to the year defined by the User, while the well costs estimates are based on 2004 $. The ***Binary A1*** sheet has the macro that can be run to solve for the binary plant performance that minimizes the LCOE. It must be displayed ("Unhide") if one elects to use this option. The ***EERE COE*** work sheet is used to calculate the LCOE when the EERE methodology is used; the ***DCF*** sheet performs a similar calculation of the LCOE using the same User input as the EERE approach. The model includes the ***Suggested Input*** sheet which has suggested User inputs for two hydrothermal scenarios (binary and flash) and one EGS scenario (binary). Again, these are suggested inputs.

The remaining sheets are typically hidden. These sheets are where the calculations are made or have data used in those calculations. The User can opt to "Unhide" if desired by right clicking with mouse on any of the worksheets in the model.

The following is a format that was used when developing the model. We have attempted to maintain this format, though Users may find this not to always be the case.

- Cells with Yellow background are cells where the User provides input.
- Cells with Red font are imported values from other worksheets within the file
- "note" adjacent to an input cell indicates there is a comment having information relevant to that input cell The comment can be seen by clicking on the cell containing "note".

For certain inputs, the User must select from a drop down list. This list must be used in order for the model to decide how to proceed with the calculations. In some instances all the options in the drop down list will be the same – this is because the option does not apply for either the resource or conversion system being used. To the left of some input cells there is a drop down list for the units in which the input is being provided. The choice of units is limited to facilitate the units conversion to those used in the model calculations (Imperial).

Methodology:

Estimates are based upon the scenario the User defines by providing input for the each of the project phases. A User can define scenarios for either Hydrothermal or EGS resources, and for either air-cooled binary or flash-steam conversion systems. Calculations will be based upon either a targeted Power Sales or a fixed number of production wells (the User defines this in the Power Plant input section on the ***INPUT*** sheet).

In characterizing the resource, its temperature and depth are defined.

It is assumed that exploration is done in phases. In the initial phase of exploration, multiple locations may be evaluated and considered for drilling. The User defines the costs for each site considered, as well as the number of sites. The User also establishes whether exploration drilling will occur, and if so at how many of the locations considered during the pre-drilling activities. The User defines the number of wells drilled at each site, and provides information relative to the type of drilling and the drilling cost. Permitting and leasing costs are also defined by the User.

For the Confirmation phase, the User specifies the number of sites where confirmation drilling occurs. These are assumed to be full-diameter wells. Allowance is made for having to do drilling of full-sized wells at more than one site in a successful project. The User defines the number of 'dry' or unsuccessful wells drilled at those sites other than the 'successful' site. For the 'successful' site the User defines the drilling success rate and the number of successful wells needed before moving to the final well field development phase of the project. Successful confirmation wells are always assumed to be production wells that support the plant operation, even though for EGS, one or more of the wells may ultimately be injection wells. It is assumed that the wells drilled during the confirmation phase will be more expensive than those drilled during the final phase of developing the well field. The model estimates drilling costs during that final phase; the User defines a multiplier (> 1) to establish the confirmation well drilling cost. When an EGS resource is evaluated, the successful confirmation wells should be stimulated – the User provides that cost.

In characterizing the Well Field Development phase, the User must define how the well drilling costs are to be determined for both the production and injection well, as well as the number of injection wells and whether any dry holes or spare wells are drilled. The model calculates the cost of the surface equipment (piping, valves, vessels, etc.) for each well, or the User can provide that cost.

The costs to stimulate a well are identified by the User. The User also defines the flow rate per well, the hydraulic drawdown, and the thermal drawdown. The flow rate per well, well diameters, well depth and hydraulic drawdown are used to establish the geothermal pumping power required per unit mass flow of geothermal fluid. These calculations include friction losses for the fluid flow in both the production and injection wells.

The power plant performance metric used is the brine effectiveness, or specific output. This is the net power produced from the plant per unit mass flow rate (net power is exclusive of geothermal pumping, but includes losses associated with fan and pumping power within the plant conversion system). Once the User establishes the conversion system type and provides the input necessary to define this metric, the project size and cost are determined.

If the scenario being evaluated is based on a specific Power Sales, the amount of flow required to produce these sales is

The number of production wells required is the total flow required divided by the flow rate per well; the number of injection wells is the required number of production wells multiplied by the ratio of injection to production wells (User defined). The Well Field Development phase costs are determined using the well count and the costs per well for drilling and the surface equipment. The well count is the number of injection wells required and the number of production wells drilled during this phase (the number of production wells required less the successful confirmation and full-sized exploration wells), as well as any spare wells and dry holes identified by the User. The surface equipment costs are based on the total number of production and injection wells required, plus any spare wells identified by the User – dry holes have no surface equipment costs.

The power plant size needed to support this level of sales is the product of the total flow rate and the plant brine effectiveness, or the sum of the power sales and the geothermal pumping power. The plant cost is determined based upon this size, the plant design temperature and the plant brine effectiveness. If there is any geothermal pumping power, the plant size is larger than the targeted power sales.

Operating labor costs are estimated based upon the type of conversion system being used and the plant size. Maintenance costs are estimated as a % of the capital costs for the plant and the well field. Pump maintenance costs are based upon the type of production pump being used (User defined), the defined pump life, and the pump cost (calculated or defined). Taxes and insurance are also included in the O&M costs. They are determined as a % of the capital costs for the project (User defines the % rate). Royalties are also included in the O&M summation. The User defines the Royalty rate – the suggested values for Royalties are the rates imposed by the BLM.

The thermal drawdown for the resource is defined by the User. This represents a decline in the resource productivity with time. For hydrothermal resources, in particular those used with air-cooled binary plants, the expectation is that the resource temperature will decline at rate of 1% per year, or less. A flash plant that does not have production pumps would likely see this resource decline as a decreasing wellhead pressure – this effect is captured with the temperature decline rate. It is postulated that the temperature will decline more rapidly in an EGS resource. At some point the power produced by the plant may decrease to a level where it is not feasible to continue operation. If this occurs, the model triggers the replacement of the entire well field at a point in the future. The maximum temperature decline allowed is calculated, or the User can opt to input the temperature decline allowed before reservoir replacement. Again, when then the temperature drops below the minimum allowed, the model replaces the entire well field – it does not drill one or two additional wells, but all the wells. This is done to simplify the model's determination of the effect of the temperature decline on power output. The number of times that the well field and reservoir can be replaced is based upon the power plant size and the resource potential that is found by the exploration activities. If 100 MW of potential is found and the plant size is 40 MW, the field and reservoir can be replaced once. If the final well field and reservoir replacement occurs before the end of the defined project life, the resource temperature and plant output continue to decline. No well field and reservoir replacement is allowed during the last 5 years of the project life.

The annual power production is based upon the power sales, which includes the effect of the declining resource temperature and the utilization factor defined by the User. The utilization factor is the ratio of the kW-hrs that is produced annual to that produced if the plant had operated continuously throughout the year at its design output. The utilization factor accounts for the output lost during outages, as well as the impact of the ambient air temperature on the plant output at the geothermal conditions used for the plant design. DOE typically uses a value of 95% for this factor; there is discussion of this factor and the value used in the original GETEM manuals. The inputted value is indicative of the impact of the ambient on output at the design geothermal condition, as well as maintenance activities. In order to account for the impact of the resource temperature decline, the power sales are predicted at one month intervals at the resource temperature that is determined for each period based on the temperature decline. Sales at each time interval is determined using the available energy (for binary plants the sink temperature is 10°C), the 2nd law conversion efficiency, the geothermal flow rate and the geothermal pumping power. If the decline reaches the maximum allowed, the well field is replaced and the geothermal fluid temperature returns to the original value, as do the power sales. The calculated sales are discounted at a User defined rate over the defined project life when determining the LCOE.

With the FRC method, the discounted sales are summed over the project life, along with the discounted sales from a plant operating at the design output for the same period. The ratio of these two totals (predicted to design) is then applied to the inputted Utilization Factor to correct it to reflect the effect of the declining resource temperature. This corrected factor is referred to as the 'Levelized Utilization Factor'. It is used with the design Power Sales to calculate the levelized total power sales for a year; that value is used in calculating the LCOE.

In previous versions of the model, the User could define the geothermal temperature used for the plant design with EGS resources. That option has been removed; the plant design temperature is the calculated wellhead temperature. This temperature is the difference between the resource temperature and the calculated temperature drop of the fluid flowing up the well. The calculation of the temperature drop is based upon an approach defined by Ramey (1962), where it is assumed that the well has flowed sufficiently long that the temperature losses in the well have reached a quasi-steady state condition.

Once the input has been provided for the Exploration, Confirmation, Well Field Development, Reservoir Definition, and Operation & Maintenance activities, the User has the option of allowing the model to determine the level of binary plant performance that minimizes the LCOE. If the model performs this optimization, a trade-off is made between the cost of the plant (which varies directly with plant performance) and the cost of the well field and reservoir (which vary indirectly with the plant performance). For each defined scenario, there is a level of plant performance that produces this minimum generation cost. If this option is not used, the User must provide the plant performance as an inputted brine effectiveness. The determination of binary plant cost is based this performance metric. Neither performance nor cost is specific to a particular working fluid. The plant cost is based on the net plant power (turbine generator output less in-plant parasitic), which is the sum of the power sales and any geothermal pumping power. The turbine-generator cost is based on the estimated gross generator output (net plant output plus estimated in-plant parasitic power). As with the binary plant performance, a User has the option to use the calculated plant cost, or to input another value.

For flash-steam conversion systems, the model estimates the optimal flash pressures based upon the resource temperature and the number of flash pressures identified (1 or 2). Note that this estimate approximates the conditions that produce the maximum power – the User may be able to achieve lower LCOE varying the flash pressures slightly from the values the model calculates. The model can be run with no geothermal pumping; doing so allows flashing to occur in the well. This option is intended to be used with the flash steam plants and not the binary plant. The model estimates the well head pressure, and if it is less than the estimate of the optimal 1st stage flash pressure, the model defaults to well head pressure for the 1st stage flash. The model's estimate for the 2nd stage (low pressure) flash pressure defaults to a value 1 psi above atmospheric pressure if the calculation of the optimal value is less than one atmosphere. If the User inputs a flash pressure that is outside of this range (1 atmosphere and the well head pressure), an Error-Warning message will be displayed.

Costs for the flash plant are made in a similar manner as for the binary plants. These costs are estimated based upon the plant size, the flash pressures, and User defined values for the levels of non-condensable gases (ncg's) and hydrogen sulfide, as well as the type of condenser, cooling water temperature range, wet bulb temperature, and type of ncg removal system. The User has the option of using the calculated flash plant cost or providing that cost.

The model's projection of binary plant performance is based upon the premise that there is a minimum temperature limit placed on the geothermal fluid leaving the power plant. This limit is based upon the solubility of amorphous silica. This limit can be placed on the flash plant – if so, it does account the increased concentration of silica in the unflashed geothermal fluid. The estimate of the 2nd stage flash pressure will default to a value that prevents silica precipitation if the calculated optimal pressure would is less. If not placed on the flash plant, it is assumed that the User will account for the added chemical cost to prevent scaling from the geothermal fluid.

<u>Limitations:</u>

- Except as described here, the model does not have input default values.

- The Producer Price Indices are from the Bureau of Labor Statistics and should be updated by the User to provide estimates outside of those years currently in the model (1995-2011).
- Binary power plants are air-cooled. Flash plants use evaporative heat rejection systems where condensed steam is used for makeup water; with EGS resources this water loss is included in the calculation of the makeup water cost.
- Though in reality successful confirmation and full-sized exploration wells could be utilized as injection wells, in the model they are always assumed to support fluid production for the power plant and decrease the number of production wells that must be drilled during the Well Field Development phase. Injection wells are always assumed to be drilled in the final phase of the well field development.
- The model does not allow for the use of small-diameter exploration wells for either production or injection.
- In calculating the casing configuration in the well, the model assumes the conductor casing at the surface cannot exceed a diameter of 48-inch. It also assumes that the minimum diameter for the upper casing interval in a production well is 13-3/8 inch; this constraint is imposed to assure sufficient clearance for a production pump. The constraint is imposed in all production wells, even if not pumped. The model also assumes the upper casing diameter cannot exceed 16 inches for both production and injection wells. These constraints are imposed regardless of the method used to determine the well costs, i.e., they are always in effect when determining the geothermal pumping power.
- The binary power plant performance and cost are based upon modeling results for geothermal temperatures between 75° and 200°C. The model will predict outside of those temperatures, however the User should be aware that those temperatures represent scenarios that are beyond the model's capabilities.
- Binary plant performance is based on a design ambient air temperature of 10°C, or 50°F. This approximates the average annual air temperature in the US.
- The costs for the binary plants are based on sizes that are 3 MW and larger. Smaller plants are outside the range of the cost data used in developing the model's cost correlations.
- The binary plants for which cost and performance correlations were derived have single vaporizer pressures, i.e., dual boiling cycles were not evaluated. These plants were however allowed to operate at supercritical pressures with a wide range of heat exchanger pinch points. It is believed that it is unlikely that dual-boiling plants would provide significantly lower costs than those estimated at equivalent levels of performance.
- For binary plants, both cost and performance correlations were developed with a temperature constraint imposed of the geothermal fluid leaving the plant to prevent silica precipitation. The removal of this constraint is not an option for binary plants as it is for flash-steam conversion systems.
- Previous version of the model included an option to change the tube material (and cost) in the geothermal heat exchangers. This option became inactive when the method of applying

the PPI's was modified. The model now defaults to always using carbon steel tubes in the geothermal heat exchangers.

- The scaling of turbine costs ($/kW) with size has the largest impact of any of the plant equipment on the variation in binary plant costs ($/kW) with size. The cost correlations have an inherent assumption that the maximum size for a binary turbine is 15,000 hp. Once the turbine for the plant reaches this size, the turbine cost ($/kW) is constant. Plant costs continue to decrease with increasing size, however the rate at which costs decrease is diminished.
- The water properties that are used in the calculations are based upon curve fits of those for saturated water. These curve fits were developed using water properties to provide estimates that were with 0.1% of those predicted using NIST properties for temperatures up to 500°F (260°C). The effect of salinity on the water properties is not included in these calculations. The correlations used continue to provide reasonable approximations of water properties at temperatures up to ~575°F (300°C). It is recommended that GETEM not be used to evaluate flash plants at higher temperatures. In evaluating those scenarios, the User should provide input for both plant performance and cost.
- When the resource temperature declines to the maximum value specified, the entire well field is replaced and that cost incurred. The model does not allow for drilling one or two wells to offset the temperature decline either by increasing temperature or flow produced to the power plant.
- The model predicts the effect of a varying resource temperature on power output after a plant has been installed. As the resource temperature deviates from the plant design temperature there is increasing uncertainty in the levels of power predicted. The calculation of plant output with the varying resource temperatures always assumes that the total fluid flow to the plant is constant.
- When using the FCR methodology for the LCOE
    - Project life is 30 years.
    - The model is unable to use the staggered BLM royalty rates; instead it uses an effective rate of ~2.9% over the project life.
    - The LCOE is based upon annual levelized costs for the well field makeup costs. These annual costs for the well field makeup are effectively spread over the entire project.
- Inflation is not included in the determination of the LCOE.
- The model's determination of drilling costs during the exploration and confirmation phases at sites or locations other than the site that is successfully developed are based on the drilling costs at the successful site.

<u>Modifications to the Model:</u>

Originally the model considered only hydrothermal resources. It has subsequently gone through several revisions. In these revisions, the emphasis has been primarily for the air-cooled binary conversion system. The modifications include the following:

- Inclusion of EGS (Enhanced Geothermal Systems). To accommodate EGS, the model
  - Requires the User to provide input defining the well stimulation costs
  - Predicts production pumping power using the bottom-hole pressure in the injection well rather than hydrostatic pressure.
  - Allows the production fluid temperature to be estimated using the Carslaw-Jaeger solution for conduction from a semi-infinite solid. This solution requires the User define a fracture system. This method is not currently being used by DOE to assess the effect of EGS temperature decline.
- Costs estimates are adjusted using the Department of Labor's Bureau of Labor Statistics Producer Price Indices (PPI) for equipment, labor, and well drilling. The PPI's allow costs from varied sources to be incorporated and adjusted to the year that is of interest to the User.
- Provision to use both SI and Imperial units for input (the model calculations are done primarily in Imperial units).
- The effect of the production fluid temperature decline on plant power output is estimated.
- A maximum allowable temperature decline was integrated into the model that triggers the replacement of the geothermal well field if exceeded. This decline rate was derived from the end-of-operation temperatures in EPRI's *Next Generation Geothermal Power Plant* report (see original GETEM manuals). The values used represent a decline of ~10% in the Carnot efficiency at the well field replacement.
- The effect of having to replace the well field at a future date is included in the LCOE.
- Production pump setting depths are calculated as a function of well flow rate, casing sizes, well depth, resource temperature and hydraulic drawdown. This change was made to better assess the benefits of improvements in production pump technologies and in well stimulation to increase reservoir permeability and reduce hydraulic drawdown.
- Injection pumping power is calculated using the same parameters. This change was made in order to more accurately reflect the impact of changing the number of injection wells relative to the number in production wells.
- Binary power plant costs are determined as a function of the plant performance, as well as resource temperature and plant size.
- The prediction of the staffing for the operation and maintenance of the plant and field was changed from a step function with size to a continuous function of plant size. This was done to eliminate the increases in the LCOE that occurred when the plant size changed slightly and produced a step change in the plant staff size.
- An estimate of the temperature drop in the production well was included that is based on a technique described by Ramey (1962). This temperature drop is a function of the bottom-hole temperature in the well, the well depth, the earth temperature gradient, properties of the earth surrounding the well, well casing/liner size, cement thickness, the well flow rate, and time. The model assumes that the temperature loss in the well reaches a quasi-steady

state level after one year. This provision was included to better characterize the temperatures produced from deep wells having lower flow rates.

- An estimate of transmission line cost is provided. This cost is based on the line voltage, distance, population setting and terrain.
- A suite of exploration methods/tools was added to the model. Once a User opts to utilize a method listed, the User then decides whether to use the model's default cost for the selected methodology. Note that DOE is not currently using this option in its evaluation of the LCOE. The costs and definition of the suite of exploration tools is currently being validated. The intent of this ongoing effort is to provide DOE and a User with more clarity as to what tools are most likely to be used.
- An alternative method for determining well drilling costs has been added to the model. This was done to allow the effect of using different hole sizes for the injection and production wells to be evaluated. Of specific interest is whether the additional cost associated with a larger injection wells is offset by the potential to drill fewer injection wells and/or reduced injection pumping requirements. It may also allow DOE to examine the effect of technology improvements (for example, bit life and rates of penetration) if it can be shown to provide representative well drilling costs. This has yet to be confirmed. How the model determines well costs is currently under review to see if it can be improved.
- An option was included to allow the successful exploration well to provide fluid to the power plant. This requires all exploration wells to be production well sized. This well is treated as a successful confirmation well in the model's determination of cost associated with the Confirmation and Well Field Development phases.
- The approach of calculating LCOE that is being considered by EERE for all renewable programs has been integrated into the model. This approach effectively replicates a discounted cash flow sheet. A discounted cash flow sheet was incorporated into the model as part of this effort, and though it its calculation of LCOE is not included in the summary of results, it has been retained and can be used.
- As part of the effort to incorporate the EERE approach for determining the LCOE, the model uses defined (User) discount rates and durations for each of the pre-operational project activities. This allows one to assess the impact of higher costs for money and/or prolonged effort for each project phase.
- The characterization of the initial costs for a project were improved by allowing the User to identify the number of sites where pre-drilling exploration work occurs, as well as the number of locations where exploration drilling occurs. The prior version of the model did allow for the inclusion of failed exploration projects; the updated approach should provide better clarity of the costs associated with these 'unsuccessful' locations.
- The model has been modified to provide for a project life of other than 30 years. Costs for permitting, leasing, and taxes/insurance have also been made User inputs.

<u>Model Input:</u>

The User defines the scenario to be evaluated. Again there are currently no default values in the model so the User must go through the input to assure that the values in the model represent the scenario being evaluated. As indicated, provide input in those cells with Yellow backgrounds. The User is advised not to make changes outside of the highlighted cells.

The input is 'grouped' both by the phase of the project (i.e., Exploration, Well Field Development, O&M, …), as well as by activities during the phase (i.e., drilling activities and non-drilling activities during Exploration). The grouping allows the input sections to be expanded and collapsed. This grouping allows the User to 'skip' those sections that are not relevant to the scenario being defined. For example, it one opts to use a flash-steam conversion system, there is no reason to expand the binary plant input as none of that input is used in the model's calculations. Generally conditional formatting is used to 'white out' those sections of input that are not relevant based on the User's input. The model uses drop down lists for input in deciding how calculations will be made; this input is also the basis for most of the conditional formatting.

The ***SUMMARY*** sheet has project phase grouping similar to those on the ***INPUT*** sheet. The ***SUMMARY*** sheet summarizes both the input and results for the project phases. Once the input has been provided to define a specific scenario, one can review results on the ***SUMMARY*** sheet and return to the appropriate section on the ***INPUT*** sheet to adjust as necessary; frequently the results for one phase are be dependent upon the input in another section (phase). For instance, the production pump setting depth that is calculated is a function of the well depth and fluid temperature, the hydraulic drawdown in the reservoir, and the well diameter(s).

Information is provided for some of the input via comments located adjacent to those cells. The comments are revealed when the cursor is place on the cell containing the word "note".

The ***Suggested Input*** sheet has suggested values for input for both Hydrothermal and EGS scenarios. These are suggested values; if the User has information/data that is specific to the scenario being evaluated, that information/data should be used

The following provides a more detailed description of the model input for each section of the ***INPUT*** sheet.

Economic Parameters - These are parameters used in the calculation of the LCOE. Input includes:

- General Parameters:
  - Year of Estimate – determines the PPI's that are applied to capital costs. The model has PPI's from 1995 to 2011
  - Utilization factor – the ratio of kW-hrs produced annually to the kW-hrs that would have been produced if the plant operated 24 hrs/day for the entire year. This utilization factor is for performance at the design plant temperature – it includes the effect of varying ambient temperatures, but not the decline in resource temperature.
  - Contingency – applied to all calculated capital costs; it is indicative of project risk and uncertainty

- Royalty – BLM rate is 1.75% for 1st 10 years and 3.5% thereafter.
- Discount rate – this is the rate used to discount the future power production and future costs. The DOE currently uses a discount rate of 7%.
- Fixed Charge Rate –this value is multiplied by the project capital costs to determine the annual cost of capitalized equipment and services. It includes rate of return to equity and interest on debt, income taxes, property taxes, and insurance. The value used in the original model was 0.128; this value was used in the EIA NEMS runs for the Annual Energy Outlook 2005 report. The value currently being used in the EIA NEMS runs is 0.108. The original GETEM manuals include a discussion of this factor and what it includes.

- Project Duration: Input in this section is used for determining the LCOE using the EERE approach (and the discounted cash flow analysis). The User provides time durations for different project phases. It is assumed that confirmation follows immediately after exploration, and that the well field development (including stimulation) and power plant construction proceed concurrently once the confirmation phase is completed. If the time interval for the well field development is less than that for the plant construction, the model assumes both start at the same time, and the well field development is completed first. Time is also defined for the permitting activities. Confirmation and exploration permitting are assumed to be done at the same time, with a permit required for each site. Similarly the Utilization Permit is assumed to cover both well field completion and plant construction, and is obtained prior to starting work on either.
- Pre-Operation Discount Rates: These values are used in the determination of the LCOE using the EERE approach.
- Depreciation Schedule: A 5 year MACRS depreciation schedule is used with the EERE approach (consistent with other EERE programs).

Resource Definition- In this input section the type of resource is defined, along with the resource temperature and depth.

Exploration - Input for the exploration phase includes definition of the general parameters for the activity, the costs not associated with drilling, and the information needed to both determine the number of wells drilled and their cost.

The User is asked to define the initial resource status; this input is used in assessing the logic for the subsequent input - it does not directly impact cost. The User also defines the potential resource found by the exploration activities; this is an important input for evaluating scenarios with more rapid thermal drawdown as it determines the number of times a well field can be replaced. This value can also be used to proportion the exploration costs, i.e., spread those costs over several projects that might be occur to fully develop the potential found. This option is not used by the DOE, and it is recommended that it not be used for any scenario having more rapid thermal drawdown for the resource.

- Pre-Drilling Costs: The User may define a project where a number of sites are evaluated before any drilling occurs (this is considered a probable scenario). Costs are defined for each site evaluated. The costs for the pre-drilling costs can be defined by activity or as a lump sum value; separate costs are to be provided for permitting.

- Exploration Drilling Costs:
  - If exploration wells are drilled, the User must define either the number of locations where drilling occurs, and the number of wells drilled at each location. If the User indicates no wells are drilled for a Greenfield project, a warning will be displayed
  - A User defines the type of well drilled – slim hole, core hole or production sized; combinations of well types can not be used. If small diameter wells and full-sized wells are to be drilled, the full sized wells must be included as confirmation well drilling, and not exploration wells.
  - A User defined multiplier is applied to the calculated well cost for the defined depth. This multiplier allows for drilling small diameter, non-production sized wells. It is recommended that a multiplier of 0.6 (or larger) be used for slim hole wells; if wells are production sized, multiplier should be >1. Exploration well costs are based on the model's determination of a production well cost.
  - The model assumes all exploration wells are drilled to resource depth. If shallow wells to be evaluated, those costs can be reflected by using lower values for the exploration well cost multiplier.
  - If the wells are production sized, the model assumes that one successful well drilled at the successful site will support plant power production. If the wells are small-diameter, they will not be used to supply fluid to the plant (or for injection).

Confirmation –The model allows for confirmation drilling at multiple sites. All wells drilled during this phase are assumed to have the same construction as production wells. Successful confirmation wells are subsequently used to support power plant operation.

- Confirmation Well Drilling Costs
  - The number of wells drilled at unsuccessful sites are defined; this allows those drilling costs to be included in the LCOE calculation.
  - Success rate represents the fraction of confirmation wells drilled that can subsequently be used to provide production to the power plant.
  - The number of confirmation wells that are drilled is defined by the User, or is based on the % of the fluid production capacity that must be confirmed during this phase of the project. If a production capacity of 50% is required, then sufficient successful confirmation wells must be drilled to provide 50% of the geothermal fluid flow required by the plant. The production capacity per well is based on the plant performance, geothermal fluid pumping power and the flow rate per well. Note that if exploration wells are full sized wells, the count of successful confirmation wells needed to confirm production capacity is reduced by 1.
  - Confirmation well cost is based upon the calculated production well cost and a multiplier defined by the User. This multiplier should always be >1, reflecting the

higher drilling cost during the initial stages of a project, i.e., there is a learning curve associated with drilling for at the successful site.

- Confirmation – Non-drilling Costs
  - Confirmation costs not associated with drilling are either inputted as a lump sum or calculated as a % of the total confirmation costs.
  - If an EGS project, the 'successful' confirmation wells should be stimulated. The User provides the cost per well for the stimulation. The count of successful confirmation wells stimulated includes the successful exploration well, if it is a full-sized well.
  - Well testing is based on the number of sites where confirmation drilling occurs, and a testing cost per site.

Well Field Development – In this phase, the User provides input necessary to define costs per well, surface equipment costs and establish the number of injection wells. The drilling success rate that is defined determines the number of wells drilled in this phase that are 'dry'. If the project is evaluated based upon the number of production wells, the model assumes this is the number of wells required, and adds the 'dry' wells and the number of defined spare wells to determine the total number of production wells drilled. If the project is based upon power sales, the number of production wells required is determined by the flow per well, the plant performance, geothermal pumping power and the desired power sales.

- Well Field Details
  - Unsuccessful or 'dry' wells cannot be used for either production or injection.
  - Spare wells are drilled as part of the initial well field development to provide reserve flow capacity in the future. Because the model is not able to include the effect of using the spare wells at a later date to off-set the decline in power production due to thermal drawdown, it is recommended that a User not include any spare wells unless some adjustment is made to the thermal drawdown used in evaluating the project.
  - The ratio of the injection well to production well depths allows for drilling injection and production wells to different depths.
  - The ratio of injection to production wells defines how many injection wells are required. The number of injection wells is based upon the total number of production wells required (which includes successful wells drilled during the confirmation and exploration phases).
- Well Drilling Costs
  - Opt to use either the Cost Curves built into GETEM or a methodology that estimates the drilling cost based on the well configuration and user information relative to bit life, rates of penetration, etc..

- The 3 Cost Curves (Low, Medium, and High) bracket the Sandia National Laboratory drilling data (see GETEM reference manuals). These costs are updated from 2004 using the Producer Price Index for drilling Oil and Gas Wells.
- GETEM's Estimate requires the User define:
  - The configuration at the bottom of both the production and injection well
    - whether the production/injection interval is open hole or perforated/slotted liner
    - the hole diameter or casing OD in the production/injection interval
  - This input is used to establish the well's casing/liner configuration based upon assumptions relative to the cement thickness, casing diameters and commercial bit sizes. The model has two constraints on the maximum casing size – one for the conductor casing and the other for the upper casing interval. If the User input for the bottom hole diameter results in an estimated casing sizes that exceed either maximum value, the User is prompted to use a smaller bottom hole diameter; if the User does not provide a smaller diameter, the model uses a default value that is the maximum diameter that does not produce upper interval diameters that exceed either constraint. The model also always assumes that production wells have upper casing diameters of 13-3/8 inch or larger in order to accommodate a production pump and casing.
  - The method has embedded values for determining time for different drilling activities and costs. The User can adjust those values by changing the multiplier/index for Trouble, Rate of Penetration, Bit Life, Casing Cost, and Cement Cost. These indices are applied to all intervals in the well. The Trouble multiplier/index is applied to the total estimated rig time for each identified activity, and is reflected in the costs for that activity, as wells as the total time to drill the well.
- The User can adjust the well cost estimates produced by either method.

- The User can opt to provide the surface equipment costs as a lump sum value per well, or can allow those costs to be calculated based upon the inputted distance from the well to the plant and the maximum pressure drop allowed. This calculation is based upon the assumption that geothermal fluid is a liquid in the surface piping.
- Other costs during the Well Field Development phase are determined as a % of the total costs for this phase. The User provides that % value.
- The User also provides the cost for the permit for the well field development. It is assumed that this permit will be for both well field development activities and power plant construction.

Reservoir Definition – In this section the User defines the 'performance' of the reservoir. This includes the flow rate for each production well, and information relevant to the hydraulic and thermal drawdown. In this section the User also defines the well stimulation cost and the subsurface water loss in EGS reservoirs. Hydrothermal resources can be stimulated. For hydrothermal resources the total production and total injection flow rates are equivalent for binary plants; for flash plants, the injection flow is less than the production flow rate because it is assumed that steam condensate is used as makeup for the evaporative losses in the heat rejection system. EGS resources have higher injection flows in order to makeup the subsurface losses (which are defined by the User);for both conversion systems, the total injection flow equals the total production flow plus defined subsurface water losses. Well flow rate and hydraulic drawdown dictate the calculated production pump depth and associated power requirement. The thermal drawdown establishes the production fluid temperature decline with time. The model assumes that there is a maximum limit for this decline, and that once this limit is reached the entire well field is replaced. This maximum decline limit is calculated by the model, or the User can input a value. The number of times that the well field replacement can occur is dependent upon the resource potential established during the exploration phase (a User input). The model estimates the power produced by the plant as the temperature declines.

- The cost to stimulate a well can be inputted or can be calculated. It is strongly recommended that this cost be inputted, as there is minimal information upon which to base a calculated cost. The calculation used is relatively simple – based upon a cost per unit surface area and a defined fracture system. This option is intended to allow a User to perform a trade-off between the stimulation cost and the thermal drawdown. At this time the ‘calculated’ costs are entirely conjecture based on the User’s input.
- Unless the User has information specific to the reservoir (permeability, height, fracture system created, etc.), it is recommended that the User opt to input a Hydraulic drawdown rate rather than use the model’s determination of the drawdown. If the User does not have data that provides a drawdown rate, it is suggested that a rate of 0.2 to 0.6 psi per 1,000 lb/hr be used for Hydrothermal resources. There is little information upon which to recommend a value for EGS reservoirs. Data from wells drilled by DOE in the Basin and Range during the 1970’s had drawdown rates of ~0.8 psi per 1,000 lb/hr. It is postulated that EGS reservoirs will have similar or higher drawdown rates. When using the model’s kA method to estimate drawdown and the User has kH information, use a width of 1 (with units consistent with the kH data).
- It is recommended that the Annual Decline Rate be used to characterize the thermal drawdown; it must be used for Hydrothermal resources.
- If the user opts to calculate the thermal drawdown, the model utilizes the Carslaw-Jaeger solution for transient conduction from a semi-infinite solid. This approach requires the User provide information relative to the number of fractures created, the fracture width and aperture, and the distance between the wells (used as the fracture length). The model has properties for rock that the User can change. Note these rock properties only affect the transient heat conduction solution – they are not used in determining well costs.

- It is postulated that there will be water losses in EGS reservoirs. The model estimates the impact of these losses on the LCOE based upon the User's input of the % of the injected flow that is lost and the unit cost of the makeup water. If the User uses a flash-steam plant with an EGS resource, the model estimates the water required for the evaporative heat rejection and can include that water consumption in this makeup water cost (this is always done for Flash-EGS scenarios regardless of the User input).

Geothermal Pumping – This input section is used to identify how the geothermal pumping power and pump costs are to be determined. Again if the model calculates the pump setting depth, those calculations rely on the input provided for Reservoir Definition (flow and drawdown), Resource Definition (temperature and depth) and Well Field Development (casing configuration).

Note that certain combinations of input to the model may produce a 'Circular Reference'. These circular references are primarily associated with calculating either the pressure in the wells and/or reservoir, or in the temperature drop calculation in the well. If the User's input produces a circular reference that can not be resolved, please contact Greg Mines (Gregory.Mines@inl.gov, or 208-526-0260).

- The User defines whether the wells are pumped. It is recommended that for binary conversion systems, the User use pumped wells. If the model calculation determines no pumping is required, the pump setting depth defaults to 0. If a flash-steam conversion system is used, the model allows flashing to occur in unpumped wells. The model estimates a surface well head pressure, and requires that the 1st flash pressure be lower than this well head pressure. If flashing does occur, a warning/error message displays. If the User opts to not have pumped wells with a binary plant and flashing is calculated, a second warning/error message is displayed.
- If the pump depth is calculated, the User must identify the excess pressure at the pump suction. This value is effectively the NPSH for the pump, and includes the pressure required to keep non-condensable gases in solution. The same excess pressure is required at the production well head, and must be provided by the pump (in this case, the excess pressure accounts for surface pressure losses between well and plant).
- The User also identifies the ID for the production casing and provides a surface roughness for the casing (0.00015 ft is recommended – from Crane Technical Paper 410).
- If the well costs are determined using the Cost Curves, the User must define the bottom hole well diameter and whether the production interval is open hole or has slotted/perforated casing. This information is used to estimate the production well casing configuration used to determine friction losses in the well
- The User inputs the type of production pump used – either Submersible or Lineshaft (there is a limit on the setting depth for 2,000 ft for the Lineshaft pump). This input is used in determining the O&M costs for the pump; it does not have any impact on the calculated pump costs.

- The User decides whether to use the model's calculated production pump cost or to provide that cost. The calculated cost requires that the User define the casing and installation costs for the pump; the model estimates the pump cost based on the calculated horsepower. The User can adjust the calculated cost.
- The injection well pumping power requires the User provide information relative to the binary conversion system and surface piping pressure loss (recommend a value of 30 to 50 psi). This information and the production well head pressure are used to establish the injection well head pressure. If a flash-steam conversion system is used, the model uses the lowest flash pressure as the injection well head pressure.
- If the well costs are determined using the Cost Curves, the User must define the bottom hole injection well diameter and whether the injection interval is open hole or has slotted/perforated casing. This information is used to estimate the injection well casing configuration, which in turn is used to estimate friction losses.
- The model's calculation of the injection pumping power is based upon having a downhole pressure that exceeds the hydrostatic pressure by 1 psi. The model prompts also prompts the User to identify whether the reservoir pressure buildup is to be included in the determination of the injection pumping power. This buildup is analogous to the hydraulic drawdown in the production well; it is strongly recommended that the User input 'Yes", in particular with EGS resources or hydrothermal resources where fluid is injected into the same formation from which fluid is produced. When included, the minimum bottom hole pressure required in the injection well is the hydrostatic pressure plus the reservoir buildup pressure plus 1 psi. The model displays the excess pressure at the bottom of the well. If the value is negative, injection pumping is included; if desired, the User can include additional excess pressure, which will further increase the pumping power.
- The model calculates the injection pumping cost based on the injection pressure that must be provided and the injection flow. The user can adjust this cost.

Operation and Maintenance – The model's calculations for Operations and Maintenance (O&M) are based in part upon the experiences of the original developers of GETEM, which suggested that O&M costs for conventional hydrothermal plants (including the well field) were between 1 and 3 ¢ per kW-hr. Based upon those experiences and discussions with plant operators (primarily binary plants) regarding the significant contributions to O&M, a methodology was developed to estimate the O&M costs. Labor is a major contributor to the operations cost; the methodology used defines the O&M staff based on both conversion system type and plant size. Maintenance costs are defined as a % of the capital costs for both the plant and the well field. Costs are also included for maintenance of the geothermal pumps. (The power for these pumps is not considered an operating expense; rather it is subtracted from the net plant output to establish the Power Sales, which is used to determine the LCOE.) The User can adjust (decrease) the plant staffing to reflect the use of increased automation in operating the plant. Operators represent ~50 to 60% of the total plant staff, with the remainder for maintenance, engineering, management and office personnel; operators are assumed to also perform some maintenance activities. If the User elects to significantly reduce staff, then the % assigned for the maintenance costs should be increased to reflect the higher cost associated with contracting for maintenance in lieu of maintaining staff to perform those activities.

- The User opts to use either the model's calculated O&M costs or provide those costs (¢ per kW-hr) for both the power plant and the well field.
- If the O&M costs are calculated, a fraction of the operator time is assigned to the well field (suggest 25 %). Labor rates are also identified for staff – default values are given, which the User can change. The total predicted staffing level is displayed – the User can adjust this total. The adjustment is applied to all staff categories.
- The annual maintenance costs for the well field and surface equipment (outside of the plant boundary) is determined as a % of the total capital costs.
- The User can also provide input to define costs to treat the geothermal fluid. Binary systems are less likely to have these chemical costs. They are more likely to be incurred with flash plants. It is unknown what they might be for EGS resources.
- The annual maintenance costs for the power plant are determined in a similar manner – as a % of the plant capital cost.
- For flash plants, the User should identify the chemical costs associated with the evaporative heat rejection system. The model estimates the cooling water flow needed and establishes the cost based on a dosage and chemical cost ($/gallon) (both are User inputs). Note when binary plants are used, these chemical costs default to 0 because air-cooled condensers are assumed.
- The production pump maintenance is based upon the type of pump used. The User must identify the probable pump life: based on prior discussions with operators it is expected that lineshaft pumps will have a longer operating life than submersible pumps. The model calculates the pump cost (the model cost calculation does not differentiate between the pump types) and a cost to remove and install a pump. The User can use these costs or provide costs. When lineshaft pumps are specified, the User also needs to provide input for the cost for the oil used to lubricate the shaft between the pump and the motor (located on the surface).
- Taxes and Insurance are determined as a % of the total capital costs; the User must define these costs. If the User opts to input the O&M costs, it is assumed that taxes and insurance are included in those inputs.

Power Plant – As part of the Power Plant input, the User indicates whether transmission lines will be included in the LCOE determination. If so, then input is provided to determine that cost. The User defines the whether the conversion system is air-cooled binary or flash-steam, and identifies whether the LCOE will be based on the Power Sales or the Number of Production Wells required. For binary plants, the User can either define the plant performance (brine effectiveness) or allow the model to determine the plant performance that minimizes the LCOE. for the plant. The optimization is performed with a macro that uses the Excel Solver Add-In (see Appendix 1 for instructions regarding this add-in). The flash-steam plant performance is based upon the flash pressures that are either calculated or inputted by the User (the model estimate of the optimal flash pressures based upon the resource temperature). For both plant types, major components are sized based on plant performance/flash pressures, calculated plant size and the resource temperature. The model estimates the direct construction cost based on these equipment cost. The direct construction costs and User input for indirect costs are used to determine the total installed cost for the power plant.

- If the User elects to include transmission costs, inputs are required both from drop down lists to establish the line voltage, terrain and population density, and to establish the distance for the transmission line. These inputs are used to establish the transmission line cost ($/mile). The costs and the approach used were developed from a PG&E presentation made in 2009. They do not include costs for substations.
- The User defines whether the LCOE determination will be based on Power sales or the number of production wells (exclusive of dry holes or spare wells) and defines the number of units, i.e., is 15 MW of sales coming from one 15 MW unit or three 5 MW units. Note the number of units defined should not drop the output per unit below ~3 MW (to assure that the costs predicted are within the size range for which the equipment correlations are based).
- The User also defines how the model is to handle any changes in plant performance for the improved scenario. One option keeps the total power sales constant and adjusts the geothermal fluid flow rate. The other keeps the flow constant, and determines sales based on the improved scenario plant performance.
- The User selects the conversion system to be used in the analysis: air-cooled binary or flash-steam.
- Binary Plant Input
    - The User establishes whether the plant performance is going to be inputted or calculated. If inputted, the model lists the maximum plant performance (brine effectiveness) for the geothermal fluid temperature; this value is the maximum level of performance for which the model's cost correlations were developed.
    - If performance is to be calculated, click on the CALCULATE box. This is a hyperlink to sheet ***Binary A1***. On this page enter a value in the cell with the yellow background that is less than the maximum displayed (suggest about half that value) and click on the red button for the Reference Scenario. A box with the Solver results will be displayed. If a solution is found, click OK to accept the results. In lieu of using solver, one can manually change the plant performance in the cell with the yellow background till an optimal value is found. (This manual changing of the performance metric to minimize the LCOE can also be done on the ***INPUT*** sheet if the User opts to input this metric.) Once completed click on the RETURN box to return to the ***Input*** sheet. Note that on ***Binary A1*** one can also optimize plant performance for the Improved Scenario. This option would be utilized if one were to define improvements that impact the cost of the exploration and confirmation phases and/or the well field development and stimulation.

- The next section of input is to define the plant cost for the reference scenario. The model uses the plant performance, plant size (net plant output – not power sales), and the geothermal fluid temperature to estimate the costs of the major components in the plant – the turbine-generator, air-cooled condenser, geothermal heat exchanger and working fluid pump. The model defaults to using carbon steel tubes in the geothermal heat exchanger. (Prior versions of GETEM allowed the tube material to be varied and the associated impact on costs reflected in the heat exchanger cost; this feature has not been integrated back into the model.) The estimated costs of these four components are displayed; a User can adjust each of these costs. Note that a PPI adjustment has been applied to each component cost shown.
- The model applies a multiplier to these equipment costs to determine the direct construction costs. The multiplier that the model determines includes other equipment installed as part of the plant construction, steel, 'other' materials, labor (including fringe and benefits), and consumables (including rentals). The PPIs are used to adjust the contributions from each to the total multiplier. This multiplier also includes the User defined freight and tax (both applied to non-labor costs). The calculated multiplier is displayed – the User can opt to use this value or input a value.
- The indirect costs for the plant construction are defined by the User as either a fixed value or as a % of the direct construction cost. These indirect costs include costs for engineering, home office, management and supervision, startup, etc..
- The User must define how the plant cost for the scenario with improvements specific to the power plant is to be defined relative to the reference scenario. If the model calculates the plant performance, then any calculated plant cost for different levels of performance will produce an increased LOCE. To show the impact of improvements for power plant technology, a User must define either the increase in performance for the same plant cost ($/kW), or the decrease in cost ($/kW) for the same level of performance. When the improvements are made in the other project phases (and not associated with the power plant), the macro for the Improved Scenario on ***Binary A1*** can be used to establish the plant performance (and cost).
- The binary plant input also allows one to assess the footprint of an air-cooled binary plant. This estimate is based upon the estimated size of the air-cooled condenser and the User defined ratio of the total plant footprint to that of the air-cooled condenser. This is for information purpose only, and is not used in the determination of the LCOE.

- Flash-Steam Input
  - The model allows the design ambient conditions to be varied in the determination of the flash plant performance. The User identifies these ambient conditions.
  - The User also identifies the isentropic efficiencies of the turbine and pumps, as well as the generator efficiency.

- Plant performance is based upon the flash pressures. The User must identify whether there will be a temperature constraint place on the geothermal fluid leaving the plant and establish whether there will be 1 or 2 stages of flashing. The model will estimate the optimal flash pressures (those producing the maximum power). The User can opt to use those values or input other flash pressures. (Note that it is probable that the User will be able to adjust the pressures and produce a higher output and lower LCOE; however these increases are not anticipated to be significant.) If the inputted high pressure flash pressure exceeds the estimated production well head pressure, a warning will be displayed
- The User must define the pressure drop between the flash vessel and the turbine.
- The User must define the condenser type and provide input relative to the cooling water temperature rise, pinch points (approach temperatures) in the condenser and cooling tower, the cooling water pump head and the non-condensable gas partial pressure in the condenser. For the different condenser types, the pinch point in the condenser will vary, as well as possibly both the cooling water pump head and cooling water temperature rise.
- Hydrothermal resources contain varying levels of non-condensable gases that come out of solution when the fluid flashes and pass through the turbine to the condenser with the steam. These gases must be removed from the condenser or they will adversely affect plant performance. The User defines the level of non-condensable gases in the geothermal fluid, including the level of hydrogen sulfide (H2S). The model assumes hydrogen sulfide must be abated, and uses this concentration to estimate the capital cost of the abatement system. The User also defines how the non-condensable gases are to be removed, the number of stages in the removal process, and if a vacuum pump is used, its efficiency.
- In order to estimate the cost of the equipment the User defines the steam condenser heat transfer coefficient. This value is used to estimate the size of all the surface condensers (the model assumes that surface condensers are used in the non-condensable gas removal system).
- The maximum droplet size is also inputted. This droplet size is used to calculate a terminal velocity, which is used with the steam flow rate to establish the diameter of the flash vessel and its cost.
- Similar to the binary cost model, estimates are provided for the major components in the flash-steam plant. The User can adjust these estimated costs, which include the PPI adjustments.
- The model applies a multiplier to these equipment costs to determine the direct construction costs. The multiplier that the model determines includes other equipment installed as part of the plant construction, steel, ‘other’ materials, labor (including fringe and benefits), and consumables (including rentals). The PPIs are used to adjust the contributions from each to the total multiplier. This multiplier also

includes the User defined freight and tax (both applied to non-labor costs). The calculated multiplier is displayed – the User can modify.

- The indirect costs for the plant construction are defined by the User as either a fixed value or as a % of the direct construction cost. These indirect costs include costs for engineering, home office, management and supervision, startup, etc..

Calculation of Levelized Cost of Electricity:

A User has the option of using either the FCR method or the EERE Approach to determine the LCOE.

With the FCR method, the inputted fixed charge rate is multiplied by the total project capital costs to determine the annual revenues need to satisfy those costs associated with the capital. The annual operating costs are then added to those revenues needed for capital. This sum represents the annual power sales that must be realized. In order to determine the LCOE, it is necessary to determine the annual power generation. To account for the degradation in power output, the model discounts the output over the plant life, as well as the output of the plant if it had operated at the design output over the entire life. The ratio of those discounted values is applied to the inputted Utilization Factor to produce a 'Levelized Utilization Factor' which is used with the design power output to calculate the levelized annual power production (the 'Levelized Utilization Factor' effectively accounts for the impact of a declining resource temperature on the Utilization or Capacity Factor). The LCOE is the annual sales revenue need to cover capital and operating expenditures divided by the levelized annual power production.

The EERE Approach replicates a discounted cash flow analysis, with one caveat. The EERE methodology can not directly utilize the model's estimate of the impact of the temperature decline on power output. To account for this decline in output, an annual decline rate for the capacity factor is determined based upon the plant output at the time of well field replacement or at the end of project life, whichever occurs first. As indicated a discounted cash flow is included in the model which uses the same costs, phase durations, and discount rates as the EERE Approach. It differs from the EERE Approach in that it utilizes the model's estimates for the annual power production (which include the effect of the resource temperature decline). Because of this, there will be some difference between the generation cost determined with the discounted cash flow sheet and the EERE Approach.

Appendix 1

To use the macros in the model, the user must enable those macros when the spreadsheet is opened. Even with the macros enabled, the model may not work. The macros in GETEM require Excel's Solver Add-in be active. To make the Solver Add-in active, it is strongly suggested that the User consult the Help files associated with the version of Excel being used.

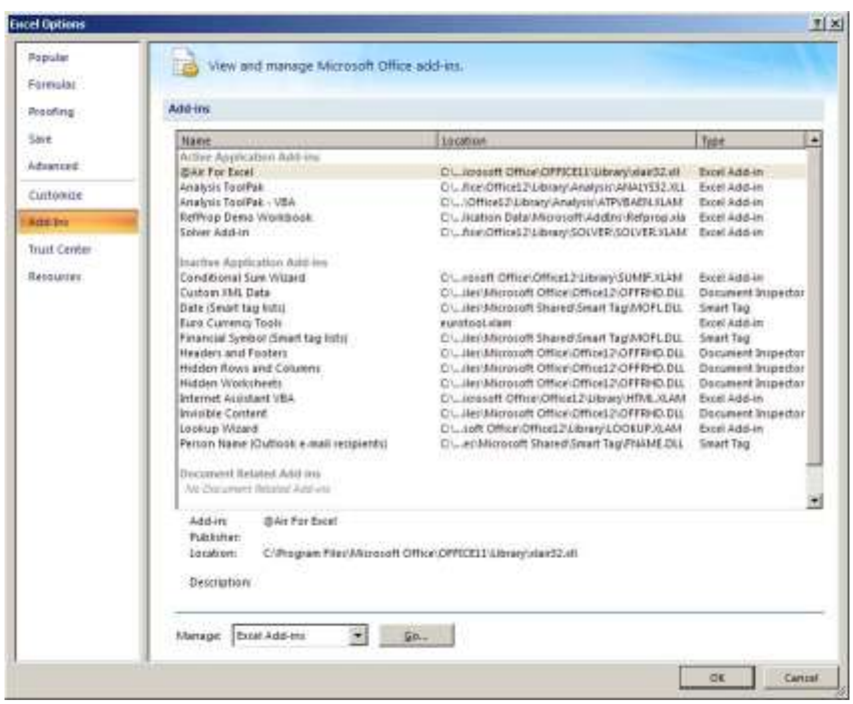
The following information maybe used; if these fail to work consult Excel's Help files.

Office 2010:

- Click on File menu, then
- Options, then
- Add-ins
- On the bottom of the Add-In page, go to
- Manage Excel Add-Ins (it will be necessary so select Excel Add-ins from the drop down menu)
- A box will be displayed with the Add-Ins that are available.
- If the Solver Add-in box is not checked, do so then click OK
- Solve should be active

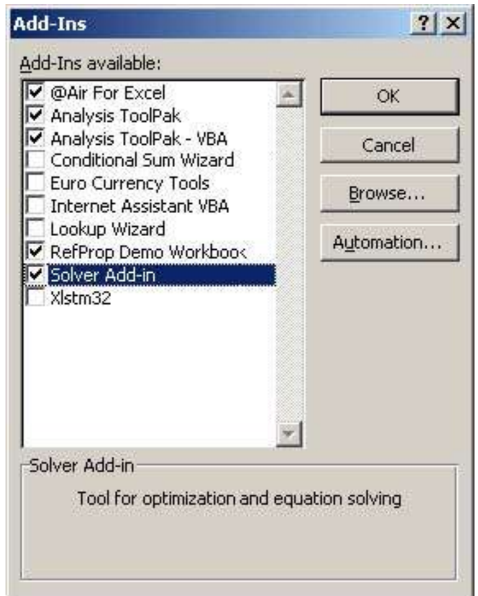
Office 2007

- Click on Windows Icon in upper left portion of screen, and select Excel Options (lower portion of the window)
- Click on Addins (see below); note this screen is similar in Office 2010.



- In the Manage window, select Excel Add-ins and click Go

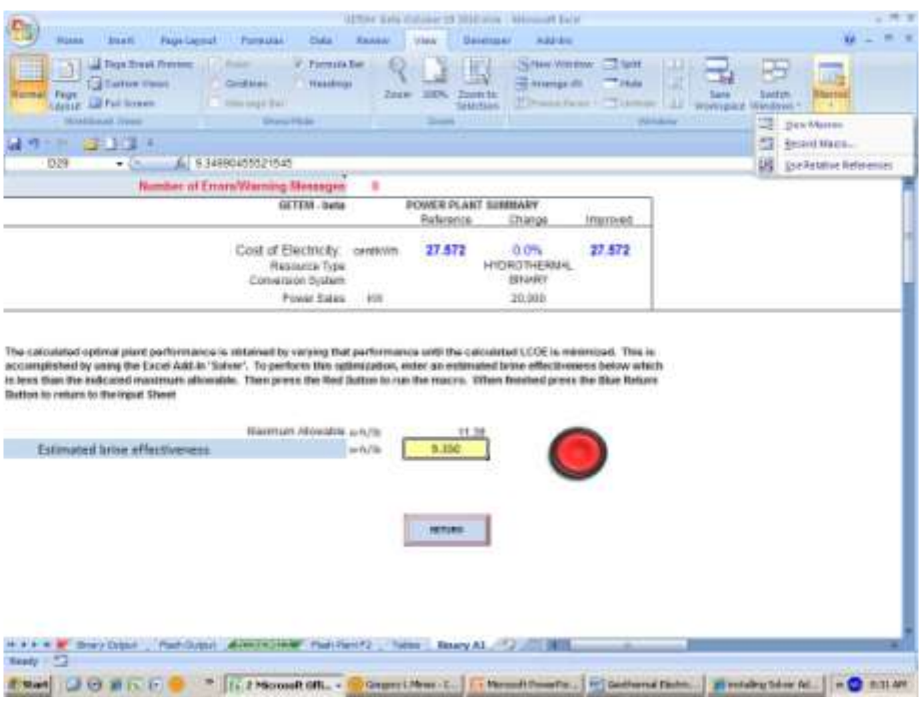
- The following box will appear (again this is similar to that in Office 2010)



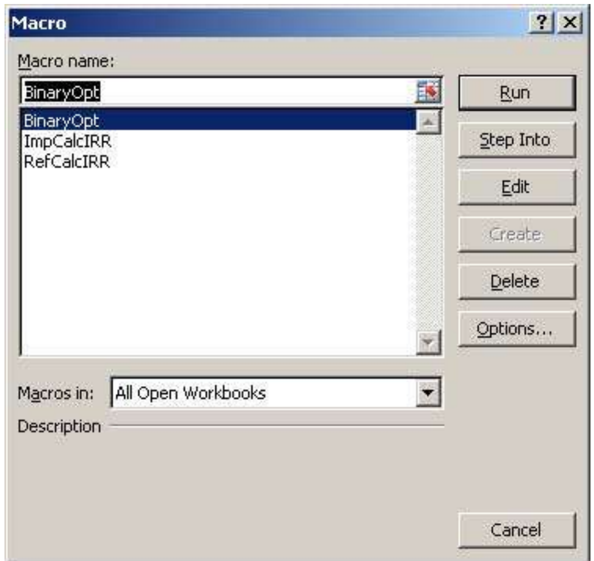
- Check the box for Solver Add-in, and then click OK
- Solver should be active

Once Solver has been added in, the macros still may not work. The following is for Office 2003-2007, but is expected to also work for Office 2010.

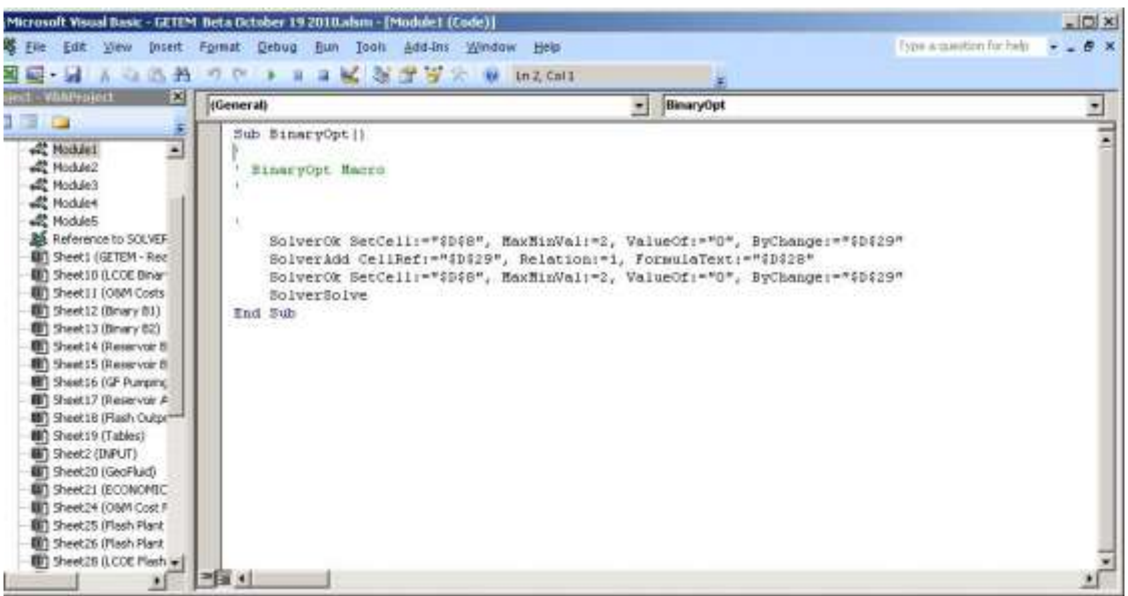
- Open the View tab and click on Macros, then View Macros (see below)



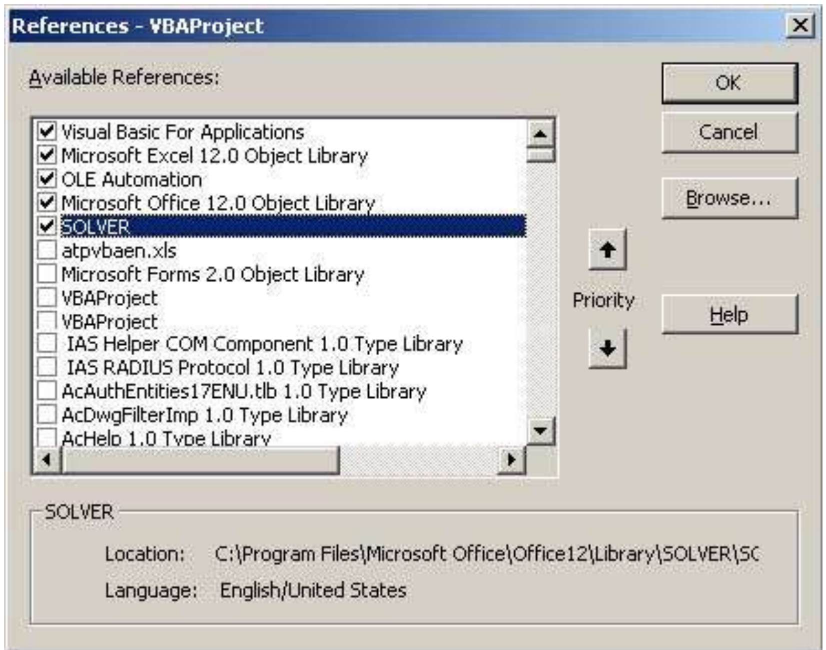
- The following screen will appear. Select the macro and click edit.



- The following screen will appear. Click on Tools,



- and then References. The following screen will appear



- Click on the box next to SOLVER, and then OK. Then close the visual basic editor and return to the Excel file.

The macro should now work.

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Appendix V

Summary of GETEM Parameters and Assumptions

Table V-1: Summary of GETEM Input Parameters and Assumptions[1]

	GETEM Input Parameters:	Units (where applicable)	Department of Energy (DOE) GETEM Default Values ($USD)	Actual Values Used	Comments
	PROJECT PHASE				
1	**ECONOMIC PARAMETERS**				
2	General Project Variables :				
3	Reference Year $		2011	2015	Changes value to 2015. Updated table using 2% per year increase for 2013-2015.
4	Utilization Factor		95%	95%	DOE recommended value.
5	Contingency	%	15.0%	15.0%	DOE recommended value. Note from GETEM: "Parameter is applied to all calculated capital costs; is indicative of project risk and uncertainty."
6	Royalty (thru Yr 10)	%	1.75%	0.00%	Using value of "0" for royalty rates. Clause 17 of the British Columbia Geothermal Resources Act indicates that a geothermal royalty will be negotiated or imposed. There is currently nothing in place.
7	Royalty (after Yr 10)		3.50%	0.00%	Using value of "0" for royalty rates. Clause 17 of the British Columbia Geothermal Resources Act indicates that a geothermal royalty will be negotiated or imposed. There is currently nothing in place.
8	Discount Rate	%	7.0%	5.0%	Using value of 5% per Geoscience BC direction.
9	Effective Tax Rate	%	39.2%	26.0%	Income not eligible for small-business deduction: 15% Federal, combined federal and provincial (British Columbia): 26%
10	Project Life (Period of Operation)	yr(s)	30	20	DOE recommended value of 30 years. All projects evaluated for a project life of 20 years, which is consistent with Volumetric Estimates conducted as well as reflective of the range of anticipated terms of Power Purchase Agreements in BC.
11	Calculations based on Fixed Charge Rate (FCR) of :		10.8%	10.8%	Using EERE Approach instead of FCR method. Therefore FCR factor of 10.8% does not affect this LCOE calculation.
12	**Method used to Calculate Cost of Electricity**		EERE Approach	EERE Approach	An alternative method integrated into the model and which uses an approach being developed within the DOE Energy Efficiency and Renewable Energy (EERE) programs. This EERE Approach effectively replicates a discounted cash flow sheet. This alternative methodology is currently being used by the Geothermal Technology Program (GTP) of the US Department of Energy (DOE). Incorporating the EERE approach into GETEM allows: (1) the project life to be varied (it is fixed at 30 years with the FCR method); (2) varying discount rates (costs of money) to be applied to each phase of the project; (3) the durations of each project phase to be changed.
13	Project Schedule & Durations :				
14	Year of Project Initiation		2009	2015	All projects evaluated using year 2015.
15	Duration of Permitting for Exploration/Confirmati	yr(s)	1	1	Some of these durations overlap. Timing of project development of 5 years (as established in GDDMs) has been utilized in this assessment, as specified under "Year to Begin Operations." Duration of Plant Design and Construction assumed to be concurrent with Well Field Development Phase, and therefore reduced from 2 years to 1 year.
16	Duration of Exploration Phase	yr(s)	2	2	
17	Duration of Confirmation Phase	yr(s)	1.5	1.5	
18	Duration of Permitting for Plant/Field (Utilization	yr(s)	1	1	
19	Duration of Well Field Development Phase	yr(s)	1.5	1.5	
20	Duration of Plant Design and Construction	yr(s)	2	1	
21	Year to Begin Operations		2015	2020	All projects evaluated using a targeted 5 years from project initiation to begin operations.
22	Year to Cease Operations / Commence Decommissioning		2045	2040	
23	Duration of Decommissioning, Dismantlement, &	yr(s)	0	0	DOE recommended value.
24	Year of Plant Closure		2045	2040	
25	Pre-Operation Discount Rates				
26	Exploration		30.0%	30.0%	DOE recommended values. Note from GETEM: "As part of the effort to incorporate the EERE approach for determining the LCOE, the model uses discount rates and durations for each of the pre-operational project activities. This allows one to assess the impact of higher costs for money and/or prolonged effort for each project phase. These values are used in the determination of the LCOE using the EERE approach."
27	Confirmation		30.0%	30.0%	
28	Well Field Development (including Stimulation)		15.0%	15.0%	
29	Plant Construction & Startup		7.0%	7.0%	
30	Inflation		0.0%	0.0%	
31	Depreciation Schedule				
32	Year 1		20.0%	25.0%	Accelerated depreciation schedule used. (Year 1 - half year 25%; all subsequent years 50%) Under Classes 43.1 and 43.2 in Schedule II of the Revenue Canada Income Tax Regulations, equipment that is eligible for Class 43.1 but is acquired after February 22, 2005 and before year 2020 may be written-off at 50 percent per year on a declining balance basis under Class 43.2.
33	Year 2		32.0%	37.5%	
34	Year 3		19.2%	18.8%	
35	Year 4		11.5%	9.4%	
36	Year 5		11.5%	4.7%	
37	Year 6		5.8%	4.7%	
38	**RESOURCE DEFINITION**				
39	Resource Temperature & Depth:				
40	Resource Temperature	C	175	Various	Most Likely Temperature value from Volumetric Analyses used for each site.
41	Resource Depth	meter	1,500	Various	2,500 m used for flash projects; 1,250 m used for binary projects, except 2,000 m for sedimentary binary (Clarke Lake and Jedney Area).
42	**RESOURCE EXPLORATION**				
43	Exploration Parameters:				
44	Potential Resource found by Exploration & Confi	MW	300	Various	Median (50% probability) value derived in Cumulative Probability calculation from Volumetric Analyses used for each site.
45	Are Exploration costs to be proportioned based on Potential Re		No	No	
46	Exploration - Pre-Drilling Costs :				
47	Number of Locations Evaluated Before Explorati	per project	6	Various	Number of locations taken to mean well pads utilized for exploration and development activities. Values used are as follows: 1 well pad for the 5-MW Clarke Lake project; 2 well pads for the 10-MW and 15-MW projects (Sloquet, Jedney, and Canoe); 3 well pads for the 20-MW and 40-MW projects (Clarke Lake, Kootenay, Lakelse Lake, L. Arrow, Okanagan; and Mt Cayley); 4 well pads for >40 MW (Meager/Pebble). Meager has already had several slim holes and full-diameter exploratory wells; Pebble has had 10 temperature-gradient wells (diamond-drill holes) drilled.
48	Permitting Process Costs for Pre-Drilling Activitie	per location	$60,000	$410	The Geothermal Resources Administrative Regulation, Section 9 provides the fees for the issue or renewal of a permit as CAD$500 (US$410). Value of CAD$500 (US$410) for the issuance of initial permit fee used.
49	How are Exploration, Pre-Drilling Costs Determined for Each Sit		Lump Sum	Lump Sum	DOE default value is US$500,000. A value of CAD$500,000 (US$410,000) has been used in this study. This covers pre-drilling costs including data research and evaluation, geological evaluation, geochemical sampling and analysis, conceptual modeling, geophysical surveying, and reporting. Additional non-drilling costs added here include transmission costs and infastructure costs (specifically road building/repairs).
50	Lump Sum Cost for Pre-Drilling Exploration Activ	per site	$500,000	Various	
51	Exploration - Drilling Costs :				
52	Will Exploration Wells Be Drilled ?		Yes	Yes	
53	Number of Sites where Exploration Drilling Occu	per project	5	Various	Number of sites taken to mean well pads utilized for exploration and development activities. Previously defined in line 47. See above.

Table V-1: Summary of GETEM Input Parameters and Assumptions[1]

	GETEM Input Parameters:	Units (where applicable)	Department of Energy (DOE) GETEM Default Values ($USD)	Actual Values Used	Comments
	PROJECT PHASE				
54	Number of Exploration Wells Drilled per site		3	1	A value of 1 exploration well per pad/site is acceptable based on GeothermEx experience and has been used herein.
55	Type of Exploration Well Drilled		Slim Hole	Slim Hole	Slim Hole most likely type of exploration well to be drilled.
56	Multiplier for Exploration Well Costs		0.6	0.6	DOE default value of 0.6 (or 60% of full-size well cost) has been used.
57	Permitting Process Costs for Drilling - Exploratio	per site	$125,000	$820	The Geothermal Resources Administrative Regulation, Section 9 provides the fees for the issue or renewal of a permit as CAD$500 (USD$410). Duration of 5 years for project development allows for 3 years of exploration and confirmation activities prior to well field development (as established in GDDMs). Value of CAD$1,000 (USD$820) is used for renewing permit 2 times (giving total of 3 years).
58	Leasing Cost	$ per acre	$30	$3	The Geothermal Resources Administrative Regulation provides the fee for the issue or renewal of a lease as CAD$200 (USD$164), with a yearly rent of CAD$10/ha (USD$3.32/acre). The rent value of CAD$10/Ha or US$3.32/acre is used here. The annual lease fee is accounted for in the following line item (#59).
59	Costs Incurred not Associated with Drilling Explo	per site	$0	$3,772	Lease cost is calculated based on area. The initial lease fee of CAD$200 (USD$164) (assumed to occur during year 3 of 5-year project development), plus CAD$4,400 (US$3,608) (assuming 22 annual lease renewals, including the remaining years 4 and 5 of project development plus 20 years of plant operation) have been included as a lump sum here - total CAD$4,600 (USD$3,772).
60	**RESOURCE CONFIRMATION**				
61	Number of Confirmation Drilling Sites Needed per Successful Project		2	2	DOE recommended value. Acceptable based on GeothermEx experience. Only project variance from this value was the use of 1 well for the Clarke Lake 5-MW run - a single site would be expected for development of 5 MW.
62	Confirmation Well - Drilling Costs :				
63	Number of wells at Each Unsuccessful Site		2	2	DOE recommended value. Acceptable based on GeothermEx experience.
64	Confirmation Well Success Ratio at Successful Site		60%	60%	DOE recommended value. Acceptable based on GeothermEx experience.
65	Are number of wells drilled determined by well count or confirmed production capacity ?		Well Count	Well Count	DOE recommended value.
66	Number of Successful Confirmation Wells	count	3	Various	DOE recommended value. Resource Confirmation takes the project to where it needs to be to get financing, with a historical threshold of 25% of target MW at the wellhead. Acceptable values for full-diameter confirmation wells as follows: 1 well for 5-MW, 10-MW and 15-MW projects; 2 wells for 20-MW and 40-MW projects; 3 wells for Meager (for a combined 6 wells at Meager/Pebble).
67	Multiplier for Confirmation Well Costs (>= 1)		1.2	1.2	DOE recommended value. Acceptable based on GeothermEx experience for slightly higher drilling costs during confirmation phase.
68	Confirmation Well - Non-Drilling Costs :				
69	Permitting Process Cost during Confirmation Pha	per site	$0	$0	No additional permitting costs identified during this phase of development.
70	How are non-drilling confirmation costs to be determined ?		% Confirmation Drilling Cost	% Confirmation Drilling Cost	
71	Percentage of Confirmation costs				
72	% of total confirmation costs attributed to non-drilling activities (exclusive of stimulation &		5.0%	2.0%	DOE recommended value of 5%. Value of 2% used here and is considered more appropriate.
73	Stimulation Costs During Confirmation				
74	Are Confirmation Wells to Be Stimulated ?		No	No	
75	Well Testing				
76	Well Testing Cost at each site	$/site	$150,000	$150,000	DOE recommended value. Acceptable value of USD$150,000 (CAD$182,927) based on GeothermEx experience.
77	**WELL FIELD DEVELOPMENT**				
78	Well Field Details:				
79	Drilling Success Rate during the final phase of well field develop		80%	80%	DOE recommended value. Acceptable based on GeothermEx experience.
80	Number of Spare Production Wells		0	1	DOE recommended value of 0. Value of 1 considered to be more appropriate in GeothermEx experience.
81	Number of Dry Wells (Unusable as Injectors) - *calculated*				
82	Ratio Injection Well to Production Well Depth		1	1	
83	Ratio of Injection Wells to Production Wells		0.75	Various	DOE recommended value of 0.75. Value of 0.75 used for flash projects. Value of 1 used for binary projects.
84	Well Drilling Costs :				
85	How are costs for drilling wells determined ?	Cost Curves	Production Well	Production Well	DOE recommended method of calculation. We are utilizing the well cost multipliers in lines 87 and 88 to adjust well costs to known, historical costs - roughly USD$1,000 per foot (CAD$4,000 per meter).
86	Adjustments to Production and Injection Well Drilling Costs :		Reference	Reference	
87	User Adjustment to Production Well Cost		1.5	Various	DOE recommended value of 1.5. DOE value over-estimates well costs in GeothermEx's experience with actual drilling costs. Value of 1.18 used for flash projects. Value of 1.29 used for binary projects.
88	User Adjustment to Injection Well Cost		1.5	Various	DOE recommended value of 1.5. DOE value over-estimates well costs in GeothermEx's experience with actual drilling costs. Value of 1.18 used for flash projects. Value of 1.29 used for binary projects.
89	Other Field Costs :				
90	How are surface equipment costs determined ?		Fixed Cost	Fixed Cost	DOE recommended method of calculation.
91	Fixed Cost				
92	Surface Equipment Cost per Well	$/well	$200,000	$200,000	DOE recommended value.
93	Other Well Field Development Costs, (% of tota	%	5.0%	5.0%	DOE recommended value.
94	Permitting (Utilization Plant) Cost for Well Field & Powe	$ / project	$1,000,000	$410,000	DOE recommended value of $1,000,000. Value of CAD$500,000 used (USD$410,000). This assumes costs for permitting well and plant construction and associated environmental analyses.
95	**RESERVOIR DEFINITION**				
96	Well Flow Rate				
97	Production Well Flow Rate	kg/s	100.0	Various	DOE recommended values of 100 kg/s for binary and 80 kg/s for flash. Acceptable based on GeothermEx experience.
98	Hydraulic Drawdown				
99	How is Hydraulic Drawdown determined?		Inputted Value	Inputted Value	
100	Input Production Well Drawdown	psi-h/1000lb	0.4	0.4	DOE recommended value. Acceptable based on GeothermEx experience.
101	Thermal Drawdown				
102	How is Thermal Drawdown Determined ?		Annual Decline Rate	Annual Decline Rate	
103	Annual Rate of Decline	%/yr	0.30%	0.30%	DOE recommended value. Acceptable based on GeothermEx experience.
104	**GEOTHERMAL FLUID PUMPING**				
105	Pump & Driver Efficiency for Production and Injection Pump		67.5%	67.5%	DOE recommended value. Acceptable based on GeothermEx experience.
106	Production Pump :				
107	Are Production Wells pumped ?		Yes	Yes	Used for binary projects only.
108	Type of production pump used		Lineshaft	Lineshaft	DOE recommended value. Acceptable based on GeothermEx experience.

Table V-1: Summary of GETEM Input Parameters and Assumptions[1]

	GETEM Input Parameters:	Units (where applicable)	Department of Energy (DOE) GETEM Default Values ($USD)	Actual Values Used	Comments
	PROJECT PHASE				
109	Calculate or Input production pump cost?		**Calculate**	**Calculate**	DOE recommended method of calculation.
110	Calculate Pump Cost :				
111	Casing cost	$/ft	**$45.00**	**$45.00**	DOE recommended value. Acceptable based on GeothermEx experience.
112	Installation Cost	$/ft	**$5.00**	**$5.00**	DOE recommended value. Acceptable based on GeothermEx experience.
113	Other Costs		**$10,000**	**$10,000**	DOE recommended value. Acceptable based on GeothermEx experience.
114	Injection Pump :				
115	Surface Equipment ΔP for binary conversion sys	**psi**	**40.0**	**40.0**	DOE recommended value. Acceptable based on GeothermEx experience.
116	The following input is requred if the Cost Curves are used to establish well cost				
117	Is injection interval open hole or cased (slotted/perforated)?		**Open Hole**	**Perforated / 9.625Slotted Liner**	DOE recommended value "Open Hole". Liners would most-likely be used on all projects. Value "Slotted-Liner" used for all projects.
118	Hole or Casing Diameter in Injection Interv	**inch**	**13.5**	**13.5**	DOE recommended value of 13.5 for Open Hole. Value of 9.625 used for liner outer diameter.
119	**OPERATION & MAINTENANCE**				
120	Input Annual O&M Costs or Calculate?		**Calculate**	**Calculate**	
121	Operating Cost Calculation				
122	Labor Costs				
123	Fraction of operator labor assigned to field		**25%**	**25%**	DOE recommended value.
124	Field Maintenance				
125	Annual Maintenance non-labor (fraction of fie	%	**1.5%**	**1.5%**	DOE recommended value.
126	Geothermal fluid treatment - chemical dosage	ppm	**0.50**	**0.50**	DOE recommended value.
127	Chemical cost	$/gal	**$10.00**	**$10.00**	DOE recommended value.
128	Power Plant Maintenance				
129	Annual O&M non-labor (fraction of plant cost)	%	**1.8%**	**1.8%**	DOE recommended value.
130	Cooling water treatment chemical dosage	ppm	**10.00**	**10.00**	DOE recommended value.
131	Chemical cost	$/gal	**$1.00**	**$1.00**	DOE recommended value.
132	Geothermal Production Pump Maintenance				
133	User adjustment for re-work cost ($\leq$ 1)		**1**	**1**	
134	Use calculated pump removal/installation cost		**Yes**	**Yes**	
135	If No, input removal/installation cost				
136	Lineshaft pump operating life [p]	yr	**3**	**5**	DOE recommended value of 3 years. Value of 5 years used based on GeothermEx experience.
137	Shaft lubricating oil dosage [o]	ppm	**1.0**	**1.0**	
138	Lubricating oil cost [o]	$/gal	**$4.00**	**$4.00**	
139	Taxes and Insurance (Plant & Well Field Capital Costs)		**0.75%**	**0.75%**	
140	**POWER PLANT**				
141	Power Plant Parameters				
142	Are calculations to be based upon Fixed Power Sales or Fixed Number of Production Wells?		**Power Sales**	**Power Sales**	DOE recommended method of calculation.
143	Power Sales	MW	**30**	**Various**	Net/Gross MW ratio values of 0.75 for binary and 0.9 for flash (based on minimum [90% probability] value derived in Cumulative Probability calculation from Volumetric Analyses) used for each site.
144	Select Conversion System				
145	Is the Conversion System Flash or Binary?		**Binary**	**Various**	"Flash" value used for flash projects. "Binary" value used for binary projects.

1 U.S. Department of Energy (U.S. DOE), 2015. Geothermal Electricity Technology Evaluation Model. Accessed on February 11, 2015 at: http://energy.gov/eere/geothermal/geothermal-electricity-technology-evaluation-model.