Report: Geothermal Technologies Program GETEM and LCOE Improvements Review
Contract Number: MIGOMR526

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Introduction

In the spring of 2011, the Geothermal Technologies Program (GTP) recognized that the GTP estimates for the LCOE from Geothermal Technology needed to be improved. The following areas of improvement were identified:

1. Site Specific Cost Variability
2. Consistency with other EERE Programs' LCOE Approach and Methodology
3. Risk Assessment/Cost
4. Specific Data Gaps, Well Drilling Costs, Power Plant Costs
5. Future LCOE Projections
6. Vetting by Industry

A plan was developed to address these issues and to incorporate the improvements in the GTP GETEM model used to calculate current and future GTP LCOEs. The plan was carried beginning in the summer of 2011 and has now been completed. The purpose of this report is to summarize and review this effort for the GTP and to suggest any appropriate future work in this area.

The primary people who were responsible for this effort were:

Mark Paster: Contractor
Greg Mines: INL
Chad Augustine: NREL
Jay Nathwani: DOE
Ella Thodal: Contractor
Steven Hanson: Contractor

Particular acknowledgment goes to Greg Mines who did all the GETEM programming.

1. Site Specific Cost Variability

The LCOE for Geothermal energy varies greatly depending on site variables including depth, temperature, lithology, and some other factors. The well depth and temperature are dominant cost drivers. To mitigate this issue a set of five Resource Categories for both Hydrothermal and EGS was developed based on resource depth and temperature. This was done in conjunction with the GTP Hydrothermal and EGS Teams. These are the base cases for the GTP LCOE estimates.

These Resources Category cases and their inputs have been inserted into GETEM to make it easy for the GTP to run these cases or a variant of them.

This Resource Category approach is analogous to what the Wind and Solar Programs do as their LCOE's vary as a function of wind speed, topography, solar incidence, etc.

For the purposes of EERE, the GTP can select the Resource Category for Hydrothermal and EGS appropriate for EERE purposes such as budget planning etc. Having an LCOE for all the Resource Categories will help EERE understand the full range of geothermal energy LCOE.

2. Consistency with other EERE Power Programs' LCOE Approach

It is vital that EERE has apples to apples LCOE information across its power production technology Programs.

A common LCOE calculation spreadsheet has been instituted by EERE for all the power Programs to help enable this. It is based on a discounted cash flow (DCF) methodology. GETEM had historically incorporated a fixed charge rate (FCR) LCOE calculation methodology. This resulted in somewhat different LCOE values compared to the EERE LCOE spreadsheet calculation. GETEM was modified to incorporate the EERE spreadsheet DCF calculation methodology. In doing so, there were also a few changes made to the EERE LCOE spreadsheet to incorporate some issues unique to geothermal energy such as well temperature decline. At the present time GETEM and the EERE LCOE spreadsheet result in LCOE values for the same cases within a negligible difference. The GETEM FCR methodology was retained as an option within GETEM.

There are a number of other factors in LCOE determinations that also need to be done in an apples to apples approach across EERE Programs. This includes such issues as installation cost factors, indirect cost factors, feedstock/raw material pricing, labor rates, G&A factors, taxes and insurance treatment, land costs, permitting costs, transmission capital /costs, reference year dollars, the definition of Technology year, etc. Several meetings and discussions were held with the EERE people responsible for the EERE LCOE spreadsheet and consistency across Programs as well with the people in the Wind and SOLAR Programs responsible for their LCOE estimates. All of these issues were discussed and there was a consensus reached on how each Program would deal with these issues to achieve as much consistency across Programs as possible.

The use of Waterfall Charts became a standard communication tool for LCOE estimates across EERE during the time frame of this project. To make things easier for the GTP, additional programming was added to GETEM so that it can automatically construct a Waterfall Chart for any particular case run in GETEM.

3. Risk Assessment/Cost

A significant part of the cost of geothermal energy stems from the risk of not locating a viable production field. This shows up as costs a company bares when it needs to explore and drill at several sites before it finds a suitable one. This can be a few sites or many sites. Some companies may not survive this cost when they experience many site failures. The cost of this risk also shows up as high costs for financing for the exploration and confirmation phases of geothermal energy projects. To try to better reflect this risk cost, two changes were made in GETEM. These were discussed with industry partners and deemed an improvement for GETEM.

The first change was to insert inputs into GETEM to specify how many sites have pre-drill exploration activity, how many of those pre-drill sites have exploration drilling, and how many of those exploration drilling sites move on to confirmation, all done to get to one good well field. GETEM includes specific costs for pre-drill exploration, exploration drilling, and confirmation on a per site basis. In this way, all the costs associate with needing to explore or confirm several sites to find one suitable one can be incorporated into the LCOE. Naturally the number of sites required for any given project varies. We talked to many people in the industry to establish base case or most likely values for these variables based on their experience. We also incorporated high and low values (see below under Specific Data Gaps) into GETEM to be able to easily see the impact of a best and a worst case scenario.

The second change that was made was to increase the interest rate assumed for the cost of financing exploration and confirmation. The standard discount rate (cost of money) agreed to for all EERE Program LCOE calculations is 7% from year 0 through the life of the plant. This is used in GETEM for the power plant construction and operating the plant for its lifetime. Higher interest rates are used for exploration, confirmation, and well field development. Other EERE LCOE Programs may take a similar approach to their risks.

4. Specific Data Gaps, Well Drilling Costs, Power Plant Costs

Specific Data Gaps

There are many inputs in GETEM used to calculate the LCOE. Estimates for their values had been arrived at from information gathered by the GTP over the years from funded projects, reports, National Laboratory efforts, industry partners, etc. Some inputs are more important than others relative to their impact on the LCOE. Various inputs had more or less validation by industry or some other validation method. There is a level of uncertainty around many of the inputs.

The level of uncertainty associated with the value of the input was characterized by estimating 10%/90% values for nearly all inputs. [A 10% value is the estimated value of the input where there is only a 10% probability that the true value is lower. The 90% value is the estimated value of the input where there is only a 10% probability that the true value is higher.] Resource Category cases were run with the most likely, 10% and 90% values for the inputs. Tornado charts were constructed from the results. Based on the Tornado charts, the more important inputs were identified. These were the ones that had the greatest change in the LCOE at the 10%/90% values. This prioritization of inputs was used to gather more information on these inputs. This was done by constructing a list of questions that was used on conference calls with industry partners. A list of the industry people that took part in these conference calls is in Table 1. The information from these conference calls was distilled along with the information the GTP had to improve the likely, and 10%/90% values for all the important GETEM inputs for all the Hydrothermal and EGS Resource Category cases.

The use of 10%/90% values and a Tornado Chart for all the more important inputs was incorporated into GETEM. The 10% /90% values can be inputted and GETEM automatically constructs the resulting Tornado Chart.

Well Drilling Costs

The cost of well drilling has a very large impact on geothermal energy LCOE. At the start of this project GETEM contained high medium and low well cost curves as a function of well depth and a well cost calculated estimate that required detailed knowledge of the well intervals and structure. The curves were based on historical data and information. Knowing how important well costs are to the LCOE, it was decided to get the latest and best information available to update GETEM in this area.

Well costs were discussed on all of the industry partner conference calls and valuable information was obtained. A well cost model developed by EGI was obtained and used to generate well costs as perceived by EGI based on their efforts in this area. Work was done with John Finger on contract to Sandia National Laboratory (SNL). SNL has developed and improved their own well cost model over the years. It fits well with proprietary well cost data that SNL was able to obtain. It also requires details concerning the well intervals and structure. John Finger is very knowledgeable about well drilling. He ran a number of well designs and well depths and provided the resulting well costs. All of the industry conference call information, EGI model results, SNL model results, along with other well cost data available from papers and reports were combined on one plot as a function of well depth. Two curves were fit through the data, one for larger diameter wells and one for smaller diameter wells. These curves were fit very closely to the SNL model and appear to be quite reasonable based on all the information available.

There is a lot of scatter in well cost data and information. The actual cost for any particular well is dependent on many factors at the site especially the lithology. The best way to account for this in GETEM is to utilize the 10%/90% values to see how high and low drilling costs impact the LCOE.

In addition to the new well cost curves now in GETEM, Greg Mines (INL) has developed a more detailed well cost model. It is less complicated and requires less detailed knowledge of well drilling than the SNL well cost model, but has sufficient detail to be able to quantify the potential impact of key research and development efforts on well costs. Variables such as penetration rate, bit life, etc. can be examined with is model. The results of this model closely match the well cost curves that were put into GETEM. This model could be placed in GETEM or left as a separate well cost model. If it were added to GETEM the user would have a choice of using the well cost curves or this GETEM well cost model. The GETEM well cost model would require a significant number of additional inputs associated with well drilling.

Power Plant Costs

Power plant costs also have a major impact on geothermal energy LCOE. The power plant cost model that was in GETEM, and associated default inputs were based on ASPEN modeling work done several years ago. Several geothermal industry power plant experts were contacted and they reviewed the GETEM power plant costs. They felt the costs and approach were very reasonable and fit with their experience. Greg Mines repeated some ASPEN modeling work using the latest ASPEN software. The GETEM equipment costs matched the latest ASPEN equipment costs results extremely well. Minor changes in indirect costs were made to the GETEM model to better match the new ASPEN model overall results.

5. Future LCOE Projections

An important part of this effort was to also try to make better projections for the potential costs of geothermal energy in the future; for Hydrothermal technology in 2020 and for EGS Technology in 2030.

All of the improvements made to the GTP geothermal energy current LCOE estimates and GETEM, also help improve the projections of future potential geothermal energy costs. Future potential costs were generated for all the same Resource Categories as the current cases since future costs will also depend on the resource temperature and depth. The Risk Assessment approach incorporated into GETEM provides for a very direct way to show how improvements in available geological data and exploration techniques can reduce the number of sites that need to be explored and confirmed. Reducing these for the future potential LCOE cases has a significant effect on the results as it should.

In developing the future potential Resource Category cases, every GETEM input was examined for possible improvement. The work done utilizing 10%/90% values and Tornado charts on the current cases determined which of the inputs were the most important to focus on. The 10% values for the current cases suggested a starting point for the likely value for the potential future cases. In addition, available information within the GTP, information gathered in the industry partner conference calls, and personal knowledge were all drawn on to provide the estimate for each input for the future potential LCOE for all the Resource Category cases.

6. **Vetting with Industry**

As discussed above, a lot of information gathered from industry conference calls was utilized in this effort. This assures a significant level of agreement with industry at least on the inputs used.

It is strongly recommended, that a Work Shop be held by the GTP with the geothermal industry and other stakeholders to review results of this project to more fully vet them. It could also help the stakeholders be more aware of GETEM and its potential value to them. The Work Shop could include:

- Review of the GETEM methodology changes: Risk Assessment, Well Cost Estimates, 10%/90% inputs and Tornado Chart, DCF methodology
- Review the Hydrothermal and EGS Resource Categories, Inputs, and Results followed by discussion
- A separate session on how to use GETEM

Results Summary

Table 2 is a summary of all of the Hydrothermal and EGS Resource Category Cases results and inputs.

Future Work

Technology cost estimates and their methodology can always be improved and require some level of maintenance to keep them up to date. The Appendix contains a list of items that are recommended to be done yearly (Maintenance) and a list of possible further improvements that could be made to GETEM that were thought about during this project but not yet implemented.

Table 1

List of Industry Contacts

Ann Robertson-Tait - Schlumberger
Mark Walters / Steve Enedy - Calpine
Susan Petty – AltaRock
Louis Capuano – Capuano Engineering Consultants
Jefferson Tester - MIT
Ben Barker – Raser Technologies
Bill Teplow – US Geothermal
William Cumming – Cumming Geoscience
Paul Thomsen- Ormat
Dr. Jorg Baumgaertner – Bestec-for-Nature

Table 2

Resource Category Results and Inputs: Summary

GTEM Input Row	GETEM Input	Hydro-A Current	Hydro-A 2020	Hydro-B Current	Hydro-B 2020	Hydro-C Current	Hydro-C 2020
	Case	A	A	B	B	C	C
	Temp. (C)	140	140	175	175	175	175
	Depth (m)	1500	1500	1500	1500	1500	1500
	Plant Type	Binary	Binary	Flash	Flash	Binary	Binary
	Power	25/15/5	25	50/30/20	50	50/30/10	50
	Well Flow Rate	160/100/70	100	110/80/50	80	160/100/70	100
	LCOE (cents/kWh)	24.24	10.67	13.86	6.66	13.71	6.55
35	TECHNOLOGY YEAR	2012	2020	2012	2020	2012	2020
	REFERENCE YEAR	2011	2011	2011	2011	2011	2011
40	Utilization Factor	96%/95%/88%	95%	96%/95%/88%	95%	96%/95%/88%	95%
41	Contingency	5%/15%/25%	10%	5%/15%/25%	10%	5%/15%/25%	10%
42	Royalty (thru Yr 10)	1.75%	1.75%	1.75%	1.75%	1.75%	1.75%
43	Royalty (after Yr 10)	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
44	Discount Rate	6%/7%/9%	7%	6%/7%/9%	7%	6%/7%/9%	7%
46	Project Life (Period of Operation) *(yrs)*	30/30/30	30	30/30/30	30	30/30/30	30
47	Calculations based on Fixed Charge Rate (FCR)	9%/10.8%/13%	10.80%	9%/10.8%/13%	10.80%	9%/10.8%/13%	10.80%
52	Duration of Exploration Phase *(yrs)*	1.5/2/4	1	1.5/2/4	1	1.5/2/4	1
53	Duration of Confirmation Phase *(yrs)*	1/1.5/2	1	1/1.5/2	1	1/1.5/2	1
55	Duration of Well Field Development Phase *(yrs)*	1/1.5/2	1.25	1/1.5/2	1.25	1/1.5/2	1.25
56	Duration of Plant Design and Construction *(yrs)*	1.25/2/2.5	1.5	1.25/1.5/2.5	1.5	1.25/2/2.5	1.5
62	Exploration *Pre-Op Discount Rate*	30%	7%	30%	7%	30%	7%
63	Confirmation *Pre-Op Discount Rate*	30%	7%	30%	7%	30%	7%
64	Well Field Development (including Stimulation) *Pre-Op Discount Rate*	15%	7%	15%	7%	15%	7%
65	Plant Construction & Startup *Pre-Op Discount Rate*	7%	7%	7%	7%	7%	7%
77	Resource Temperature (C)	140	140	175	175	175	175
78	Resource Depth (m)	1500	1500	1500	1500	1500	1500
85	Number of Locations Evaluated Before Exploration Drilling Begins	1/6/10	5	1/6/10	5	1/6/10	5
86	Permitting Process Costs for Pre-Drilling Activities	$60k	$60k	$60k	$60k	$60k	$60k
89	Lump Sum Cost for Pre-Drilling Exploration Activities at each site	$100k/$500k/$1M	$350k (.7 factor)	$100k/$500k/$1M	$350k (.7 factor)	$100k/$500k/$1M	$350k (.7 factor)
152	Will the Project have Exploration Drilling?	Yes	Yes	Yes	Yes	Yes	Yes
153	Number of Sites where Exploration Drilling Occurs	1/5/10	3	1/5/10	3	1/5/10	3
154	Site Exploration Drilling Cost	$1M/$3M/$7M	$1.8M (.6 factor)	$1M/$3M/$7M	$1.8M (.6 factor)	$1M/$3M/$7M	$1.8M (.6 factor)
155	Permitting Process Costs for Drilling - Exploration/Confirmation Phases	$125k	$125k	$125k	$125k	$125k	$125k
156	Leasing Cost *(per acre)*	$2/$30/$1,000	$30	$2/$30/$1,000	$30	$2/$30/$1,000	$30
	Total Exploration Costs (M$)	$19.07M	$7.90M	$19.14M	$7.95M	$19.09M	$7.92M
	Total Exploration Costs (M$/MW)	$1.27M	$0.32M	$0.64M	$0.16M	$0.64M	$0.16M
159	Number of Confirmation Drilling Sites Needed per Successful Project	1/2/4	1.5	1/2/4	1.5	1/2/4	1.5
161	Number of wells at Each Unsuccessful Site	2	2	2	2	2	2
162	Confirmation Well Success Ratio at Successful Site	80%/60%/40%	75%	80%/60%/40%	75%	80%/60%/40%	75%
164	Number of Successful Confirmation Wells Required	1/3/6	2	1/3/6	2	1/3/6	2
170	Multiplier for Confirmation Well Costs (>= 1)	1/1.2/1.5	1.2	1/1.2/1.5	1.2	1/1.2/1.5	1.2
172	Confirmation Well Cost Used	$3.80M	$2.28M	$3.80M	$2.28M	$3.80M	$2.28M
182	% of total confirmation costs attributed to non-drilling activities	5%	5%	5%	5%	5%	5%
183	enter Stimulation Cost	NA	NA	NA	NA	NA	NA
185	Well Testing Cost at each site	$150k	$150k	$150k	$150k	$150k	$150k
	Total Confirmation costs (M$)	$28.21M	$9.00M	$28.21M	$9.00M	$28.21M	$9.00M
	Total Confirmation costs (M$/MW)	$1.88M	$0.36M	$0.94M	$0.18M	$0.94M	$0.18M
189	Drilling Success Rate during the final phase of well field development	90%/80%/60%	85%	90%/80%/60%	85%	90%/80%/60%	85%
194	Ratio of Injection Wells to Production Wells	0.75/0.75/2	0.75	0.4/0.75/2	0.75	0.6/0.75/2	0.75
225	Production Well Cost Used	$1.5M/$3.16M/$7.0M	$1.9M (.6 factor)	$1.5M/$3.16M/$7.0M	$1.9M (.6 factor)	$1.5M/$3.16M/$7.0M	$1.9M (.6 factor)
228	Injection Well Cost Used	$1.5M/$3.16M/$7.0M	$1.9M (.6 factor)	$1.5M/$3.16M/$7.0M	$1.9M (.6 factor)	$1.5M/$3.16M/$7.0M	$1.9M (.6 factor)
232	Surface Equipment Cost per Well	$100k/$200k/$400k	$200k	$150k/$250k/$450k	$250k	$100k/$200k/$400k	$200k
237	Other Well Field Development Costs, (% of total cost)	5%	5%	5%	5%	5%	5%
238	Permitting (Utilization Plant) Cost for Well Field & Power Plant	$500k/$1M/$2M	$1M	$500k/$1M/$2M	$1M	$500k/$1M/$2M	$1M
241	Production Well Flow Rate *(kg/sec)*	160/100/70	100	110/80/50	80	160/100/70	100
246	enter Inputted Stimulation Cost	NA	NA	NA	NA	NA	NA
255	Input Production Well Drawdown *(psi-h/1000lb)*	0.2/0.4/1.2	0.4	0.2/0.4/1.2	0.4	0.2/0.4/1.2	0.4
256	Ratio of Injection Well Buildup to Production Well Drawdown	1	1	1	1	1	1
268	Annual Rate of Decline *(%/yr)*	0.2%/0.4%/1%	0.4%	0.3%/0.5%/0.75%	0.5%	0.2%/0.4%/1%	0.4%
282	Subsurface Water loss as % of injected flow (> 0)	NA	NA	NA	NA	NA	NA
284	Makeup Water cost *($/acre-ft)*	NA	NA	NA	NA	NA	NA
	Total Well Field Development (M$)	$26.81M	$38.93M	$58.71M	$63.52M	$38.05M	$49.65M
	Total Well Field Development (M$/MW)	$1.79M	$1.56M	$1.96M	$1.27M	$1.27M	$0.99M

	GETEM Input	Hydro-A Current	Hydro-A 2020	Hydro-B Current	Hydro-B 2020	Hydro-C Current	Hydro-C 2020
	Case	**A**	**A**	**B**	**B**	**C**	**C**
	Temp. (C)	**140**	**140**	**175**	**175**	**175**	**175**
	Depth (m)	**1500**	**1500**	**1500**	**1500**	**1500**	**1500**
	Plant Type	**Binary**	**Binary**	**Flash**	**Flash**	**Binary**	**Binary**
	Power	**25/15/5**	**25**	**50/30/20**	**50**	**50/30/10**	**50**
	Well Flow Rate	**160/100/70**	**100**	**110/80/50**	**80**	**160/100/70**	**100**
	LCOE (cents/kWh)	**24.24**	**10.67**	**13.86**	**6.66**	**13.71**	**6.55**
GTEM Input Row							
286	Pump & Driver Efficiency for Production and Injection Pump	80%/67.5%/60%	75%	80%/67.5%/60%	75%	80%/67.5%/60%	75%
294	Excess Pressure at pump Suction and/or well head *(psi)*	50	50	NA	NA	50	50
296	Production pump casing diameter *(in)*	9.625	9.625	NA	NA	9.625	9.625
299	Is production interval open hole or cased (slotted/perforated)?	Open	Open	Open	Open	Open	Open
300	Hole or Casing Diameter in Production Interval *(in)*	14.5/12.25/8.25	12.25	14.5/12.25/8.25	12.25	14.5/12.25/8.25	12.25
303	Type of production pump used	Lineshaft	Lineshaft	NA	NA	Lineshaft	Lineshaft
311	Calculated Installed Pump Cost	$0.40M	$0.38M	NA	NA	$0.43M	$0.41M
312	Adjustment to calculated pump cost	0.7/1/2	1	NA	NA	0.7/1/2	1
316	Is injection interval open hole or cased (slotted/perforated)?	Open	Open	Open	Open	Open	Open
317	Hole or Casing Diameter in Injection Interval *(in)*	14.5/12.25/8.25	12.25	14.5/12.25/8.25	12.25	14.5/12.25/8.25	12.25
325	Calculated injection pump cost	$1.08M	$1.40M	$1.14M	$1.37M	$1.07M	$1.35M
326	Adjustment to calculated injection pump cost	1	0.93	1	0.93	1	0.93
353	Labor Multiplier (burdened labor cost)	1.2/1.8/2.2	1.8	1.2/1.8/2.2	1.8	1.2/1.8/2.2	1.8
355,356	User adjustment to Reference Scenario O&M Staff	0.75/1/1.5	0.8 (.8 factor)	0.75/1/1.5	0.8 (.8 factor)	0.75/1/1.5	0.8 (.8 factor)
358	Annual Maintenance non-labor (fraction of field cost) *(%)*	0.5%/1.5%/4%	1.2% (.8 factor)	0.5%/1.5%/4%	1.2% (.8 factor)	0.5%/1.5%/4%	1.2% (.8 factor)
360	*Field Maintenance* Chemical Cost ($/gal)	NA	NA	$10	$10	NA	NA
362	Annual O&M non-labor (fraction of plant cost) *(%)*	1.2%/1.8%/2.2%	1.7% (.92 factor)	1.2%/1.8%/2.2%	1.7% (.92 factor)	1.2%/1.8%/2.2%	1.7% (.92 factor)
364	*Power Plant Maintenance* Chemical cost ($/gal)	NA	NA	$1	$1	NA	NA
374	Lineshaft pump operating life [p] *(yr)*	5/3/1	6	5/3/1	3	5/3/1	6
380	Taxes and Insurance (Plant & Well Field Capital Costs)	0.75%	0.75%	0.75%	0.75%	0.75%	0.75%
387	*Transmission Lines* Number of Miles	0/0/50	0	0/0/50	0	0/0/50	0
393	Power Sales *(MW)*	25/15/5	25	50/30/20	50	50/30/10	50
398	Is the Conversion System Flash or Binary?	Binary	Binary	Flash	Flash	Binary	Binary
416	Adjustment to T-G cost	0.5/1/2	0.93			0.5/1/2	0.93
418	Adjustment to ACC cost	0.5/1/2	0.93			0.5/1/2	0.93
420	Adjustment to GF HX cost	0.5/1/2	0.93			0.5/1/2	0.93
422	Adjustment to WF Pump cost	1	0.93			1	0.93
429	Installation multiplier used for direct costs	2.25/2.66/3	2.47 (.93 factor)			2.25/2.66/3	2.46 (.93 factor)
433	Indirect Cost Percentage Multiplier	6%/12%/15%	12%			6%/12%/15%	12%
439	Reference Plant Cost Used *Adjustment*	0.8/1/1.5	NA			0.8/1/1.5	NA
448	Installed Plant Costs Used *(/kW)*	$3,496	$2,698			$2,304	$1,865
	Calculated Plant Cost (M$)	$64.49M	$82.82M	$79.35M	$95.50M	$78.87M	$105.80M
	Calculated Plant Cost (M$/MW)	$4.30M	$3.31M	$2.64M	$1.91M	$2.63M	$2.12M
456	T,wet bulb *(F)*			40/60/80	60		
459	Turbine efficiency			85%/80%/75%	82.5%		
461	Cooling water and condensate pump efficiency			80%/75%/70%	78%		
464	Number of flashes			2	2		
475	CW pump head *(ft)*			65	65		
476	Cooling Water temperature rise - DT,cooling water *(F)*			15/20/30	20		
479	Condenser NCG partial pressure *(inch-Hg)*			0.315	0.315		
481	NCG level *(ppm)*			200/2,000/20k	2000		
483	H2S level *(ppm)*			0/20/200	20		
484	Method of NCG removal			Hybrid	Hybrid		
497	Calculated Turbine-Generator Cost *($/kW)*			$391	$324		
498	Adjustment to T-G cost			0.5/1/2	0.93		
502	Adjustment to Cooling Tower cost			0.5/1/2	0.93		
504	Adjustment to Condenser Cost			0.5/1/2	0.93		
506	Adjustment to Pump Cost			0.5/1/2	0.93		
508	Adjustment to NCG Removal Cost			0.5/1/3	0.93		
510	Adjustment to H2S Abatement Sys Cost			0.5/1/4	0.93		
517	Installation multiplier used for direct costs			2/2.81/3	2.62 (.93 factor)		
521	Inputted % Multiplier for Indirect Cost			6%/12%/15%	8%		
527	Flash Plant Cost Used ($/kW)			$2,483	$1,808		
527	Flash Plant Cost Used ($/kW) *embedded multiplier*			0.85/1/1.33	NA		
	Calculated Total Capital Cost (M$)	$138.59M	$138.65M	$185.40M	$175.97M	$164.22M	$172.37M
	Calculated Total Capital Cost (M$/MW)	$9.24M	$5.55M	$6.18M	$3.52M	$5.47M	$3.45M

	GETEM Input	Hydro-D Current	Hydro-D 2020	Hydro-E Current	Hydro-E 2020	EGS-A Current	EGS-A 2030
	Case	**D**	**D**	**E**	**E**	**A**	**A**
	Temp. (C)	**225**	**225**	**140**	**140**	**100**	**100**
	Depth (m)	**2500**	**2500**	**2500**	**2500**	**2000**	**2000**
	Plant Type	**Flash**	**Flash**	**Binary**	**Binary**	**Binary**	**Binary**
	Power	**50/40/20**	**50**	**25/15/5**	**25**	**15/10/5**	**25**
	Well Flow Rate	**110/80/50**	**80**	**160/100/70**	**100**	**60/40/30**	**100**
	LCOE (cents/kWh)	**11.52**	**5.45**	**32.48**	**13.84**	**77.53**	**20.22**
GTEM Input Row							
35	TECHNOLOGY YEAR	2012	2020	2012	2020	2012	2030
	REFERENCE YEAR	2011	2011	2011	2011	2011	2011
40	Utilization Factor	96%/95%/88%	95%	96%/95%/88%	95%	96%/95%/88%	95%
41	Contingency	5%/15%/25%	10%	5%/15%/25%	10%	5%/15%/25%	10%
42	Royalty (thru Yr 10)	1.75%	1.75%	1.75%	1.75%	1.75%	1.75%
43	Royalty (after Yr 10)	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
44	Discount Rate	6%/7%/9%	7%	6%/7%/9%	7%	6%/7%/9%	7%
46	Project Life (Period of Operation) *(yrs)*	30/30/30	30	30/30/30	30	30/20/10	30
47	Calculations based on Fixed Charge Rate (FCR)	9%/10.8%/13%	10.80%	9%/10.8%/13%	10.80%	9%/10.8%/13%	10.80%
52	Duration of Exploration Phase *(yrs)*	1.5/2/4	1	1.5/2/4	1	0.5/1/3	1
53	Duration of Confirmation Phase *(yrs)*	1/1.5/2	1	1/1.5/2	1	1/1.5/2	1
55	Duration of Well Field Development Phase *(yrs)*	1/1.5/2	1.25	1/1.5/2	1.25	2/2/3	1.5
56	Duration of Plant Design and Construction *(yrs)*	1.25/1.5/2.5	1.5	1.25/2/2.5	1.5	1.25/2/2.5	1.5
62	Exploration *Pre-Op Discount Rate*	30%	7%	30%	7%	30%	7%
63	Confirmation *Pre-Op Discount Rate*	30%	7%	30%	7%	30%	7%
64	Well Field Development (including Stimulation) *Pre-Op Discount Rate*	15%	7%	15%	7%	15%	7%
65	Plant Construction & Startup *Pre-Op Discount Rate*	7%	7%	7%	7%	7%	7%
77	Resource Temperature (C)	225	225	140	140	100	100
78	Resource Depth (m)	2500	2500	2500	2500	2000	2000
85	Number of Locations Evaluated Before Exploration Drilling Begins	1/6/10	5	1/6/10	5	1/3/5	2
86	Permitting Process Costs for Pre-Drilling Activities	$60k	$60k	$60k	$60k	$60k	$60k
89	Lump Sum Cost for Pre-Drilling Exploration Activities at each site	$100k/$500k/$1M	$350k (.7 factor)	$100k/$500k/$1M	$350k (.7 factor)	$150k/$250k/$500k	$150k (.6 factor)
152	Will the Project have Exploration Drilling?	Yes	Yes	Yes	Yes	Yes	Yes
153	Number of Sites where Exploration Drilling Occurs	1/5/10	3	1/5/10	3	1/2/3	1.5
154	Site Exploration Drilling Cost	$1M/$3M/$7M	$1.8M (.6 factor)	$1M/$3M/$7M	$1.8M (.6 factor)	$1M/$1.5M/$2M	$1.0M
155	Permitting Process Costs for Drilling - Exploration/Confirmation Phases	$125k	$125k	$125k	$125k	$250k	$250k
156	Leasing Cost *(per acre)*	$2/$30/$1,000	$30	$2/$30/$1,000	$30	$2/$30/$1,000	$30
	Total Exploration Costs (M$)	$19.09M	$7.89M	$19.07M	$7.89M	$4.52M	$2.36M
	Total Exploration Costs (M$/MW)	$0.48M	$0.16M	$1.27M	$0.32M	$0.45M	$0.09M
159	Number of Confirmation Drilling Sites Needed per Successful Project	1/2/4	1.5	1/2/4	1.5	1/1.5/3	1
161	Number of wells at Each Unsuccessful Site	2	2	2	2	1.5	0
162	Confirmation Well Success Ratio at Successful Site	80%/60%/40%	75%	80%/60%/40%	75%	100%/100%/80%	100%
164	Number of Successful Confirmation Wells Required	1/3/6	2	1/3/6	2	2/3/6	2
170	Multiplier for Confirmation Well Costs (>= 1)	1/1.2/1.5	1.2	1/1.2/1.5	1.2	1/1.2/1.5	1.2
172	Confirmation Well Cost Used	$7.27M	$4.36M	$7.27M	$4.36M	$5.41M	$2.71M
182	% of total confirmation costs attributed to non-drilling activities	5%	5%	5%	5%	5%	5%
183	enter Stimulation Cost	NA	NA	NA	NA	$1M/$2.5M/$5M	$500k
185	Well Testing Cost at each site	$150k	$150k	$150k	$150k	$500k	$500k
	Total Confirmation costs (M$)	$53.72M	$17.01M	$53.72M	$17.01M	$25.81M	$6.52M
	Total Confirmation costs (M$/MW)	$1.34M	$0.34M	$3.58M	$0.68M	$2.58M	$0.26M
189	Drilling Success Rate during the final phase of well field development	90%/80%/60%	85%	90%/80%/60%	85%	100%/100%/80%	100%
194	Ratio of Injection Wells to Production Wells	0.3/0.75/2	0.75	0.75/0.75/2	0.75	0.5/0.5/1	0.5
225	Production Well Cost Used	$3.0M/$6.06M/$9.0M	$3.63M (.6 factor)	$3.0M/$6.06M/$9.0M	$3.63M (.6 factor)	$3.25M/$4.51M/$7.25M	$2.26M (.5 factor)
228	Injection Well Cost Used	$3.0M/$6.06M/$9.0M	$3.63M (.6 factor)	$3.0M/$6.06M/$9.0M	$3.63M (.6 factor)	$3.25M/$4.51M/$7.25M	$2.26M (.5 factor)
232	Surface Equipment Cost per Well	$150k/$250k/$450k	$250k	$100k/$200k/$400k	$200k	$100k/$200k/$400k	$200k
237	Other Well Field Development Costs, (% of total cost)	5%	5%	5%	5%	5%	5%
238	Permitting (Utilization Plant) Cost for Well Field & Power Plant	$500k/$1M/$2M	$1M	$500k/$1M/$2M	$1M	$500k/$1M/$2M	$1M
241	Production Well Flow Rate *(kg/sec)*	110/80/50	80	160/100/70	100	60/40/30	100
246	enter Inputted Stimulation Cost	NA	NA	NA	NA	$1M/$2.5M/$5M	$500k
255	Input Production Well Drawdown *(psi-h/1000lb)*	0.2/0.5/1.2	0.5	0.2/0.5/1.2	0.5	0.2/0.4/1.0	0.2
256	Ratio of Injection Well Buildup to Production Well Drawdown	1	1	1	1	1	1
268	Annual Rate of Decline *(%/yr)*	0.3%/0.5%/0.75%	0.5%	0.2%/0.4%/1%	0.4%	0.2%/0.5%/1%	0.25%
282	Subsurface Water loss as % of injected flow (> 0)	NA	NA	NA	NA	2%/5%/10%	1%
284	Makeup Water cost *($/acre-ft)*	NA	NA	NA	NA	$800/$2,000/$3,000	$2,000
	Total Well Field Development (M$)	$63.31M	$53.02M	$39.22M	$58.60M	$150.78M	$92.13M
	Total Well Field Development (M$/MW)	$1.58M	$1.06M	$2.61M	$2.34M	$15.08M	$3.69M

	GETEM Input	Hydro-D Current	Hydro-D 2020	Hydro-E Current	Hydro-E 2020	EGS-A Current	EGS-A 2030
	Case	**D**	**D**	**E**	**E**	**A**	**A**
	Temp. (C)	**225**	**225**	**140**	**140**	**100**	**100**
	Depth (m)	**2500**	**2500**	**2500**	**2500**	**2000**	**2000**
	Plant Type	**Flash**	**Flash**	**Binary**	**Binary**	**Binary**	**Binary**
	Power	**50/40/20**	**50**	**25/15/5**	**25**	**15/10/5**	**25**
	Well Flow Rate	**110/80/50**	**80**	**160/100/70**	**100**	**60/40/30**	**100**
	LCOE (cents/kWh)	**11.52**	**5.45**	**32.48**	**13.84**	**77.53**	**20.22**
GTEM Input Row							
286	Pump & Driver Efficiency for Production and Injection Pump	80%/67.5%/60%	75%	80%/67.5%/60%	75%	80%/67.5%/60%	85%
294	Excess Pressure at pump Suction and/or well head *(psi)*	NA	NA	50	50	50	50
296	Production pump casing diameter *(in)*	NA	NA	9.625	9.625	9.625	9.625
299	Is production interval open hole or cased (slotted/perforated)?	Open	Open	Open	Open	Perforated/slotted	Perforated/slotted
300	Hole or Casing Diameter in Production Interval *(in)*	14.5/12.25/8.25	12.25	14.5/12.25/8.25	12.25	11.75/9.625/8.625	9.625
303	Type of production pump used	NA	NA	Lineshaft	Lineshaft	Lineshaft	Lineshaft
311	Calculated Installed Pump Cost	NA	NA	$0.41M	$0.39M	$0.15M	$0.24M
312	Adjustment to calculated pump cost	NA	NA	0.7/1/2	1	0.7/1/2	1
316	Is injection interval open hole or cased (slotted/perforated)?	Open	Open	Open	Open	Perforated/slotted	Perforated/slotted
317	Hole or Casing Diameter in Injection Interval *(in)*	14.5/12.25/8.25	12.25	14.5/12.25/8.25	12.25	11.75/9.625/8.625	9.625
325	Calculated injection pump cost	$0.90M	$0.94M	$1.15M	$1.48M	$1.29M	$2.24M
326	Adjustment to calculated injection pump cost	1	0.93	1	0.93	1	0.9
353	Labor Multiplier (burdened labor cost)	1.2/1.8/2.2	1.8	1.2/1.8/2.2	1.8	1.2/1.8/2.2	1.8
355,356	User adjustment to Reference Scenario O&M Staff	0.75/1/1.5	0.8 (.8 factor)	0.75/1/1.5	0.8 (.8 factor)	0.75/1/1.5	0.8 (.8 factor)
358	Annual Maintenance non-labor (fraction of field cost) *(%)*	0.5%/1.5%/4%	1.2% (.8 factor)	0.5%/1.5%/4%	1.2% (.8 factor)	0.5%/1.5%/4%	1% (.67 factor)
360	*Field Maintenance* Chemical Cost ($/gal)	$10	$10	NA	NA	NA	NA
362	Annual O&M non-labor (fraction of plant cost) *(%)*	1.2%/1.8%/2.2%	1.7% (.92 factor)	1.2%/1.8%/2.2%	1.7% (.92 factor)	1.2%/1.8%/2.2%	1.5% (.83 factor)
364	*Power Plant Maintenance* Chemical cost ($/gal)	$1	$1	NA	NA	NA	NA
374	Lineshaft pump operating life [p] *(yr)*	5/3/1	3	5/3/1	3	5/3/1	6
380	Taxes and Insurance (Plant & Well Field Capital Costs)	0.75%	0.75%	0.75%	0.75%	0.75%	0.75%
387	*Transmission Lines* Number of Miles	0/0/50	0	0/0/50	0	0/0/50	0
393	Power Sales *(MW)*	50/40/20	50	25/15/5	25	15/10/5	25
398	Is the Conversion System Flash or Binary?	Flash	Flash	Binary	Binary	Binary	Binary
416	Adjustment to T-G cost			0.5/1/2	0.93	0.5/1/2	0.9
418	Adjustment to ACC cost			0.5/1/2	0.93	0.5/1/2	0.9
420	Adjustment to GF HX cost			0.5/1/2	0.93	0.5/1/2	0.9
422	Adjustment to WF Pump cost			1	0.93	1	0.9
429	Installation multiplier used for direct costs			2.25/2.66/3	2.46 (.93 factor)	2.25/2.65/3	2.09 (.8 factor)
433	Indirect Cost Percentage Multiplier			6%/12%/15%	12%	6%/12%/15%	12%
439	Reference Plant Cost Used *Adjustment*			0.8/1/1.5	NA	0.8/1/1.5	NA
448	Installed Plant Costs Used *(/kW)*			$4,126	$3,126	$7,063	$4,703
	Calculated Plant Cost (M$)	$72.18M	$69.62M	$79.71M	$96.58M	$95.31M	$167.52M
	Calculated Plant Cost (M$/MW)	$1.80M	$1.39M	$5.11M	$3.86M	$9.53M	$6.70M
456	T,wet bulb *(F)*	40/60/80	60				
459	Turbine efficiency	85%/80%/75%	82.5%				
461	Cooling water and condensate pump efficiency	80%/75%/70%	78%				
464	Number of flashes	2	2				
475	CW pump head *(ft)*	65	65				
476	Cooling Water temperature rise - DT,cooling water *(F)*	15/22.5/30	22.5				
479	Condenser NCG partial pressure *(inch-Hg)*	0.32	0.32				
481	NCG level *(ppm)*	200/2,000/20k	2000				
483	H2S level *(ppm)*	0/20/200	20				
484	Method of NCG removal	Hybrid	Hybrid				
497	Calculated Turbine-Generator Cost *($/kW)*	$334	$298				
498	Adjustment to T-G cost	0.5/1/2	0.93				
502	Adjustment to Cooling Tower cost	0.5/1/2	0.93				
504	Adjustment to Condenser Cost	0.5/1/2	0.93				
506	Adjustment to Pump Cost	0.5/1/2	0.93				
508	Adjustment to NCG Removal Cost	0.5/1/3	0.93				
510	Adjustment to H2S Abatement Sys Cost	0.5/1/4	0.93				
517	Installation multiplier used for direct costs	2/2.51/3	2.33 (.93 factor)				
521	Inputted % Multiplier for Indirect Cost	6%/12%/15%	8%				
527	Flash Plant Cost Used ($/kW)	$1,751	$1,356				
527	Flash Plant Cost Used ($/kW) *embedded multiplier*	0.85/1/1.33	NA				
	Calculated Total Capital Cost (M$)	$208.30M	$147.55M	$188.72M	$180.08M	$276.41M	$268.53M
	Calculated Total Capital Cost (M$/MW)	$5.21M	$2.95M	$12.58M	$7.20M	$27.64M	$10.74M

	GETEM Input	EGS-B Current	EGS-B 2030	EGS-C Current	EGS-C 2030	EGS-D Current	EGS-D 2030	EGS-E Current	EGS-E 2030
	Case	B	B	C	C	D	D	E	E
	Temp. (C)	150	150	175	175	250	250	325	325
	Depth (m)	2500	2500	3000	3000	3500	3500	4000	4000
	Plant Type	Binary	Binary	Binary	Binary	Flash	Flash	Flash	Flash
	Power	25/15/7	35	30/20/10	40	40/25/15	50	40/30/20	50
	Well Flow Rate	60/40/30	100	60/40/30	100	60/40/30	80	60/40/30	80
	LCOE (cents/kWh)	28.64	7.02	24.77	5.85	17.94	5.15	13.91	3.91
GTEM Input Row									
35	TECHNOLOGY YEAR	2012	2030	2012	2030	2012	2030	2012	2030
	REFERENCE YEAR	2011	2011	2011	2011	2011	2011	2011	2011
40	Utilization Factor	96%/95%/88%	95%	96%/95%/88%	95%	96%/95%/88%	95%	96%/95%/88%	95%
41	Contingency	5%/15%/25%	10%	5%/15%/25%	10%	5%/15%/25%	10%	5%/15%/25%	10%
42	Royalty (thru Yr 10)	1.75%	1.75%	1.75%	1.75%	1.75%	1.75%	1.75%	1.75%
43	Royalty (after Yr 10)	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
44	Discount Rate	6%/7%/9%	7%	6%/7%/9%	7%	6%/7%/9%	7%	6%/7%/9%	7%
46	Project Life (Period of Operation) *(yrs)*	30/20/10	30	30/20/10	30	30/20/10	30	30/20/10	30
47	Calculations based on Fixed Charge Rate (FCR)	9%/10.8%/13%	10.80%	9%/10.8%/13%	10.80%	9%/10.8%/13%	10.80%	9%/10.8%/13%	10.80%
52	Duration of Exploration Phase *(yrs)*	0.5/1/3	1	0.5/1/3	1	0.5/1/3	1	0.5/1/3	1
53	Duration of Confirmation Phase *(yrs)*	1/1.5/2	1	1/1.5/2	1	1/1.5/2	1	1/1.5/2	1
55	Duration of Well Field Development Phase *(yrs)*	2/2/3	1.5	2/2/3	1.5	2/2/3	1.5	2/2/3	1.5
56	Duration of Plant Design and Construction *(yrs)*	1.25/2/2.5	1.5	1.25/2/2.5	1.5	1.25/1.5/2.5	1.5	1.25/1.5/2.5	1.5
62	Exploration *Pre-Op Discount Rate*	30%	7%	30%	7%	30%	7%	30%	7%
63	Confirmation *Pre-Op Discount Rate*	30%	7%	30%	7%	30%	7%	30%	7%
64	Well Field Development (including Stimulation) *Pre-Op Discount Rate*	15%	7%	15%	7%	15%	7%	15%	7%
65	Plant Construction & Startup *Pre-Op Discount Rate*	7%	7%	7%	7%	7%	7%	7%	7%
77	Resource Temperature (C)	150	150	175	175	250	250	325	325
78	Resource Depth (m)	2500	2500	3000	3000	3500	3500	4000	4000
85	Number of Locations Evaluated Before Exploration Drilling Begins	1/3/5	2	1/3/5	2	1/3/5	2	1/3/5	2
86	Permitting Process Costs for Pre-Drilling Activities	$60k	$60k	$60k	$60k	$60k	$60k	$60k	$60k
89	Lump Sum Cost for Pre-Drilling Exploration Activities at each site	$150k/$250k/$500k	$150k (.6 factor)	$150k/$250k/$500k	$150k (.6 factor)	$150k/$250k/$500k	$150k (.6 factor)	$150k/$250k/$500k	$150k (.6 factor)
152	Will the Project have Exploration Drilling?	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
153	Number of Sites where Exploration Drilling Occurs	1/2/3	1.5	1/2/3	1.5	1/2/3	1.5	1/2/3	1.5
154	Site Exploration Drilling Cost	$1M/$1.5M/$2M	$1.0M	$1M/$1.5M/$2M	$1.0M	$1M/$1.5M/$2M	$1.0M	$1M/$1.5M/$2M	$1.0M
155	Permitting Process Costs for Drilling - Exploration/Confirmation Phases	$250k	$250k	$250k	$250k	$250k	$250k	$250k	$250k
156	Leasing Cost *(per acre)*	$2/$30/$1,000	$30	$2/$30/$1,000	$30	$2/$30/$1,000	$30	$2/$30/$1,000	$30
	Total Exploration Costs (M$)	$4.46M	$2.32M	$4.46M	$2.32M	$4.46M	$2.31M	$4.45M	$2.30M
	Total Exploration Costs (M$/MW)	$0.30M	$0.07M	$0.22M	$0.06M	$0.18M	$0.05M	$0.15M	$0.05M
159	Number of Confirmation Drilling Sites Needed per Successful Project	1/1.5/3	1	1/1.5/3	1	1/1.5/3	1	1/1.5/3	1
161	Number of wells at Each Unsuccessful Site	1.5	0	1.5	0	1.5	0	1.5	0
162	Confirmation Well Success Ratio at Successful Site	100%/100%/80%	100%	100%/100%/80%	100%	100%/100%/80%	100%	100%/100%/80%	100%
164	Number of Successful Confirmation Wells Required	2/3/6	2	2/3/6	2	2/3/6	2	2/3/6	2
170	Multiplier for Confirmation Well Costs (>= 1)	1/1.2/1.5	1.2	1/1.2/1.5	1.2	1/1.2/1.5	1.2	1/1.2/1.5	1.2
172	Confirmation Well Cost Used	$7.27M	$3.63M	$9.36M	$4.68M	$8.60M	$4.30M	$10.73M	$5.36M
182	% of total confirmation costs attributed to non-drilling activities	5%	5%	5%	5%	5%	5%	5%	5%
183	enter Stimulation Cost	$1M/$2.5M/$5M	$500k	$1M/$2.5M/$5M	$500k	$1M/$2.5M/$5M	$500k	$1M/$2.5M/$5M	$500k
185	Well Testing Cost at each site	$500k	$500k	$500k	$500k	$500k	$500k	$500k	$500k
	Total Confirmation costs (M$)	$33.12M	$8.46M	$41.37M	$10.66M	$38.34M	$9.86M	$46.74M	$12.10M
	Total Confirmation costs (M$/MW)	$2.21M	$0.24M	$2.07M	$0.27M	$1.53M	$0.20M	$1.56M	$0.24M
189	Drilling Success Rate during the final phase of well field development	100%/100%/80%	100%	100%/100%/80%	100%	100%/100%/80%	100%	100%/100%/80%	100%
194	Ratio of Injection Wells to Production Wells	0.5/0.5/1	0.5	0.5/0.5/1	0.5	0.5/0.5/1	0.5	0.5/0.5/1	0.5
225	Production Well Cost Used	$3.5M/$6.06M$9.0M	$3.03M (.5 factor)	$6.0M/$7.80M/$10.0M	$3.90M (.5 factor)	$6.0M/$7.16M/$15.0M	$3.58M (.5 factor)	$7.5M/$8.94M/$17.5M	$4.47M (.5 factor)
228	Injection Well Cost Used	$3.5M/$6.06M$9.0M	$3.03M (.5 factor)	$6.0M/$7.80M/$10.0M	$3.90M (.5 factor)	$6.0M/$9.75M/$15.0M	$4.87M (.5 factor)	$7.5M/$11.89M/$17.5M	$5.95M (.5 factor)
232	Surface Equipment Cost per Well	$100k/$200k/$400k	$200k	$100k/$200k/$400k	$200k	$150k/$225k/$400k	$225k	$150k/$225k/$400k	$225k
237	Other Well Field Development Costs, (% of total cost)	5%	5%	5%	5%	5%	5%	5%	5%
238	Permitting (Utilization Plant) Cost for Well Field & Power Plant	$500k/$1M/$2M	$1M	$500k/$1M/$2M	$1M	$500k/$1M/$2M	$1M	$500k/$1M/$2M	$1M
241	Production Well Flow Rate *(kg/sec)*	60/40/30	100	60/40/30	100	60/40/30	80	60/40/30	80
246	enter Inputted Stimulation Cost	$1M/$2.5M/$5M	$500k	$1M/$2.5M/$5M	$500k	$1M/$2.5M/$5M	$500k	$1M/$2.5M/$5M	$500k
255	Input Production Well Drawdown *(psi-h/1000lb)*	0.2/0.4/1.2	0.2	0.2/0.4/1.2	0.2	0.2/0.5/1.2	0.25	0.2/0.5/1.2	0.25
256	Ratio of Injection Well Buildup to Production Well Drawdown	1	1	1	1	1	1	1	1
268	Annual Rate of Decline *(%/yr)*	0.2%/0.5%/1%	0.25%	0.2%/0.5%/1%	0.25%	0.2%/0.5%/1%	0.25%	0.2%/0.5%/1%	0.25%
282	Subsurface Water loss as % of injected flow (> 0)	2%/5%/10%	1%	2%/5%/10%	1%	2%/5%/10%	1%	2%/5%/10%	1%
284	Makeup Water cost *($/acre-ft)*	$800/$2,000/$3,000	$2,000	$800/$2,000/$3,000	$2,000	$800/$2,000/$3,000	$2,000	$800/$2,000/$3,000	$2,000
	Total Well Field Development (M$)	$58.07M	$45.66M	$76.97M	$45.68M	$61.94M	$32.85M	$41.13M	$18.46M
	Total Well Field Development (M$/MW)	$3.87M	$1.30M	$3.85M	$1.14M	$2.48M	$0.66M	$1.37M	$0.37M

	GETEM Input	EGS-B Current	EGS-B 2030	EGS-C Current	EGS-C 2030	EGS-D Current	EGS-D 2030	EGS-E Current	EGS-E 2030
	Case	B	B	C	C	D	D	E	E
	Temp. (C)	150	150	175	175	250	250	325	325
	Depth (m)	2500	2500	3000	3000	3500	3500	4000	4000
	Plant Type	Binary	Binary	Binary	Binary	Flash	Flash	Flash	Flash
	Power	25/15/7	35	30/20/10	40	40/25/15	50	40/30/20	50
	Well Flow Rate	60/40/30	100	60/40/30	100	60/40/30	80	60/40/30	80
	LCOE (cents/kWh)	28.64	7.02	24.77	5.85	17.94	5.15	13.91	3.91
GTEM Input Row									
286	Pump & Driver Efficiency for Production and Injection Pump	80%/67.5%/60%	85%	80%/67.5%/60%	85%	80%/67.5%/60%	85%	80%/67.5%/60%	85%
294	Excess Pressure at pump Suction and/or well head *(psi)*	50	50	50	50	NA	NA	NA	NA
296	Production pump casing diameter *(in)*	9.625	9.625	9.625	9.625	NA	NA	NA	NA
299	Is production interval open hole or cased (slotted/perforated)?	Perforated/slotted	Perforated/slotted	Perforated/slotted	Perforated/slotted	NA	NA	NA	NA
300	Hole or Casing Diameter in Production Interval *(in)*	11.75/9.625/8.625	9.625	11.75/9.625/6.625	9.625	8.625/7.0/6.625	7	8.625/7.0/6.625	7
303	Type of production pump used	Lineshaft	Lineshaft	Lineshaft	Lineshaft	NA	NA	NA	NA
311	Calculated Installed Pump Cost	$0.11M	$0.21M	$0.07M	$0.19M	NA	NA	NA	NA
312	Adjustment to calculated pump cost	0.7/1/2	1	0.7/1/2	1	NA	NA	NA	NA
316	Is injection interval open hole or cased (slotted/perforated)?	Perforated/slotted	Perforated/slotted	Perforated/slotted	Perforated/slotted	Perforated/slotted	Perforated/slotted	Perforated/slotted	Perforated/slotted
317	Hole or Casing Diameter in Injection Interval *(in)*	11.75/9.625/8.625	9.625	11.75/9.625/6.625	9.625	8.625/7.0/6.625	7	8.625/7.0/6.625	7
325	Calculated injection pump cost	$0.60M	$1.30M	$0.45M	$1.14M	$0.81M	$1.08M	$0.67M	$0.84M
326	Adjustment to calculated injection pump cost	1	0.9	1	0.9	1	0.9	1	0.9
353	Labor Multiplier (burdened labor cost)	1.2/1.8/2.2	1.8	1.2/1.8/2.2	1.8	1.2/1.8/2.2	1.8	1.2/1.8/2.2	1.8
355,356	User adjustment to Reference Scenario O&M Staff	0.75/1/1.5	0.7 (.7 factor)	0.75/1/1.5	0.7 (.7 factor)	0.75/1/1.5	0.7 (.7 factor)	0.75/1/1.5	0.7 (.7 factor)
358	Annual Maintenance non-labor (fraction of field cost) *(%)*	0.5%/1.5%/4%	1% (.67 factor)	0.5%/1.5%/4%	1% (.67 factor)	0.5%/1.5%/4%	1% (.67 factor)	0.5%/1.5%/4%	1% (.67 factor)
360	*Field Maintenance* Chemical Cost ($/gal)	NA	NA	NA	NA	$10	$10	$10	$10
362	Annual O&M non-labor (fraction of plant cost) *(%)*	1.2%/1.8%/2.2%	1.5% (.83 factor)	1.2%/1.8%/2.2%	1.5% (.83 factor)	1.2%/1.8%/2.2%	1.5% (.83 factor)	1.2%/1.8%/2.2%	1.5% (.83 factor)
364	*Power Plant Maintenance* Chemical cost ($/gal)	NA	NA	NA	NA	$1	$1	$1	$1
374	Lineshaft pump operating life [p] *(yr)*	5/3/1	6	5/3/1	6	5/3/1	3	5/3/1	3
380	Taxes and Insurance (Plant & Well Field Capital Costs)	0.75%	0.75%	0.75%	0.75%	0.75%	0.75%	0.75%	0.75%
387	*Transmission Lines* Number of Miles	0/0/50	0	0/0/50	0	0/0/50	0	0/0/50	0
393	Power Sales *(MW)*	25/15/7	35	30/20/10	40	40/25/15	50	40/30/20	50
398	Is the Conversion System Flash or Binary?	Binary	Binary	Binary	Binary	Flash	Flash	Flash	Flash
416	Adjustment to T-G cost	0.5/1/2	0.9	0.5/1/2	0.9				
418	Adjustment to ACC cost	0.5/1/2	0.9	0.5/1/2	0.9				
420	Adjustment to GF HX cost	0.5/1/2	0.9	0.5/1/2	0.9				
422	Adjustment to WF Pump cost	1	0.9	1	0.9				
429	Installation multiplier used for direct costs	2.25/2.66/3	2.12 (.8 factor)	2.25/2.66/3	2.12 (.8 factor)				
433	Indirect Cost Percentage Multiplier	6%/12%/15%	12%	6%/12%/15%	12%				
439	Reference Plant Cost Used *Adjustment*	0.8/1/1.5	NA	0.8/1/1.5	NA				
448	Installed Plant Costs Used *(/kW)*	$4,057	$2,019	$3,116	$1,648				
	Calculated Plant Cost (M$)	$63.84M	$77.73M	$63.50M	$70.26M	$47.20M	$58.57M	$41.81M	$45.82M
	Calculated Plant Cost (M$/MW)	$4.26M	$2.22M	$3.18M	$1.76M	$1.89M	$1.17M	$1.39M	$0.92M
456	T,wet bulb *(F)*					40/60/80	60	40/60/80	60
459	Turbine efficiency					85%/80%/75%	85%	85%/80%/75%	85%
461	Cooling water and condensate pump efficiency					80%/75%/70%	80%	80%/75%/70%	80%
464	Number of flashes					2	2	2	2
475	CW pump head *(ft)*					65	65	65	65
476	Cooling Water temperature rise - DT,cooling water *(F)*					15/20/30	20	15/24/30	24
479	Condenser NCG partial pressure *(inch-Hg)*					0.32	0.32	0.32	0.32
481	NCG level *(ppm)*					200/2,000/20k	2000	200/2,000/20k	2000
483	H2S level *(ppm)*					0/20/200	20	0/20/200	20
484	Method of NCG removal					Hybrid	Hybrid	Hybrid	Hybrid
497	Calculated Turbine-Generator Cost *($/kW)*					$405	$298	$380	$296
498	Adjustment to T-G cost					0.5/1/2	0.9	0.5/1/2	0.9
502	Adjustment to Cooling Tower cost					0.5/1/2	0.9	0.5/1/2	0.9
504	Adjustment to Condenser Cost					0.5/1/2	0.9	0.5/1/2	0.9
506	Adjustment to Pump Cost					0.5/1/2	0.9	0.5/1/2	0.9
508	Adjustment to NCG Removal Cost					0.5/1/3	0.9	0.5/1/3	0.9
510	Adjustment to H2S Abatement Sys Cost					0.5/1/4	0.9	0.5/1/4	0.9
517	Installation multiplier used for direct costs					2/2.44/3	2.18 (.9 factor)	2/2.18/3	1.95 (.9 factor)
521	Inputted % Multiplier for Indirect Cost					6%/12%/15%	8%	6%/12%/15%	8%
527	Flash Plant Cost Used ($/kW)					$1,816	$1,131	$1,363	$898
527	Flash Plant Cost Used ($/kW) *embedded multiplier*					0.85/1/1.33	NA	0.85/1/1.33	NA
	Calculated Total Capital Cost (M$)	$159.49M	$134.18M	$186.30M	$128.93M	$151.94M	$103.59M	$134.13M	$78.69M
	Calculated Total Capital Cost (M$/MW)	$10.63M	$3.83M	$9.32M	$3.22M	$6.08M	$2.07M	$4.47M	$1.57M

Appendix

Vet the GTP Resource Category Case Results and GETEM

1. **Action Item:** Plan and hold a Workshop with stakeholders to help validate GETEM, our cases, inputs and results.
2. **Action Item:** Define the amount of power potentially available for each of the Resource Categories in the U.S.
3. **Action Item:** Consider additional or other Resource Categories

Improved Well Cost Modeling

4. **Action Item:** Decide whether or not to integrate the new well cost model developed by Greg Mines directly into GETEM or leave it as a separate stand alone model.

Improved Power Plant Cost Modeling

5. **Action Item:** **Greg** will continue to work with the new ASPEN power plant model. Updates to the GETEM power plant model may be made after this work is completed.

Water Losses/Use

6. **Action Item:** **Greg** will add to GETEM to separately account for water use in EGS for stimulation and initial reservoir fill.

Other Items

7. **Action Item:** G&A Burden Rate: Solar uses 20-30% (1.2-1.3). Wind has labor data that in theory includes G&A. We are now using 1.2/1.8/2.2 for 10/likely/90 values. This could be re-visited.
8. **Action Item:** Permitting Costs: Chad had gotten additional information from Ormat clarifying their permitting costs. We need to revisit the fact Ormat says they pay to fully permit both conformation sites for field development and power plant at $1M-$2M each since it takes time and they do not know which one or both will be a successful site. Our current input for Hydrothermal assumes only one confirmation site is fully permitted.

Waterfall Chart

9. **Action Item:** The assignment of variables to Deployment Barriers and System Validation is quite arbitrary. Can/should we eliminate these categories? It is potentially confusing

how only permitting is shown as a Deployment Barrier in the Baseline Cost but a chunk of the Financing Risk is split out to Deployment Barriers in the waterfall decrement. The split of parts of other items to the System Validation waterfall decrement is appropriate but possibly confusing. Finally, it might be very valuable to split out Well Field Development as a separate category from Exploration (and Confirmation?) since both are significant. We should think about these potential issues.

Gathering Data from Geothermal Projects

In order to continue to improve GETEM, additional data should be gathered from projects funded by the GTP.

10. **Action Item:** Consider setting up an LCOE Working Group (LCOE WG) to help mine any and all data from GTP Projects relevant to the LCOE effort and to spread the use of GETEM in GTP Projects.

11. **Action Item:** NGDS is setting up a database of information on Geothermal Projects. **We** should supply them with a list of data that would be helpful to improve GETEM. A way to start would be to review all the GTEM inputs and boil that down to a list of the most important data.

GETEM and Geothermal LCOE Maintenance

12. **Action Item**: Each year the new cost indices need to be inserted into GETEM and the Reference Year Dollars input updated to the next year. (Based on communications with Ooki in January 2013.) **(On-Going)**

13\. **Action Item:** Each year all of the case inputs, 10-90s etc. should be reviewed to try to reflect improvements achieved in the technology and the Technology Year input should be changed to the new year. (Based on communications with Ooki in January 2013.) [Note: For Geothermal, the Technology Year is the Year that the Well Field and Power Plant start to be constructed. The technology used is the state of the art technology of that year.] **(On-Going)**

14\. **Action Item:** The GTP should routinely check if any changes are being made to the EERE LCOE spreadsheet calculations to be sure GTEM results match the results from the EERE spreadsheet.

Additional Potential GETEM and Geothermal LCOE Improvements

15. Some cases may more accurately be represented by multiple Power Plants. This can be accomplished better in GETEM by using row 203 on the Master Improvement Tab and row 399 on the Input Tab (row 399 on the Other Inputs Tab) to call for multiple Power Plants. Greg will investigate the impact of multiple Power Plants on the appropriate cases to decide whether or not we should utilize this option.

16. Should we spread capital expenditures in each phase evenly over the phase length of time or front or back load it? Will this work in the EERE LCOE math?

17. Should we make the time needed for Confirmation a function of the number of wells and or sites? Should we make the time needed for Well Field Development a function of the number of wells? well depth?

18. Add the "DCF LCOE" method as a third choice calculation method. (EERE LCOE and FCR are the current choices.)

19. I think row 51 is confusing to people and should be eliminated.

20. Consider adding a choice to base the power plant design at a temperature in between the initial reservoir temperature and the final reservoir temperature which can yield a more optimized (lower) LCOE. (Currently GETEM uses the initial reservoir temperature minus the temperature rise from the bottom to the top of the well.)

21. Well replacement: Can we have GETEM add replacement/additional wells? We first need to learn more about what happens in the real world. (Note: Well replacement/ addition will need to be worked through in the EERE LCOE math if we choose to do this.)

22. We have discussed with industry people what impacts the maximum temperature for Binary plant use. Binary plants with well pumping work well up to about 180 C. Current well pumps start to have durability issues at this temperature. If the system can operate without a well pump Binary Plants can work up to about 330 C but the economics of Flash plants start to be better at about 270 C. This information is important for cases run in GETEM.

23. Greg is intending to create another version of GETEM that uses a separate program (not available to most people) that calculates the properties of water. This would improve the results of higher temperature GETEM cases (>275 C?) and at least serve as a check against the standard GETEM results for these cases**.**

24. Should we be more explicit in GETEM about installation factors and indirect costs? We currently use 5% of total Confirmation costs (R187), 5% of Well Field Development costs (R241), and an overall (Lange) factor of 2.76 (R439) for the Power Plant. (Power Plant costs also include Sales Tax and Freight and 12% indirects [within the Lange factor?].) There appears to be installation costs but no indirect costs for the well pumps? Another about 15% (case dependent) is also added on for contingency.

25. Consider making the ambient wet bulb temperature a 10/90. This will require some significant changes in GETEM especially for Binary Plants.

26. When the Resource Temperature exceeds 325 C, modeling a Flash Plant in GETEM may not be appropriate. At some temperature, one would switch to dry steam. We should determine what that temperature is. Should we add a dry steam plant to GETEM?