Hydrologic challenges to heating Cornell using Earth Source Heat (ESH) and a strategy for meeting them

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Abstract

To reduce carbon emissions Cornell proposes to heat its campus by producing >60°C brine from 2 to 3 km depth. Twenty percent of its heating needs can be met by producing at 364 gpm. Demonstrating production and reinjection at this rate constitutes Cornell's ESH pilot project. The standard hydrologic analysis reported here shows that a transmissivity of >0.26 D m is required. Only in specific locations in specific strata is the transmissibility under Cornell likely to be this high. Production and injection over 20 years will draw fluids and change pressures to distances of 4 to 33 km from the wells. This raises concerns that injected fluids might short-circuit to the production well and cool its produced fluids, and that increased fluid formation pressures could trigger earthquakes. The short-circuiting risk can be eliminated and the earthquake risk reduced by taking advantage of the stratigraphically layered nature of the Cornell subsurface and producing below while injecting above an interval of impermeable strata. A strategy of first finding the most permeable targets with 3D seismic and Fracture Seismic surveys, and then drilling to determine if these locations have sufficient permeability for production and injection to be separated stratigraphically in this fashion is suggested.

1. Introduction

Cornell's Earth Source Heat (ESH) project (Gustafson et al. 2018) seeks to heat Cornell's campus by extracting warm water from 2 to 3 km below the campus to supply 5.6 MW_{th}. The proposed first step is a pilot to demonstrate that brines with a temperature of at least 60°C can be produced and returned to the subsurface at a rate of 0.023 $m^3\ s^{-1}$ (364 gpm). This rate of warm water production would meet ~20% of Cornell's campus heating needs. The project faces three main technical challenges: (1) finding or creating the subsurface permeability needed to produce and re-inject at the required rate, (2) avoiding short circuiting of reinjected fluids to the production well, and (3) avoiding triggering earthquakes by the steady reinjection of produced fluids over 20 years.

This paper presents the results of a standard hydrologic analysis. The analysis suggests that finding the required permeability may be challenging. A transmissivity of 0.26 Darcy meters (1 Darcy over an interval of 0.26 m, or 0.1 Darcy over a 2.6 m thick interval, etc.) is required to meet the target production rate of 0.023 $m^3\ s^{-1}$. Available data suggests that finding this level of permeability will be challenging in the campus subsurface. Twenty years of injection and production will draw and return brine from distances of 4 to 33 km from the wells, depending on how much water the formation yields as it is decompressed (its specific storage). This wide draw of fluids and its associated pressure change means short circuiting and earthquake risk will need to be diagnosed and managed carefully. There is a trade-off between these risks. If the injection and production wells are close together, the earthquake risk is minimized because the pressure drawdown by production largely cancels the pressure buildup by injection, but for small ell separation impairment of heat production by fluid short circuiting is more likely. In a layered stratigraphy producing from an underlying and injecting into an overlying strata with an impermeable stratum between would eliminate short-circuiting and minimize earthquake risk.

In what follows we briefly review the stratigraphy under Cornell and hydrologic theory and then: (1) identify the permeability required for successful EHS production, (2) use appropriate hydrologic parameters to determine how far fluids will be drawn and subsurface pressure changed by 20 years of heat production, and (3) sketch a ESH production strategy that minimizes risk and is appropriate for layered stratigraphy under Cornell. The hydrologic analysis is simple and straight forward, but has implications that are important to defining a strategy to meet the challenge of extracting heat from the Cornell subsurface.

2. The stratigraphy under Cornell

The stratigraphy under Cornell consists of flat-lying layers deposited on a metamorphic basement. It has been described in detail by (Jordan 2019), and its generally flat-lying nature has been confirmed by 2D seismic lines (May et al. 2019). About 4 km of cover has been eroded. Compacted Upper Devonian (~420 Ma) silicate rocks are exposed at the surface. From the surface to ~2.3 km depth the layers are shale, siltstone and salt, including several intervals of very organic rich black shales that contain over-pressured natural gas (e.g., the Marcellus and Utica in Figure 1). Carbonates underlie this silicate package, and the carbonates unconformably overlie a lower amphibolite grade metamorphic basement at ~3 km depth. The intervals considered most likely to be permeable yet deep enough for ESH production are near vertical fault clusters in the Trenton-Black River carbonates (T-BR in Figure 1) that have been targeted for gas production, and paleo-valleys filled with sands and conglomerates in the Ausable member of the Potsdam sandstone formation that lies on top of the metamorphic basement (red arrows next to the stratigraphic column in Figure 1; Jordan, 2019).

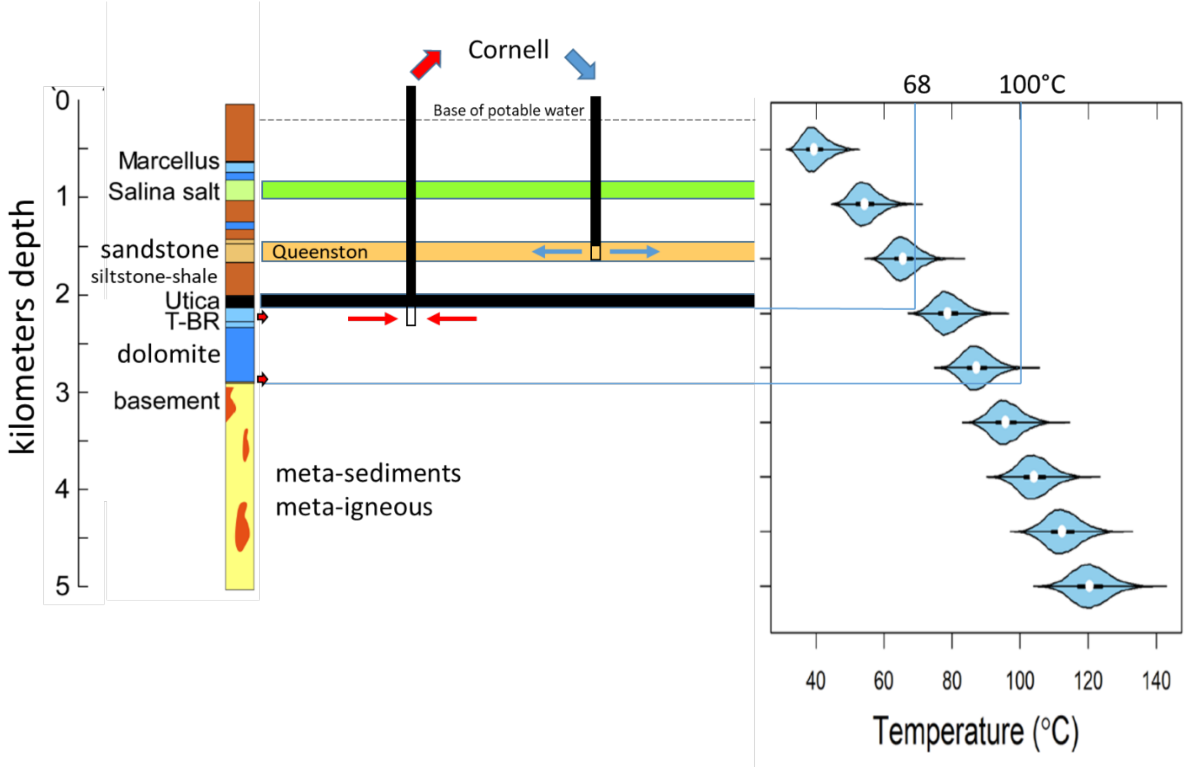

Figure 1. Cartoon illustration of stratigraphy under the Cornell campus adapted from figures from (Gustafson et al. 2018). The two most promising intervals for ESH production are vertically fractured grabens in the Trenton-Black River (T-BR) and sand and gravel filled paleo-valleys on top of basement, indicated by small red arrows outlined in black next to the stratigraphic column. Pore waters are generally brines below ~300 m (dashed black line).

To establish seismic background, Cornell monitored ambient seismic events in the local area from November 2015 to October 2016 with 12 specially installed seismic systems. These local CorNet seismometers detected 26 events: 13 micro-earthquakes $-1.6<M<1.6$, 12 potentially anthropogenic events $-3.6<M<-1.3$, and 1 quarry blast $M=1.6$ (McLeod et al. 2020).

3. Hydrologic analysis

3.1 Hydrology

3.1.1 The Theis Solution

The simplest case is production from a single well penetrating a confined (impermeable barriers above and below) aquifer. As water is produced, decompression of the water and compaction of the formation drive water into the well. Initially the water in the well will stand at level h_o in Figure 2. As water is produced the water level in the well will fall and the water levels some distance from the well will also drop, forming a cone of depression. This is shown in Figure 2 as a drop in hydraulic head by h from h_o. For ESH we are interested in knowing:

(1) the aquifer permeability required to produce at 364 gpm for 20 years, and

(2) the distance from the production (and injection) wells that water pressure will be reduced (increased) over 20 years.

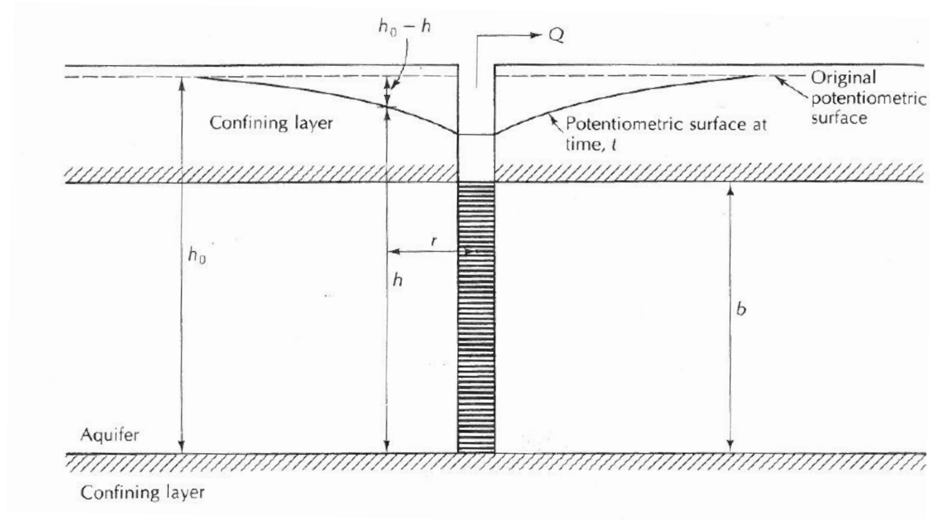

Figure 2. Figure illustrates the drop in hydraulic head as a function of distance from the well, h(r), from its original potentiometric surface (dashed line at h_o) in a confined aquifer after some period of production, The Theis solution in equation (1) gives the drawdown ($\Delta h = h_o - h$) as a function of production rate, time, and aquifer properties Note the thickness of the confined aquifer is b. Figure is from Fetter, 2001, p154.

The solution to the problem posed in Figure 2 is given by the Theis equation:

$$\Delta h = \frac{-Q}{4\pi T} W(u)$$
$$W(u) = \int_u^\infty \frac{e^{-x}}{x} dx$$
$$u = \frac{r^2 S}{4Tt} \qquad (1)$$
$$T = Kb$$
$$S = S_s b$$

Here, Q[m^3 s^{-1}] is the steady pumping rate, t[s] is the time since start of pumping, K[m s^{-1}] is the hydraulic conductivity, u[-] is a dimensionless parameter that defines the well function W, T[m^2 s^{-1}] is the transmissivity, and S[-] is the storativity. Notice that the transmissivity and storativity equal the hydraulic conductivity and specific storage, S_s, times the thickness of the confined aquifer, b. The specific storage is the m^3 of water that a m^3 of formation will yield when the hydraulic head is dropped 1 m. Because water is very incompressible, the water yield is almost entirely due to the compression of the rock matrix. If a more compressible fluid such as gas were present in the pore space, fluid expansion would play a more important role, but that is not expected to be the case here. The solution given by (1) is described in every hydrology text (e.g., Freeze and Cherry 1979; Fetter 2001; Domenico and Schwartz 1990). Figure 3 tabulates and plots W(u).

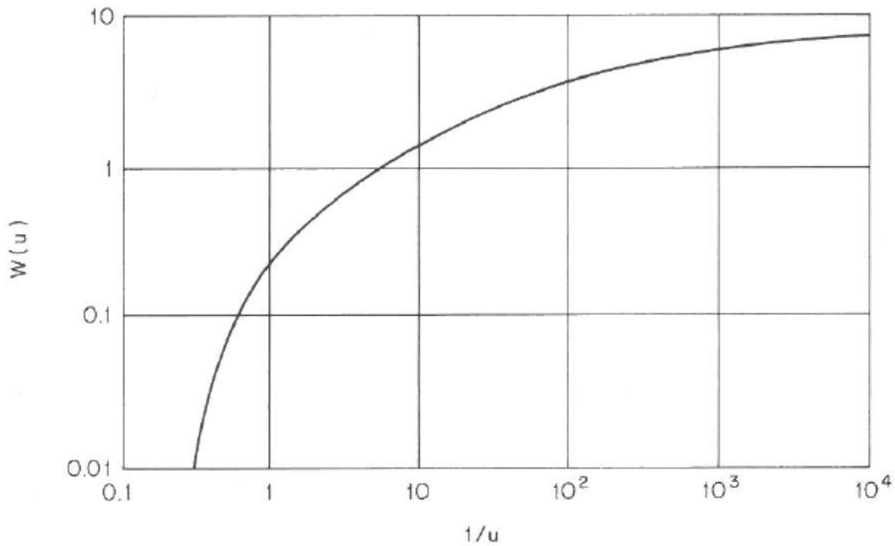

Table 8.1 Values of $W(u)$ for Various Values of u

u	1.0	2.0	3.0	4.0	5.0	6.0	7.0	8.0	9.0
$\times 1$	0.219	0.049	0.013	0.0038	0.0011	0.00036	0.00012	0.000038	0.000012
$\times 10^{-1}$	1.82	1.22	0.91	0.70	0.56	0.45	0.37	0.31	0.26
$\times 10^{-2}$	4.04	3.35	2.96	2.68	2.47	2.30	2.15	2.03	1.92
$\times 10^{-3}$	6.33	5.64	5.23	4.95	4.73	4.54	4.39	4.26	4.14
$\times 10^{-4}$	8.63	7.94	7.53	7.25	7.02	6.84	6.69	6.55	6.44
$\times 10^{-5}$	10.94	10.24	9.84	9.55	9.33	9.14	8.99	8.86	8.74
$\times 10^{-6}$	13.24	12.55	12.14	11.85	11.63	11.45	11.29	11.16	11.04
$\times 10^{-7}$	15.54	14.85	14.44	14.15	13.93	13.75	13.60	13.46	13.34
$\times 10^{-8}$	17.84	17.15	16.74	16.46	16.23	16.05	15.90	15.76	15.65
$\times 10^{-9}$	20.15	19.45	19.05	18.76	18.54	18.35	18.20	18.07	17.95
$\times 10^{-10}$	22.45	21.76	21.35	21.06	20.84	20.66	20.50	20.37	20.25
$\times 10^{-11}$	24.75	24.06	23.65	23.36	23.14	22.96	22.81	22.67	22.55
$\times 10^{-12}$	27.05	26.36	25.96	25.67	25.44	25.26	25.11	24.97	24.86
$\times 10^{-13}$	29.36	28.66	28.26	27.97	27.75	27.56	27.41	27.28	27.16
$\times 10^{-14}$	31.66	30.97	30.56	30.27	30.05	29.87	29.71	29.58	29.46
$\times 10^{-15}$	33.96	33.27	32.86	32.58	32.35	32.17	32.02	31.88	31.76

SOURCE: Wenzel, 1942.

Figure 3. The Theis well function W(u) plotted and tabulated. From Freeze and Cherry (1979, p318,319)

3.1.2 Sustainable production

What level of production can be sustained by a well for a very long time? When t is large, u is small. Take $u=10^{-12}$. $W(u=10^{-12}) = 27.05$ (see Fig. 3 table). Taking $27.05/4\pi\approx 2$, by equation (1a):

$$Q[m^3\ s^{-1}] = 0.5\ T\Delta h[m]. \tag{2}$$

Equation (2) states that half the transmissivity multiplied by the feasible long term drop in head in the production well gives a good estimate of the rate at which a well can be steadily pumped for long durations of time. The equation is a good approximation for long term production because the production will decline only quite slowly from its rate at $u=10^{-12}$. For example, after an interval of time 10 times longer ($u=10^{-13}$), the production rate will be only 8% less (e.g., 27.05/29.36=0.92).

3.1.3 Radius of influence

From how far away will a well draw water and depress aquifer pressure after a long period of pumping? The distance to which drawdown extends depends on the storativity and transmissivity of the aquifer, and the time the well is pumped. For long periods of time (small u) a good approximation (Appendix A) to (1) is:

$$\Delta h = \frac{-2.3Q}{4\pi T}\log\frac{2.25Tt}{r^2 S}. \tag{3}$$

At a distance, r_{Infl}, where $\Delta h=0$, the argument of the log function must be equal to 1, and thus $\frac{2.25Tt}{r_{Infl}^2 S}=1$. In other words, the distance water is drawn from a well producing for time t from a confined aquifer of storativity S is:

$$r_{Infl} = \sqrt{\frac{2.25Tt}{S}}. \tag{4}$$

3.1.4 Diagnostics

How water levels drop in a well as it is produced can indicate the presence of a permeable or impermeable zone at some distance. From equation (1) above it follows that, for a homogeneous aquifer, the head will change in a well that is steadily produced at a rate Q in the following fashion:

$$\Delta h(t) = \frac{-Q}{4\pi T} W\left(\frac{r_w^2 S_s b}{4Tt}\right). \qquad \text{Single production well} \tag{5}$$

If there is a permeable zone at a distance 0.5 r_s, we can approximate this by placing an injection well at a distance r_s.

$$\Delta h(t) = \frac{-Q}{4\pi T}\left\{W\left(\frac{r_w^2 S_s b}{4Tt}\right) - W\left(\frac{(r_w + r_s)^2 S_s b}{4Tt}\right)\right\}. \qquad \text{well dipole} \tag{6}$$

If there is a permeability barrier at distance 0.5 r_s, we can approximate this circumstance by placing an image production well at distance r_s:

$$\Delta h(t) = \frac{-Q}{4\pi T}\left\{W\left(\frac{r_w^2 S_s b}{4Tt}\right) + W\left(\frac{(r_w + r_s)^2 S_s b}{4Tt}\right)\right\}. \qquad \text{well pair} \tag{7}$$

3.2 Hydrologic parameters for ESH extraction

Equations (2) and (4) tell us the permeability required for Cornell's ESH project, and how far away from a producing well water will be drawn for defined aquifer properties. To answer the questions posed above we first determine the transmissivity that is required for Cornell's ESH project to be a success, then estimate the aquifer specific storage, and finally use this specific storage estimate to determine the distance water will be drawn by Cornell's heat production pilot over 20 years.

3.2.1 Transmissivity required for Cornell's ESH pilot

Cornell's pilot goal is to produce 5.6MW$_{th}$ (5.6 million watts of thermal energy) by producing subsurface brine that is hotter than 60°C. As shown by equation (5), this requires a production rate of 14 to 23 L s^{-1} (liters per second) or 222 to 364 gpm (gallons per minute):

$$Q = \frac{Q_H}{\rho C_p T} = \frac{5.6\times10^6\,J\,s^{-1}}{4.08\times10^6\,J\,m^{-3}\,C^{-1}\begin{Bmatrix}60C\\100C\end{Bmatrix}} = \begin{Bmatrix}23\\14\end{Bmatrix} L\,s^{-1} \quad . \tag{5}$$

Here Q_H is the thermal heat production goal of the pilot, ρC_p the heat capacity of brine, and the brine is assumed to be either 60 or 100°C.

From (2), the transmissivity required for long term production at this rate is ~4.6 x 10^{-5} m^2 s^{-1}:

$$T > \frac{Q}{0.5\Delta h} = \frac{0.023\,m^3\,s^{-1}}{0.5\times1000\,m} = 4.6\times10^{-5}\,m^2 s^{-1} = 0.26 \text{ D m.} \tag{6}$$

Here we assume after 20 years of production the water level in the well bore has been drawn down 1 km. A transmissivity of Kb=4.6 x 10^{-5} m^2 s^{-1} is equivalent to an intrinsic permeability of 0.26 Darcies over one meter or about one Darcy over one foot, as indicated in (6).

Equation (6) expresses transmissivity (the rate at which a well can accept or produce water) in two equivalent ways. The Transmissivity is expressed in hydrologic units of m^2 s^{-1} and in intrinsic permeability units of D m. The hydrologic units (m^2 s^{-1}) assume the viscosity of the fluid is that of water and the gravitational acceleration is that of the Earth at sea level, and combine these parameters with permeability to make a lumped parameter called hydraulic conductivity, K. The D m units separate the units in K so that the formation permeability is not combined with viscosity and gravity but rather is expressed separately as intrinsic permeability, k. The equations below illustrate these interrelations. The first equation indicates that, for the Transmissivity needed for Cornell's ESH project (Kb = 4.6 x 10^{-5} m^2 s^{-1}), the hydraulic conductivity of a 30 m portion of the well must be 1.53 x 10^{-6} m s^{-1}. The second equation shows that a hydraulic conductivity K of 1.53 x 10^{-6} m s^{-1} corresponds to an intrinsic permeability k of 8.4 x 10^{-15} m^2 or 8.4 mD. The last equation shows how transmissivity can be equivalently computed in Darcy units (T=kb).

$$K = \frac{T}{b} = \frac{4.6\times10^{-5}\,m^2 s^{-1}}{30\,m} = 1.53\times10^{-6}\,m\;s^{-1}$$

$$k = \frac{\upsilon}{g}K = \frac{5.5\times10^{-8}\,m^2 s^{-1}}{10\,m\,s^{-2}}1.53\times10^{-6}\,m\,s^{-1} = 8.4\times10^{-15}\,m^2 = 8.4\,mD$$

$$T = kb = 8.4\,\mathrm{mD}\times30\,m\times3.28\,\mathrm{ft\,m^{-1}} = 826\,\mathrm{mD\,ft}$$

The utility of transmissivity is that it does not specify where in a well the loss or gain of water occurs, only how much water the well can accept or produce for a given change in head. This is often the only concern. A homeowner only cares how much water their well can produce and is not concerned where the water enters the well. One D ft of transmissivity could be provided a 1 ft interval of the wellbore with a 1 Darcy permeability, or a 100 ft interval of the wellbore with a 0.01 D permeability. The production characteristics of the well would be the same.

3.2.2 Estimate of specific storage

Specific storage is the m^3 of water produced from a m^3 of rock per m drop in hydraulic head. It depends on the compressibility of the rock and water:

$$S_s = \rho g(\alpha + \phi\beta), \tag{7}$$

where ρ is the density of water, g is the acceleration of gravity, ϕ is porosity, α is the compressibility of the rock, and β the compressibility of water, both of the latter in Pa^{-1}. Figure 4A shows the compressibility of water and various kinds of rock, and Figure 4B computes specific storage from these ranges in compressibility using equation (7). It can be seen from Figure 4B that the specific storage of jointed rock, the rock type we are most likely dealing with in ESH production in the Ithaca area, ranges from 2×10^{-6} to 10^{-4} m^{-1}.

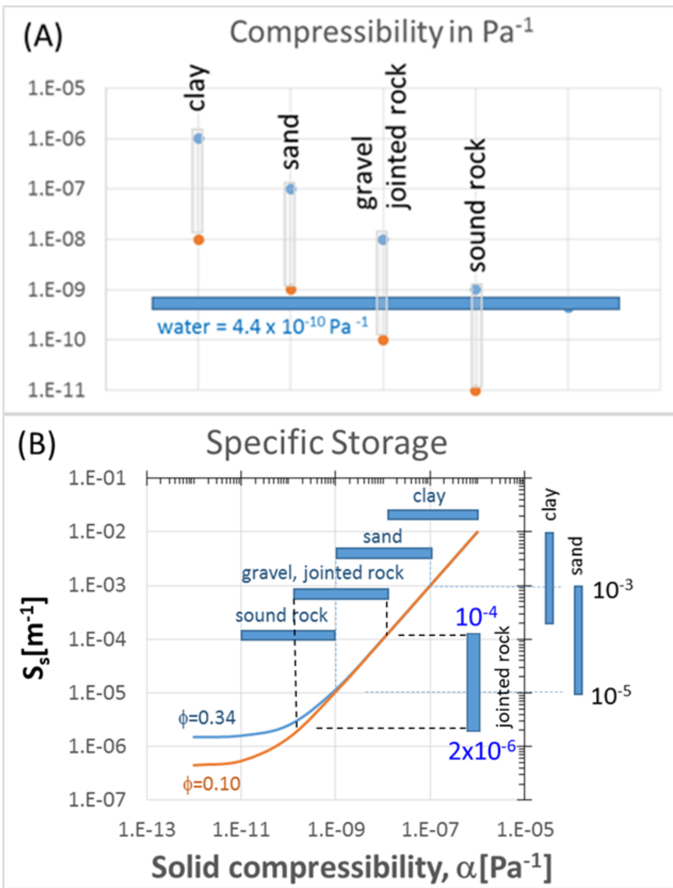

Figure 4. (A) water and rock compressibility from Freeze and Cherry (1979, Table 2.5). (B) Specific storage computed for these values using equation (7).

3.3 Single well hydrologic response

3.3.1 Calculation of radius of influence

The radius of influence after 20 years of hot water production computed from equations (4) for these values of specific storage ranges from 4.6 to 33 km:

$$r_{\mathrm{infl}} = \sqrt{\frac{2.25Tt}{S_s b}} = \sqrt{\frac{(2.25)(4.6\times10^{-5}\,m^2s^{-1})(20\,y)(3.15\times10^{7}\,s\,y^{-1})}{\begin{Bmatrix}10^{-4}\\2\times10^{-6}\end{Bmatrix} m^{-1}\,30\,m}} = \begin{Bmatrix}4.6\\33\end{Bmatrix} km\,. \qquad (8)$$

Clearly water could be produced from a large distance. If the formation being produced is fractured, and the draw becomes more channeled with distance from the well, warm waters could be drawn from even further than indicated in (8).

3.3.2 Drawdown in the production well

Drawdown will progress as the log of time as shown in Figure 5, and deviations from this drawdown trajectory will indicate whether adjacent zones are more or less permeable. The heavy black line shows the drawdown over 20 years for production at the Cornell EHS pilot target rate of 0.023 $m^3\,s^{-1}$ (364 gpm). The drawdown is shown for the two end member values of specific storage determined in Figure 4. After 20 years of production, the plots show that the single well drawdown is 1011 and 855 m for S_s=2 x 10^{-6} m^{-1} and 1 x 10^{-4} m^{-1} respectively. The colored curves show the drawdown when an image production or injection well is placed 0.5, 1, or 4 km away. As discussed in section 1.4, placing an image well at these distances is equivalent to placing a very permeable or very impermeable boundary at half the well separation. Adjacent permeability arrests the drawdown after some time, whereas adjacent impermeability increases the drawdown. The impact of the image wells occurs sooner for lower values of specific storage. The figures show that changes in the rate at which hydraulic head drops in a steadily-produced production well provides information on the permeability adjacent to the well and the distance to that contrasting permeability. The drawdown response provides no information on the direction to the contrasting permeability, however.

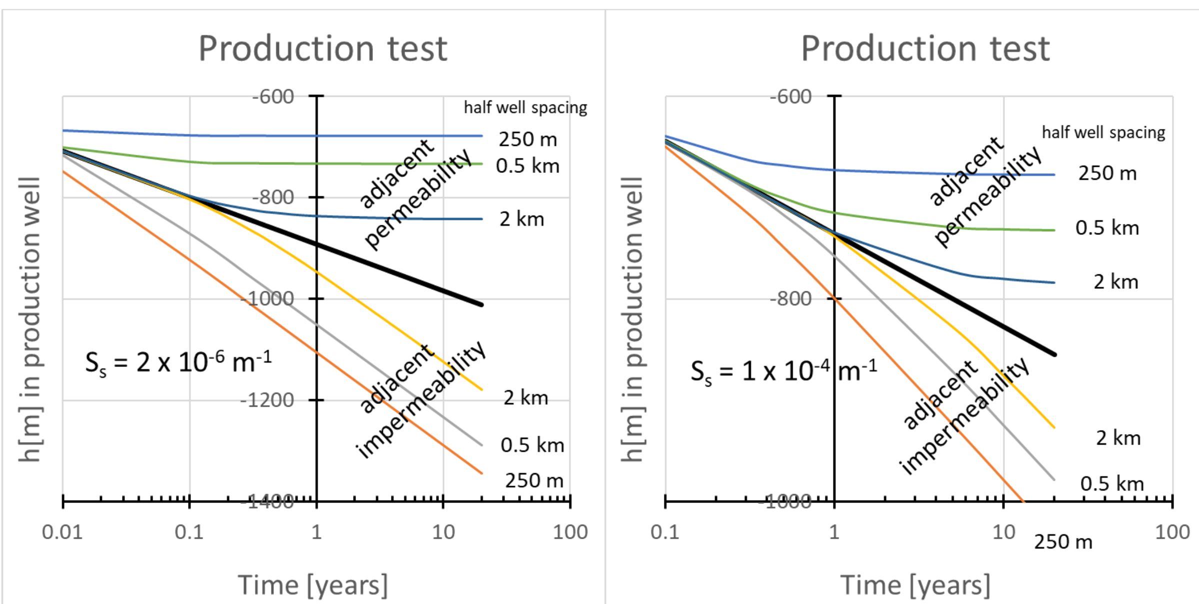

Figure 5. Meters of drawdown, h (defined in Figure 2), is calculated as a function of time in a production well produced at 0.023 $m^3\,s^{-1}$ (364 gpm) in a homogeneous confined aquifer 30 m thick when there is only a single well (heavy black line), and when image wells are also present (colored curves) at twice the distances indicated by the numbers adjacent to the colored curves. The left plot is for a specific storage of 2x10^{-6} m^{-1}, and the right plot for 1x10^{-4} m^{-1}. The colored curves illustrate how the drawdown history of a well indicates whether the adjacent formation is more or less permeable.

3.3.3 Drawdown away from the production well

Figure 6 plots the head drawdown away from a single production well assuming a wellbore radius of 0.1 m. In Fig. 6A the drawdown in the single production well is plotted as a function of time. The drawdown approaches that acquired after 20 years of production in a few days, changes only very slowly after that, and is not much changed by specific storage. Figure 6B and 6C plot drawdown as a function of the log of distance from the wellbore. The extent of drawdown depends strongly on the specific storage and its limit is well characterized by the radius of influence calculated by equation (8).

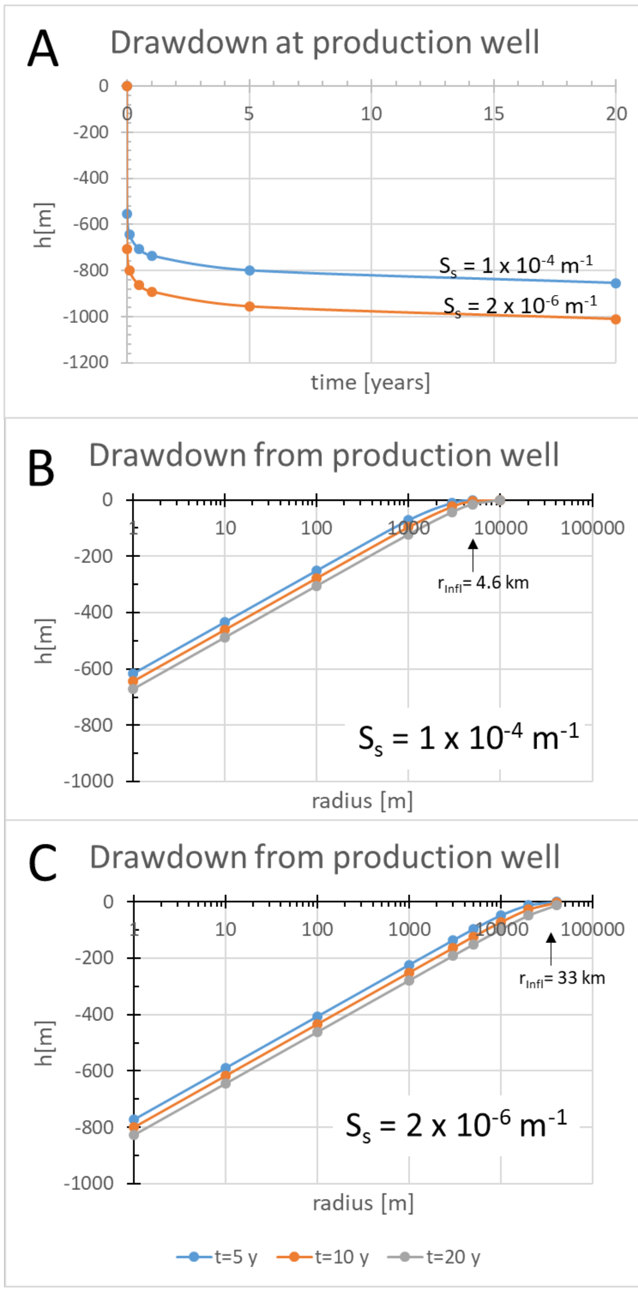

Figure 6. Drawdown at increasing radial distance away from a single production well producing at 364 gpm as required for Cornell's ESH pilot. Specific storage S_s are shown on each plot. r_{infl} is the radius of influence calculated using equation (8). In all plots T=4.6x10^{-5} m^2 s^{-1} and b=30 m.

3.4 Two well hydrologic response

In the conventional mode of ESH operation, produced water is returned to the same aquifer some distance from the production well. If the wells are close together, the increase in hydraulic head near the injection well is largely cancelled short distances away by the head drawdown in the production well. But as the separation between wells increases, the cancellation diminishes. At 4 km spacing the increase in pressure 20 km from the injection well is 25% of the increase that would occur if the production well were not present. This is illustrated in Figure 7 for the lower bound specific storage.

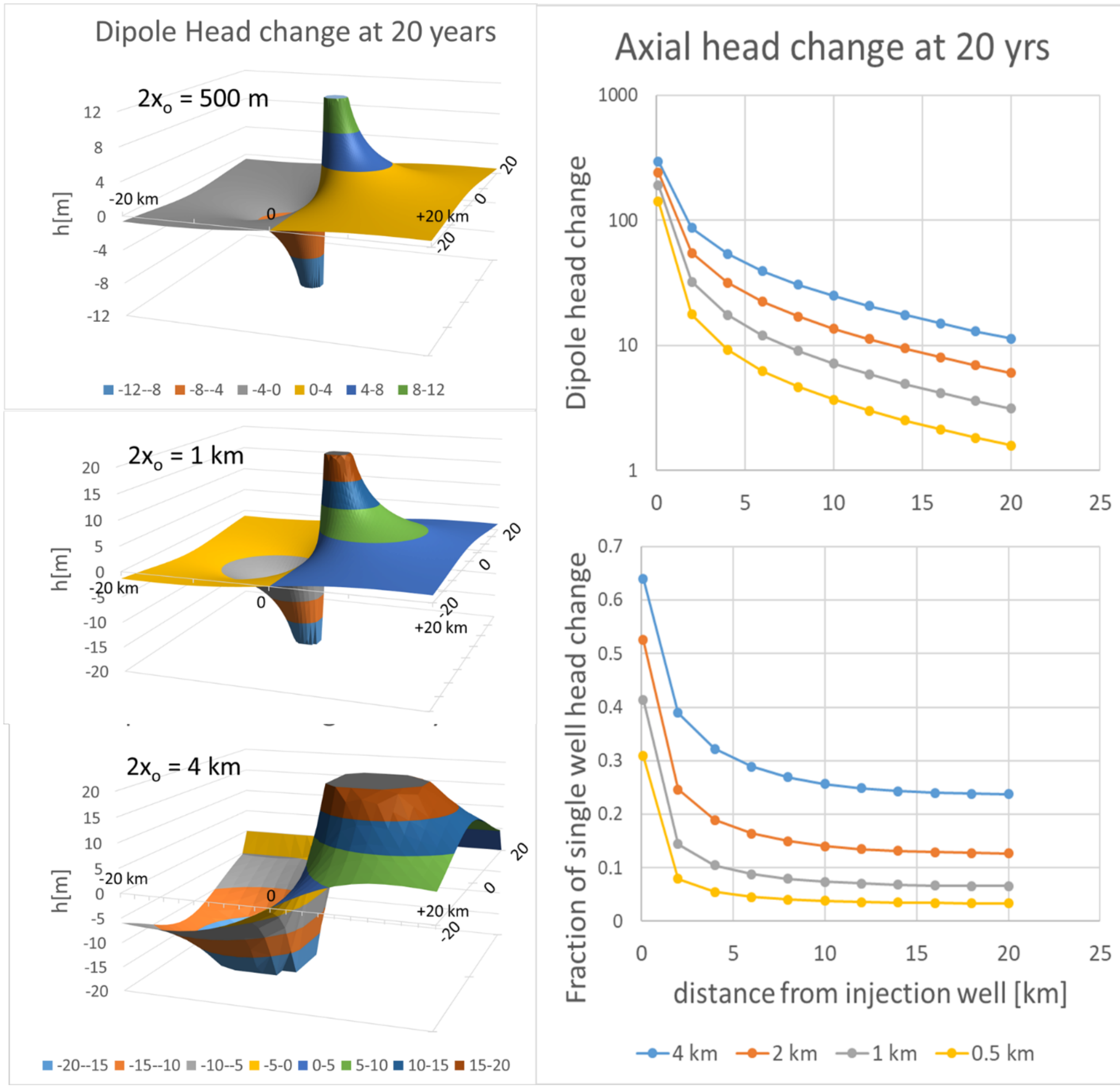

*Figure 7. Pattern of hydraulic head change after 20 years of heat production and re-injection at the rates (364 gpm) required for Cornell's ESH pilot. (**left**) Panels show the pattern of head change if the well separation is 0.5, 1, and 4 km. The drawdown or buildup near the wells has been truncated to allow the head changes near the wells to be seen more clearly in the plots. (**top right**) Panel shows the head change away from the injection/production well pair, starting 100m from the injection well. (**bottom right**) Panel plots the same data as the top right figure, but expresses the head change as the fraction of the head increase which would result from a single injector well. It can be seen that, 20 km from the injection well, the increase in head for an injection well separated by 4 km from its production pair is about 25% of that if the production well were not present. One hundred meters from the injection well (first data point), the dipole head change is 65% of the single injection well head change (a 295 m head increase compared to a 461 m increase). In all plots $T=4.6\times10^{-5}$ m^2 s^{-1}, b=30 m, and $S_s=2\times10^{-6}$ m^{-1}.*

To summarize: Figure 6 shows that pressure drawdown (or build up) quickly extends to the radius of influence. Figure 5 shows that the rate of drawdown of a single test well can indicate whether an adjacent more permeable zone has been missed. Figure 7 shows that the pressure increase around an injection well is cancelled less by an adjacent production well as the production well is moved farther away. The plots in Figure 7 start 100 m from the injection well (where the head changes are already strongly reduced) and proceed away from the injection-production well pair along the line joining them. At the injection and production wellbores, the head changes are nearly the same as those for a single isolated well. Although not shown because of truncation, the production well drawdown in Figure 7 for the injection/production well pair is nearly the same as that plotted in Figures 5 and 6 for a single production well.

4. Hydrologic Data

4.1 Measured transmissivity in the Queenston and Potsdam Formations

In 1993, the 11,829 ft (3.6 km) Bale #1 well was drilled through the entire Paleozoic stratigraphy and 100 ft into basement in Schuyler Co, NY. Its purpose was to determine if brine generated in the construction of a bedded salt gas storage facility could be disposed of at the rate of 1400 gpm by injection into a subsurface formation. The permeabilities of the Queenston Formation and the lower 700 m of sedimentary section were considered the most promising formations for injection and were therefore the intervals tested.

The lower sedimentary units, from the Black River Formation through the Potsdam Formation and the upper 35 m of basement rock, were found to have no significant permeability. This lowermost 2262 ft of the well accepted water at only 0.88 gpm under ~2000 psi of excess pressure. This was too low an injectivity to warrant further testing. A spinner log indicated that most of the flow exited the 11,829 ft well below 11,600 ft. This suggests that the Potsdam siliciclastics and the top 35m of basement have some, albeit insufficient, permeability. (S.A. Holditch & Associates, Inc., Houston, Tx 1993).

The Queenston sandstone showed much greater but still inadequate permeability. The injectivity of the Queenston formation was 15.1 gpm over a 33 ft interval under an excess pressure of ~700 psi. Buildup/falloff testing yielded a transmissivity of 9.739 md-ft (0.296 mD over 33 ft) (S.A. Holditch & Associates, Inc., Houston, Tx 1993). Subsequent testing of a 96 ft interval of the Queenston indicated a higher transmissivity of 28.8 md-ft (0.3 mD over 96 ft). The upper part of the Queenston is over 900 ft thick. The 96 ft interval tested was presumably the interval thought most likely to be permeable. (S. A. Holditch & Associates, Inc., Houston, Tx 1994). Since 28.8 mD-ft equals 8.8 mD-m, the Queenston formation has a transmissivity 30 times less than the 260 mD-m needed (section 3.2.1) for the Cornell ESH pilot well.

4.2 Trenton-Black River permeability

Camp and Jordan (2017) investigated the possibility of repurposing Trenton-Black River (T-BR) gas fields for geothermal heat extraction, focusing on the Quackenbush Hill field. Hosted in dolomite, this field is one of the highest producing fields in the T-BR and hosts its best producing well. The field is located in “two ENE-trending, en-echelon fault bounded grabens, and measures 13 km in length and 3 km at its widest point”. Much of the Quackenbush data is proprietary, and Camp and Jordan pieced together permeability estimates from two vertical and one horizontal well cores taken from ~3050 m below the surface where the temperature was ~90°C. One of the vertical cores was drilled just outside the graben in tight limestone. The other vertical well was 64 m from the first, within the graben, and completely dolomitized. It had a porosity of 2.7% and an average permeability of 22.5 mD. The 10 m horizontal core had an average porosity of 3.2% and an average permeability of 0.11 mD. The Whitman #1 core from an adjacent gas reservoir in the T-BR has an average porosity of 7% and average horizontal permeability of 2.1 D. Its vertical permeability was 2.6 mD.

4.3 Potsdam transmissivity

The Potsdam sandstone in northern NY and Quebec forms a ~450 m thick aquifer on the northern boundary of the Adirondack Dome. It grades upwards through its three members (Allens Falls, Ausable and Keeseville) from a less permeable argillaceous sandstone to a more permeable quartz-rich and matrix poor sandstone. Permeability is mainly in sub-horizontal bedding-related fractures spaced <10 m apart. Transmissivities range from 1.15×10^{-4} to 11.5×10^{-4} m^2 s^{-1}, well above the 0.46×10^{-4} m^2 s^{-1} required by Cornell's ESH project (section 3.2.1). (Williams et al. 2010).

Field evidence suggests the Potsdam is much less permeable south of the Adirondack Dome. There are no water wells in the granite, gneiss, or Potsdam sandstone (or basement granites or gneiss) in the West Milton area 9 miles southwest of Saratoga springs, although in other areas these units produce at 5 to 10 gpm. The most productive near-basement wells in this area are in the Theresa carbonates where the average production rate is 25 gpm (Mack, Pauszek, and Crippen 1964).

The saline Saratoga cold mineral springs in the Hudson lowlands at Saratoga (Figure 8) are a mix of meteoric water recharging the Cambrian carbonates and shield-type brines from under the Adirondack dome (Siegel et al. 2004). Their discharge along an ~10 km portion of the McGregor-Saratoga high angle extensional fault illustrates the importance of faulting on fluid flow, and their chemistry suggests the metamorphic Adirondack rocks are permeable enough to allow recharge through the Adirondack Dome.

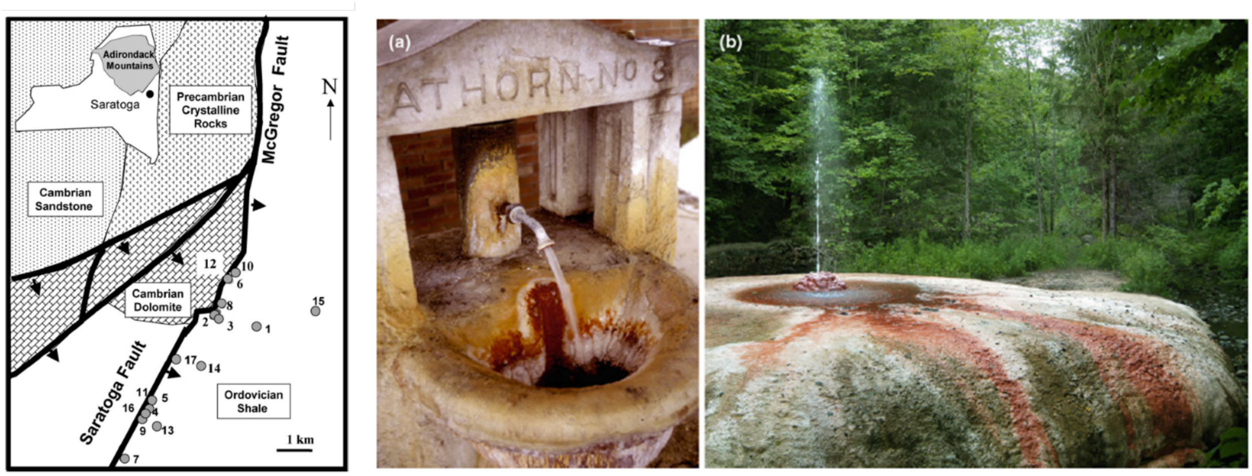

Figure 8. The saline, CO_2-rich Saratoga cold spring that discharge along the McGregor-Saratoga fault are thought to be a mix of meteoric water recharging through the Cambrian sandstones and carbonates and shield brines under the Adirondack dome displaced by flow into the exposed metamorphic basement. Left figure from (Siegel et al. 2004)

4.4 Metamorphic basement permeability

The surface of the Precambrian metamorphic basement 9 miles southwest of Saratoga Springs is highly irregular with relief of 450 to 500 feet (Mack, Pauszek, and Crippen 1964). Porosity is <5% and permeability is related to joints and other fractures. Well productivity is low (5 to 10 gpm). Production is always associated with horizontal decompression fractures (personal communication David Valentino, Oswego State, January 9, 2020).

5. Discussion

5.1 Transmissivity

The transmissivity required to produce warm bine at the pilot rate of 0.023 m^3 s^{-1} (364 gm) is 0.26 D m. Table 1 places the permeability data reviewed in section 4 in the context of the production rate required for Cornell's ESH pilot, generally by calculating the length of borehole needed to produce at 364 gpm.

Table 1. Summary of production-related data discussed in section 4.

	data	Required production interval [m]
Queenston Formation (S. A. Holditch & Associates, Inc., Houston TxCayuta 1994)		
Bale #1 Well	T= 8.8 mD m	260 mD m needed Queenston could be more sand-dominated and could be more permeable in the middle of Tompkins County (Tamulonis, Jordan, and Jacobi 2014)
Trenton-Black River dolomite (Camp and Jordan 2017)		
Whitmore #1 core	$\bar{k}_H$ =2.1 D $\bar{k}_V$ =2.6 mD	1.2 cm 3000 m
Quackenbush vertical core	$\bar{k}$ =22.5 mD	11.5 m
10 m Quackenbush horiz. core	$\bar{k}$ =0.11 mD	2363 m
Potsdam sandstone (Williams et al. 2010; Palmer, Taylor, and Terrell 2017)		
North of Adirondack dome	T>0.65 D m, 450m	180 m
South of Adirondack dome	5 gpm over 30 m	2184 m
	10 gpm over 30 m	1092 m
Theresa carbonate W. Milton	25 gpm over 30 m	436 m
Bale #1 well	0.9 gpm over 690 m	ESH target production not possible
Metamorphic basement (Mack, Pauszek, and Crippen 1964)		
West Milton area	5 gpm over 30 m	2184 m
	10 gpm over 30 m	1092 m

The data in Table 1 and the discussion in section 4 suggests producing brine below 2 km depth at 364 gpm will not be easy. Consider:

1. The Potsdam and metamorphic basement entries in Table 1 are all from shallow wells and mostly from domestic water wells which we assume are 100 ft (30 m) deep. Permeability is from horizontal fractures, which suggests erosional decompression is an important factor.

Only 0.88 gpm could be injected into the Bale #1 well over an interval of 690 m between 2916 and 3605 m depth under ~2000 psi pressure (or 1400 m excess head). Either decompression has greatly increased the permeability of basement and Potsdam formation rocks, or the Bale #1 well was extremely unlucky in its placement. The most reasonable conclusion is that decompression has opened the shallow horizontal fractures that account for the near-surface permeability observed. At depth, horizontal fractures will not be open and the permeability will be much less, as observed in the Bale #1 well.

2. The Queenston formation has low transmissivity. A transmissivity 30 times greater than measured would be needed to return the 364 gpm of brine production used for Cornell heating. A 3000 ft long horizontal well might accommodate the disposal needs.
3. The Trenton-Black River is the most promising target for finding the permeability needed for ESH production, but this formation is probably only a good target in grabens like the Quackenbush where it is extensively faulted and dolomitized. Dolomite is much denser than limestone, so dolomitization produces porosity and open permeable passageways.
4. By analogy to the Quackenbush, the Theresa carbonate is probably the second best permeability target.
5. Carbonate strata above the Utica Shale might be targets for shallow re-injection.

In summary: **Finding permeability in the Trenton-Black River or other carbonates or formations may not be easy, and will require targeted drilling.**

5.2 Radius of influence

The radius of influence, the distance from which water will be drawn by Cornell's ESH production, is calculated by equation (8) and shown in Figure 6. As shown by equation (8), for a transmissivity sufficient to meet Cornell's pilot production needs, the distance of draw depends on time and how much water the produced formations can yield (e.g., the storativity, *Sb*). We have calculated the draw for a range of specific storage values appropriate for fractured rock, assuming a confined aquifer thickness of 30 m. Under these assumptions the draw after 20 years of pumping at 364 gpm is between 4.6 and 33 km from the well.

These calculations give insight but require discussion. First, the calculations assume that the drawdown cone will encounter no barriers. What happens if the volume of rock from which water can be drawn has limits? For example, suppose Cornell is producing water from the dolomitized portion of a Quakenbush-type graben that is 13 km long, 3 km wide, and 100 m thick, i.e., a 3.9 km^3 volume of dolomite. The dolomitized part of this graben has the same volume as a cylinder of confined aquifer 30 m thick with radius 6.4 km. Thus, very roughly speaking, we might expect that if the specific storage of the dolomite were >~$4x10^{-5}$, Cornell could produce for 20 years without problems. Of course, one would want to do calculations that take into account the actual dimensions of the produced volume. We use simple geometries here because we do not know the shape or dimensions of the volume that will be produced, but these methods give an idea of the volume that will be needed, and this volume depends on the storativity $S_s b$, the amount of brine that can be extracted from the formation being tapped.

Second, the volume being tapped by production can and is expected to have a very irregular geometry. There are good general reasons to expect that flow will become more and more channelized as the distance of flow increases. A good discussion of the reasons for believing this is provided by (Malin et al. 2020). This means that Cornell's production well may draw fluid from a very large distance.

The permeability of the channels will likely increase with the distance of draw, so sustaining the production rate despite the large draw may not be an issue, but **fluids could be drawn (introduced) from (to) very great distances in a highly directional fashion**.

5.3 Dipole flow management

Conventional ESH practice reinjects produced brines in the same formation. This has the advantage that the pressure increase that would be related to fluid injection is largely cancelled by the nearby production well, as shown in Figure 7A. In an environment where flow is through fractures, it is highly likely that flow will short circuit from the injection to the production well if the wells are close together, however. Short-circuit cooling of the produced fluids can be delayed and reduced by moving the injection and production wells further apart, but, as shown by Figure 7, this will also result in the increase in fluid pressure associated with injection being less reduced by production. Less pressure cancelation means more risk of triggering small earthquakes.

Flow channeling will increase the earthquake risk. Suppose for example that the injection well finds a permeable channel in the direction away from the production well. More of the injected fluid would enter this channel and raise fluid pressure more, raise it more rapidly, and at greater distances.

In the conventional dipole approach a great deal of effort is likely to be spent avoiding short circuiting, and managing the earthquake risk. The tools to manage these risks are few: stimulating specific intervals of the wellbores, plugging flow in parts of the wellbore, and drilling new wells or spurs off existing wells. An installed wellbore pair that starts to cool because of short circuiting of flow between the injection and production wells will be difficult and expensive to remedy, and the problem may not show up until years after the initiation of thermal production.

5.4 Utilizing layered stratigraphy

In a layered stratigraphy like that under Cornell **the short-circuiting risk can be eliminated and the earthquake risk reduced by stratigraphically separating the injection and production wells with an intervening low permeability strata, as illustrated in Figure 1**.

The risk of cooling by short-circuiting is eliminated. The very low permeability Utica shale and the low permeability siltstones that overlie the T-BR means there will be no communication with brines injected in the Queenston or carbonate strata above it. Flow into a well tapping the Trenton-Black River, for example, will come from the T-BR or underlying strata. The fluids moving to the well will be from the same depth or deeper, and thus be at the same temperature or hotter.

The earthquake risk is reduced because the risk of triggering earthquakes in the basement is decreased, not increased, by brine production. The larger earthquake risk lies in the basement. Injecting into shallow strata could trigger earthquakes, but, provided the least principle stress is in the horizontal plane (which seems to be the case near Cornell), the magnitude of the earthquakes that could be triggered by brine injection at shallower levels will be limited by the limited depth interval over which normal or strike-slip movement could occur, the fact shallow strata are weaker than the metamorphic basement, and the likelihood that substantial strain energy has not built up in the shallow strata because they are decoupled from deeper crustal stresses by weak salt and shale layers. These factors will decrease the magnitude of the small earthquakes that could be triggered by the re-injection of ESH fluids (see Appendix B). Earthquake risk can be managed by seismic monitoring and yellow light reduction of injection rates, but reduction of earthquake magnitude by injecting into shallow strata could be a valuable added safeguard. ESH injection rates are similar to the injection rates that triggered earthquakes in Oklahoma (Barbour, Norbeck, and Rubinstein 2017), so the issue of earthquake triggering is substantial and must be considered seriously and managed carefully.

5.5 Strategy for evaluating viability of ESH at Cornell

The discussion above suggests the following strategy for evaluating the viability of ESH production under the Cornell Campus:

1. Carry out a 3D seismic and fracture seismic survey (3D/FS)

    Permeability is by far the most important factor governing success of heat extraction from depth under Cornell. If natural permeability can be found that is sufficient to support brine extraction at ~364 gpm there is substantial prospect for project success. A 3D seismic survey should be carried out to identify any small grabens in the Trenton Black-River or valleys in the Potsdam Formation, or other structures in other formations, that could be permeable enough to support the pilot injection/production. In conjunction with the 3D seismic survey, a passive fracture seismic survey should be carried out to image the harmonic emissions of the fluid filled fractures that can support flow. The fracture seismic method and how it is related to permeability is well described by (Sicking and Malin 2019). A fracture seismic survey can be carried out at the same time using the same instruments as the 3D seismic survey. Cornell has already solicited a proposal from ARM to carry out and interpret a fracture seismic survey, and the recent International Continental Scientific Drilling (ICSD) workshop held at Cornell 8-10 January 2020 was supportive of the idea that both 3D and FS surveys be carried out prior to drilling a pilot hole. Ideally, the seismic array should be emplaced in shallow drill holes so that the network can be used for monitoring as the viability of the project is assessed, and reestablished for more permanent monitoring if Earth Source Heat extraction is implemented.

2. Drill a small diameter test hole into shallow and deep locations likely to have the greatest permeability based on the 3D/FS surveys and carry out hydraulic tests

    The primary purpose of a test hole from the perspective of this report is to measure the maximum permeability of shallow hydraulically-isolated strata and of strata >2 km below the Cornell campus. The well bore should be of sufficient diameter to support the packers, casing, etc. needed for the permeability testing. It should target the locations deemed most likely to be permeable based on 3D/FS surveys in recommendation (1) above.

    If the permeability of the most permeable zone at >2 km depth is such that brine can be produced at 364 gpm, the next question is whether such production can be sustained for 20 years. Some indication may be provided by the rate of drawdown, but valuable additional information could come from the distribution of fracture seismic signals induced by the testing. These signals will indicate the geometry and extent of the reservoir from which hot brine will be drawn. The 3D/FS array deployed in (1) above should be retained or re-established during the fluid flow testing so that fracture seismic signals can be recorded as the well is tested, and the regions from which brine is drawn mapped.

The permeability of shallow formations should also be tested on the way to the deep target to determine if there are better options for brine injection at ~364 gpm than the Queenston.

The stress profile should be measured in the test hole. This is important for determining whether the earthquake risk is of either a strike-slip or normal fault nature. If the horizontal stress is not the minimum stress, injecting at shallow depths would be less effective in limiting earthquake magnitude since the area of the thrust fault that could be triggered is not constrained by the thickness of the shallow stratigraphy.

As discussed in the ICDP workshop, the test well, especially if it is continuously cored, would provide valuable geoscientific data that would help justify its cost.

3. If the test well finds zones that can be separately produced and injected into at 364 gpm, proceed with drilling a proper larger diameter production and injection wells, and install and operate the pilot heating system. Try the stratigraphically separated injection and production strategy first, but drill the injection well such that it could be extended to the depths influenced by the production well if production declines and a pressure assist is desired to increase it.
4. If the test well does not find the requisite permeability, carry out tests to determine if higher permeability zones might be located nearby, and either drill into them with a spur or tap into them with stimulation techniques.
5. If the permeability needed to produce and inject at 364 gpm cannot be found or produced, reevaluate the project and be prepared to terminate it.

Undoubtedly stimulation strategies will be suggested to increase the production and injection to the target rates. These strategies should be examined critically, particularly in regard to short circuiting and the volume of rock that can be swept thermally.

6. Summary

This report uses standard hydrologic methods to determine the transmissivity (permeability-thickness product) needed to produce brine at the 364 gps rate required by the Cornell ESH pilot project. The needed transmissivity requires a permeability greater than that generally found in the Cornell subsurface. Thus the first task is to locate zones beneath Cornell with the required permeability. When this is done, a second task is to show that brine can be produced from and injected into the permeable formation(s) for 20 years.

Brine is likely to be drawn from (or return waters introduced to) very substantial distances by 20 years of production (injection). This means there is unavoidable risk of triggering earthquakes. If the produced brines are injected into the same formation, there is also a substantial risk the injected fluids will short-circuit to the production well and reduce the temperature of its produced fluids.

Short circuiting risk can be eliminated and earthquake risk limited by stratigraphically separating the injection and production wells, provided the shallow horizontal stress is the minimum stress. The layered stratigraphy in the Ithaca area has some significant potential advantages for safe and effective ESH production.

A strategy of first carrying out 3D seismic and fracture seismic surveys to identify the locations beneath Cornell that are most likely to have the needed permeability, then drilling a test well to determine if these locations are indeed permeable enough, and then testing to determine if fluids can be produced or disposed with stratigraphically-separated wells for over 20 years is suggested. If test results are positive, Cornell can proceed with its pilot ESH program with reasonable confidence of success. If the permeability required for production and injection cannot be found or produced in the pilot well, or if the reservoir for production or storage appears too small, the project should be carefully reevaluated.

Appendix A: Calculating W(u)

W(u) in equation (1) in the text is very easy to calculate by summing a few terms in a series.

$$e^{-x} = 1 + \sum_{n=1}^{\infty} (-1)^n \frac{x^n}{n!}$$

$$\int_u^{\infty} \frac{e^{-x}}{x} dx = c + \left(\ln x - x + \sum_{n=2}^{\infty} (-1)^n \frac{x^n}{nn!} \right)_u^{\infty} = -0.5772 + u - \ln u + \sum_{n=2}^{\infty} (-1)^{n-1} \frac{x^n}{nn!} \qquad \text{(A1)}$$

$$\int_u^{\infty} \frac{e^{-x}}{x} dx \sim \ln \frac{1}{u} - 0.5772 = \ln \frac{1}{1.78u} = \ln \frac{2.25Tt}{r^2 S} \qquad \text{considering just first few terms}$$

$$\Delta h = \frac{-Q}{4\pi T} \int_u^{\infty} \frac{e^{-x}}{x} dx \sim \frac{-Q}{4\pi T} \ln \frac{2.25Tt}{r^2 S} = \frac{-2.3Q}{4\pi T} \log \frac{2.25Tt}{r^2 S}$$

The equality in the second equation follows because *W(u)*=0 when *u*=infinity. The third equation follows because ln 1/1.78 = -0.5772. The equality in the last equation follows because 2.3 log x = ln x.

More terms are needed to define W(u) when u is large, but when u<1 only a 3 terms suffice, and for u<0.1 ln 1/1.78u is a good approximation. To capture large u, we sum the series to n=50 and on occasion to n=100 terms.

Table A1. Evaluation of the number of terms in the sum in equation (2b) required to fit W(u) for large u. Also evaluation of the remarkable validity of W(u<~0.1)= ln 1/1.78u.

u	5	1	0.1	0.01	1e-5
W(u)	0.0011	0.219	1.82	4.04	10.94
ln 1/1.78u	-1.91	-0.5766	1.725	4.028	
sum to n=3	3.50	0.228	1.82	4.04	
sum to n=5	2.205	0.219			
Sum to n=20	0.0011				

Appendix B: Reduction of earthquake risk by injection into shallow Ithaca stratigraphy

The magnitude of an earthquake depends the area of rupture, A, the shear modulus of the material ruptured, μ, and the displacement of the ruptured area, D (Hanks and Kanamori 1979):

$$
\begin{aligned}
M &= \left(Log_{10} M_o - 9.05\right)/1.5 \\
M_o &= \mu A D
\end{aligned}
\qquad \text{(B1)}
$$

The dependencies in (B1) suggest injecting into shallow strata that are separated by impermeable strata from basement in the Ithaca area could substantially reduce earthquake relative to the risk of injecting at deeper levels with hydrologic access to basement.

1. As shown in Figure B1, if the produced brine is reinjected above the impermeable Utica Shale the rupture interval likely lies between the Utica shale and the Salina salt, both of which are weak decoupling horizons. This means that little strain energy is likely to have accumulated in the stratigraphic interval that would be affected by injection.
2. The shear modulus, μ, of sand and shale is much less than metamorphic basement rock.
3. The depth interval of rupture is at most ~1 km for this shallow stratigraphy, which is much less than the >10 km depth interval of rupture conceivable in the basement. The area of potential rupture is thus much less for shallow injection in the Ithaca stratigraphy than it is for deep injection which could pressurize the basement metamorphic rocks.
4. If production is from below injection, and isolated from it by impermeable strata, pressure will be reduced in the deeper sedimentary and basement formations and the more serious basement earthquake risk will thus be reduced, not increased, by ESH extraction.

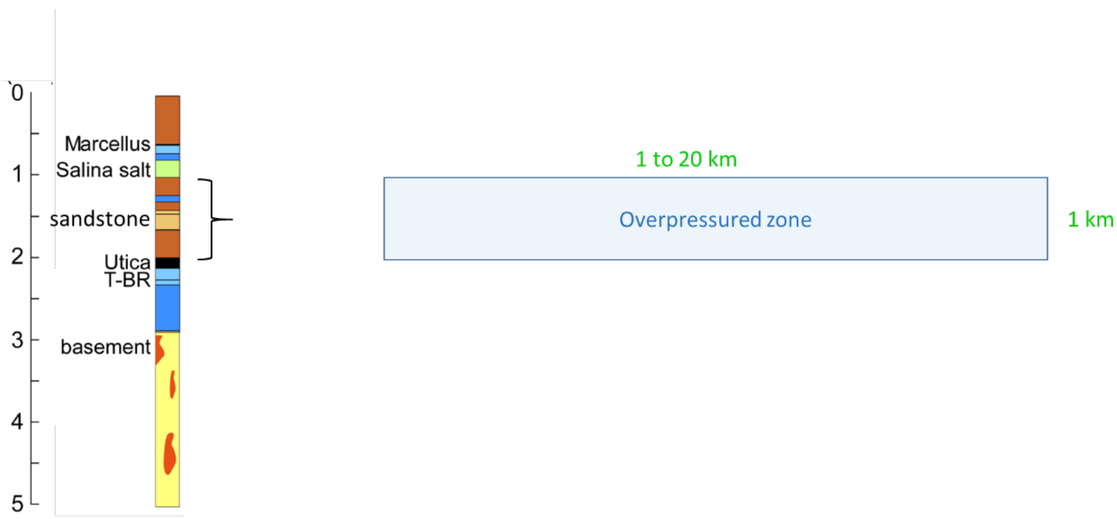

Figure B1. If injection well is above the decoupling Trenton Black-River (T-BR) but below the Salina salt, the rupture interval will be ~1 km.

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