	ILLINOIS DEPARTMENT OF NATURAL RESOURCES Office of Oil and Gas Resource Management One Natural Resources Way Springfield, Illinois 62702-1271	

HIGH VOLUME HORIZONTAL HYDRAULIC FRACTURING PERMIT APPLICATION HVHHF-10

References to "1-xx" or "§1-xx" are to the Hydraulic Fracturing Regulatory Act., 225 ILCS 732/1-1 et seq. References to "240.xxx" and "245.xxx" are to 62 Ill. Admin. Code 240 and 245, respectively.

Attachment: HVHHFOperationsPlan
Please save attachment and use the file name above.

High Volume Horizontal Hydraulic Fracturing Operations Plan §1-35(b)(6), 245.210(a)(6).

Geological description.
Please list and describe in this attachment all formation(s) affected by the high volume horizontal hydraulic fracturing operation, including (but not limited to) the formation(s) to be stimulated and the formations constituting or contributing to the confining zone. For each such formation, please describe the lithology, extent, thickness, permeability, porosity, transmissive faults, fractures, water or water source content, and susceptibility to vertical propagation of fractures. For each formation, state if any of these features are unknown.

a) what is the anticipated surface treating pressure range?
b) what is the maximum anticipated injection treating pressure?
c) what is the estimated or calculated fracture pressure of the producing zone?
d) what is the estimated or calculated fracture pressure of the confining zones?
e) what is the planned depth of all proposed perforations?
f) what is the planned depth to the top of the open hole section?
g) what is the type, source and volume of base fluid anticipated to be used?

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Woolsey Operating Company, LLC
Woodrow #1H-310408-193
White County, Illinois
High Volume Horizontal Hydraulic Fracturing Permit Application
HVHHF-10: Operations Plan

Geologic Formations Affected:
New Albany Gp. (Target)
Compton / Chouteau
Borden / Springville
Ft. Payne
Lingle

Herein are listed the geologic descriptions of all formations that near the target zone that *may be* affected by the HVHHFO of the proposed, permitted well. As requested, the lithology, extent, thickness, permeability/porosity, water or water source content and susceptibility to vertical propagation of fractures will be discussed for each of the formations referenced below. In regard to transmissive faults and large through-going fractures, it can be stated that according to a 3-D seismic survey collected over the proposed location / prospect area, there are none that exist anywhere near the proposed wellbore, and specifically that part of the well bore that will be in the reservoir zone, the New Albany Shale (herein referenced as 'NAS').

*The drilling objective is the NAS; this shale is of Group status and actually is composed of 3 Formations, in ascending order from the base to the top, is the Blocher Shale Formation, the Selmier Shale Formation and the Grassy Creek Shale Formation. They are described below.

<u>Blocher Shale:</u> olive black, organic-rich, massive appearing to faintly laminated, slightly calcareous silty shale with common thin gray, sharply bedded traction deposits composed of silty calcarenites and calcisiltites. Average core measured porosity is 3 to 4% and has permeability in the nanodarcy range, and thus, is extremely tight. Some fractures are recognized in this section but are not large or long and typically mineralized. With the exception of saturation measurements, no information was collected or tested in regard to water from this formation.

Selmier Shale: olive gray, organic rich, but lesser so than the Blocher below and Grassy Creek above, pyritic, burrowed and bioturbated silty shale that represents more oxic deposition. Average core measured porosity is 5 to 6% and has permeability in the nanodarcy range, and thus is extremely tight. Some fractures are recognized in this section but are not large or long and typically mineralized. With the exception of saturation measurements, no information was collected or tested in regard to water from this formation.

Grassy Creek Shale *(horizontal target Formation)*: dark gray to black, pyritic, organic-rich, faintly laminated and locally burrowed and bioturbated, slightly silty shale / mudrock that possesses thin light gray beds composed of quartz grains; algal cysts (*tasmanites*) express laminations. Average core measured porosity is 5 to 7% and, although the most permeably of the three NAS formations is also in the nanodarcy range, and is extremely tight. Natural fractures do exist in this section, especially in the lower 50', and are up to a foot or two long, vertically; most are mineralized but some open fractures do exist. Horizontal, healed, fractures associated with prior oil generation also exist. With the exception of saturation measurements, no information was collected or tested in regard to water from this formation.

*The potential formations that may be affected by the HVHHFO ***above*** the NAS, in *ascending* order are as follows: Compton Limestone, Borden Shale (a.k.a., Springville Shale), and the Fort Payne Limestone. All three formations are lower Mississippian in age. They are described below.

Compton Limestone: light grey to green mottled crinoid wackestone to sparse packstone with thin shale wisps, 8-10' thick throughout the prospect area. No measured porosity or permeability for this formation exists in or near the prospect area however, from cores in the basin these rocks visually are extremely tight and non-permeable (all logs in a 5 mile radius corroborate these visual observations). Fractures are at a minimum as small, healed (mineralized) microfractures. No information exists on water from the formation.

Borden Shale (a.k.a., Springville Shale): dark greenish gray, flaggy to slightly laminated, burrowed shale, 40-50'thick throughout the prospect area. No measured porosity or permeability for this formation exists in or near the prospect area however, from cores in the basin these rocks visually are extremely tight and non-permeable, and due to the layering specifically non-permeable vertically (all logs in a 5 mile radius corroborate these visual observations). Very few fractures exist in this formation and, when present, are small, healed (mineralized) microfractures. No information exists on water from this formation.

Fort Payne Limestone: very dark gray to black, extremely dense siliceous lime mudstone; the unit is slightly silty and spiculitic in the lower half and grades upward into a lighter colored lime mudstone that becomes increasingly cherty upward; the chert is dark to light gray mottled and burrowed. This formation is ~500' thick in the prospect area. No measured porosity or permeability for this formation exists in or near the prospect area however, from cores in the basin these rocks visually are extremely tight and non-permeable (all logs in a 5 mile radius corroborate these visual observations). As stated previous, the limestone is extremely dense, particularly in the lower half and not fractured; fractures do occur upward in the section but are restricted to the small chert nodules and are mineralized. No information exists on water from this formation.

*The potential formations that may be affected by the HVHHFO ***below*** the NAS, in <u>*descending*</u> order are as follows: the Devonian, Lingle Limestone Formation. This formation is described below.

<u>Lingle Limestone:</u> light to medium and dark gray, crinoidal wackestone to packstone, with some rugose and button (*M. discus*) corals; this unit is argillaceous and in places, cherty. The chert occurs as 1 to 3" nodules and is medium to dark gray mottled with crinoid fragments. The formation in the prospect area is 75 to 85' thick. This unit in places throughout the Illinois Basin is porous near the top (typically 3 to 8%), near an intraformational unconformity, and does produce oil however, examination of all logs within a 5 mile radius of the proposed location show the Lingle to be extremely tight throughout. No measured porosity or permeability for this formation exists in or near the prospect area. Some fracturing was noted in collected cores, largely in the sections that contained chert but they were small fractures and most typically mineralized. No information exists on water from this formation.

Based on the lithology and gross petrophysics of the under and overlying units, it is not anticipated that the aforementioned units will be susceptible to vertical fracture propagation during completion of the NAS, Grassy Creek Shale Formation.

a) 1,000 psi – 7,900 psi
b) 7,900 psi **This number should actually be the downhole, in reservoir formation "injection pressue"; i.e. the Pnet value (see below for explanation and discussion) of 3,480 psi.*
c) 2,875 psi
d) 4,000 psi
e) Between 5,275' TVD and 5,245' TVD
f) N/A
g) Slickwater (3% KCl), Local well(s), Approx. 7,000,000 gal.

Woolsey Operating Company, LLC (WOC) states in HVHHF-10: Operations Plan that the Maximum Anticipated Surface Pressure will be 7,900 psi. and the Calculated Pressure of the Producing Zone is 2,875 psi. To understand the apparent discrepancy between the two the following variables (from measured data) need to be addressed:

Friction Pressure of the Frac Fluid moving in the Casing (P_f)

Friction Pressure of the Perforations (P_{pf})

Hydrostatic Pressure of the Frac Fluid (P_h)

Effect of Tortuosity (P_t)

Regional Stress ($P_{Sh\mathit{min}}$)

When the Fracture Stimulation ("Frac") is initiated, pressure is applied to effectively a closed container. The treatment pressure must increase to overcome a number of well bore and near well bore restrictions before fracturing of the shale can begin. The initial rate is low and not all perforations will be open to accept fluid. As fluid moves through the perforation it encounters the near well bore. This is the area which includes the perforation gun debris along with cement and drilling fluids invasion. Many times the near well bore damage will require much higher pressures than the virgin shale zone to initiate a fracture through it. As frac fluid makes its way into the shale it encounters a highly tortuous path through the anisotropic medium. In addition it must overcome the regional stress. All of which increases the surface treatment pressure. Eventually, the frac fluid creates enough pathways (induced fractures) through the shale that fluid is able to move away from the well bore avoiding the tortuosity which is seen in the lower surface treating pressure with time and volume. The pressure envelope around the treatment stage rapidly decreases with distance so that the actual pressure at the confining zone interface is much lower than the treating pressure at the well bore. The interrelations of the aforementioned variables and discussion are expressed numerically, based on measured and collected data, in the attached supplementary diagram and associated discussion, below.

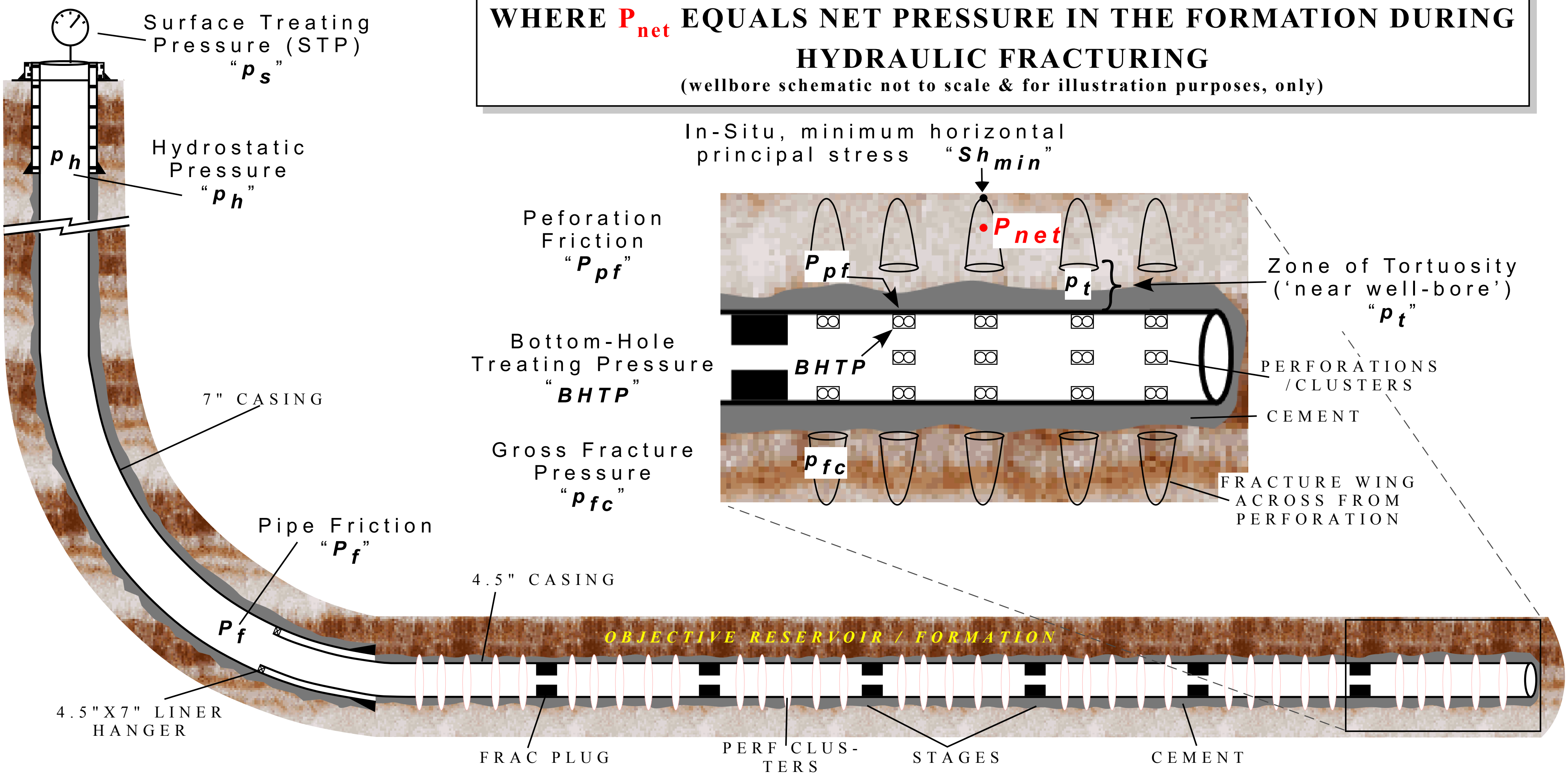
As mentioned, surface treating pressure does not equate to the actual pressure in the formation rather, that pressure is the 'net pressure' or P_{net}. P_{net} is the excess pressure, above all other pressure variables, of the fracturing fluid inside the fracture above that simply to keep the fracture open. To understand this, first the bottom-hole treating pressure (BHTP) at the perforations needs to be calculated; whereas the hydrostatic head adds more pressure to the system, much of it is lost due to pipe friction (P_f). As the fracturing fluid passes through the peforations, there are additional pressure drops due to pipe friction (P_f) and tortuosity (P_t) near well-bore, which further lowers the treating pressure; this value is the gross fracture pressure (P_{fc}). However, this is not the final pressure being put on the reservoir formation as the in-situ minimum horizontal principal stress (Sh_{min}), which is the stress within the formation that acts as a load on the formation, counters this pressure. As illustrated in the diagram, now that the pressure drops due to friction, tortuosity and intra-formation stress have been accounted for, the P_{net}, or true pressure on the formation has been quantified. The calculated 3,480 psi for the P_{net} is above the fracture gradient ("fracture pressure", per the HVHHF-10, Operations Plan) of the formation at a 2,875 psi gradient and thus, will be enough pressure to breakdown the reservoir formation and facilitate artificial fracture propagation. *Therefore, the anticipated maximum surface treating pressure of 7900 psi equates to only 3,480 psi of pressure ("injection treating pressure", per the HVHHF-10, Operations Plan) within the reservoir objective.*

Furthermore, the P_{net} of 3,480 psi is substantially less than the over and underlying carbonate confining units (Compton/Ft. Payne & Lingle Limestones, respectively) of which have fracture gradients ("fracture pressure") of 4,000 psi. Considering that the pressure envelope around the treatment stage rapidly decreases with distance (~80 feet of vertical distance to the nearest confining zone, the Compton Limestone) *the P_{net} value will be even less than the 3,480 psi; therefore, fracturing will not propagate into or through the upper or lower confining unit and thus, not allow the transmission of fluids out of the producing zone.* The Compton/Ft. Payne upper confining unit, of which will not be fractured and breached during hydraulic fracturing operations, will be at a projected ~5100 TVD; the base of the deepest water aquifer is at ~700' TVD, a vertical distance of 4400 feet between the two. *Therefore, there will be no resultant contamination upward of surface aquifers or sources of drinking water (USDWs).* To do so would, literally, defy the laws of physics. From an operations standpoint, it would be an engineering impossibility.

In addition to measured rock mechanics and seismically defined stresses, from which the aforementioned was derived, microseismic studies of two wells completed in the New Albany Shale, Grassy Creek Formation, substantiate the data above in that those treatments did not fracture up into or past our confining zones of the Compton/Ft. Payne, or below the Lingle Limestone. In fact, in one instance, our fracture treatment did not penetrate past the Selmier Shale—the formation immediately below the reservoir objective, the Grassy Creek.

SIGNIFICANT PRESSURES AFFECTING P_{net} (Net Pressure): WHERE P_{net} EQUALS NET PRESSURE IN THE FORMATION DURING HYDRAULIC FRACTURING

(wellbore schematic not to scale & for illustration purposes, only)



KNOWNS

*Avg. Depth of Horiz: 5260 TVD
*Casing String: 5560' of 7"; 5050' of 4.5" (P-110)
*Stages: 39 @ ~110' (all not shown, here)
*Perforations: 5 clusters at 6 shots per cluster; 30 holes per stage @ 0.48" diameter
*Frac Rate: 80 BPM
*Frac Fluid: 3% KCl
*Frac Fluid Density, specific gravity: 8.54 ppg
*Frac Gradient of the NAS/G.C. Formation: *2875 psi*

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p_s - 7900 psi *(anticipated max.)*
p_h - 2335 psi
P_f - 2353 psi
P_{pf} - 555 psi
p_t - 2175 psi
Sh_{min} - 1672 psi

CALCULATIONS

1. $p_s - P_f + p_h$ = BHTP

7900 - 2353 + 2335 = 7882 psi

2. BHTP - P_{pf} - p_t = p_{fc}

7882 - 555 - 2175 = 5152 psi

3. p_{fc} - Sh_{min} = P_{net}

5152 - 1672 = 3480 psi

SUMMARY

P_{net} i.e. net pressure is the *most crucial value* as it is the excess pressure of the fracturing fluid inside the fracture above that simply to keep the fracture open. This excess pressure provides the energy available at any given time to hold open the fracture and make it grow. The 3480 psi is above the formations fracture gradient of 2875 and will facilitate artificial fracture propagation. Equally as important, this pressure is below the fracture gradient of the over & underlying carbonate confining units, which have a 4000 psi fracture gradient. ***An anticipated maximum surface treating pressure of 7900 psi equates to only 3480 psi active net pressure in the reservoir objective.***