Well Design Report

GeoHRC: Large-Scale, Deep Direct-Use System in a Low-Temperature Sedimentary Basin

Prepared by

Loudon Technical Services LLC
Jim Kirksey

August 5, 2019

DOE Award # DE-EE0008106

Well Design Discussion

The large scale Deep Direct Use (DDU) geothermal project in the low temperature environment of the Illinois Basin requires drilling and completing two wells. One well would be the producing well and would be built to deliver a flow rate of approximately 6000 barrels per day (bpd) of brine from the lower Mt. Simon formation at a depth of approximately 6300 feet. The injection well would be constructed to return the produced brine into the lower Mt. Simon formation at a depth of approximately 6300 feet. Each well has different design criteria that must be met.

The producing well is designed to meet two criteria, a casing large enough to accommodate an electric submergible pump (ESP) sized to deliver the required flow rate and then how to cost effectively insulate the wellbore to minimize heat loss so that the produced fluid reaches the surface at a temperature as close to the bottom hole temperature as possible. The first criteria to be met is designing a well capable of delivering a flow rate of 6000 bpd. The flowrate defines downhole pump size as well as the tubular sizes. Based on the 6000-bpd flow rate, a pump diameter of 5.625'' will be required. This pump diameter will require a production casing of 7'' OD. Wellbore stability and severe lost circulation issues have been encountered in almost all offset wells, so an intermediate casing or protection string is included in this well design. While it might be possible to eliminate this casing string, it is prudent to leave it in the initial design until more local knowledge is gained. This string also helps insulate the wellbore to prevent heat loss during production. The ESP will be placed deep into the well to deliver warm fluids to the surface as quickly as possible again to prevent heat loss from the produced fluid. The production string will be plastic lined for corrosion protection. A packer will be employed to make it possible to place an insulating fluid in the tubing casing annulus and to protect the production casing from the corrosive brine fluid. The seven-inch casing across the Mt. Simon producing zone will be a chrome alloy to protect the casing from corrosion. The production casing will be cemented to surface. While cementing to surface is not required in a producing well the insulation benefit of the of cemented casing is important.

The injection well is designed to meet the requirements of a Class I injection well. Shallow geothermal applications typically do not require this as the returned water meets US EPA USDA drinking water requirements. The brine produced from the Mt. Simon formation has a high total dissolved solids (TDS) content and as a result the injection well will be required to be permitted as a Class I injection well. As a result, all casing strings must be cemented to surface. For reasons discussed above a protection casing string will be employed. The injection casing across the injection interval will be a chrome alloy. The tubular sizes will be 5 ½'' for the injection casing and 2 7/8'' for the injection tubing. Friction pressure was considered and while the friction in the 2 7/8'' tubing might be higher by 250 psi over the next larger size, 3 ½', the cost of additional surface pump horsepower would be more economical than constructing a larger wellbore to accommodate the larger 3 ½'' tubing.

The above discussion illustrates that the well design is integrated into many determining factors. Flow rates, fluid composition, subsurface conditions, and temperature are all factors that influence the final well design. The well designs that are presented here are intended to demonstrate what a typical DDU project in a deep reservoir might look like. They should be reviewed and modified as needed to optimize well design for a specific project. A primary function of creating the well design is to obtain a relative cost for each type of well. These well designs provide a glimpse into the well cost of a DDU project. Some adjustment and optimization might lower the costs presented here by a small fraction but as a starting point for an experimental project the cost numbers are sound. A discussion in the costing section of each well will detail a few of these options.

The costs presented here are good faith estimates based on current market conditions. Actual market conditions at the time of well construction could increase or decrease the true cost of the well.

The final section of the report presents a matrix showing well cost for selected flow rates.

Well Diagram DDU Producing Well

The well diagram for the Producing Well is shown below in Figure 1-1.

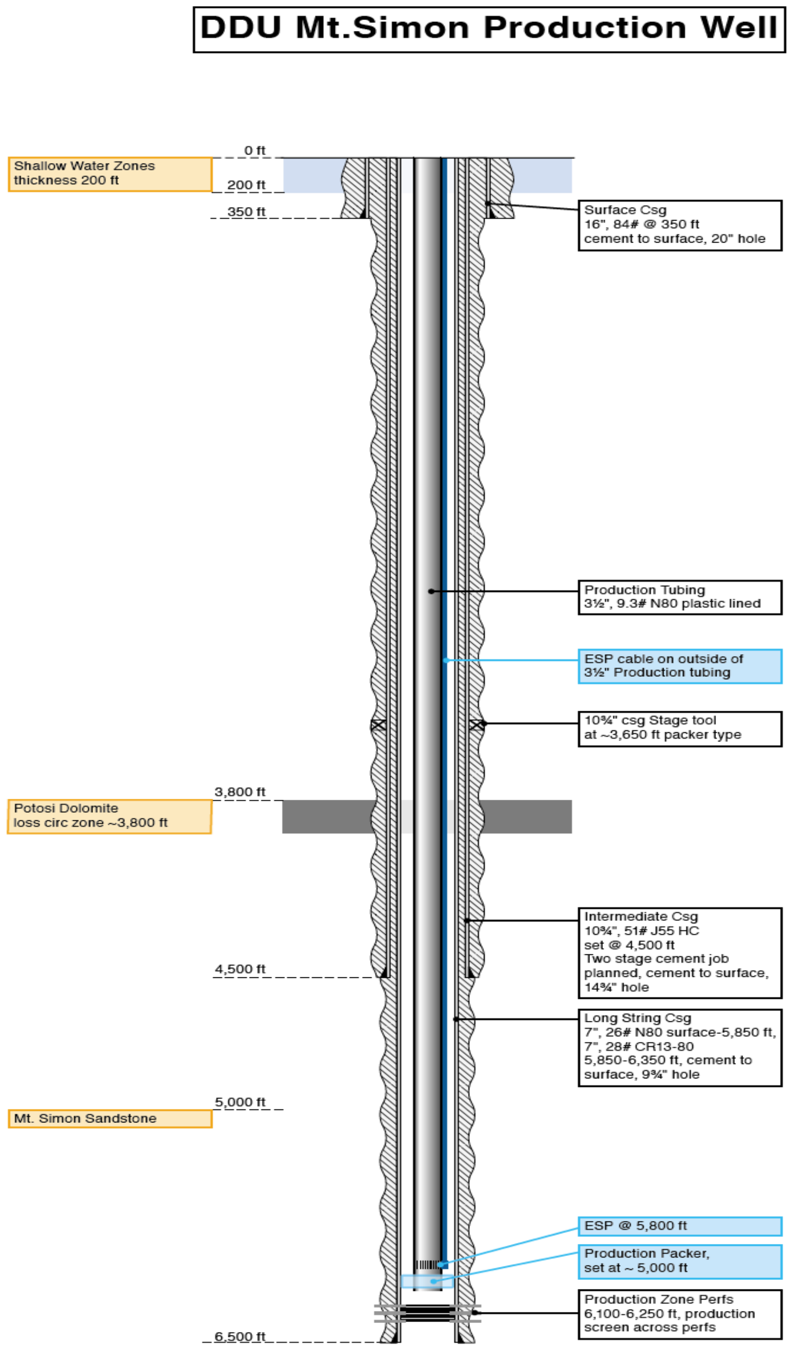

Figure 1-1 Production Well Diagram

Production Well Detail

The producing well will be drilled into the lower Mt. Simon formation at a depth of +/- 6500 feet. The casing and corresponding hole sizes are shown below in Table 1-1. The drilling operation should take approximately 55 days.

String-Depth	Size in	Hole size in	ID	Weight #/ft	Grade
Surface 0-350 ft	16	20	15.01	84	J-55
Int. 0- 4500 ft	10 3/4	14 3/4	9.65	51	J-55 HC
Prod 0- 5850 ft	7	9 3/4	6.276	26	N-80
Prod 5850-6500 ft	7	9 3/4	6.184	28	Cr13-80

Table 1-1 Casing and Hole Detail

All casing strings will be cemented to surface. Two stage cementing technique will be employed on the intermediate casing string and on the production string if required. The well cement and properties are shown below in table 1-2

String Depth	Type	Density ppg	Yield Cu ft/sk	K btu/hr ft- °F
Surface 0-300 ft	Class A	15.6	1.18	.73
Int Lead 3650-0	Cmt/poz	12.5	1.85	.54
Int Tail 4500-3650 ft	Class A	15.6	1.18	.73
Prod Lead 5500-0 ft	LiteCRETE	11.5	1.73	.3
Prod Tail 6500-5500 ft	Class A	15.6	1.18	.73

Table 1-2 Cementing Detail

The well will be drilled using a freshwater mud system on all strings. A severe lost circulation zone is expected to be encountered in the Potosi section of the Knox at approximately 3500-3800 feet. The section may require setting cement plugs and/or drilling with a loss of returns to the intermediate casing point. A packer type cementing stage collar will be used to ensue cement can be placed along the length of the wellbore. The long string casing will be cemented to surface with the lead cement designed to have a low thermal conductivity.

The well will be completed in the lower Mt. Simon formation at a to be determined interval. For costing purposes, a 150-foot interval was considered. Tubing conveyed perforating is recommended for this length of interval. Production testing is budgeted prior to final completion. Final completion will consist of a 4 ½'' internal screen to be deployed across the perforated interval to mitigate expected sand production. If during testing the sand production is found to be less than expected, the screen could be eliminated. A production packer will be set above the producing interval to facilitate the placement of insulating fluid in the tubing casing annulus and for protection of the production string casing from corrosion. The 5.625'' ESP will be run on 3 ½'' plastic lined 9.3#/ft N-80 tubing with tailpipe below the pump latching into the production packer. The ESP is 102 stages requiring 405 horsepower. The estimated kVA is 502 at 480 volts and 60 HZ. The pump will require a surface power station and controller. Downhole pressure and temperature during production can be observed and recorded with the controller. The plastic lining of the 3 ½'' production tubing will provide protection from corrosion from the heavy brine at a lower cost than chrome alloys.

The insulating annular fluid will be a viscous brine-based fluid that is designed to reduce the thermal conductivity by 30% over a base brine fluid. Flow loop testing suggests a thermal conductivity range of 0.2 BTU/hr ft ^{o}F. This compares to a base brine thermal conductivity of approximately 0.3 BTU/hr ft ^{o}F for a non-viscous brine. Other insulating options exist but at higher cost. These are discussed in the discussion on well costs.

Production Well Cost

The estimated cost of drilling and completing the production well is $4.3 MM. The detail of this cost is shown below in Fig 1-2.

Illinois DDU Geothermal Mt. Simon Producing Well

AUTHORIZATION FOR EXPENDITURES - Est Cost

In US $

Operator:	TBD	Project Type :	DDU Geothermal		
Contract Area:		Well Name :	Mt. Simon Producer # 1		
Contract Area #:		Well Type :	Brine producer		
Prepared by	JMK	Platform/Tripod :		AFE #:	1
		Field/Structure :	Champaign	Date:	05-Mar-19
		Basin :	Illinois		

Location | Surface Coordinate

Surface Elev. | Elevation

	PROGRAM	ACTUAL
Spud Date		
Compl Date		
In Service		
Drilling Days		

	PROGRAM	ACTUAL
Rig Days	60	
Total Depth	6350	
Well Cost $/Ft.	$0.00	
Well Cost $/Day	$0.00	

Close Out Date: | Completion Type: Open Hole | Well Status: Pre Permit

	Description	Dry Hole Budget	Completed Budget	Total Budget	Actual Expenditure	Actual Over/Under	% Over/Under
1	**TANGIBLE COSTS**						
2	Casing	472,550	0	472,550	$0	472,550	100%
3	Casing Accessories; Float Equip & Liners	70,785	0	70,785	$0	70,785	100%
4	Tubing		102,500	102,500	$0	102,500	100%
5	Well Equipment - Surface	23,000	34,500	57,500	$0	57,500	100%
6	Well Equipment - Subsurface	0	237,500	237,500	$0	237,500	100%
7	Other Tangible Costs	0	20,000	20,000	$0	20,000	100%
8	Contingency	42,475	29,588	72,063	$0	72,063	100%
9	**Total Tangible Costs**	**$608,810**	**$424,088**	**$1,032,898**	**$0**	1,032,898	100%
10	**INTANGIBLE COSTS**						
11	**PREPARATION & TERMINATION**						
12	Surveys	6,000	0	6,000	$0	6,000	100%
13	Location Staking & Positioning	2,500	0	2,500	$0	2,500	100%
14	Wellsite & Access Road Preparation	84,000	0	84,000	$0	84,000	100%
15	Service Lines & Communications	57,000	0	57,000	$0	57,000	100%
16	Water Systems	6,000	0	6,000	$0	6,000	100%
17	Rigging Up/Rigging Down/ Mob/Demob	130,000	0	130,000	$0	130,000	100%
19	**Total Preparations/MOB**	**$285,500**	**$0**	**$285,500**	**$0**	285,500	100%
20	**DRILLING - W/O OPERATIONS**						
21	Contract Rig	893,760	104,000	997,760	$0	997,760	100%
22	Drlg Rig Crew/Contract Rig Crew/Catering	0	0	0	$0	0	
23	Mud, Chem & Engineering Servs	178,250	10,000	188,250	$0	188,250	100%
24	Water	37,000	2,000	39,000	$0	39,000	100%
25	Bits, Reamers & Coreheads	85,000	0	85,000	$0	85,000	100%
26	Equipment Rentals	88,364	0	88,364	$0	88,364	100%
27	Directional Drlg & Surveys	0	0	0	$0	0	
28	Diving Services	0	0	0	$0	0	
29	Casing & Wellhead Installation & Inspection	58,500	3,000	61,500	$0	61,500	100%
30	Cement, Cementing & Pump Fees	273,000	0	273,000	$0	273,000	100%
31	Misc. H2S Services	0	0	0	$0	0	
32	**Total Drilling Operations**	**$1,613,874**	**$119,000**	**$1,732,874**	**$0**	1,732,874	100%
33	**FORMATION EVALUATION**						
34	Coring	0	0	0	$0	0	
35	Mud Logging Services	132,500	0	132,500	$0	132,500	100%
36	Drillstem Tests	0	0	0	$0	0	
37	Open Hole Elec Logging Services	200,000	0	200,000	$0	200,000	100%
39	**Total Formation Evaluation**	**$332,500**	**$0**	**$332,500**	**$0**	332,500	100%
40	**COMPLETION**						
41	Casing, Liner, Wellhead & Tubing Installation	0	10,000	10,000	$0	10,000	100%
42	Remedial Cementing and Fees	0	0	0	$0	0	
43	Cased Hole Elec Logging Services	25,000	30,000	55,000	$0	55,000	100%
44	Perforating & Wireline Services	0	60,000	60,000	$0	60,000	100%
45	Stimulation Treatment	0	0	0	$0	0	
46	Production Tests	0	50,000	50,000	$0	50,000	100%
48	**Total Completion Costs**	**$25,000**	**$150,000**	**$175,000**	**$0**	175,000	100%
49	**GENERAL**						
50	Supervision	194,250	40,000	234,250	$0	234,250	100%
51	Insurance	0	0	0	$0	0	
52	Permits & Fees	5,000	0	5,000	$0	5,000	100%
53	Marine Rental & Charters	0	0	0	$0	0	
54	Helicopter & Aviation Charges	0	0	0	$0	0	
55	Land Transportation	16,000	0	16,000	$0	16,000	100%
56	Other Transportation	0	0	0	$0	0	
57	Fuel & Lubricants Non Rig	6,000	0	6,000	$0	6,000	100%
58	Camp Facilities	40,500	0	40,500	$0	40,500	100%
59	Allocated Overhead - Field Office	0	0	0	$0	0	
60	Allocated Overhead - Main Office	240,600	41,000	281,600	$0	281,600	100%
61	Allocated Overhead - Overseas	0	0	0	$0	0	
62	Contingency Intangible Costs	137,961	17,500	155,461	$0	155,461	100%
64	**Total General Costs**	**$640,311**	**$98,500**	**$738,811**	**$0**	738,811	100%
65	**TOTAL INTANGIBLE COSTS**	**$2,897,185**	**$367,500**	**$3,264,685**	**$0**	3,264,685	100%
	TOTAL TANGIBLE COSTS	**$608,810**	**$424,088**	**$1,032,898**	**$0**	1,032,898	100%
66	**TOTAL WELL COST**	**$3,505,995**	**$791,588**	**$4,297,583**	**$0**	**4,297,583**	**100%**
67	**Timed Phased Expenditures**						
68	**-This Year**						
69	**-Future Years**						
70	**Total**						

Figure 1-2 Production Well Cost Estimate

Producing Well Cost Discussion

The cost of \$4.3 MM is considerable for a well depth of 6500 feet. To achieve the desired flow rate of 6000 bpd a pump diameter of 5.625'' is required. This requires the use of 7'' casing so immediately the larger pipe and hole sizes increase the cost. The intermediate casing adds cost as well. Due to the severity of the potential loss zone in the Potosi formation however it is prudent to include it. Eliminating this casing string and the associated cost of cementing would reduce well cost by approximately \$400,000 however if the lost circulation is severe the intervention cost could quickly rise into the hundreds of thousand dollars. The worst outcome could be that the well could not be drilled to the target depth. If the injection well was to be drilled first and local geology confirmed, then a fact-based decision could be made as to whether the intermediate casing could be removed. The Potosi formation and the associated severe lost circulation was encountered at all the wells in the IBDP and ICCS projects located some 35-40 miles to the west. About 35-40 miles south, a disposal well into this formation has injected over <u>one trillion</u> gallons of wastewater with no surface pressure.

A few tens of thousand dollars could be saved by not cementing the production casing to surface, but the insulation value of the cement justifies the additional cost of cementing to surface.

The use of the plastic lined production tubing is a savings of approximately \$180,000 over the use of chrome alloy tubing.

If sand production is less than expected the production screen might be eliminated with a savings approaching \$100,000.

For insulation purposes a silicate fluid could be placed in the annular space between the production tubing and the production casing. This material would add approximately \$60,000 to the cost of the well but would have a thermal conductivity of +/- 0.28 BTU/hr ft ^{o}F. Vacuum insulated tubing (VIT) could be used to further lower the thermal conductivity to approximately 0.0069 BTU/hr-ft ^{o}F but at an additional cost of \$400,000. A dual wall insulated tubing could be used to lower the thermal conductivity to approximately 0.0347 BTU/hr-ft would increase well costs by approximately \$225,000.

A surface pump control box at a cost of \$20,000 is included in the cost estimate.

The well cost includes a contingency of 7.5% for tangible costs and a 5% contingency for intangible costs. An overhead cost of 7.5% is also included for project management.

Well Diagram Injection Well

The well diagram for the Injection Well is shown below in Figure 1-3

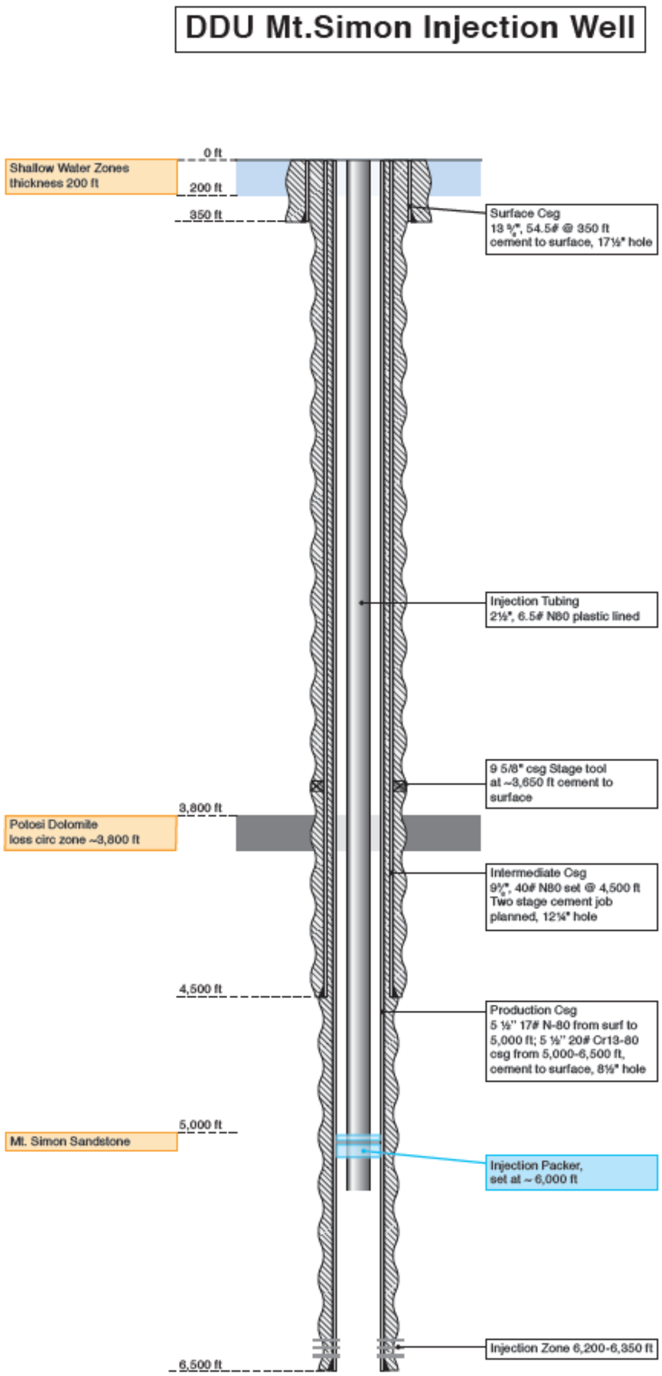

Figure 1-3 Injection Well Diagram

Injection Well Detail

The DDU project injection well will be used to return the produced brine to the lower Mt. Simon formation at a depth of approximately 6500 feet. The well will be drilled to approximately 6500 feet allowing room for additional injection zones to be opened if needed. The drilling should take approximately 50 days. The well will be used for the injection of heavy (+/- 200,000 TDS) brines and as such is regulated by the Illinois Environmental Protection Agency with guidance from the US EPA. There has been discussion that the well might be drilled under a Class V experimental permit, but this would have no bearing on well construction as the well would still have to be constructed to Class I standards. Class I standards state that all casing strings must be cemented to surface and that all components must be compatible with the injected fluid.

The casing and the corresponding borehole are presented below in Table 1-3.

String-Depth	Size in	Hole size in	ID	Weight #/ft	Grade
Surface 0-350 ft	13 3/8	17 1/2	12.615	54.5	J-55
Int. 0- 4500 ft	9 5/8	12 1/4	8.835	40	J-55 HC
Inj 0- 5000 ft	5 1/2	8 1/2	4.892	17	N-80
Inj 5000-6500 ft	5 1/2	8 1/2	4.778	20	Cr13-80

Table 1-3 Casing and Wellbore detail Injection Well

As per regulations all casing strings will be cemented to surface. Cement types and properties are shown below in Table 1-4

String Depth	Type	Density ppg	Yield Cu ft/sk	K btu/hr ft- °F
Surface 0-300 ft	Class A	15.6	1.18	.73
Int Lead 3650-0	Cmt/poz	12.5	1.85	.54
Int Tail 4500-3650 ft	Class A	15.6	1.18	.73
Inj Lead 4500-0 ft	Cmt/poz	12.5	1.85	.3
Int Tail 6500-4500 ft	Class A	15.6	1.18	.73

Table 1-4 Injection Well Cementing Detail

The intermediate casing will be cemented in two stages using a packer type cementing stage collar. The chrome alloy casing across the injection zone is per regulation. The injection string will be cemented in one stage unless well conditions dictate a two stage cementing operation is required.

The well will be drilled with a freshwater drilling mud. Lost circulation is expected in the Potosi section of the Knox formation at approximately 3500-3800 feet. The loss of returns will require mitigation with cement plugs or drilling to intermediate casing point with partial or no returns.

After the well is cased and cemented a section of approximately 150 feet of the lower Mt. Simon formation will be perforated using tubing conveyed perforating technique. Injection testing including a step rate test will be conducted to determine adequate injectivity and formation fracturing pressure. Other tests might be performed to acquire additional reservoir information.

An injection packer would then be run into the well on 2 7/8'' 6.5#/ft N-80 tubing which is to be plastic lined. The wet surfaces of the packer will be constructed of a chrome alloy material. The tubing-casing annulus will be filled with a weighted brine containing corrosion control additives.

The surface facility will consist of an injection pump, pressure and temperature measurement recording equipment as well as flow meters to measure the volume of injected fluid. A small tank will be required. No downhole gauge is planned unless the injection permit specifically requires one as injection pressure should be well below fracturing pressure.

Injection Well Cost

The estimated cost of drilling and completing the DDU injection well is $3.82 MM. A detailed Cost Estimate is presented below in Figure 1-4

Illinois DDU Geothermal Mt. Simon Injection Well
AUTHORIZATION FOR EXPENDITURES - Est Cost

In US $

Operator:	TBD	Project Type :	DDU Geothermal
Contract Area:		Well Name :	Mt. Simon DDU Injector # 1
Contract Area #:		Well Type :	Brine injector
Prepared by	JMK	Platform/Tripod :	AFE #: 1
		Field/Structure :	Champaign Date: 04-Mar-19
		Basin :	Illinois

Location
Surface Elev.
Surface Coordinate
Elevation

	PROGRAM	ACTUAL		PROGRAM	ACTUAL
Spud Date			Rig Days	60	
Compl Date			Total Depth	6300	
In Service			Well Cost $/Ft.	$0.00	
Drilling Days			Well Cost $/Da	$0.00	

Close Out Date: Completion Type: Open Hole Well Status: Pre Permit

	Description	Dry Hole Budget	Completed Budget	Total Budget	Actual Expenditure	Actual Over/Under	% Over/Under
1	**TANGIBLE COSTS**						
2	Casing	399,400	0	399,400	$0	399,400	100%
3	Casing Accessories; Float Equip & Liners	62,850	0	62,850	$0	62,850	100%
4	Tubing		89,500	89,500	$0	89,500	100%
5	Well Equipment - Surface	20,000	48,000	68,000	$0	68,000	100%
6	Well Equipment - Subsurface	0	25,500	25,500	$0	25,500	100%
7	Other Tangible Costs	0	0	0	$0	0	
8	Contingency	38,544	11,344	49,888	$0	49,888	100%
9	**Total Tangible Costs**	**$520,794**	**$174,344**	**$695,138**	**$0**	695,138	100%
10	**INTANGIBLE COSTS**						
11	**PREPARATION & TERMINATION**						
12	Surveys	6,000	0	6,000	$0	6,000	100%
13	Location Staking & Positioning	2,000	0	2,000	$0	2,000	100%
14	Wellsite & Access Road Preparation	84,000	0	84,000	$0	84,000	100%
15	Service Lines & Communications	50,000	0	50,000	$0	50,000	100%
16	Water Systems	5,500	0	5,500	$0	5,500	100%
17	Rigging Up/Rigging Down/ Mob/Demob	130,000	0	130,000	$0	130,000	100%
19	**Total Preparations/MOB**	**$277,500**	**$0**	**$277,500**	**$0**	277,500	100%
20	**DRILLING - W/O OPERATIONS**						
21	Contract Rig	813,960	125,000	938,960	$0	938,960	100%
22	Drlg Rig Crew/Contract Rig Crew/Catering	0	0	0	$0	0	
23	Mud, Chem & Engineering Servs	164,250	5,000	169,250	$0	169,250	100%
24	Water	30,000	2,000	32,000	$0	32,000	100%
25	Bits, Reamers & Coreheads	77,500	0	77,500	$0	77,500	100%
26	Equipment Rentals	87,614	0	87,614	$0	87,614	100%
27	Directional Drlg & Surveys	0	0	0	$0	0	
28	Diving Services	0	0	0	$0	0	
29	Casing & Wellhead Installation & Inspection	46,000	3,000	49,000	$0	49,000	100%
30	Cement, Cementing & Pump Fees	258,000	0	258,000	$0	258,000	100%
31	Misc. H2S Services	0	0	0	$0	0	
32	**Total Drilling Operations**	**$1,477,324**	**$135,000**	**$1,612,324**	**$0**	1,612,324	100%
33	**FORMATION EVALUATION**						
34	Coring	0	0	0	$0	0	
35	Mud Logging Services	120,000	0	120,000	$0	120,000	100%
36	Drillstem Tests	0	0	0	$0	0	
37	Open Hole Elec Logging Services	155,000	0	155,000	$0	155,000	100%
39	**Total Formation Evaluation**	**$275,000**	**$0**	**$275,000**	**$0**	275,000	100%
40	**COMPLETION**						
41	Casing, Liner, Wellhead & Tubing Installation	0	6,000	6,000	$0	6,000	100%
42	Remedial Cementing and Fees	0	0	0	$0	0	
43	Cased Hole Elec Logging Services	27,000	35,000	62,000	$0	62,000	100%
44	Perforating & Wireline Services	0	60,000	60,000	$0	60,000	100%
45	Stimulation Treatment	0	0	0	$0	0	
46	Production Tests	0	70,000	70,000	$0	70,000	100%
48	**Total Completion Costs**	**$27,000**	**$171,000**	**$198,000**	**$0**	198,000	100%
49	**GENERAL**						
50	Supervision	201,500	60,000	261,500	$0	261,500	100%
51	Insurance	0	0	0	$0	0	
52	Permits & Fees	0	20,000	20,000	$0	20,000	100%
53	Marine Rental & Charters	0	0	0	$0	0	
54	Helicopter & Aviation Charges	0	0	0	$0	0	
55	Land Transportation	12,900	0	12,900	$0	12,900	100%
56	Other Transportation	0	0	0	$0	0	
57	Fuel & Lubricants Non Rig	5,500	0	5,500	$0	5,500	100%
58	Camp Facilities	39,500	0	39,500	$0	39,500	100%
59	Allocated Overhead - Field Office	0	0	0	$0	0	
60	Allocated Overhead - Main Office	210,000	47,000	257,000	$0	257,000	100%
61	Allocated Overhead - Overseas	0	0	0	$0	0	
62	Contingency Intangible Costs	132,353	34,155	166,508	$0	166,508	100%
64	**Total General Costs**	**$601,753**	**$161,155**	**$762,908**	**$0**	762,908	100%
65	**TOTAL INTANGIBLE COSTS**	**$2,658,577**	**$467,155**	**$3,125,732**	**$0**	3,125,732	100%
	TOTAL TANGIBLE COSTS	**$520,794**	**$174,344**	**$695,138**	**$0**	695,138	100%
66	**TOTAL WELL COST**			**$3,820,870**	**$0**	**3,820,870**	**100%**
67	Timed Phased Expenditures						
68	-This Year						
69	-Future Years						
70	Total						

Figure 1-4 Injection Well Cost Detail

Injection Well Cost Discussion

The injection well cost of $3.62 MM is reasonable for a Class I injection well to this depth. There are very few opportunities to lower the cost; however, there are possibilities that could cause the cost to increase. The intervention to control the severe loss circulation zone is included in the estimate. If the lost circulation zone is especially severe then the cost of intervention could exceed the amount budgeted. The use of the plastic lined injection string saves about $150,000 over the use of a chrome alloy injection string. If the injection permit requires frequent surveillance logging runs to be made in the well, then the plastic-coated tubing might not be appropriate or may have to be replaced every few years. It may still be cheaper in the long run to have a planned replacement of the lower cost material than the larger cost of the alloy tubing. Another item that could raise the cost would be if the permit requires a down hole pressure monitoring. If so then the cost would increase by $75,000-100,000. There might be enough contingency built into the AFE to cover that but if so, it would require the other components to come in at estimated cost or below. As previously mentioned, the cost presented are today's cost. Market conditions could raise or lower the overall cost of the injection well.

An estimate of $25,000 is included for the surface facilities.

The well cost includes a contingency of 7.5% for tangible costs and a 5% contingency for intangible costs. An overhead cost of 7.5% is also included for project management.

Production/Injection Rate Cost Matrix

The final step of the well design task was to develop a matrix so that the costs of both injection and producing wells could be estimated for different flow rates. Injection is assumed to be into the same horizon as production is from. Four ranges of flow with the associated well costs are presented below in Table 1-5.

Flow Rate bbl/day	Prod well $M	Inj Well $M	Total Cost $M
2000-4000	3.90	3.30	7.20
4000-7200	4.30	3.82	8.12
7500-10000	4.40	4.32	8.72
10000-12000	5.10	4.45	9.65

Table 1-5 Well Costs for Different Flow Rates

The costs presented in Table 1-5 are estimates and not based on a line by line analysis as the costs presented for the Well AFE's were; however, they are representative for the purpose of illustrating how costs change with flow rates. The well geometries for each type of well changed as flow rates increased so that the matrix above has three different wellbore geometries for each type of well.