

1 **Analytical Model and Experimental Testing of the**
2 **Limits of Hydraulic Fracture Caging**

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10 **Key Points:**

- 11 1. Fracture caging uses boundary wells to limit fluid-driven fracture growth and to contain
12 flow in hydropropped fractures
- 13 2. Fracture caging fails if production rates are too constricted or if fractures do not
14 intersect boundary wells
- 15 3. Fracture caging can be achieved with as few as two boundary wells, but three or more
16 wells increases stability

17 **Abstract**

18 Enhanced Geothermal Systems (EGS) are a promising concept for unlocking the great potential
19 of Hot Dry Rock (HDR) resources for clean and sustainable energy production. It can be argued
20 that three of the foremost unsolved challenges for EGS are: induced seismicity, uneconomically
21 low flow rates, and premature cooling of the produced fluid. We propose that fracture caging
22 could be a solution to these three challenges. Fracture caging is the placement of a ‘cage’ of
23 boundary wells around injection wells before fluid stimulation or circulation begins. This
24 fracture cage is intended to contain injected fluids and to thereby limit fracture growth. In the
25 long term, this fracture cage permits sustained high-pressure fluid injection to hold fractures
26 open using hydraulic pressure (i.e., ‘hydropropping’) instead of by using proppant particles or by
27 shear asperity propping. In this study, we present an analytical model and laboratory experiments

28 that quantitatively explore the limits of tensile hydraulic fracture caging. Discoveries from this
29 work include: (1) the maximum flow rates that can be caged are limited by flow constrictions in
30 the boundary wells but are not limited by the injection pressure, (2) a hydraulic fracture can be
31 caged with as few as two boundary wells, and (3) tensile fractures can be hydropped without
32 growing larger during sustained high-pressure fluid injection into a cage.

33 **Plain Language Summary**

34 Geothermal energy is entering a new frontier where power plants that can generate electricity
35 using the heat of the Earth will no longer be limited to rare high-grade resources. The key issues
36 holding back deployment are well established: (1) typical hot rock resources lack water for
37 energy production, (2) engineering rock to accommodate the flow rates for needed for power
38 production is not trivial, (3) the hot rock must be accessed by costly wells, and (4) geothermal
39 systems pose a risk for triggering earthquakes. In this paper, we present our most recent research
40 to investigate a new approach to geothermal resource development that we call ‘fracture caging’.
41 At its core, fracture caging merely asks for boundary wells to be drilled in a circle around future
42 water injection wells. Our work demonstrates that this up-front investment provides a reliable
43 solution to contain fluid flow. This permits injection and extraction rates can be set to the most
44 optimal values for economic power generation. Likewise, this cage should be able to contain
45 triggered earthquake risk. Our work is a pioneering step towards enabling enhanced geothermal
46 energy to unlock the frontier of clean geothermal energy anywhere.

47 **1 Introduction**

48 Geothermal resources can provide sustainable clean baseload energy for industrial, commercial,
49 and residential uses. Increased use of geothermal energy will help to reduce carbon emissions for
50 climate change mitigation and it will be a key component of the energy transition away from
51 fossil fuels. Despite these benefits, geothermal energy is underutilized in practice. According to a
52 U.S. Department of Energy report, the maximum rated output capacity of geothermal energy
53 production in the United States was only 3.7 GWe in 2019, which could be increased to 60 GWe
54 by 2050 once the technical barriers, including induced seismicity and poor economics, are
55 properly addressed [Hamm et al., 2019].

56 Enhanced Geothermal Systems (EGS) have the most potential for growth because, unlike a
57 conventional hydrothermal system, EGS do not require abundant in-situ water nor do they
58 require permeable rock [Hamm et al., 2019]. The EGS concept is typically envisioned as a well
59 doublet with one well for water injection and the other for production. This vision assumes that
60 flow is established by creating new fractures or reactivating preexisting fractures in geothermal
61 reservoirs [Tester et al., 2006; Kelkar et al., 2016]. However, there are some outstanding
62 technical problems that hinder unlocking the great potential of EGS. First, fluid injection induced
63 seismicity has been identified as a major threat [Cuenot et al., 2008; Catalli et al., 2013;
64 Ellsworth, 2013]. For example, a Mw 5.7 earthquake has been linked to at an EGS pilot site in
65 Pohang, South Korea [Kim et al., 2017] even though state-of-the-art mitigation methods were
66 employed. These methods included cyclic soft stimulation, the so-called traffic light system, and
67 real-time seismic monitoring. Second, high-rate and high-pressure water injection is often
68 required to achieve economic power production from EGS [Petty et al., 2013; Garcia et al.,
69 2016]. Existing seismicity mitigation measures impose limits on injection rates and pressures with
70 the goal of reducing seismic risk, but paradoxically no methods yet exist to predict what these
71 limits should be for a given site. To be fair, the theory is understood for how such limits could be
72 predicted, but the reality is that we lack the required input data to parameterize these predictive
73 models. Third, short circuited flow of water between injection and production wells is common.
74 Short circuiting is when the working fluid preferentially flows along a single path, as opposed to
75 a multiple paths, which in turn results in a low effective surface area for heat extraction. This
76 leads to premature cooling of the produced fluid and inefficient utilization of the hot rock
77 resource. These short circuits are inevitable due to fracture heterogeneity and fluid-rock
78 interactions at elevated temperatures that promote flow channeling [André et al., 2006; Pruess,
79 2008; Gee et al., 2021]. Solutions to prevent short circuiting are practically limited to in-well
80 zonal flow control tools and techniques. Research and the development of new technologies are
81 required to address these technical problems.

82 Recently, we introduced the concept of ‘fracture caging’ to limit induced seismicity and to
83 enable sustained high-rate high-pressure fluid circulation [Frash et al., 2018 & 2021]. Fracture
84 caging involves boundary wells surrounding an injection well to proactively limit fracture
85 stimulation and achieve fluid flow containment in a geothermal reservoir. However, our prior
86 work did not investigate the limits of fracture caging because the experiments were too short in

87 duration to confirm halting of fracture growth, did not investigate the minimum number of
88 boundary wells that could cage a hydraulic fracture, and did not identify the parameters that
89 control the maximum flow rate that can be caged. Here, we will rectify these shortcomings and
90 will demonstrate that fracture caging holds promise for field-scale application.

91 To elaborate on fracture caging and the motivations for studying it, we hypothesize that fracture
92 caging has the potential to solve the three foremost technical challenges related to EGS viability:
93 (1) induced seismicity that can damage nearby structures, (2) excessively low flow rates that
94 preclude economic power generation, and (3) thermal short circuiting that leads to premature
95 cooling of the produced fluid. To confront seismicity, controlling fracture growth and achieving
96 fluid containment using fracture caging offers the means to limit the length of fracture slip, thus
97 controlling the maximum magnitude of seismicity [Kanamori and Anderson, 1975]. To confront
98 low flow rates, EGS requires long-term fluid injection at high-rate and high-pressure without the
99 typically expected increase to seismic risk [Jeanne et al., 2015]. Fracture caging could decouple
100 flow rate and pressure from seismic risk, removing the need for flow limits. To confront thermal
101 short circuiting, increased active fracture surface area and a uniform flow sweep without
102 channeling is required. Fracture caging opens the possibility of propping fractures open with
103 high-pressure fluid which could mitigate the severe flow channeling caused by heterogeneous
104 closed areas in fractures. When this tensile opening occurs without fracture growth, we refer to
105 this condition as ‘hydropropping’ because the high-pressure fluid is the proppant. With
106 hydropropping neither solid sand proppant nor shear propping would be required to maintain
107 hydraulic conductivity. In addition, the removal of pressure limits using caging will increase
108 options for in-well tools for long-term flow control, such as limited entry casing perforations
109 [Frash, 2022].

110 Our recently proposed concept of fracture caging requires more development and validation
111 before it can be confidently applied. A crucial next step is to conduct experiments to validate the
112 ability of fracture caging to halt fracture growth during sustained high-rate high-pressure flow.
113 Previous experiments were too brief to be conclusive on in this regard. By extension, proof of
114 stable hydropropping is also needed. The premise of drilling multiple boundary wells is an
115 economic deterrent against using caging, so models and experiments are needed to investigate
116 the minimum number of boundary wells that can cage an active fracture. In this modeling and
117 experimental study, we present an analytical model to predict the maximum flow rate that can be

118 caged at any scale and we present a series of new laboratory experiments to evaluate the
119 performance of fracture caging in three, four, and five well geometries. In addition to verifying
120 the ability of boundary wells to halt fracture growth, these lab experiments tested hydropropped
121 fracture stability across a range of flow rates and a range of open versus closed configurations for
122 the boundary wells. With the inclusion of acoustic emission measurements, these experiments
123 provide a rich dataset with applications beyond our interest area. Ultimately, we will prove that a
124 hydraulic fracture can be halted by as few as two wells, that larger fractures are easier to cage
125 than smaller fractures, that the maximum caged flow rate is primarily a function of well
126 diameter, and that stable hydropropped fractures are possible even when the injection pressure
127 exceeds the static pressure required for fracture growth.

128 **2 Fracture Caging Analytical Model**

129 In this section we present our conceptual model for how fracture caging can be achieved in
130 fractures of any size. We begin with a simple model to estimate fracture radius as a function of
131 cumulative injected volume. Next, we consider frictional flow effects to predict caged fracture
132 stability as a function of injection rate. The geometry, fluid properties, and material properties
133 used in this section are consistent with those used for our experiments. Ultimately, our results
134 indicate that caging should be possible in commercial geothermal systems.

135 *2.1 Fracture radius from injected volume*

136 We require a model to predict uncaged fracture radius as a function of injected fluid volume in
137 order to verify that caging can halt hydraulic fracture growth. Later, we will use this model to
138 compare predicted uncaged radii to measured caged radii. We start with the same homogeneous,
139 elastic, impermeable, Newtonian fluid, and laminar flow assumptions that are used by many
140 analytical hydraulic fracture models. These assumptions will be met in our experiments by using
141 acrylic as our host material and oil as our fluid. Next, we must point out that existing analytical
142 hydraulic fracture models were created to predict hydraulic fracture radius and net pressure as a
143 function of a constant injection rate and time [Detournay, 2004]. In the case of fracture caging,
144 these existing models can only be applied up until when the fracture first intersects a boundary
145 well. After this time, fluid is both being injected and produced so volume balance is no longer
146 controlled solely by the injection parameters. Consequently, existing hydraulic fracture growth

147 models are not directly applicable to fracture caging. Instead, we will assume that the fracture is
 148 caged at a constant radius with steady-state hydropropping and uniform net pressure. This
 149 permits the use of Sneddon's equation [Sneddon and Lowengrub, 1969] to estimate the aperture
 150 (w) at the center of an elliptical penny-shaped tensile hydraulic fracture as a function of radius
 151 (R_f) with its uniform net pressure at the critical limit for propagation (P_c).

$$152 \quad w = \frac{8P_c(1-\nu^2)R_f}{\pi E} \quad (1)$$

153 The Young's modulus (E) and Poisson's ratio (ν) for acrylic can be taken as 2.6 GPa and 0.40,
 154 respectively. Since the fracture geometry is elliptic, we can estimate the volume (V) of this
 155 fracture directly from the radius (R_f) and center-point aperture (w). Rearranging, we can now
 156 estimate the fracture radius as a function of the cumulative injected fluid volume.

$$157 \quad V = \frac{2\pi R_f^2 w}{3} \quad (2)$$

$$158 \quad R_f = \sqrt[3]{\frac{3VE}{16P_c(1-\nu^2)}} \quad (3)$$

159 Many analytical solutions to predict critical fracture pressure (P_c) and dimensions (w , R_f) have
 160 been proposed, such as by using linear-elastic-fracture-mechanics [Valko and Economides,
 161 1996] or by using both flow and fracture mechanics [Detournay, 2016]. These solutions require
 162 material parameters such as fracture toughness which are notoriously difficult to measure.
 163 However, in our case, we have the advantage of measuring the critical fracture pressure in the
 164 same material, using the same fluid, and at the same dimensions as our experiments. Later, we
 165 will detail our measurements of this value (P_c) at 2.3 ± 0.1 MPa.

166 *2.2 Caging injection rate limit*

167 Let us consider pressure losses with flow through a hydropropped fracture that is maintained at
 168 the critical limit for fracture propagation (P_c). Again, our experiments will show this value to be
 169 2.3 ± 0.1 MPa in acrylic. The flow rate that is needed to induce this critical pressure in a caged
 170 and hydropropped fracture will be the maximum rate that can be caged. Further, a caged fracture
 171 includes simultaneous injection and production at equal total rate. Ideally, the total production
 172 rate will be equally split among all production wells. Here, we will not attempt to account for
 173 how fracture heterogeneity and flow instability will result in non-equal flow distribution. The

174 frictional flow terms that are most likely to control caged fracture flow inside an arbitrarily
 175 shaped fracture include: (ΔP_x ; Eq. 4; Jeppson, 1974) pressure losses with flow through the wells,
 176 (ΔP_r ; Eq. 5; Yen, R.T., 1962) pressure losses with flow through the near-wellbore zone, (ΔP_l ;
 177 Eq. 6; Witherspoon et al., 1980) pressure losses with flow through narrow fractures, and (P_p) the
 178 backpressure at the outlet of the boundary wells.

$$179 \quad \Delta P_x = \frac{1.14 \times 10^8 Q^{1.852} \mu x}{f^{1.852} (2R_w)^{4.87}} \quad (4)$$

$$180 \quad \Delta P_r = \frac{6Q\mu \ln(r/R_w)}{\pi h^3} \quad (5)$$

$$181 \quad \Delta P_l = \frac{12Q\mu l}{Hh^3} \quad (6)$$

182 Where, Q is volumetric flow rate, μ is fluid viscosity, l is flow path length, H is flow path height
 183 or width, h is hydraulic aperture, R_w is well radius, f is pipe roughness, and x , r , and l are
 184 distances along the flow line. Rough pipe has an f value of around 80. Standard units for the
 185 above equations are m, s, and Pa. Without assuming specific well locations within a fracture, we
 186 will estimate fracture net pressure using total hydraulic force (F) over the respective area of the
 187 fracture (A).

$$188 \quad P_c = \frac{F}{A} \quad (7)$$

$$189 \quad F = \sum \int (\Delta P_i + P_{io}) dx \quad (8)$$

190 Where i is the flow element (e.g., well, near-well, or fracture) and io is the pressure downstream
 191 of this element. The only element that will not influence the ability to cage the fracture is the
 192 pressure loss through the injection well because the fracture's net pressure is a consequence of
 193 the downstream losses. To account for fracture stranding (i.e., multiple fractures, N_f) and
 194 multiple boundary wells (N_p), we can impose simple division if we assume an equal distribution
 195 of flow.

$$196 \quad Q_{pro} = \frac{Q_{inj}}{N_p} \quad (9)$$

$$197 \quad h = \frac{w}{N_f} \quad (10)$$

198 Given a fracture radius, well diameter, and well spacing, this system of equations can be solved
 199 to calculate the injection rate limit for a caged hydraulic fracture. Our solution is provided in our

200 online data repository (<https://zenodo.org/record/8274273>). To aid upscaling, we will take a
201 constant ratio of 0.75 between the well spacing and fracture radius. Also, we will take the radius
202 of influence of the near well zone to be 1/6th of the well spacing. For well length, we use a ratio
203 of 2 with respect to the well spacing. These ratios ensure that crucial flow constricting processes
204 are accounted for, and the ratios allow us to evaluate caging at small and large scales by varying
205 the well spacing and well diameter (Fig. 1). This model predicts that fracture caging is possible
206 at the lab scale (i.e., 1 to 100 cm) and the field scale (i.e., 100 to 1000 m). At field scales, the
207 maximum injection rate (Q_{inj}) that can be caged is predicted to be primarily a function of the well
208 diameter due to the backpressure that builds from flow through the production well (Q_{pro}). The
209 model also predicts that caging becomes easier as the fracture grows with a given well spacing
210 because longer fractures will have larger apertures, lower near-well pressure losses, and lower
211 in-fracture pressure losses.

212 **3 Experiment Description**

213 Hydraulic fracture caging laboratory experiments were conducted using high viscosity oil
214 injection into blocks of acrylic. Each block contained one central injection well surrounded by
215 two or more boundary wells (Fig. 2). The boundary wells were pre-drilled before injection so
216 that they could cage an approaching hydraulic fracture during the stimulation process. Once a
217 hydraulic fracture became caged by these boundary wells, as would be indicated by halting of
218 fracture growth, the boundary wells would continue to serve the role of production wells (i.e.,
219 producers) during experimentation with hydropropping. Collectively, these experiments for
220 fracture caging investigated the effects of fracture orientation, the number of boundary wells
221 during stimulation, the number of active producers during hydropropping, injection rates, and
222 boundary well flow control methods.

223 *3.1 Experimental setup*

224 Polymethyl methacrylate (i.e., PMMA or acrylic) was selected for our experiments primarily
225 because it is transparent which allows close observation of hydraulic fracturing and fluid
226 circulation. Beneficially, this material has extremely low permeability, is non-porous, has a
227 tendency toward brittle fracture, and its deformation can be described as elastic dominated.

228 These properties eliminate undesirable complexities, such as diffusive flow, while retaining the
229 ability to unambiguously measure hydraulic fracture radius due to its transparency.

230 The injection fluid was high-viscosity oil with red dye to enhance visibility. At 20° C room
231 temperature, this oil has a viscosity of 404 cP. Combining this with our targeted stimulation rate
232 of 0.5 mL/min, estimated duration of at least 1.0 s, and fracture toughness of 1.55 MPa-m²
233 [Weerasooriya, 2006], it can be shown that this yields toughness-dominated hydraulic fracture
234 growth [Detournay, 2004]. Based on our experience, using this oil slows fracture propagation
235 enough for standard 60 fps video to observe growth at the laboratory scale.

236 Wells were drilled into each acrylic block using the design shown in Fig. 2. The upper portion of
237 each well was sealed using stainless steel tubing and epoxy. The lower portions of the wells were
238 open-hole (i.e., no casing). The center well was notched with a 45° circular plunge cut to a depth
239 of 0.16 cm to guide hydraulic fractures into a transverse orientation. Well spacing was constant
240 as the number of boundary wells was set at either 2, 3 or 4, with separation angles of 180°, 120°,
241 and 90° respectively. Outside the blocks, 0.152 cm inner diameter (i.e., 1/8") stainless steel
242 tubing with a nominal length of 200 cm connected each well to its own syringe pump.

243 Digital cameras were used to record video of the fracture throughout each experiment. Blocks
244 were unconfined to allow visual observation. Although external polyaxial stresses are known to
245 be important and possible to simulate in the laboratory [Frash et al., 2015; Hu and Ghassemi,
246 2017], such approaches do not allow the visual observation of fracture growth that we require to
247 unambiguously confirm fracture caging. Conveniently, notches, such as ours, can be used to
248 orient hydraulic fractures in the laboratory when applied stresses are negligible.

249 Threshold triggered acoustic emissions (AE) were monitored throughout all experiments. A total
250 of 8 piezoelectric sensors were epoxied to the surfaces of each sample. The sample, the AE
251 sensors, and wiring were all shielded in a metal cabinet to minimize noise. Each AE sensor had a
252 resonant frequency of 2.1 MHz by thickness and 196 kHz by diameter. While it is possible to
253 perform source location and deconvolution with our data [Ohtsu, 1991 & 1995], here we employ
254 AE only for event counting.

255 *3.2 Experimental procedures*

256 Our experiments were conducted in four phases: ‘hydraulic fracturing’, ‘fluid circulation’, ‘flow
257 heterogeneity’, and ‘critical pressure’. Details follow and any exceptions are detailed in the
258 experiment results section.

259 The ‘hydraulic fracturing’ phase used a constant injection rate to induce a fluid driven fracture in
260 our notched central injection well. While care was taken to bleed all air from injection pump, the
261 boundary wells were either: (C1) bled of air and configured to actively maintain backpressure
262 using servo-mechanical motors or (C2) they were filled with 50 mL of air to serve as a passive
263 pressure accumulator. For the first control mode (C1), the backpressure was set at 0.5 MPa
264 which was the minimum control setpoint. This control response was slow, but enabled
265 production rate measurement. For the second control mode (C2), the backpressure was
266 atmospheric at 0.77 atm due to the 2220 m elevation of our facility. This (C2) control response
267 was immediate to minimize pressures surges. These details will be shown to be crucial for
268 caging.

269 The ‘fluid circulation’ phase involved multiple stages of continuous oil injection at increased
270 rates and pressures while oil production rates were measured using the active control mode (C2)
271 for the pumps. This process investigated the cage stability and the viability of hydropropping. In
272 other words, whether-or-not a caged fracture could support long-term, high-rate, and high-
273 pressure fluid injection without inducing fracture growth.

274 The ‘flow heterogeneity’ phase was completed next. Now, the influence of boundary well shut-in
275 (i.e., closure) was investigated by sequentially stopping all but one of the boundary well pumps
276 while continuing fluid injection. This process investigated the robustness of a caged fracture in
277 the event of one or more boundary wells becoming clogged or being taken offline for
278 maintenance. Such events will occur in field applications of fracture caging and hydropropping
279 for EGS.

280 The ‘critical pressure’ phase was completed after confirming caged hydraulic fracture stability
281 with long-term injection. In this phase, all production was halted while injection continued until
282 fracture growth resumed. This provided the critical pressure (P_c) measurement for our model and
283 it confirmed the ability to resume fracture growth by disabling the fracture cage.

284 This experiment design was inspired by field observations from the decameter-scale multi-well
285 EGS Collab project [Fu et al., 2021; Meng et al., 2021]. In this project, long-term high-pressure
286 fluid injection was performed and stable hydropropping was suspected due high production rates
287 and a lack of microseismic activity. During this time, the distribution of production was unsteady
288 and heterogenous which indicated issues such as chemical dissolution and precipitation, thermal
289 flow channeling, poromechanical effects, biological growth, flow instabilities, and particulate
290 mobilization and clogging. We imposed heterogeneous fracture flow in our experiments to assess
291 the performance of fracture caging in non-ideal circumstances to provide assurance that caging
292 can be reliably maintained in more complex scenarios.

293 **4 Experiment Results**

294 The main objective of the present study was to demonstrate fracture caging during hydraulic
295 stimulation and during hydropropping with sustained high-pressure fluid circulation. For
296 completeness, we examined situations that led to both caged and uncaged fractures. This enabled
297 us to not only verify that sustained caging and hydropropping are possible, but also to evaluate
298 the limits of fracture caging.

299 *4.1 Caged fracture with four boundary producers*

300 First, we present an experiment where a hydraulic fracture was successfully and stably caged by
301 four boundary producers (Fig. 3). The pressure accumulator control mode (C2) was employed to
302 maximize the chance of successful fracture caging. A hydraulic fracture was induced at a
303 breakdown pressure of 39.5 MPa using injection at 0.5 ml/min. As shown in the images (Fig. 4),
304 the fracture grew rapidly from 0 to 0.012 min (0.72 s) when it first intersected a boundary well
305 with an estimated injected volume of less than 0.1 mL and a nominal radius of 35 mm. Next,
306 injection continued but the fracture grew more slowly until it halted all growth at 0.129 min
307 (7.74 s) with the injected volume now totaling at 2.9 mL and the radius reaching 55 mm.
308 Thereafter, the fracture size remained unchanged at its 55 mm radius until 217 min (13,000 s)
309 despite more than 245 mL being injected at rates of up to 8 mL/min. At this time and if the
310 acrylic block had been larger, the predicted uncaged radius of the fracture would have been 394
311 mm per Eq. (3). At around 217 min, the finally fracture grew again because fluid was being
312 injected into the boundary well at a rate of up to 20 mL/min without any simultaneous

313 production. In hindsight, the pumps should have been disconnected from the block at this time
314 because this injection was performed merely to purge air from the pumps, so this injection into
315 the block was unintended. Later, growth was intentionally induced at 231 min using injection
316 without production. The only mechanism for halting of fracture growth throughout this process
317 was fracture caging, so this result unequivocally proves that fracture caging can halt fracture
318 growth and that caging can contain high-pressure fluids during long-term injection to enable
319 stable hydropropping.

320 During fluid circulation, injection pressures reached up to 6.22 MPa which is much higher than
321 the static critical pressure of 2.28 MPa. Meanwhile, the flow rate from each producer was
322 variable, oscillating between 20% and 32% of the injection rate. This indicates flow instability
323 despite the fracture radius remaining constant. The heterogeneous flow tests further investigated
324 this flow instability. To begin, the injection rate was maintained at 2.0 ml/min, one producer was
325 controlled under a constant pressure of 0.25 MPa, and the other three producers were all set an
326 initial constant production rate of 0.5 ml/min. This combination of constant pressure and
327 constant rate control of the four producers improved flow stability. Next, all but one of the
328 producers were sequentially shut-in. The hydraulic fracture retained a constant caged length
329 throughout, confirming the possibility of stable hydropropping.

330 Over the course of this experiment, more than 600 events were recorded. Of these, 38 events
331 were associated with hydraulic fracture breakdown. Additional AE activity was recorded while
332 the boundary pumps were bled of air from 150 to 220 min. AE was also recorded when the
333 fracture propagated at 231 min during the critical pressure stage. While these periods of AE
334 activity did coincide with fracture growth, the results are ambiguous to interpret which highlights
335 the unambiguous value of using transparent acrylic.

336 *4.2 Caged fracture with three boundary producers*

337 Second, we conducted a fracture caging experiment using three boundary producers (Fig. 5). The
338 fracture breakdown pressure was measured at 37.5 MPa with an injection rate of 0.5 mL/min.
339 Just as the four boundary well experiment, the fracture growth was rapid until it intersected the
340 first boundary well at 0.006 min (Fig. 6). The growth then slowed until it halted at 0.181 min, at
341 which time the fracture was now fully caged as verified by continued injection. This injection
342 continued until 139 min when a total volume of 178 mL of oil had been injected. The radius of

343 the fracture up until the critical pressure test at 139 min had remained stable at 46.6 mm, despite
344 the predicted uncaged radius being as large as 355 mm. Injection continued after this critical
345 pressure tests with the new fracture radius of 48.1 mm, ultimately injecting 338 mL which is
346 enough fluid to create an uncaged fracture of 438 mm radius. Notably, the injection pressure at 8
347 mL/min decreased after the critical pressure test, going from 5.5 MPa to 4.2 MPa. This reduced
348 injection pressure with a larger hydraulic fracture indicates a positive relationship between
349 increasing fracture size and more stable caging. Our model agrees with this observation by
350 predicting higher caged injection rate limits when the fracture is larger. Just as the four boundary
351 well experiment, this result again confirmed stable hydraulic fracture caging and stable
352 hydropropping with only three boundary wells.

353 *4.3 Caged fracture with two boundary producers*

354 In the third experiment, the injection borehole was caged by only two boundary producers while
355 the other experiment procedures remained generally the same (Fig. 7). Hydraulic fracture
356 breakdown occurred at 15.7 MPa with injection at 0.5 mL/min and this lower peak pressure
357 coincided with slower fracture growth. In this case, the hydraulic fracture first reached a
358 boundary well at 0.045 min and halted growth due to caging at 0.122 min (Fig. 8). Fracture
359 growth resumed between 15.1 and 17.3 min when the injection rate was increased to 8.0 mL/min
360 despite simultaneous production from the boundary wells. At 17.3 min, a total of 44 mL oil had
361 been injected while the actual caged fracture radius reached 43.8 mm. This radius is being 20%
362 less than the model predicted uncaged radius of 223 mm at this injected volume. At 58.7 min
363 growth resumed again at the injection rate of at 8.0 mL/min, but around this time the fracture
364 was stable at the injection rate of 4 mL/min or less, including during injection at 2 mL/min
365 during the flow heterogeneity stage with one boundary well shut-in. The final growth was
366 observed at 74.3 min during the critical pressure test which measured a respective value of 2.6
367 MPa for inducing fracture propagation. Interestingly, injection at 8 mL/min was resumed at 90
368 min but the radius of the fracture remained constant in this time. These results indicate that
369 fracture caging is possible with as few as two boundary wells, but the cage is less stable than
370 what was achieved with three or more boundary wells. For this reason, we conclude that at least
371 three wells is the minimum number of wells needed to reliably cage a hydraulic fracture.

372 *4.4 Uncaged fractures*

373 Our fourth, fifth, and sixth experiments present failed fracture caging scenarios (Fig. 9). These
374 three scenarios all used oil-filled boundary wells with the active servo-mechanical pump pressure
375 control mode (C1). In other words, we expected a slower production rate response time when the
376 hydraulic fracture hits the production wells. This decision was fateful in revealing that fracture
377 caging is most effective when coupled with the ability to rapidly accommodate surge flow. Surge
378 flow is high when the hydraulic fracture first intersects the boundary wells. If we correct the
379 injection rates to account for pump and well elastic ballooning (i.e., pressure dependent injected
380 volume) we observe surge flow rates faster than 40 mL/min in the early stages of hydraulic
381 fracture propagation. This was most apparent in the sixth experiment with its four boundary
382 wells since the transverse hydraulic fracture was able to propagate to the outer edge of the acrylic
383 block despite active production from the boundary wells. This result was unlike the first
384 experiment that used control mode (C2) with its faster flow response which enabled the fracture
385 to be completely caged. Note that this control mode was the only difference between these two
386 experiments since the breakdown pressure was nearly identical at 39.5 and 38.4 MPa,
387 sequentially. Additionally, in the sixth experiment, pressure rise was observed in all four
388 boundary well pumps with maximum pressures of 0.8, 1.6, 2.5, and 3.1 MPa reached as the four
389 pumps attempted to maintain 0.5 MPa. Collectively, these results demonstrate that caging can
390 fail when the production rate is too constricted, especially during stimulation.

391 The fourth and fifth experiments demonstrate an altogether different failure mechanism. Both of
392 these experiments used three boundary wells. Both of these experiments failed to induce
393 transverse hydraulic fractures, perpendicular to the injection well. In the fourth experiment, the
394 hydraulic fracture was longitudinal and completely missed the boundary wells. In the fifth
395 experiment, the hydraulic fracture was inclined and intersected only one boundary well. Slowed
396 fracture growth was observed in the fifth experiment, similar to what was observed in the sixth
397 experiment, but the fracture still reached the outer edge of the block because the production rate
398 was too low. The cause of the longitudinal fracturing in these experiments stems from Kirsch
399 stresses and inadequate notching to overcome the tendency for hydraulic fractures to be
400 longitudinal when the applied far-field compressive stresses are low, isotropic, or near-isotropic.
401 This issue is also prevalent in field wells for the same reasons, but the stress anisotropy can
402 exceed 10 MPa, which helps steer fractures perpendicular to the minimum principal stress.

403 A keen eye will notice that experiments five and six included oil injection after the hydraulic
404 fracture cage had failed and reached the outer edge of the block. This injection was performed to
405 evaluate fluid containment by fracture caging when the hydraulic fracture growth is uncontained.
406 The recovery rates in these cases ranged from 11 to 42% of the injected fluid. Higher recovery
407 rates were achieved at lower injection rates. More fluid was able to be recovered when more
408 boundary wells were intersected. This result demonstrates that caging can see partial success
409 when the fractures are uncontained but the lowest resistance leak paths will still dominate. In this
410 case, the flow path from the injection well to the outer edge of the block at its 0 MPa gauge
411 pressure provided much less flow resistance than flow from the injection well to the boundary
412 wells which each imposed 0.5 MPa backpressure. Actually, it is remarkable that the recovery
413 rates could even be as high as 42% when the fracture was not caged.

414 **5 Discussion**

415 This study focuses on fracture caging in homogeneous, elastic, and impermeable material. We
416 must acknowledge that uncertainties at a geothermal site, such as rock heterogeneity, in-situ
417 stress variation, and complex natural fractures, are key factors that could greatly affect the
418 performance of a fracture cage. While we continue to pursue studies of these complexities, we
419 also hope that the work presented here serves to motivate others in the community to investigate
420 the potential of fracture caging in more complex and realistic scenarios. With luck, it may turn
421 out that fracture caging, or some variant of this concept, could help to unlock more than 60 GWe
422 of clean power generation in the United States [Hamm et al., 2019], and even more globally. Our
423 study demonstrates that such an effort could be worthwhile as the scientific community explores
424 the concept of fracture caging for subsurface flow containment and injection induced seismicity
425 control.

426 In the beginning of this paper, we claimed that fracture caging could be a solution to the grand
427 challenges of EGS that include: (1) limiting induced seismicity, (2) increasing flow rates, and (3)
428 delaying cooling. The results in this study do support this claim, but in a non-obvious way.

429 To elaborate on seismicity control (1), our results unequivocally prove that boundary wells can
430 contain fracture growth and they can enable stable hydropropping. This implies that the lengths
431 of hydraulically activated fractures can be controlled using caging. While uncertainties do persist
432 with respect to the mechanics of fluid injection into critically stressed faults [Ito and Zoback,

433 2000; Zoback and Gorelick, 2012; Galis et al., 2017] and its connection to caging the maximum
434 seismic magnitude [Frash et al., 2021], the basic premise that limiting the volume of perturbed
435 rock should reduce seismicity is logical. Here, we presented a model and experimental evidence
436 for the concept that fracture caging can limit the volume of perturbed rock by halting hydraulic
437 fracture growth and by containing flow in hydropropped fractures. Therefore, our evidence that
438 caging can contain the perturbed volume of rock during high-rate, high-pressure, long-term fluid
439 injection is also evidence that caging should be able to limit induced seismicity.

440 With respect to increasing permissible flow rates (2), standard seismicity mitigation procedures
441 [Majer et al., 2012] seek to limit seismic risk by imposing injection pressure and flow rate limits.
442 Unfortunately, these limits they tend to cause EGS to become uneconomic, especially when the
443 realized injection pressures happen to be higher than what was hoped for during project
444 planning. Economic flow for EGS demands controllable rates so that heat extraction can be
445 optimized for maximum power generation over the lifespan of the well. Conventional solid
446 particle proppants may be able to help reduce injection pressures and increase achievable flow
447 rates, but the stability of proppants in the long term is unlikely due to crushing, embedment, and
448 chemical dissolution. The next alternative is shear asperity propping where existing shear
449 fractures and faults are used to provide flow conduits. If the permeability of these features is low,
450 but not too low, medium-pressure fluid injection offers the chance to enhance permeability
451 through shear stimulation. However, high-performance shear-fracture dominated systems are a
452 Goldilox problem, requiring an improbable, unpredictable, and uncontrollable mix of suitable
453 parameters to come together in order to make EGS economic [Meng et al., 2022]. Also, these
454 shear reliant systems risk large seismic events of 4.0 Mw and greater [Kim et al., 2018].
455 Compounding the problem, both shear and particle propped fractures will have highly
456 heterogeneous flow [Welch et al., 2022; Katende et al., 2022] while flow in more open fractures
457 tends to be more sheet-like [Petrovich et al., 2013], with sheet-like flow being more ideal for
458 efficient heat extraction [Okoroafor et al., 2022]. Now, we have demonstrated hydropropping as
459 an alternative to shear and solid particle propping. Hydropropping offers sheet-like flow for
460 increased heat recovery efficiency and it effectively removes pressure and flow rate limiters,
461 provided large enough wells are used (Fig. 1). In short, hydropropping could be a solution to
462 safely achieving the high flow rates that EGS needs to be economic.

463 The link between caging and delayed onset of cooling the produced fluid (3) in EGS is perhaps
464 the least obvious connection. Conveniently, an analytical model was developed that predicts
465 delayed cooling as fluid flows from one well, through fractures, to another well [Gringarten et
466 al., 1975]. This model predicts that larger well spacing, increased flowing surface area, and more
467 fractures will result in a slower onset of produced fluid cooling, assuming the total injection rate
468 is a fixed value. With fracture caging and hydropropping eliminating injection pressure limits, it
469 now could be possible to control the distribution of flow into multiple fractured zones using in-
470 well flow control methods, such as by limiting the size of perforations through the casing of the
471 wells to impose a higher backpressure. Increased backpressure helps to equalize flow from one
472 fracture to the next in a simple way that does not require complex high-temperature tolerant
473 tools. We note that increasing backpressure by this method is incompatible with standard (i.e.,
474 non caged) seismicity mitigation procedures because there is no way to prevent injection
475 pressure limits from being exceeded when using limited-size perforations. Combining this ability
476 to better control flow distribution with the improved heat transfer efficiency of sheet-like flow
477 offers a two-prong benefit towards delaying the onset of cooling. Thus, fracture caging could be
478 a solution to not only reducing seismic risk (1) and better optimizing flow rates (2), caging could
479 also be a solution to delaying the onset of cooling in the production wells (3).

480 Much more work is needed before caging can become a deployed tool to better control fluid flow
481 for geothermal systems. Furthermore, it does not escape our notice that caging could also have a
482 future role in oil and gas, hydrogen storage, saltwater disposal, nuclear waste disposal, superfund
483 site contaminant treatment, and carbon sequestration applications. This study serves as a step in
484 an effort to improve the robustness of our energy economy. Future work on this topic will benefit
485 from contributions from the greater scientific and technical community.

486 **6 Conclusions**

487 These results from our model and experiments reveal crucial information about the feasibility of
488 fracture caging for enhanced geothermal systems (EGS). First, the experiments unequivocally
489 prove that boundary wells can halt hydraulic fracture growth. Second, the experiments prove that
490 a caged fracture can be held open with high-pressure fluid without inducing fracture growth.
491 This presents hydropropping as a feasible alternative to injecting solid proppant particles or
492 relying on shear asperity propping to maintain fracture permeability. Third, the model and

493 experiments demonstrate that fracture caging has an upper flow rate limit, above which fractures
494 will resume growth (Fig. 2 and Fig. 8). The model predicts two domains to this limit. At close
495 well spacing as was used in the experiments, fracture conductivity dominates the injection rate
496 limit. At larger well spacing as is appropriate to commercial EGS, the maximum caged injection
497 rate is dominated by frictional flow losses through the wells. Increasing well diameter enables
498 faster injection rates to be caged. Fourth, the experiments demonstrate that unstable fracture
499 caging will occur with two or fewer boundary wells. Stable fracture caging is demonstrated to
500 require three or more wells. This result is important for economics since geothermal wells are
501 very expensive and our companion work predicts that caged EGS could be economic with three
502 boundary wells [Frash et al., 2023]. Fifth, this work demonstrates the importance of stimulating
503 fractures perpendicular to the wells, whether by notching, perforating, or exploiting the in-situ
504 stress state. A hydraulic fracture that bypasses all the wells in a cage will obviously cause caging
505 to fail. Sixth, even when a hydraulic fracture is not caged a large fraction of the injected fluid can
506 be recovered from the boundary wells. Seventh, our model to predict the limits of fracture caging
507 is simplistic so new advanced models would be beneficial for more fully exploring the limits of
508 fracture caging, especially with respect to the effects of porous rock, shear fracture activation,
509 and the interplay between caging and seismic risk. Eighth, our AE measurements reinforce the
510 notion that microseismic data is unreliable for monitoring fracture growth yet is still better than
511 nothing since AE activity often coincides with fracture growth. Overall, this work presents not a
512 small step, but rather a leap forward in validating fracture caging and hydropropping as tools to
513 improve the control of fluid flow and fracture growth in the subsurface.

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519 **Open Research**

520 Data including timeseries, videos, and our model's script in the Python language can be accessed
521 freely at <https://zenodo.org/record/8274273> (doi: 10.5281/zenodo.8274273).

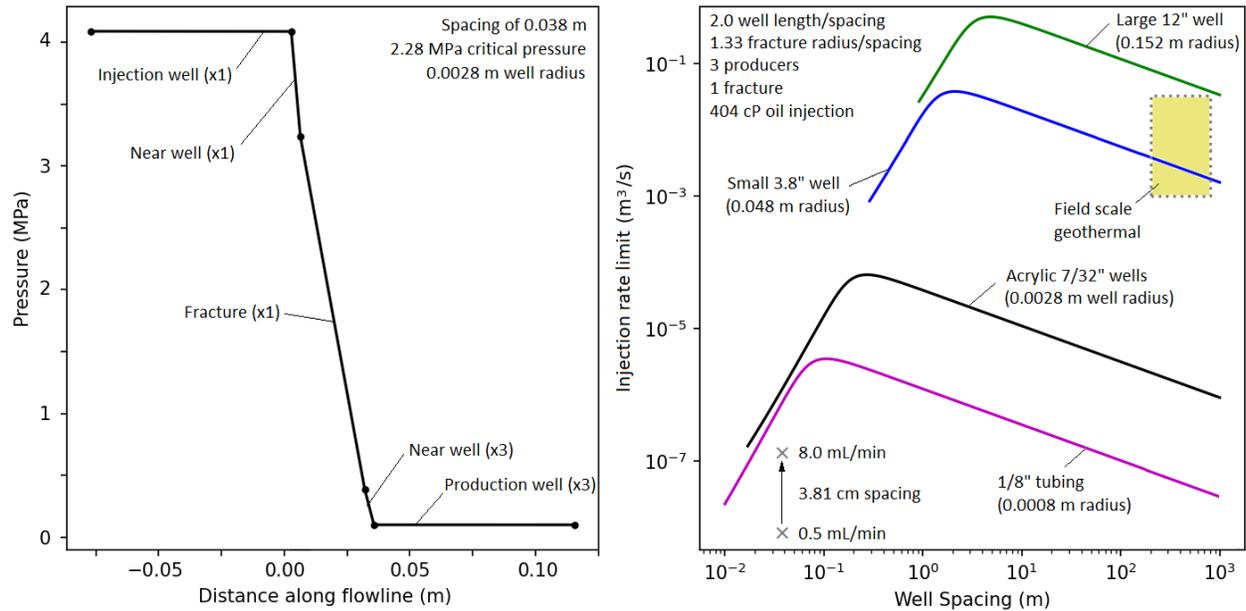
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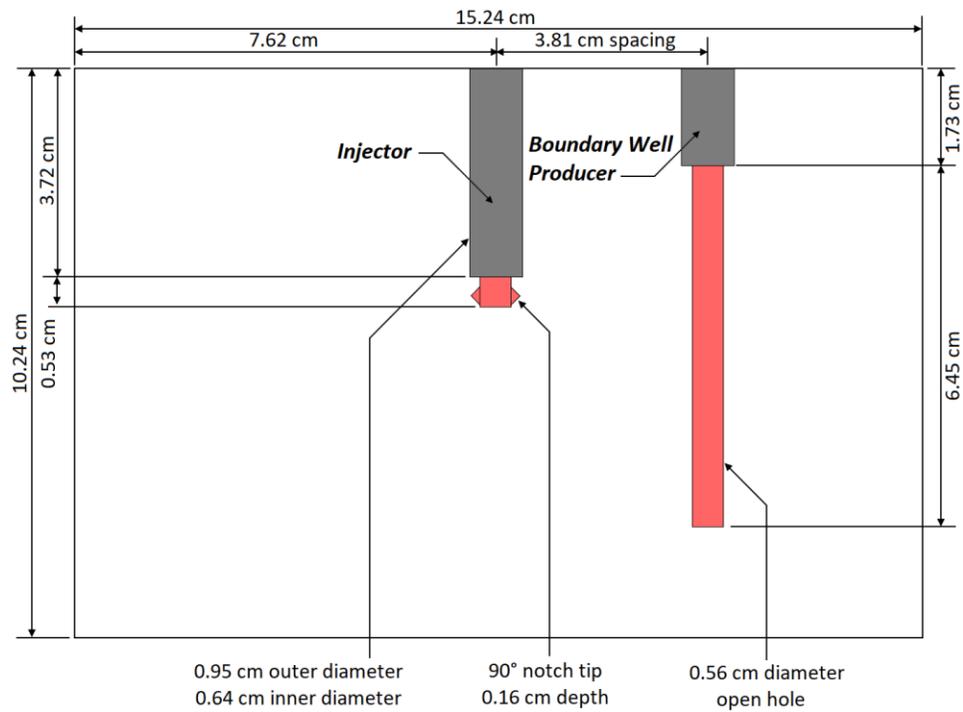
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- 629

630 **Tables and Figures**

631

632 Fig. 1. Our analytical model's prediction of caging across dimensional scales. (Left) Pressure
 633 profile with flow through the injection-well, near-injection-well, fracture, near-production-wells,
 634 and production-wells. In this case, pressure losses are dominated by the fracture in laboratory-
 635 scale experiments unless the boundary wells are choked. (Right) Maximum caged injection rate
 636 limit as a function of well spacing and well radius. The shaded box in the upper right highlights
 637 the well spacing and flow rates needed for full-scale enhanced geothermal systems. Two \times 's
 638 mark the lower and upper flow rates in our laboratory experiments.

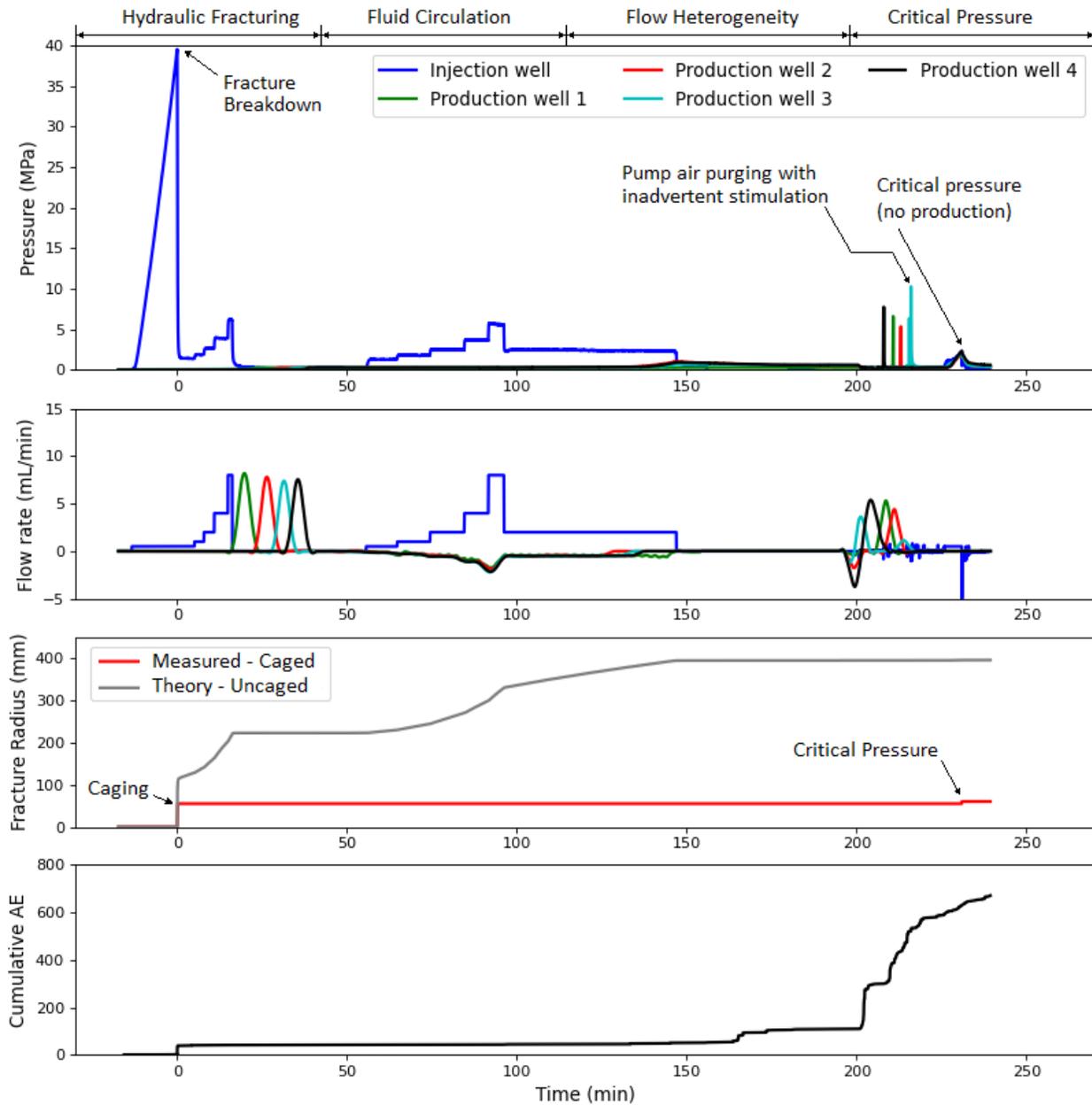
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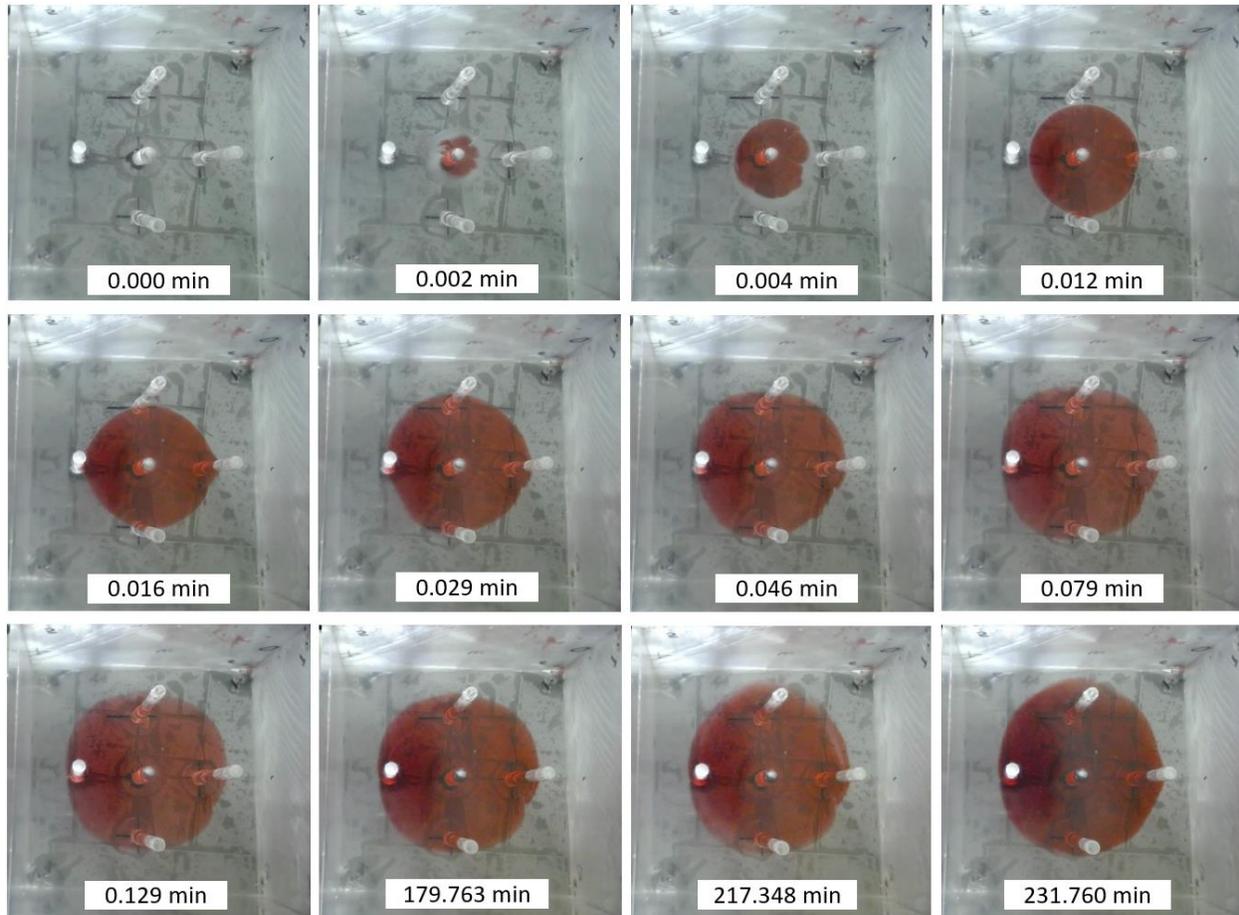
641 Fig. 2. Nominal dimensions of the hydraulic fracture experiments.

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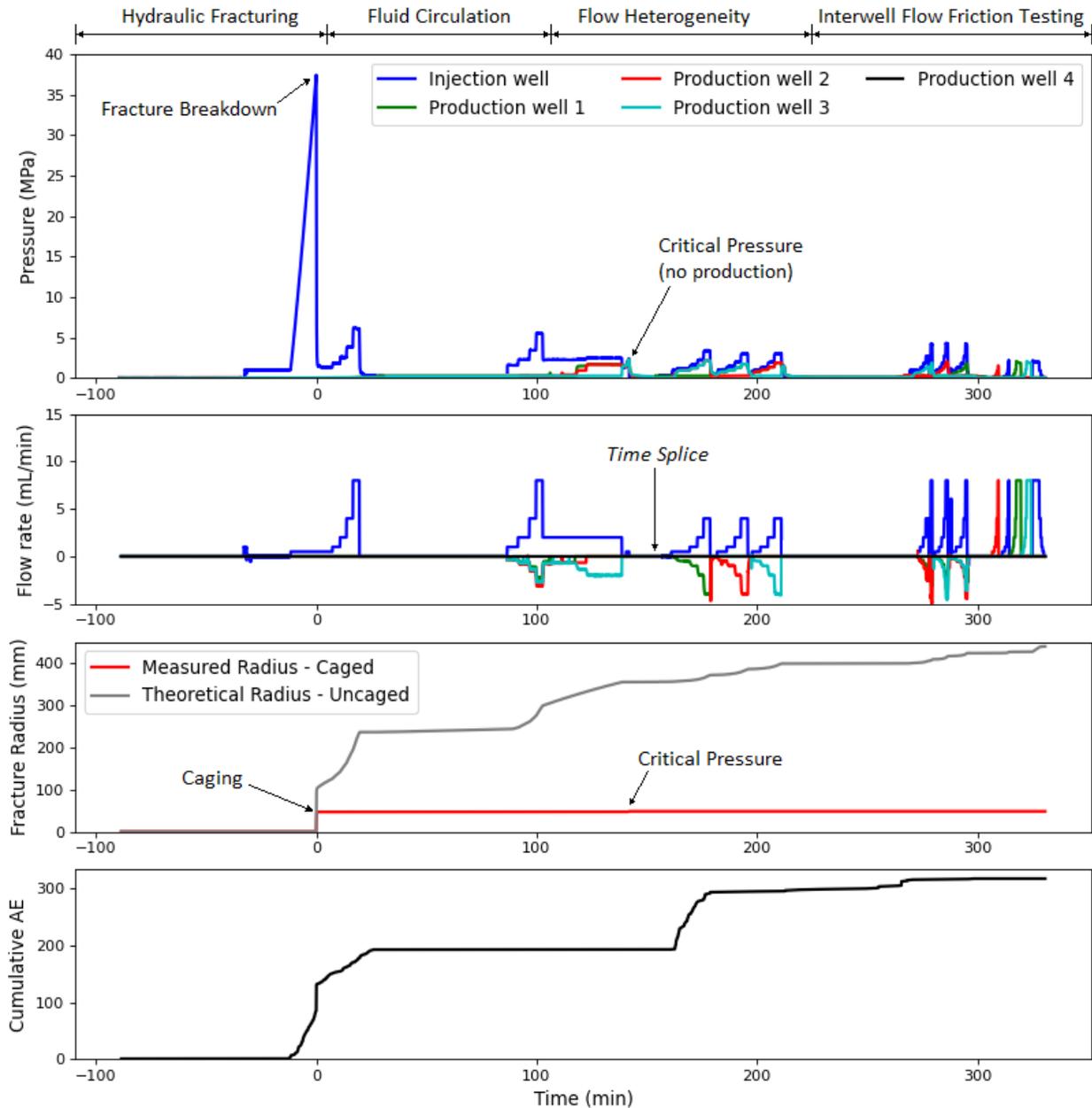
643

644 Fig. 3. Timeseries of fracture caging with four boundary wells and 50 mL of air in each
 645 boundary pump to accommodate the hydraulic fracture breakdown's flow surge. Plotted data
 646 includes a theoretically predicted fracture radius for an uncaged fracture in the same acrylic
 647 material as a function of measured injected volume with a nominal net pressure of 2.3 MPa.
 648 Measured fracture growth and acoustic emissions were negligible after the fracture was caged at
 649 0.13 min (7.7 s). Later in the experiment at 217 and 231 min fracture propagation was induced
 650 by injecting without production to measure the 2.28 MPa critical pressure for propagation.
 651 Acoustic emissions occurred during fracture propagation and heterogeneous flow.



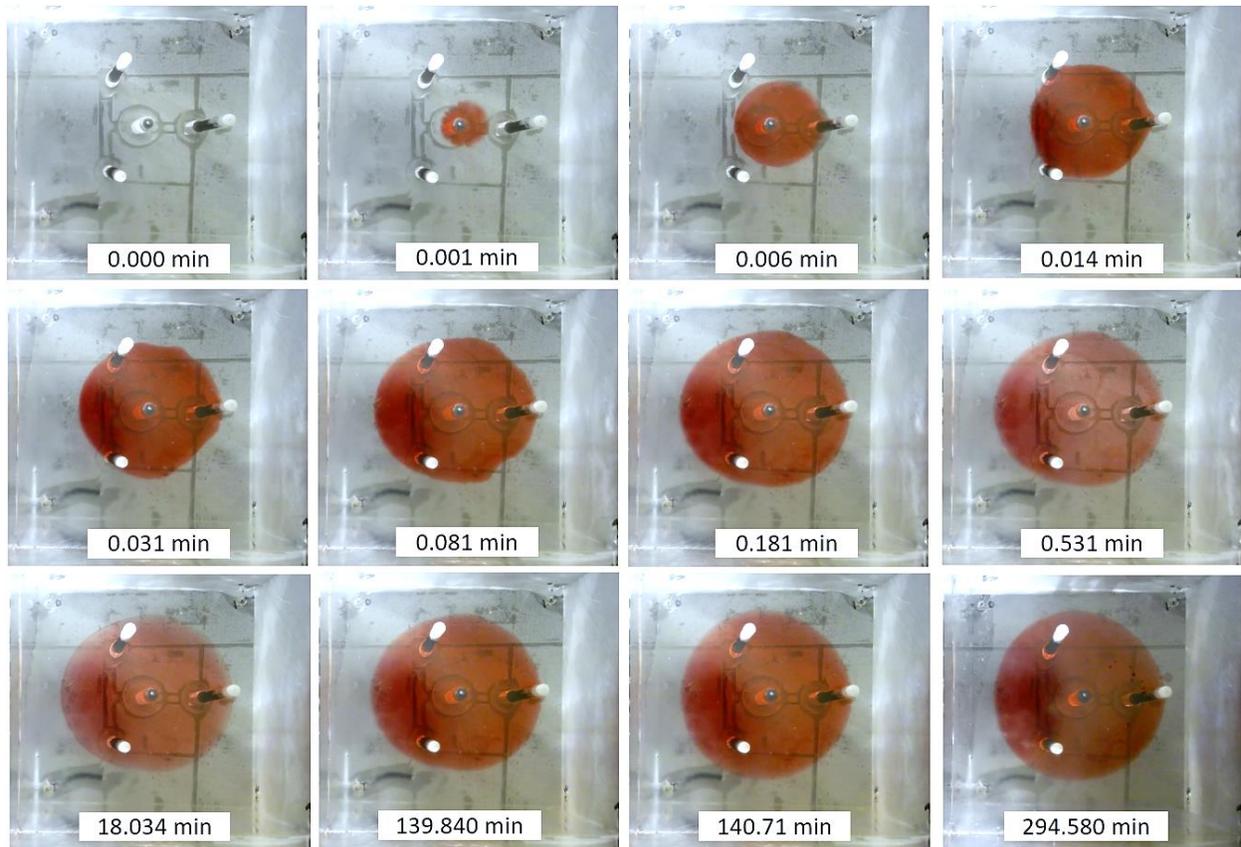
652

653 Fig. 4. Placing four boundary producers around the injector enabled successful caging during
 654 hydraulic fracturing ($0.000 < t < 50$ min), fluid circulation at 0.5 to 8.0 mL/min ($50 < t < 120$
 655 min), and heterogeneous flow ($120 < t < 200$ min). Injection without production measured a
 656 critical pressure of 2.3 MPa for renewed fracture growth. This result unequivocally demonstrates
 657 that hydraulic fracture growth can be halted by a cage of boundary wells and that a fracture can
 658 be stably hydropped for fluid circulation at high net pressures without solid proppants nor
 659 shear stimulation. Video of our experiments can be accessed from our online data repository
 660 (<https://zenodo.org/record/8274273>).



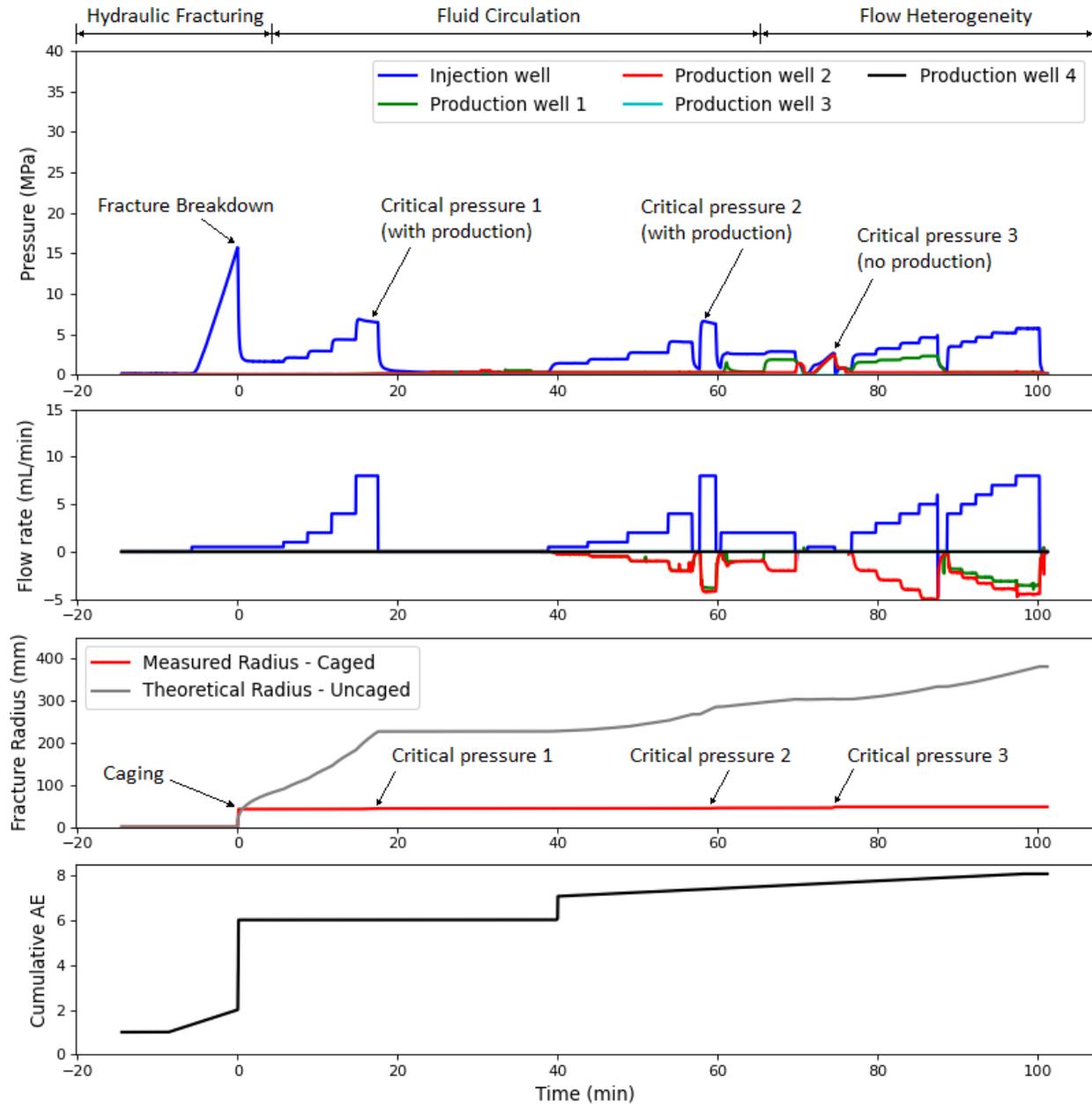
661

662 Fig. 5. Timeseries of fracture caging with three boundary wells and 50 mL of air in each
 663 boundary pump to accommodate the hydraulic fracture breakdown's flow surge. Measured
 664 fracture growth and acoustic emissions were negligible after the fracture was caged at 0.18 min.
 665 Later in the experiment at 140 min fracture propagation was induced by injecting without
 666 production to measure the 2.3 ± 0.1 MPa critical pressure for propagation.



667

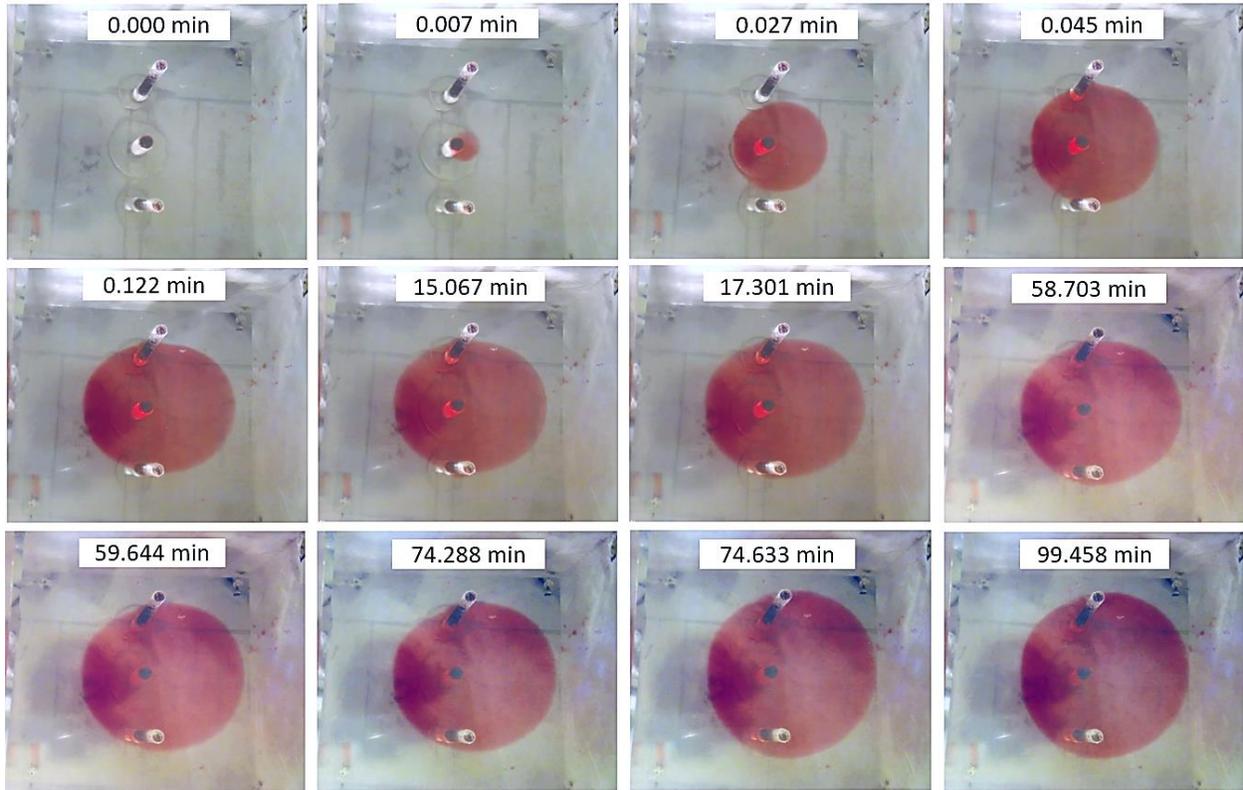
668 Fig. 6. Placing three boundary producers around the injector enabled successful caging during
 669 hydraulic fracturing ($0.000 < t < 18$ min), fluid circulation ($18 < t < 105$ min), and heterogeneous
 670 flow ($145 < t < 300$ min). Injection without production measured a critical pressure of 2.3 MPa
 671 for renewed fracture growth (i.e., 140 min).



672

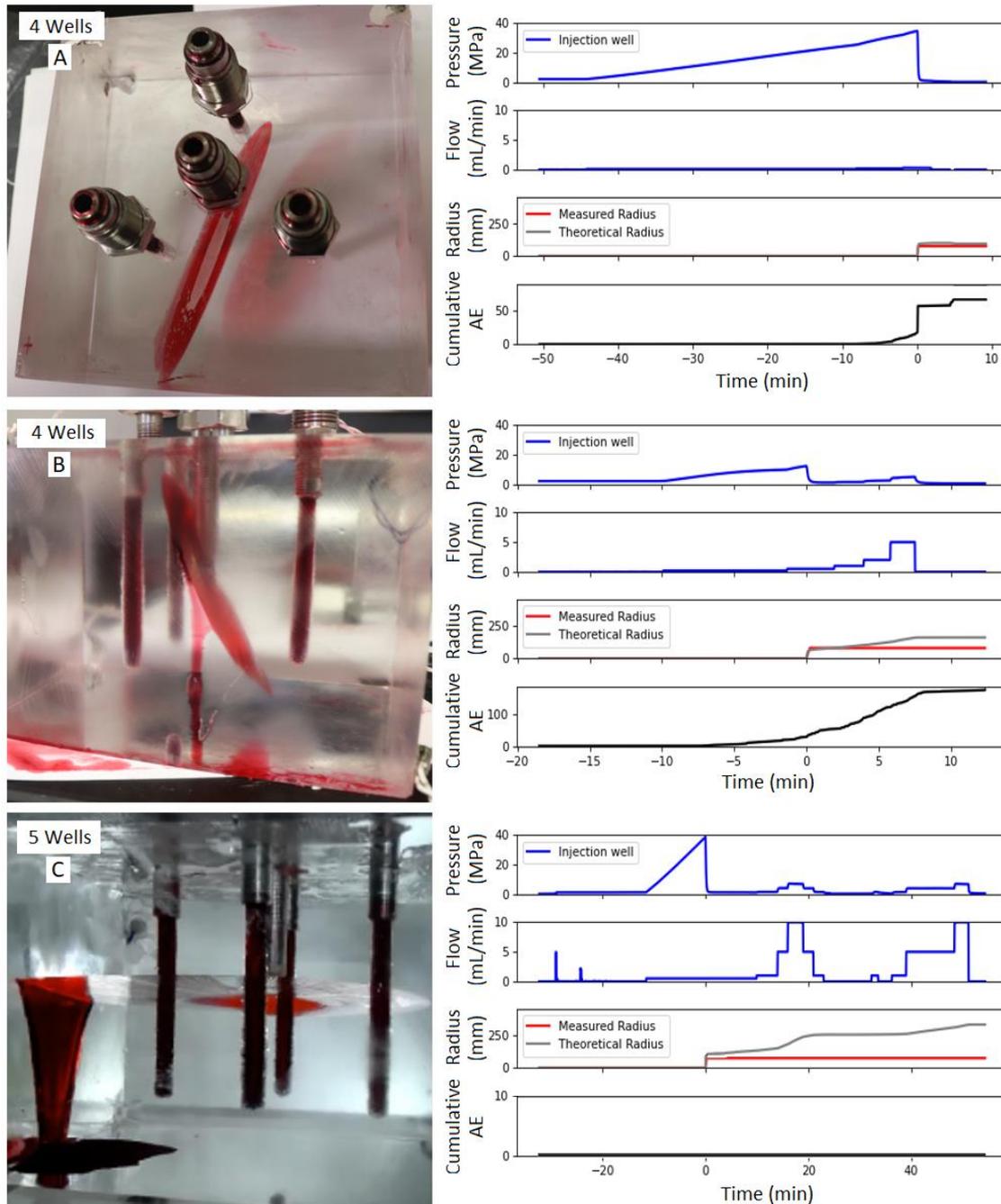
673 Fig. 7. The two-producer pattern did successfully cage, but this cage was less stable than the
 674 three-producer and four-producer alternatives. This instability was evident from fracture growth
 675 at 8.0 mL/min injection. Asymmetry in the caged fracture is another indicator of instability (c.f.,
 676 Fig. 8). Fracture growth was induced by high circulation rates at 16 min and again at 59 min.
 677 Stable injection-only growth was induced with 0.5 mL/min injection at 74 min. After each period
 678 of fracture growth, the fracture was observed to become more stable until 8.0 mL/min was
 679 eventually accommodated without fracture growth. This result agrees with our model in that
 680 increasing fracture radius improves cage effectiveness.

681



682

683 Fig. 8. Fracture caging with two boundary wells was unstable during fluid circulation because
 684 fracture propagation reinitiated during 8 mL/min injection at 16 min and 59 min, despite the
 685 simultaneous fluid production. At its largest radius after the critical pressure test at 74 min, the
 686 fracture finally became more stable and able to accommodate fluid circulation at 8 mL/min
 687 without growing. This validates the analytical model's prediction that higher flow rates can be
 688 caged as a fracture grows larger.



689

690 Fig. 9. Scenarios demonstrating uncaged hydraulic fractures. These hydraulic fractures reached
 691 the outer edge of the block because of (A) entirely missing the boundary wells or (B and C) the
 692 boundary wells flowing too slowly to contain the fractures. Unlike the caged experiments, the
 693 boundary wells and pumps in these cases were bled of air to minimize hydraulic compliance.
 694 These scenarios show the importance of accommodating the surge in flow that occurs when the
 695 hydraulic fracture first intersects each boundary well.