

UNITED STATES PATENT AND TRADEMARK OFFICE

BEFORE THE PATENT TRIAL AND APPEAL BOARD

INTELLIGENT WELLHEAD SYSTEMS, INC.,
Petitioner,

v.

DOWNING WELLHEAD EQUIPMENT, LLC,
Patent Owner.

IPR2024-00300
U.S. Patent No. 11,560,770

**DECLARATION OF JOHN HUGHETT
SUPPORT OF PATENT OWNER'S PRELIMINARY RESPONSE**

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I, John Hughett, do hereby declare as follows:

I. INTRODUCTION

1. I am making this declaration at the request of Downing Wellhead Equipment, LLC in the matter of the *Inter Partes* Review of U.S. Patent No. 11,560,770 (“the ’770 Patent”).

2. I am also being reimbursed for reasonable and customary expenses associated with my work and testimony in this investigation. My compensation is not contingent on the outcome of this matter or the specifics of my testimony.

3. I have been asked to provide my opinions regarding whether the Petition filed by Intelligent Wellhead Systems, Inc. establishes that there is a reasonable likelihood that claims 1-38 (“the Challenged Claims”) of the ’770 Patent are unpatentable as they would have been novel and non-obvious to a person having ordinary skill in the art (“POSITA”) at the time of the invention, in light of the prior art. It is my opinion that the Petition (and supporting evidence) does not show that there is a reasonable likelihood that the Challenged Claims are unpatentable.

4. In the preparation of this declaration, I have studied:
- a. the ’770 Patent, Ex. 1001;
 - b. the prosecution history of the ’770 Patent (“’770 File History”),
Ex. 1010;

- c. U.S. Patent Publication No. 2022/0268141 (“Krupa”), Ex. 1003;
- d. U.S. Patent Publication No. 2019/0233275 (“Carr”), Ex. 1004;
- e. International Patent Publication No. WO2020145978 (“Beuterbaugh”), Ex. 1005;
- f. U.S. Patent No. 8,490,685 (“Tolman”)), Ex. 1006.
- g. U.S. Patent Publication No. 2007/0023184 (“Jackson”), Ex. 1007;
- h. Declaration of Dr. Robert Durham, Ex. 1002;
- i. Petitioner’s IPR Petition of U.S. Patent No. 11,560,770, (the “Petition”); and

5. In forming the opinions expressed below, I have considered:

the documents listed above;

the relevant legal standards, including the standard for obviousness, and any additional authoritative documents as cited in the body of this declaration; and

my own knowledge and experience based upon my work in the field of hydraulic fracturing as described below.

6. Unless otherwise noted, all emphasis in any quoted material has been added.

II. QUALIFICATIONS AND PROFESSIONAL EXPERIENCE

7. My complete qualifications and professional experience are described in my *Curriculum Vitae*, a copy of which can be found in EX2007. The following is a brief summary of my relevant qualifications and professional experience.

8. I have over 50 years of experience in completing oil and gas wells. A part of the completion process is hydraulic pressure treating. I have designed and performed hydraulic pressure treatments many thousands of times. I have developed hydraulic pressure treating techniques that were instrumental in production increases in a number of formations.

9. Additionally, I have set quite a number of records for hydraulic pressure treatments. Some of these records, in vertical wells, included frac jobs that pumped more than 2 million pounds of sand then 3 million pounds, 4 million pounds, and 5 million pounds. These jobs were primarily performed in the hottest play of the period, the Cotton Valley.

10. During this same time period I was an expert panelist at the SPE Cotton Valley Symposium which was held every two years. I was a panelist each year along with a person from the largest super major oil & gas company working the basin. These “massive hydraulic fracture treatments” required constant innovation at the surface in order to successfully complete these jobs. This involved such things as improvements in blenders, sand handling, well site

plumbing from the pressure pumpers to the well, and fluid handling. All of which I worked on in conjunction with the pressure pumper that I utilized.

11. Later, I worked extensively in the Deep Upper Wilcox of South Texas. Those wells were very high pressure and required massive hydraulic treatments to be commercial. This involved a piping system that was much higher pressured than in the other areas of the continental United States. The pumps on the pressure pumping equipment also had to be able to exert very high pressures in order to perform the stimulations. I designed these jobs and the systems necessary to perform these tasks. Additionally, I was on site supervising the pumping of these jobs.

12. As time progressed and shale became economically viable (about 2005) frac jobs changed due to the advent of horizontal completions. This necessitated changes in the frac equipment at the surface. One of the changes which I was involved in with a pressure pumper client was the advent of a “missile” manifold which allowed for faster and safer rig up and rig down of piping to the individual pressure pumper units. Yet later another improvement which again I was involved in heavily was the use of “zipper” manifolds which allowed rapid change from pumping operations on one well to another well.

13. As a part of my consulting engineering practice, I have worked for hydraulic pressure pumping companies to assist in design of new surface piping

layouts. This work continues, there is always room for improvement in pressure pumping operations both at the surface and downhole. I have also worked as a consultant to operators and service companies in connection with hydraulic pressure treatments and techniques in a variety of applications.

14. I received my Bachelor's Degree in Engineering from Texas Tech University in Lubbock, Texas.

III. LEVEL OF ORDINARY SKILL IN THE ART

15. I understand there are multiple factors relevant to determining the level of ordinary skill in the pertinent art, including (1) the levels of education and experience of persons working in the field at the time of the invention; (2) the sophistication of the technology; (3) the types of problems encountered in the field; and (4) the prior art solutions to those problems.

16. For the purposes of this Declaration, I have been instructed to apply May 17, 2021 as the critical date, but I have not performed my own analysis. I note that my conclusion that the Challenged Claims are patentable over the asserted prior art does not depend upon a specific priority date, as the prior art fails to teach every element of the Challenged Claims.

17. A person of ordinary skill in the art ("POSITA") in the field of the '770 Patent, as of the critical date of May 17, 2021, would have been someone knowledgeable and familiar with hydraulic fracturing principles that are pertinent

to the '770 Patent. That person would typically hold a degree in petroleum or mining engineering, mechanical engineering, or a comparable discipline, and at least two years of experience in oil and gas extraction, or an equivalent combination of education and experience. Lack of work experience can be remedied by additional education, and vice versa.

18. For purposes of this Declaration, in general, and unless otherwise noted, my statements and opinions, such as those regarding my experience and the understanding of a POSITA generally (and specifically related to the references I consulted herein), reflect the knowledge that existed in the field as of the critical date of the '770 Patent (*i.e.*, May 17, 2021). Unless otherwise stated, when I provide my understanding and analysis below it is consistent with the level of a POSITA prior to the priority date of the '770 Patent.

IV. RELEVANT LEGAL STANDARDS

19. I am not an attorney. In preparing and expressing my opinions and considering the subject matter of the '770 Patent, I am relying on certain basic legal principles that counsel have explained to me. These principles are discussed below.

20. I understand that prior art to the '770 Patent includes patents and printed publications in the relevant art that predate the priority date of the invention recited in the '770 Patent.

21. I have been informed that a claimed invention is unpatentable under 35 U.S.C. § 102 if each and every element of the claim is disclosed by a single prior art reference. I also understand that a prior art reference must be enabling so that the claimed subject matter may be made or used by one skilled in the art.

22. I understand that a prior art reference may disclose concepts either expressly or inherently. With respect to inherency, I understand that the fact that a certain result or characteristic may occur or be present in the prior art reference is not sufficient to establish the inherency of that result or characteristic. That is, I understand that the mere fact that a certain thing may result from a given set of circumstances is not sufficient to establish inherency with respect to the disclosure of a prior art reference. In other words, I understand that inherency may not be established by mere probabilities or possibilities that a certain result or characteristic may occur or be present in the prior art reference.

23. Instead, I understand, to establish inherency, there must be some extrinsic evidence that makes clear the missing descriptive matter is necessarily present in the thing described in the prior art reference, and that such missing descriptive matter would be so recognized by persons of ordinary skill. Thus, I understand that, for a reference to inherently disclose a concept, the reference must necessarily include that concept.

24. I have been informed that a claimed invention is unpatentable under 35 U.S.C. § 103 if the differences between the invention and the prior art are such that the subject matter as a whole would have been obvious at the time the invention was made to a person having ordinary skill in the art to which the subject matter pertains. I have also been informed by counsel that the obviousness analysis takes into account factual inquiries including the level of ordinary skill in the art, the scope and content of the prior art, and the differences between the prior art and the claimed subject matter.

25. I have further been informed that obviousness concerns whether a POSITA not only could have made but would have been motivated to make the proposed combinations or modifications of prior art to arrive at the claimed invention. I have been informed by counsel that the Supreme Court has recognized several rationales for combining references or modifying a reference to show obviousness of claimed subject matter. Some of these rationales include the following: (a) combining prior art elements according to known methods to yield predictable results; (b) simple substitution of one known element for another to obtain predictable results; (c) use of a known technique to improve a similar device (method, or product) in the same way; (d) applying a known technique to a known device (method, or product) ready for improvement to yield predictable results; (e) choosing from a finite number of identified, predictable solutions, with a

reasonable expectation of success; and (f) some teaching, suggestion, or motivation in the prior art that would have led one of ordinary skill to modify the prior art reference or to combine prior art reference teachings to arrive at the claimed invention.

26. I also understand that use of hindsight is not permitted in an obviousness analysis. I understand this to mean that the reasons for combining references or modifying the teachings of a reference must be apparent at the time of the invention and thus apparent absent the use of hindsight.

V. BACKGROUND OF THE RELEVANT TECHNOLOGY

A. History of Hydraulic Fracture Treating

27. Petroleum refers both to crude oil and natural gas, a naturally occurring substance that is found in subterranean formations. The formations may be sandstones, limestones, dolomites or even shales. Shales are very fine-grained sedimentary rocks that may contain clays, clastics, and carbonates. Such rocks contain very small pore spaces and were deposited in a continental to marine environment millions of years ago.

28. Most rocks that form petroleum reservoirs were deposited under water or occasionally as windblown particles that were subsequently submerged. Such reservoirs initially had pore spaces filled with water. Over geologic time, these rocks are buried at great depths in the earth where temperatures and pressures are

high. Organic material (kerogen), typically in the shales can ultimately be transformed into oil and gas in a series of complex processes over a long period of time. A variety of organic chemicals result from these processes with varying numbers of mainly carbon and hydrogen atoms. Other less common components include oxygen, nitrogen and sulfur.

29. Hydrocarbons refers to compounds containing only carbon and hydrogen and constitute the largest volume of petroleum sources. When only a few carbon atoms exist in a hydrocarbon molecule, the compound tends to exist as a gas at normal surface temperatures and pressure. Compounds with many carbon atoms (and subsequently larger molecular size) exist as liquids at normal temperatures and pressures.

30. As organic molecules deposited (primarily in shales) are exposed to high temperatures and pressures over time, various reactions take place and some of the molecules are expelled from the shale rock into adjacent sands or carbonates as such reservoir rocks tend to have greater pore space to accommodate hydrocarbons and permeability to allow it to flow. Generally, the hydrocarbons which migrate from the shales have lower density than the water previously filling the pores of adjoining rocks and due to buoyancy will continue to rise until they can no longer do so. If there are no impediments to the flow of these hydrocarbons,

they will eventually reach the surface of the earth and be released into the atmosphere or into the ocean.

31. In some cases, the structure or stratigraphy of porous rocks is such that hydrocarbons can no longer migrate upward and are “trapped” in what can become a petroleum reservoir. Traps may be caused by various combinations of structures, faults or changes in stratigraphy. Normally a rock layer with very low permeability exists above trapping porous rocks containing the petroleum (and often some residual water that was not displaced). Petroleum reservoirs exist at depths from very near the surface of the earth to more than 30,000 feet below the earth’s surface.

32. Most liquid crude oils in a reservoir have some dissolved (associated) natural gas. Many natural gas reservoirs contain some larger molecules that exist as a gas in the subsurface but may drop out of the gas at surface conditions (condensates).

33. Most of the world’s oil and gas production comes from the types of conventional reservoirs previously described. Such reservoirs have reasonably high levels of porosity (often from 10% to more than 35% of the bulk volume of the rock is pore space and available to contain fluids) and high permeabilities permitting fluids to flow easily through the rocks. Tight reservoirs tend to have lower porosities and are far less permeable. As a rule, tight reservoirs require

stimulation to improve the flow capacity of the reservoir. Hydraulic fracturing or “fracking” is the most common type of stimulation for tight gas reservoirs.

Unconventional reservoirs include production from shales, tight sands, coal, mudstones, or ultra-low permeability reservoirs requiring a new completion and stimulation approach over historical tight reservoirs. As a rule, unconventional reservoirs require both horizontal wells and high rate, multiple stage hydraulic fracturing. In multiple stage hydraulic fracturing, each “stage” is an individual hydraulic fracturing operation that creates fractures in a section of the formation surrounding the wellbore. As explained in more detail below, each individual stage is accomplished by perforating a given length of well casing, isolating the perforated section from any other perforations, and pumping to fracture the stage. This process is costly and requires a large amount of surface equipment.

B. Shales

34. Shales are the most abundant types and volumes of rocks in sedimentary basins worldwide. Shales are the most abundant sources of hydrocarbons (source rock) for oil and gas fields and due to their low permeabilities forming the hydrocarbon seal for many fields. A conventional oil or gas field needs a source, a reservoir (usually porous sandstones or carbonates such as limestone or dolomite), a trap (such as a structural closure, sealing fault, or pinchout), and a seal. The source is necessary for hydrocarbons to exist, and some

pathway is necessary for these hydrocarbons to migrate. The reservoir porosity was usually water filled at the time of deposition, allowing the hydrocarbons to migrate through the porosity due to having lower density than the water. The trap and seal are necessary to prevent continued migration (to keep the hydrocarbons in place), allowing the reservoir to accumulate and store oil or gas. As a result, geologists and geochemists have studied shales extensively with most of their historical effort focused on shale's source rock potential. The fact that many shales still contain significant amounts of natural gas is no surprise to drillers and geologists. It is routine to observe natural gas "shows" while drilling through shales, occasionally in significant volumes. But while it may be clear to most readers what porous sandstone or carbonate rock is like (the rocks that form most oil and gas reservoirs), shales remain somewhat of a mystery.

35. There are multiple definitions of what constitutes shale. A geologist once mentioned that the way to differentiate between siltstone and shale was to put it in your mouth. If it tastes gritty, it is a siltstone. If it tastes smooth or oily, it is shale.

36. Shales are sedimentary rocks composed of clastics (portions of older rocks) comprised of silts, muds, and clays. Geological definitions of shales typically reference their grain size as being clay-like (less than 1/256th mm diameter particles). Silts are also defined based on grain sizes (between 1/16th and

1/256th mm) and are positioned between clays and sands. Very fine silts can be primarily composed of quartzitic materials that are lacking in typical clay minerals. Clay minerals often include kaolinite, montmorillonite-smectite, illite, and chlorite. There are dozens of pure clays, with most clays being mixtures of multiple pure clays. One important clay type in oilfield operations is bentonite, a typical weighting component of drilling mud. Another physical property often used in defining shales is their tendency to split into thin sheets or slabs (fissility). Muds are simply mixtures of water and very fine silt, clay, and soil particles. Mudstones are hardened muds that may not show fissility unless desiccated. While most shales are clastics, significant carbonate components can be present in shales. The formations we refer to as shale gas or shale oil plays are often layers of shales and layers of silts and/or carbonates.

37. The depositional environment of shales that are resource plays is typically a low-energy one that allows very fine-grained particles that will constitute future shales to be deposited. High-energy deposits, such as channel sands and turbidites, may also lead to shale deposition. The low depositional environments associated with marine shales means that their geological and petrophysical properties change relatively slowly over large distances compared with the higher levels of heterogeneities in many sandstones and carbonates.

Petrophysicists take advantage of this when analyzing logs of varying vintages and from varying suppliers by normalizing log responses in marine shales.

38. Very fine-grained, organic material (usually from plant materials) is often deposited concurrently with the silt, mud, and clay matter that will eventually form shales. Total organic carbon (TOC) is the weight-percent of organic carbon in the shale (and does not include carbon from carbonates for example). Because many shales have relatively high organic carbon content, shales can serve as source rocks for oil and gas reservoirs when subject to certain heat and temperature conditions. The organic content originated with living material, ultimately from plant, animal, and bacterial matter such as algae, plankton, or decomposed plant materials. After death, the materials decompose, and the decomposition products can form new polymers to form kerogen. Diagenesis is controlled primarily by biological and chemical activity associated with mineralogy and redox conditions. Complex thermal transformations characterize subsequent kerogen transformation.

39. The word kerogen was originated by Professor Crum Brown (of the University of Edinburgh, Scotland) and referred specifically “...to the carbonaceous matter in shale that gives rise to crude oil in distillation” (Brown 1979). Kerogen now refers more broadly to all solid organic material in sedimentary rocks; kerogen is generally insoluble in water or organic solvents due to their high molecular weights. Bitumen refers to the insoluble portion.

40. Kerogen may be formed under various circumstances from this organic matter, which can be broken down into lighter organic materials under heat and pressure. Most oil and gas produced originated with such shales as sources with a few exceptions.

41. Shales generally have extremely low permeability due to their very fine grain size. Permeabilities are so low in most shales that excellent seals for oil and gas fields can be formed by shales. Drillers and mud loggers have long known that many shales contain significant quantities of natural gas, because natural gas shows are commonplace during drilling through shales. While some shales are rich in heavy hydrocarbons (oil shales), this discussion focuses on shales that are likely to contain natural gas or oil.

42. It is important to note that the type of shale production being discussed here is generally conventional oils or gas produced from relatively deeply buried shales that are produced in a manner roughly similar to conventional wells. We refer to this as shale oil and shale gas. The term oil shale is widely applied to petroleum extracted from shallow rocks with very high kerogen content. Many of the rocks referred to as oil shales are not actually shales—these rocks are often physically mined rather than having the hydrocarbons produced through wellbores. Oil shales contain typically solid or ultraviscous hydrocarbon material in their pores. While some oil shales can be burned directly, most require some

sort of extractive process coupled with upgrading to yield oil like hydrocarbons.

Oil shales are not discussed here.

43. Shale gas production has been recorded for over a century in the Devonian age formations in the Appalachian basin. More than 20,000 wells have been drilled in these shallow shales. Older (and deeper) Devonian shales include the Marcellus formation, which is now a major focal point for the application of advanced technology. Because we have known about these shales and their hydrocarbon potential for decades, if not more than a century, why has it taken so long to produce them? The answer is clear: the technology to drill, evaluate, complete, and produce these shale plays has only been available for about two decades.

44. While shales are known to be the principal source for conventional hydrocarbon plays as well as seals, shales can also be the reservoir and trap. Most of the gas created in such reservoirs would be thermogenic in origin, although some shales (e.g., the Antrim) have significant quantities of biogenic gas. Gas is stored in shales either as free gas in the pore spaces or adsorbed onto the organic material or surface walls in the shale.

45. Thermogenic methane was formed when organic matter was compressed at very high pressures for a very long time. Just as in oil formation, thermogenic methane is a cracking process that transforms organic particles carried

in the clastic material, which then forms the origin of shales. The nature of the organic material and time and pressure dictate what is formed.

C. Well Construction

46. Drilling and completion of oil and gas wells in North America dates back to the mid-19th century when cable tools were used to drill shallow wells. Most wells drilled today use rotary tools. In a modern drilling example, drilling rigs use drill bits at the bottom of sections of heavy drill pipe to construct the well. Drilling proceeds by imparting torque from powerful top drive motors to which is connected to the drill pipe and rotates the pipe and bit. Mud is pumped down the center of the drill pipe, out through the bit and back up through the annular space between the exterior of the drill pipe and the wellbore that is being drilled. Mud serves to cool the bit, lift cuttings to the surface and minimize the influx of oil, water or gas from the formations being drilled through into the wellbore. Horizontal sections are drilled utilizing drilling motors that are installed just above the drill bit and powered by the flow of the drilling fluid through the motor. As the well is drilled deeper, more strings of drill pipe are added.

47. Fresh water intervals near the surface of the earth need to be protected from oil, water, or saltwater and as soon as the wellbore is drilled through such formations, the drill pipe and bit are removed, and steel casing is lowered into the hole. Cement is pumped down through the casing to fill the annulus between the

outside of the casing and the wellbore walls. Water is used to displace the cement inside the casing. Once the cement hardens, drilling recommences with a smaller diameter drill bit that will fit inside the casing. As the well is drilled deeper, higher pressures may be encountered. Higher reservoir pressures require heavier (greater density) muds to prevent influx of reservoir fluids. However, if mud weights are too high, the pressure could exceed the rock strength and stresses in previously drilled sections. Thus, it may be necessary to run additional strings of casing which are cemented in and subsequent drilling takes place with a smaller drill bit. Sometimes cement is not returned all the way to the surface and sometimes additional strings of casing (called liners) are also not run all the way back to surface.

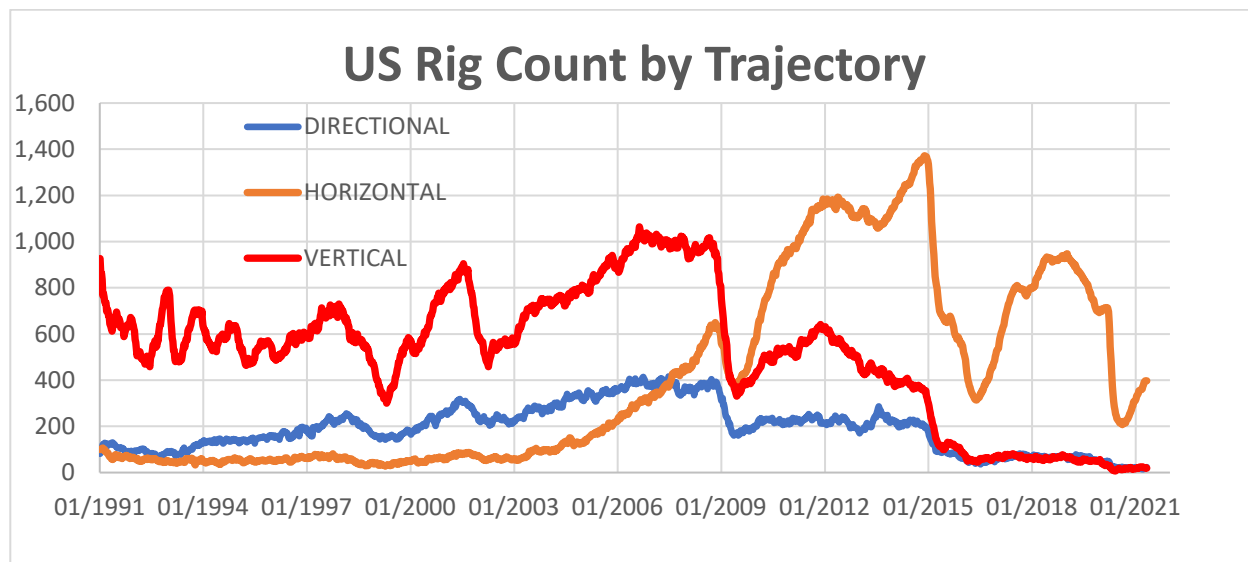
48. At various points in the well construction process, measurements of electrical conductivity, acoustic velocity, density, natural radioactivity, and other properties are made using tools lowered into and subsequently retrieved from the wellbore in order to help characterize the formations encountered. Collectively, these tools are referred to as logs and the process as logging. Many of the measurements can be made in near real-time with tools included behind the bit in the drill string. These data can be retrieved by encoding the data into mud pulses which can be interpreted at the surface. Mud pulse telemetry can be thought of as a kind of “Morse code” communication. Wired pipe is drill pipe with built in

electronics that permit higher frequency measurements from downhole.

Measurements while drilling (MWD) can include both logging while drilling (LWD) and other measurements while drilling (MWD) includes such information as the inclination, azimuth and orientation of the drill bit.

49. MWD is particularly useful in directional and horizontal drilling.

Most wells drilled in the United States today are horizontal wells. Figure 1 shows US rig activity since 1991. From 1991 to 2003, horizontal wells ranged from 3.7% to just over 10% of all wells drilled. Today they average more than 90% of all wells drilled. The reason for this change is the rapid growth of unconventional wells using horizontal drilling technology and multi-stage hydraulic fracturing. Directional wells are primarily drilled offshore.



D. Horizontal Drilling

50. Most wells are drilled as vertical wells meaning they go more or less straight down. It has long been known that wellbores sometimes drill at angles other than straight down which occasionally had unwanted results. Tools have been developed to measure hole inclination and more sophisticated versions offer compass orientations and inclination with depth so that the well path can be known with a reasonable degree of accuracy. Deliberate deviation of a wellbore was developed when undrillable debris (junk) was left in a hole and it was desired to drill around the junk rather than redrilling the entire wellbore. This directional drilling is known as sidetracking. Tools developed to sidetrack were extended to enable wells to be deviated and drilled from a surface location to another subsurface location removed from the surface location. Sometimes this is necessary to access oil or gas reserves located beneath water, buildings, or any other surface location where a drilling rig and subsequent oil and gas wells could not be placed. In offshore applications, all of the wells are often drilled from a relatively small surface location (the offshore platform) and are directionally drilled to the desirable locations in the reservoir. Directional drilling technologies continue to advance and world class directional wells are able to reach more than 7.5 miles from the surface location.

51. Horizontal drilling is an extension of directional drilling technology enabling wells to start out vertically and then turn approximately 90 degrees to be horizontal. In many applications of horizontal wells, multiple wells are drilled spaced closely apart on the same pad and extend horizontally through a reservoir in parallel with one another. Drilling multiple wells in this manner increases the amount of the reservoir that can be fractured, which will increase recovery of oil or gas. While horizontal wells have been drilled experimentally for decades, commercial applications started in the 1980s. Typical applications included:

- Development of naturally fractured reservoir where the fractures were nearly vertical. Horizontal wells could be drilled to encounter many times more fractures than a vertical well.
- Development of thin reservoirs to increase flow rates. For example, a vertical well drilled through a 20-foot-thick interval only encounters 20 feet of pay. A horizontal well could encounter hundreds to thousands of feet of pay from the same interval.
- Minimizing water or gas coning. In some oil reservoirs the oil layer is underlain by water or overlain by natural gas. Vertical wells might draw the unwanted fluids into the oil producing area and decrease producing rates or ultimate recoveries. A horizontal well drilled in the oil zone could have a significantly decreased tendency to “cone” in the unwanted fluids.

E. Well Completions

52. When wells have been drilled to their total depth and the final casing or liner has been installed and cemented in place, decisions based on well logs, cores and other data select the completion interval(s). In conventional wells this includes perforation of the casing and the cement sheath to enable fluid flow from the perforated formation into the wellbore. Tubing is often run to a depth above the completed interval and reservoir fluids can flow into the wellbore and up the tubing. Flow rates can be adjusted by changing the size of the orifices through which fluid passes at the surface (chokes). Perforation of the casing and cement sheath may be accomplished by various methods, although the most common approach involves using shaped explosive charges to precisely pierce the casing. Charges are loaded into an assembly and positioned within the wellbore by wireline operation. As production continues, pressures decline near the wellbore and in the reservoir resulting in lower flow rates. Various types of pumps can be installed for liquid production or compressors in the case of gas production.

53. Conventional wells typically have reasonably high permeability but may still benefit from stimulation. Occasionally permeability reductions near the wellbore (damage) arise from the drilling, cementing or production activities. Injecting acid or other solvents may address the issue. Sometimes small hydraulic

fracturing treatments enable the wellbore to access part of the reservoir further out from the damaged area.

F. Hydraulic Fracturing

54. The idea of hydraulic fracture treatments was first conceived in the 1860s. Various methods were tried to stimulate shallow, hard rock wells in Pennsylvania, New York, Kentucky, and West Virginia without a great deal of success. By the 1930s the idea of injecting acid into the ground to stimulate a well began to be tried. The “pressure parting phenomena” was recognized.

55. The first attempts at fracturing formations were not hydraulic in nature—they involved the use of high explosives to break the formation apart and provide “flow channels” from the reservoir to the wellbore. There are records indicating that this took place as early as 1890. Indeed, one of the predecessor companies of BJ Services, the Independent Torpedo Company (founded in 1905), used nitroglycerine to explosively stimulate formations in Ohio. This type of reservoir stimulation reached its ultimate conclusion with the experimental use of nuclear devices to fracture relatively shallow, low permeability formations in the late 1950’s and early 1960’s. In the late 1930’s, acidizing had become an accepted well development technique. Several practitioners observed that above a certain “breakdown” pressure, injectivity would increase dramatically. It is probable that many of these early acid treatments were in fact acid fractures.

56. The first intentional hydraulic fracturing process for stimulation was performed in the Hugoton gas field in western Kansas, in 1947. The Klepper No 1 well was completed with 4 gas producing limestone intervals, one of which had been previously treated with acid. Four separate treatments were pumped, one for each zone, with a primitive packer being employed for isolation. The fluid used for the treatment was war-surplus napalm, surely an extremely hazardous operation. However, 3000 gals of fluid were pumped into each formation.



Klepper Well No.1, Hugoton gas field, Kansas. Economides, 2007

57. Although post treatment tests showed that the gas injectivity of some zones had been increased relative to others, the overall deliverability from the well was not increased. It was therefore concluded that fracturing would not replace acidizing for limestone formations. However, by the mid-1960's, propped

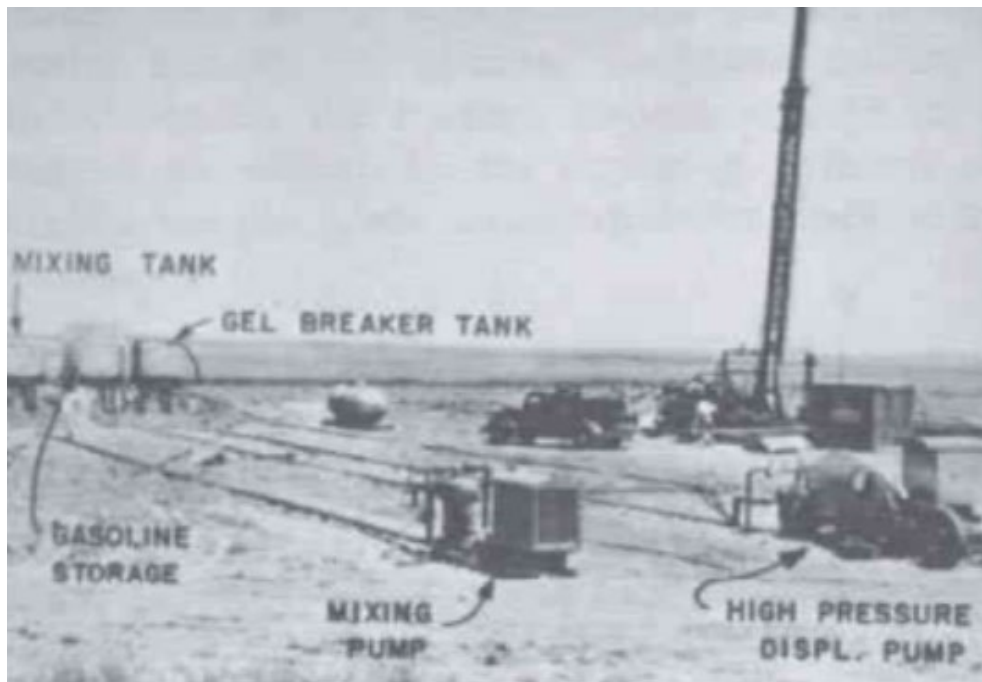
hydraulic fracturing had replaced acidizing as the preferred stimulation method in the Hugoton field. Early treatments were pumped at 1 to 2 bpm with sand concentrations of 1 to 2 ppg.

58. Today, thousands of these treatments are pumped every year, ranging from small skin bypass fracs, to massive fracturing treatments that end up costing many millions of dollars. Many fields only produce because of the hydraulic fracturing process. In spite of this, many industry practitioners remain ignorant of the processes involved and of what can be achieved.

59. In low permeability (tight) reservoirs, hydraulic fracturing is required to obtain commercial flow rates. In such wells, permeability is low due to low porosity, very small grain sizes, occlusion of many of the pore throats with clays, silica overgrowth or other material.

60. The first commercially successful hydraulic fracture treatments were conducted by Halliburton Oil Well Cementing Company (HOWCO) in 1949. The first was the Pickens No. 1 well, in Stephens County, Oklahoma and the second was in Archer County, Texas - both on March 17, 1949. These first jobs were pumped using conventional cement pumping equipment. In the following year, 332 wells were treated, with an average production increase of 75%. As techniques improved, applications of the fracturing process grew very rapidly in the United States. By the mid-1950s more than 3,000 wells were being treated per

month. These first jobs consisted of approximately 750 gallons of fluid laden with 400 pounds of sand. Equipment evolved very rapidly. The first 500,000 pound hydraulic fracture treatment in the free world was performed in October 1968, by Pan American Petroleum Corporation in Stephens County, Oklahoma.



61. Hydraulic fracturing is a process in which a fluid is injected into the perforated interval at high rates and pressures. This fluid, most commonly water, containing a biocide, friction reducer and surfactant, along with guar gum to increase viscosity. Injection pressures must be sufficiently high to overcome the minimum *in situ* stress and rock strength. When this occurs, the formation can fail. Most North American reservoirs have minimum stresses aligned approximately horizontally resulting in hydraulic fractures that are vertical and approximately

planar in shape. Vertical wells that are hydraulically fractured may have multiple stages that stimulate multiple layers of rock encountered.

62. Over the years numerous propping agents have been utilized including plastic pellets, steel shot, Indian glass beads, aluminum pellets, high-strength glass beads, rounded nut shells, resin-coated sands, centered bauxite, and fused zirconium.

63. Most hydraulic fracturing jobs include proppants with the slick water fluids. Proppants can be sand or synthetic material designed to fill the hydraulic fractures created during the stimulation process. When pumping is completed, pressure is bled off and the created fracture tries to close. Fluid pumped during the job flows back into the wellbore to be produced back (flowback) but the proppant remains in the created fracture, preventing the fracture from closing. The permeability of the propped hydraulic fracture volume is orders of magnitude greater than that of the reservoir and the area of the created hydraulic fractures are similarly much greater than the interval near the wellbore.

64. Unconventional reservoirs often have permeabilities that are substantially lower than those of tight reservoirs. These permeabilities are so low that prior to the unconventional revolution most operators did not think commercial production was possible. In such reservoirs, horizontal wells and

many (dozens to more than fifty) orthogonal hydraulic fractures are created requiring huge numbers of pump trucks and specialized equipment.

65. Between 1981 to 1998 Mitchell Energy and Development experimented with horizontal drilling and hydraulic fracture treatments in the Barnett Shale formation of North Texas. Commercial success came when the company combined these treatments with slick water, a low viscous mixture that could rapidly be pump down well to deliver much higher pressure to the rock than before. By 2005, this was the beginning of the shale gas boom.

G. Hydraulic Fracturing Equipment

66. The design of pressure pumping equipment, sand handling equipment, blending equipment, along with the required plumbing for these fracture jobs was evolving at a very fast pace in the 1960s and 1970s and continues today.

67. In the 1970s and 1980s the size of hydraulic fracture treatments dramatically increased. During this time two of the most active plays in the United States were the Cotton Valley sands of East Texas and Northern Louisiana, along with the Deep Upper Wilcox sands in South Texas. The wells were drilled vertically and massive hydraulic fracture treatments pumped during the completion. The volume of sand in these jobs increased to more than 6 million pounds per treatment. This involved changes in the way the proppant (sand) was handled. Storage systems for the proppant and handling systems changed

regularly. The pressure pumpers' discharge to the wellhead was through frac iron laid on the ground and made up with hammer unions. Typically, this was done with a single line going to the well.

1. Suction Hoses

68. It is essential that sufficient suction hoses be used between the tanks and the blender. The only force available to move the fluid to the blender is the suction of the inlet pump and hydrostatic pressure from a difference in fluid levels. This is not much. In order to ensure that the suction pump receives fluid at sufficient rate, a simple rule applies:

One 4" diameter 10' suction hose will carry up to 10 bpm of gel.

69. If 20 bpm is required, then two hoses will be needed, and so on. In addition, longer hoses will carry less rate. For instance, 20' of 4" diameter hose will only carry half as much rate, i.e., 5 bpm. So if 20 bpm were required from tanks which were 20' away, 4 x 4" flow lines would be required.

70. From this it is easy to see why the blender is usually placed as close as possible to the frac tanks, and why the frac tanks are often manifolded together with 8" (or larger) diameter lines.

71. Also consider the comparative diameter of manifolds and suction hoses. For instance: An 8" manifold has a flow area of 50.26 sq inches. This corresponds to the same flow area as 4 x 4-inch hoses (50.24 sq inches).

Therefore, there is little point in building an 8” manifold and then using only 3 x 4” suction hoses.

72. Finally, remember that there is a difference between suction and discharge hoses. Suction hoses need to be rigid, otherwise the suction pump of the blender can suck them flat. Discharge hoses, which generally do not have to carry suction, are often made from non-rigid hoses, which collapse flat when there is no fluid in them. This makes for easier storage and makes the hoses easier to carry. As a general rule-of-thumb, suction hoses can be used for the discharge (provided they have the correct pressure rating) but discharge hoses cannot be used on the suction.

2. Discharge Hoses

73. The discharge hoses run from the blender to the high pressure frac pumps. Generally, one discharge hose is required from the blender to each pump. These hoses do not need to be rigid (see above comments on suction hoses) but must have sufficient pressure rating. They must also have crimped connections (similar to high pressure hydraulic hose connections) and not the old-style clamps. Discharge hoses should also be fitted with “whip-checks” at each connection.

74. For rates below 5 bpm per pump, a single 3” discharge hose is required for each pump. At rates above 5 bpm, a single 4” hose should be used - although at very high rates (15 bpm +), more than one hose may be required.

3. High Pressure Flow Lines

75. When pumping abrasive fluids—such as a frac gel with proppant—down a high-pressure treating line, there is a limit to how fast it is advisable to pump. Above this pump rate, seals on Chiksans, swivels and hammer unions start to wash out. It is generally accepted in the industry that the velocity of the frac fluid should not exceed 40 ft sec-1.

76. The actual inside diameter of high-pressure flow lines is often significantly less than the nominal diameter. The equation for Qmax should be used with the actual diameter. HP flexible lines, such as Coflexip hoses, and large diameter lines not connected with Chiksans have separate guidelines. For these, the manufacturer's instructions should apply.

4. High Pressure Pumps

77. Most high-pressure pumps used in hydraulic fracturing are of the triplex variety, although quintuplex pumps are becoming more popular. Triplex means that there are three pistons acting to pump the fluid, quintuplex means that there are five. These pistons are driven by a rotating crankshaft, as illustrated in Figure 2.

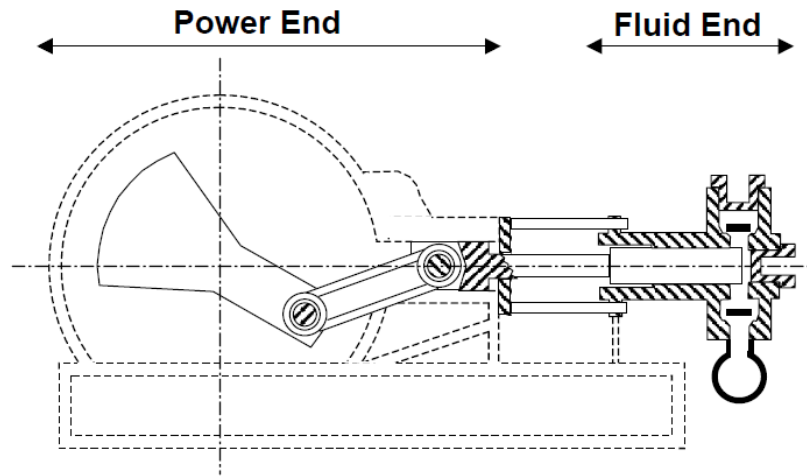


Figure 2: Schematic diagram of a generic frac pump

78. Figure 3 and Figure 4 show what happens while the pump is operating. Figure 3 shows the suction or inlet stroke of the cycle. As the plunger moves back towards the power end, fluid is pushed through the suction valve by the blender. The spring acting to close this valve requires 20 to 40 psi just to lift it up, so the blender must provide a boost of pressure significantly greater than this in order to quickly fill the fluid end.

79. Figure 4 shows the power or discharge stroke. As the plunger moves away from the power end, the increased pressure in the fluid end causes the suction valve to close, and once this pressure is high enough, the discharge valve to open.

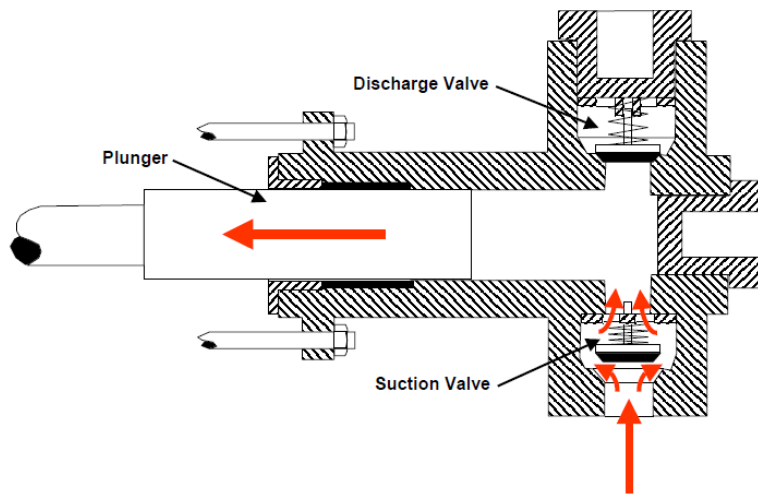


Figure 3: Generic frac pump, suction stroke

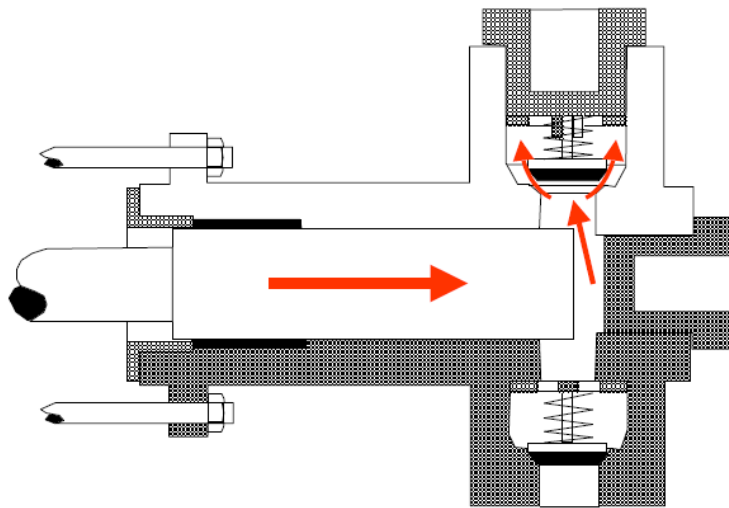


Figure 4: Generic frac pump, discharge stroke

80. Frac pumpers come in a variety of sizes, ranging from 350 HHP to 2700 HHP. Bigger pumps are more cost effective for big treatments but are very expensive and can be difficult to move on roads and onto location. Smaller pumps may require more operators, more maintenance (per horsepower—maintenance per pump unit is not significantly affected by size) and take up more space on location.

5. Blenders, Gel Hydration, and Liquid Additives

81. The blender is the heart of the fracturing operation. Although modern blending equipment is often highly automated, the blender operator (or Blender Tender) still retains one of the most critical positions on any location. Figure 5 shows a generic schematic diagram of a frac blender:

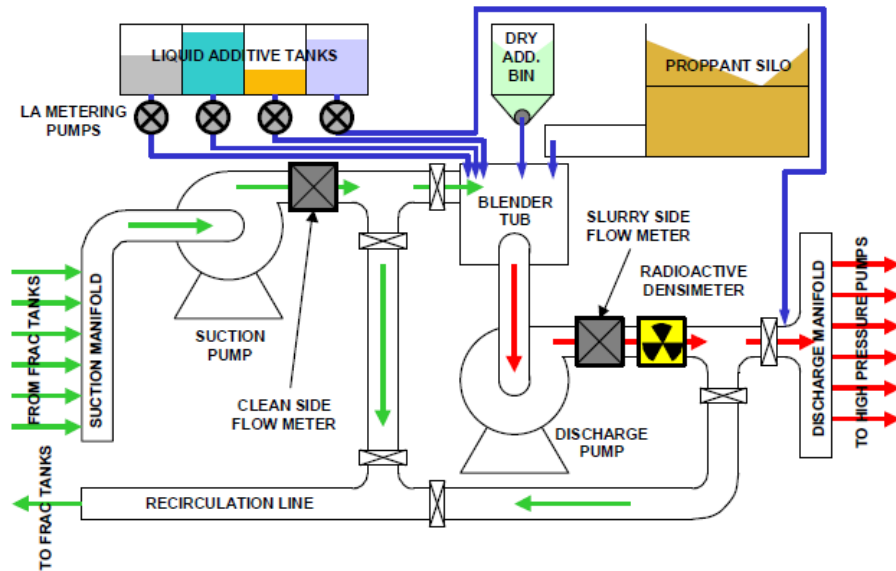


Figure 5 Generic flow diagram for a frac blender. Some blenders fitted with tub that combines the functions of the blender tub and the discharge pump.

82. The blender performs the following functions:

- a. Pre-gelling tanks;
- b. Blending liquid and dry additives on the fly;
- c. Blending proppant on the fly;
- d. Providing supercharge for the high-pressure pumps; and
- e. Metering and recording a variety of job critical parameters.

83. When pumping a treatment, the frac spread can be set up to either gel the frac tanks before the treatment—so that all the fluids are prepared beforehand—or to mix the gel on the fly.

6. Proppant Storage and Handling

84. Proppant has to be stored on location, ready for use. It has to be kept clean and dry and must be delivered to the blender smoothly and quickly. Figure 6 shows frac sand being delivered to the hopper of a blender.

85. There are two main methods for ensuring the smooth flow of proppant from the storage bin to the blender. The first method is to use a gravity-feed system, which relies on the proppant being stored in a bin that is higher than the blender hopper. A gate valve is used to control the sand rate. This can be done with either large vertically mounted bins (Figure 6) or from a dump truck.



Figure 6 Frac sand being delivered from a Sand King to the blender

86. The second method is to use a conveyor system to move the proppant from the bin or dumper to the blender hopper. This method is typically used on larger frac jobs, particularly large land jobs, as there is usually insufficient space around the blender hopper for all the bins to be positioned.

7. Wellheads

87. Production wellheads are not typically designed for hydraulic fracturing treatments. The high rates and abrasive sand generally would erode the internals of a typical wellhead. Specialized wellheads known as “frac trees” are often used in place of existing wellheads. Alternatively, a Wellhead Isolation Tool (WIT), often referred to as a “Tree Saver” can be used. A WIT is a device that allows treatments to be pumped at a standard temperature and pressure (“STP”) higher than the maximum pressure rating of the wellhead. This allows treatments to be pumped at much higher rates than would normally be possible. The WIT does this by completely isolating the wellhead from the treating fluid.

88. A frac head (or goat head (Figure)) may be used when multiple lines are used for a frac tree or tree saver.

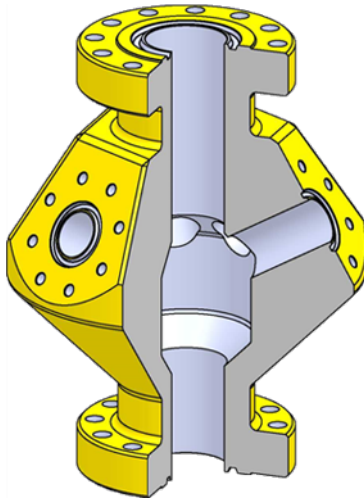


Figure 7 Example cutaway of a frac head

<http://www.qihangwellhead.com/products/API-6A-Frac-Head-Goat-Head-for-Fracturing-Wellhead-Assembly-3281453.html> or
https://img.hisupplier.com/var/userImages/2018-06/26/223100075_s.jpg

8. Manifolds

89. In general, a manifold is a pipe fitting that connects multiple pipes in various ways. Everyday examples include the manifold for a sprinkler system (Figure 8). In such a system, water from the main sprinkler line is connected to a manifold that allows the sprinkler system to dispense water to individual stations by opening one manifold valve at a time.



Figure 8 Example home irrigation manifold

90. Another everyday example showing the reverse use of a manifold is an automobile exhaust manifold (Figure 9). The exhaust manifold collects exhaust gases from multiple cylinders into one pipe. On modern engines, an intake manifold, sometimes known as an intake manifold, distributes air to the engine's cylinders. So in an automobile engine, we have manifolds that both combine the flow of air from many pipes into one and distribute the flow from a single pipe into multiple lines like the home sprinkler system.



Figure 9 Exhaust manifold for an automobile.

91. Manifolds are common in multiple locations in a hydraulic fracturing operation. Water is pumped from the storage pond to fill up a series of water storage tanks connected by a manifold. These multiple tanks are connected to a hydration unit (if present) through a manifold. The fluid then moves to the blender where the remaining additives and proppants are mixed with the water and pressurized to approximately 100 psi. Water from the blender enters the low-pressure side of the missile manifold, a long set of manifolds that distribute the low-pressure water to the inlets of the pumps. Figure 10 shows a series of pump trucks connected to the missile manifold. Connections are often with flexible hoses. Quintiplex pumps (or similar) pressurize the fluid to high pressures and back to the high-pressure manifold side of the missile manifold. In the case of hydraulic fracturing a single well, high pressure steel lines (typically 3 or 4 inches in diameter and 10 feet in length) connect the high-pressure outlet from the missile manifold to the frac head atop the frac tree. The frac tree can be a specialized tree (the most common) or a conventional wellhead equipped with or without a tree saver.



Figure 10 missile manifold

92. Around 2005 the missile manifold trailer was developed allowing the pressure pumper discharge to be placed into the trailer and then to the wellhead greatly shortening the rig up time. This was during the time that the Barnett Shale in the Newark East Field development was getting started in earnest. The next major development was creation of the goats head, which allowed multiple lines to be discharged from the missile manifold trailer to the wellhead.

93. When multiple flow lines are used from the missile manifold to the frac head, swivel joints (chiksans) and smaller sections of pipe (elbows and pup joints) may be used to connect the lines. Hammer unions provide seals for threaded connections so that the treating lines do not need to be rotated. Several alternative connection technologies are available. The frac head where multiple lines connect into one flow stream functions as yet another type of manifold.

94. After the introduction of the missile manifold, a second intermediary manifold known as a “zipper manifold” was introduced. The zipper manifold accepts pressurized fluid from the missile and distributes it to each of several connected wellheads. Instead of physically moving the pump’s discharge line from one well to the next, the zipper manifold allows an operator to direct the flow to a given well by opening only the valve associated with that well. Further improvements to manifold configurations allowed wireline and perforation operations to take place in one well during pumping operations in another well connected to the same manifold, which reduced non-pumping time between stages.

95. First, by providing a flow path from the pump to each of the wells, the labor required by single-well operations to change from pumping into one well to pumping into the next was eliminated. Second, zipper manifolds significantly reduced downtime in multi-well operations by allowing operators to complete fracturing and perforation operations simultaneously, rather than sequentially.

When all stages in a single well are completed one after another, fracturing operations are performed, then the next stage is perforated before the next stage can be fractured. Fracturing and wireline operations can take hours, so the wireline or pumping crew is idle for a significant amount of time while the other is working. When a zipper manifold is utilized, fracturing operations can take place in a first well, while the next stage to be fractured in a second well is perforated. When operations in both wells are completed, the valves on the first well are closed and the valves on the second well are opened so that when pumping resumes, the fluid is now directed to the second well. Thus, downtime in fracturing operations is reduced the time, if any, that perforation operations exceed the fracturing operation, and the time required to manipulate the valves and restart the pumps.

96. Almost all the onshore wells in the United States require hydraulic fracture treatment. The current number of stages, or frac jobs, is approximately 60 per well. These hydraulic fracture treatments have pump pressures between 9,500 psi and 10,000 psi along with rates of 100 barrels per minute. It is these pressures and rates that drive improvement in the pressure pumpers and delivery systems to the wellbore.

H. Fracturing Systems - Examples

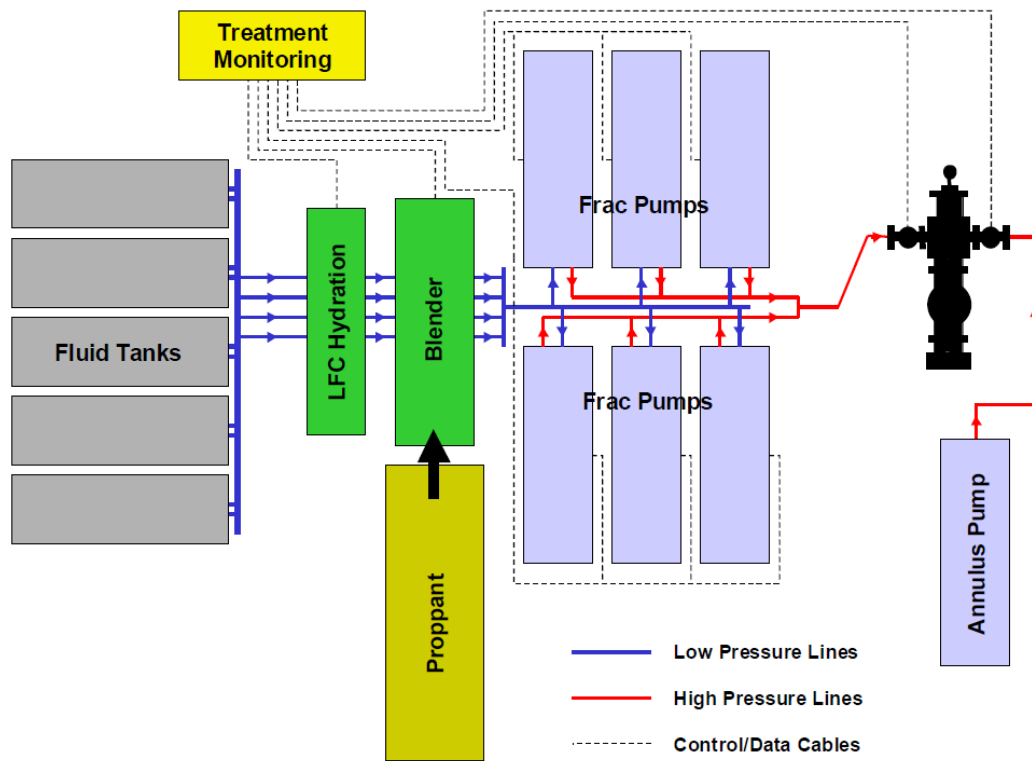


Figure 11 Schematic of a frac spread



Figure 12 Large scale treatment, carried out on several low permeability zones simultaneously.

97. Here is a manifold (the missile) going to a manifold and 4 individual flow lines going to well heads. Each line is more than one piece of pipe.

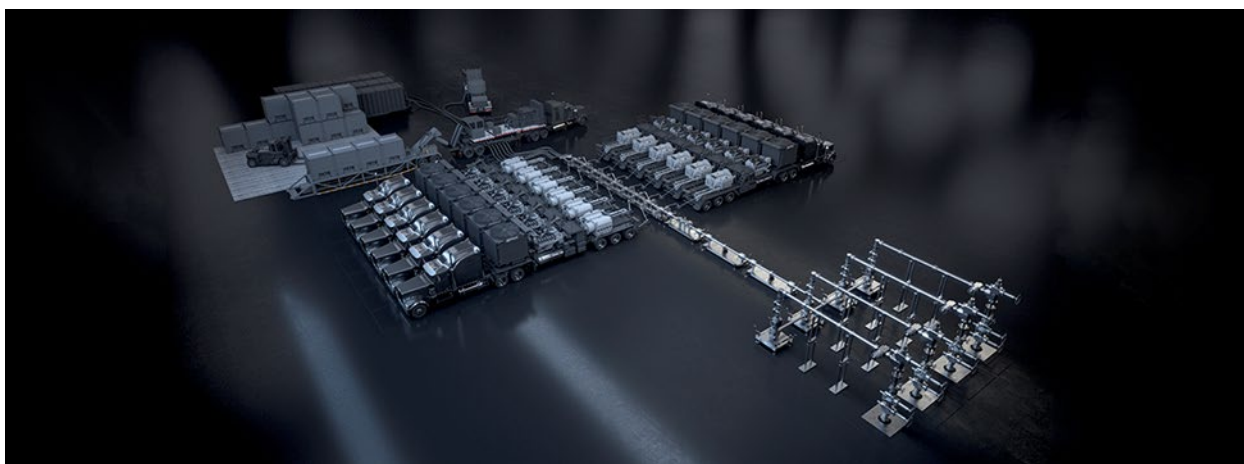


Figure 13 <https://www.worldoil.com/news/2017/5/4/weirs-new-simplified-system-reduces-non-productive-time>



Figure 14 Simultaneous fracture treatments being performed on three Barnett shale gas wells, north of Fort Worth (Source: BJ Services Hydraulic Fracturing hand



Figure 15 A “frac stack” atop BP’s D-1 well in Oklahoma’s Woodford shale while the well was being refractured in early 2013. BP doubled production from horizontal shale gas wells last year in a program meant to determine if refracturing

could be done economically [Renewing Mature Shale Wells Through Refracturing \(spe.org\)](https://www.spe.org)

1. Fracturing trees are conventional structures that have long been known and used in the industry.

98. Once the frac valve was developed, the frac tree became the standard.

The frac valve was developed in East Texas during the Cotton Valley boom of the 1980s. The first frac valves were operated manually. By the 1990s the standard had become one manual frac valve (lower master) below a hydraulic operated frac valve (upper master). This is the same valve sequence utilized on frac trees today. On top of these two valves there is typically a cross with two valves on each wing and a goat's head on top of the cross. On top of the goat's head is a swab valve. The goats head was developed in the early stages of the Barnett Shale boom, approximately late 2005. This assembly, which is referred to as a frac tree, is typically utilized while performing hydraulic fracture treatments on wells. Generally, once the hydraulic fracture treatments are completed, the frac tree is removed and a production christmas tree is placed on the well. Virtually every well that I have been involved with since the development of the frac tree has utilized this device.

2. Using lengths of pipe and various connectors to assemble pathways between a manifold and a well has long been a common practice.

99. Once the missile manifold became prevalent in hydraulic fracture stimulation operations in the 2005 timeframe, piping was utilized to go from the

manifold to the well, i.e., frac tree. The industry has always used piping (lengths of pipe) to go from the missile manifold to the well. After 2010 this changed slightly in that the discharge of the missile manifold goes to an intermediate manifold, referred to as a zipper stack, and from there to the individual well frac trees. These pathways are made up of individual lengths of pipe coupled together utilizing connection blocks, hammer unions and flanges. Which connectors and couplings are used is often determined by the particular geography of the operation. Whether it be for single- or multi-conduit connections between a manifold and a fracturing tree, spacing and alignment is always a concern. To address this concern, practitioners have long relied on the ability to use various connectors (tees, crosses, or other connection blocks) and pipes to redirect fluid flow between a manifold and a frac tree to accommodate the space available at a given site. Because well locations vary greatly in size, sometimes due to terrain, the rig up of frac iron may vary location to location even in the same field. This has been a constant battle over the last 50+ years.

100. Over the last 45 years, efforts have been made to streamline the assembly of these connections. There has been and is a continuing effort to reduce the assembly time and to render the location safer. The faster that these systems can be assembled and maintain high reliability, less money is expended by the operator.

3. Valves are commonly used to control the flow of fluid during fracturing operations, and using two valves in series is a similarly common practice.

101. A tenet of engineering design principles for the flow of high-pressure fluids dictates that there be two valves in series. This can easily be seen in the christmas tree utilized while producing a well. For a high-pressure well there is universally a lower master valve and an upper master valve. On the wing of this same christmas tree, there is an inner wing valve and an outer wing valve. The same principles and safety precautions are commonplace in hydraulic fracture treatment plumbing. To put it another way, it is common practice to utilize two valves in series for any application that calls for a valve to be exposed to high-pressure fluids. The reasoning behind two valves in series is one valve is the one commonly used and the other is the backup in the event of damage to the primary valve.

102. This principle is very well understood in the industry. This is a primary tenet of good engineering design.

4. The use of flanged connections is common in fracturing systems.

103. The use of flanged connections has been prevalent at the well site since long before 2011. This is true during all phases of a well's lifecycle. During the drilling phase of the well's lifecycle, while drilling the well we utilize a choke and kill manifold to allow for well control operations in the event that well control

would be necessary. This manifold is one that lies horizontally on the ground on a skid and all the connections are flanged for the valving and piping required.

During the completion phase of the well's lifecycle, the missile manifold utilizes flanged connections, the zipper manifold uses flanged connections for the valving and piping, and the wellhead/frac stack utilize flanged connections. In addition, there are numerous flanged connections on the pressure pumping equipment. During the producing phase of the well's lifecycle, there are numerous flanges utilized including in the christmas tree.

104. When possible, the preference is to use a flange connection versus a hammer union connection. The hammer union connection is more prone to leakage for a variety of reasons including improper makeup, gasket wear and possibly debris in the connection sealing area. A flange connection has the benefit having the studs and nuts properly torqued for an even seal and the use of metal ring gasket's that provide better sealing. The hammer union is a faster makeup connection but has the aforementioned drawbacks.

105. The industry is utilizing more flange connections than ever. This is partially due to better tools in the field to facilitate quick makeup. These tools allow for fast makeup and torquing and because of these advantages, flanges are gaining in popularity.

5. Fracturing systems having a single connection between a manifold and a well head or fracturing tree follow a common and long-known design.

106. This was and is a common methodology. The first wells that were commercially fracture treated utilized single conduits (piping) from the pumps to the wellhead. When I was initially fracking wells in the 1970s, we utilized mainly single lines to the wellhead. This type of rig up continued into the 1980s. As the fracturing of tight sand wells became more common, in the mid to late 1980s, we began to use two lines to the wellhead as higher pump rates and pressures were required in those operations. That being said, it has always been and continues to be common practice to fracture shallower wells with only a single line. Today we often utilize a single line to go from a modified zipper stack manifold to the frac tree. The evolution of surface rig up plumbing has been constant and is continuing today. If the well site allows it, systems with only a single line between the manifold and each fracturing tree are employed as such systems have improved reliability and reduced rig up time as compared to multi-line fracturing systems. Additionally, there can be reductions in friction-induced pressure by changes in the plumbing.

6. Continuing Evolution

107. As can be seen from the above the fracking development has been continuous and will continue to be so. The patent at issue here is the '770 Patent

issued to Downing. This patent is part of the continuing evolution of fracking equipment at the surface. Simply put, the invention allows the pressure pumping company to continue pumping operations continuously rather than stopping to change wells to be stimulated. The most difficult part of this system is the ability to switch between wells to be stimulated without ever shutting down the pressure pumping equipment. In the past, a major impediment to this concept was being able to make the switch from well A to well B without causing undue stress on well B such as a “water hammer” may cause.

108. Additionally, one must consider the pumping schedule for the Frac stages being pumped. In the example above well A at the end of its pumping schedule will be on flush. The flush fluid is essentially slick water with no proppant in it. This is designed to displace the proppant that may be in the wellbore into the interval being stimulated. When switching to well B, that well is at the beginning of its pumping schedule. In contrast to a flush cycle, the beginning stages of a pumping schedule typically involve pumping a “prepad” followed by acid. In the third step, “pad” is pumped, which is typically slick water.

109. As you can see from these first three steps, they are different than the last steps in the well A. It is imperative to a successful stimulation job that the pumping schedule can be maintained during this well switch operation.

VI. OVERVIEW OF THE '770 PATENT

110. The '770 Patent is entitled “Hydraulic Fracturing Plan and Execution of Same” and was issued by the United States Patent Office on January 24, 2023. Specifically, the '770 Patent describes a process for “executing [a continuous pumping swap (or “CP swap”)] from hydraulically fracturing ... the n_1 well (e.g., well 105D) to hydraulically fracturing ... the n_1+1 well (e.g., well 105B),” which “transitions the zipper valves from one well to the other, opening the second well and subsequently shutting-in the first well, all while pumping.” '770 Patent, 14:43-48. Stated differently, by opening the valve and beginning pumping into a second well, while still pumping into a first well, and then closing the valve in a first well, pumping can occur continuously throughout the changeover.

111. As shown in '770 Patent Figures 16D and 16E, during the CP swap “[t]he transition [between wells] is instantaneous and the total time between stages measured at treatment pressure is less than 20 seconds (as fast as 19 seconds in some instances).” '770 Patent, 14:45-51.

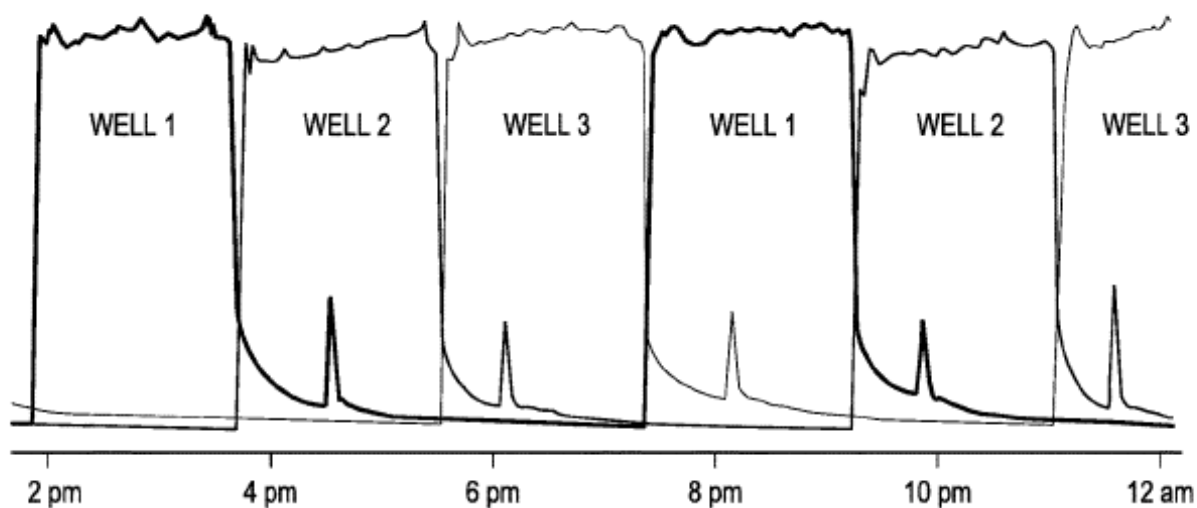


FIG. 16D

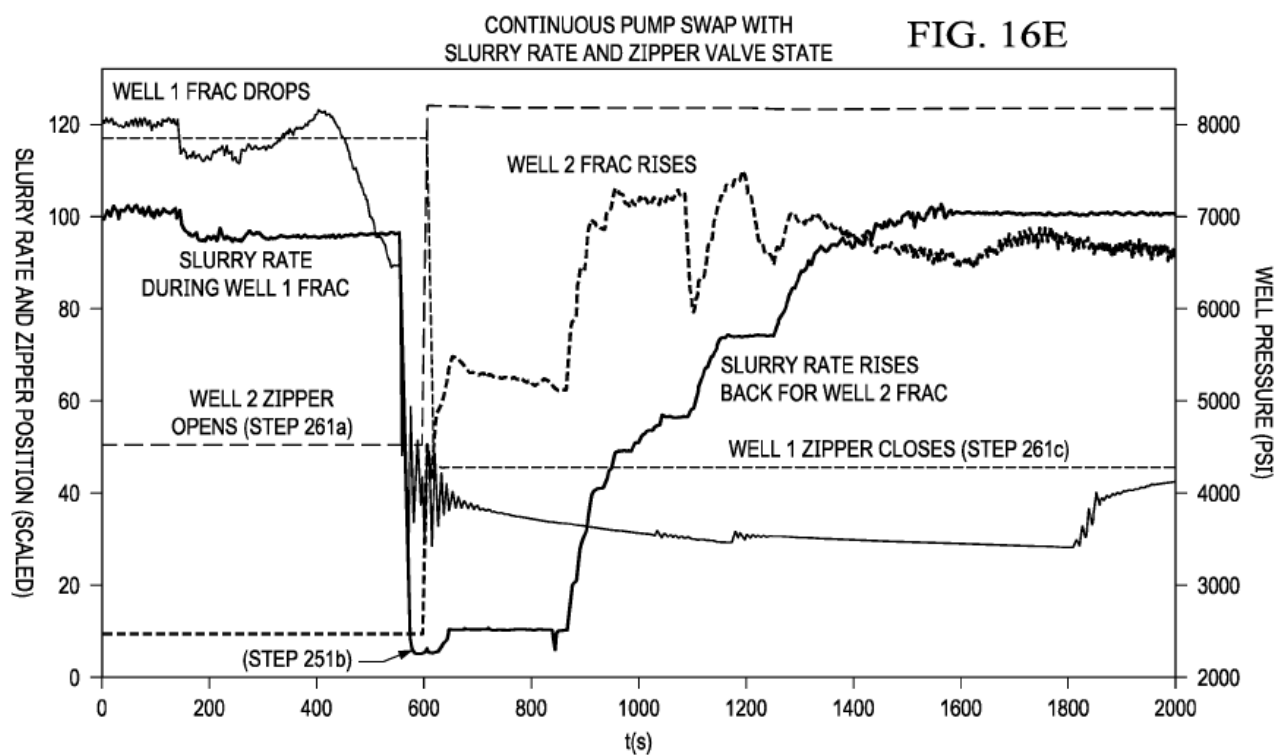


FIG. 16E

112. Referring specifically to Figure 16E, pressure and flow rate conditions are plotted against time during the CP swap from “Well 1” (e.g., well 105D of Figures 16B and 16C) to “Well 2” (e.g., well 105B of Figure 16A). The horizontal axis indicates time. The left vertical axis indicates zipper valve position, as well as slurry rate as an example flow rate condition. The right vertical axis indicates well pressure as an example pressure condition.

113. Initially, the zipper valve for Well 1 (well 105D) is fully open and the zipper valve for Well 2 (well 105B) is fully closed. As a result, the well pressure of Well 1 (well 105D) is around 8,000 psi, the well pressure of Well 2 (well 105B) is less than 3,000 psi, and the slurry rate is around 100 scaled. At step 251b, it is determined that the hydraulic fracturing fluid has satisfied a condition, namely a flow rate condition at which the slurry flow rate is below an upper threshold (about 10 scaled) and above a lower threshold (about 0 scaled). In addition to, or instead of, determining that the hydraulic fracturing fluid has satisfied the flow rate condition, at step 251b it is determined that the hydraulic fracturing fluid has satisfied another condition, namely a pressure condition at which the fluid pressure, which corresponds to the well pressure, is below an upper threshold corresponding to the well pressure (about 5,000 psi) and above a lower threshold (about 3,000 psi). In response to determining that the one or more of these conditions have been satisfied, the zipper valve for Well 2 (well 105B) is opened.

114. At this point along the horizontal axis (about 600 seconds), with both of the zipper valves for Wells 1 and 2 opened, the slurry rate is still below about 10 scaled and above about 0 scaled (indicating continuous pumping of the hydraulic fracturing fluid), the well pressure in Well 1 is decreasing, and the well pressure in Well 2 is increasing. The zipper valve for Well 1 (well 105D) is then closed after the zipper valve for Well 2 (well 105B) is opened. After the closing of the zipper valve for Well 1 (well 105D), the slurry rate increases back up to around 100 scaled, the well pressure in Well 2 (well 105B) increases and reaches steady state of between 6,000 psi and 7,000 psi, and the well pressure in Well 1 (well 105D) eventually settles to around 4,000 psi. After the passage of 20 seconds or so before the 600-second mark on the horizontal axis, the well pressure in Well 2 (well 105B) becomes about equal to what the well pressure in Well 1 (well 105D) was about 20 seconds earlier, indicating as instantaneous the transition from the frac stage at Well 1 (well 105D) to frac stage at Well 2 (well 105B).

115. The CP swap described in the '770 Patent enables hydraulic fracturing pressure pumps to run continuously during multiwell zipper fracturing stimulations, thereby avoiding the need to shut down the pumps between frac stages. Shutting down pumps is disadvantageous as it introduces delays, for example while the pumps are shut down, re-primed (in some instances), and restarted, as discussed above.

116. The '770 Patent distinguishes the CP swap process from a conventional “regular swap.” '770 Patent, 4:22-26 (“FIG. 12 is a flow diagram illustrating various sub-steps of a sixth step of the method illustrated in FIG. 1B, which sixth step is or includes determining whether to permit a regular swap or a continuous pumping swap (or ‘CP swap’), according to one or more embodiments.”). In contrast to the inventive CP swap method of the '770 Patent, conventional regular swap methods begin by closing the valve on one well before opening the valve on the next well. With both valves closed, pumping operations must cease. Next, the valve on the second well is opened. Pumping then resumes, but a delay occurs while the pumps are primed (in some instances) and brought back up to operating pressure.

VII. CLAIM CONSTRUCTION

117. It is my understanding that in order to properly evaluate the '770 Patent, the terms of the claims must first be interpreted. It is my understanding that for the purposes of this *inter partes* review, the claims are to be given their ordinary and customary meaning as would be understood by one of ordinary skill in the art in light of the specification and prosecution history, unless the inventor has set forth a special meaning for a term.

118. Additionally, claim terms are normally not interpreted in such a way that would exclude embodiments disclosed in the specification, except in cases of

clear disclaimer in the specification or prosecution history. I have been further informed that claim terms only need to be construed to the extent necessary to resolve the relevant inquiry.

119. For purposes of my analysis here, I have analyzed the claim terms according to the ordinary and customary meaning as would have been understood by a POSITA as of the critical date of the '770 Patent (May 17, 2021).

VIII. THE CLAIMED SUBJECT MATTER WAS DISCLOSED PRIOR TO KRUPA

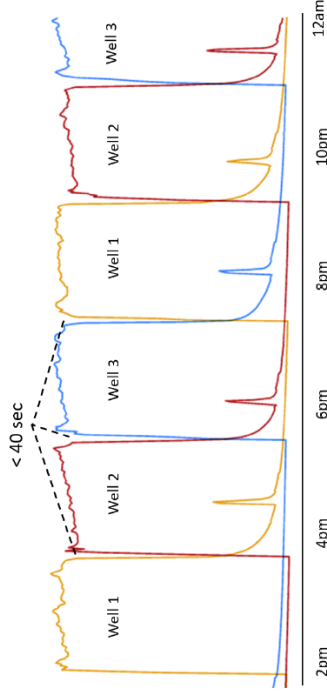
120. I understand that Downing previously disclosed its continuous pumping invention in a webpage that was published on October 12, 2020 on its public-facing website (Exs. 2001 and 2002), prior to any filing date associated with the Krupa prior art reference. I have been asked to perform an analysis comparing Downing's webpage to the portions of Krupa cited in the Petition, and I understand that if Downing's webpage discloses those portions of Krupa, such portions are not prior art. In my opinion, Downing's webpage discloses the portions of Krupa related to continuous pumping, including opening a second well while a first well is still open, and subsequently closing the first well.

121. I have been informed and understand that for purposes of this analysis, the subject matter disclosed in Downing's webpage must be the same as the subject matter disclosed in Krupa. However, it is not necessary for Downing's webpage to disclose the same subject matter using the same words as Krupa.

Additionally, I have been informed and understand that only the portion of Krupa that was previously disclosed by Downing's webpage can be disqualified as prior art, and that other portions of Krupa that were not disclosed by Downing's webpage may still be available as prior art.

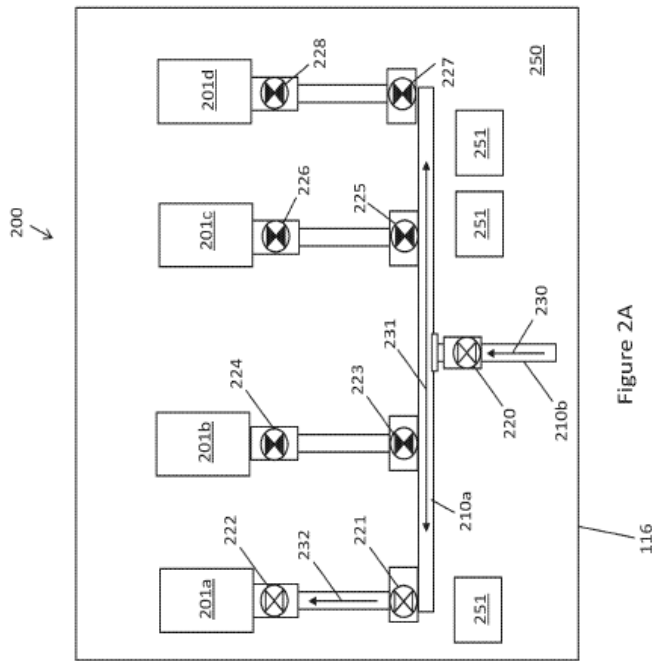
122. In analyzing Downing's webpage and Krupa, I direct my analysis to only the portions of Krupa that Petitioner relies upon in Grounds 1, 2, and 4.

123. In the below chart, I identify the relevant claim limitations, the portions of Krupa cited in the Petition, and the portions of Downing's October 2020 webpage on continuous pumping that disclose the same subject matter cited by Krupa.

Claim Limitation	Petition's Mapping to Krupa	Downing's Prior Public Disclosure
[1.5]/[8.7]- “(c) during pumping of the fluid into the first well via the first valve, opening a second valve associated with a second well;”	<i>Krupa</i> discloses methods of fracturing multiple wells that “allow the [CP] of fluids, connecting the initial and terminal “cleaning” portions of the frac operations of a first well and a second well, respectively.” [0058]. <i>Krupa</i>’s CP methods “include pumping the fluids into a second well via the at least one pump manifold while continuously pumping the fluids into the first well by opening a second set of valves.” [0005]. Figure 2B illustrates where “a second set of valves 223, 224 may be opened while the first set of valves 221, 222 remain open during the pumping of the flush fluid.” [0043].	“The Freedom Series Completion System with FS iControl enables instant transitions between stages, allowing your pumps to run continuously[.]” [Website Exhibit***] p. 1. The FS iControl “automat[es] the hydraulic gate valves.” [Website Exhibit***] p. 1. “FS iControl’s proprietary algorithms integrated with the Freedom Series Completion System transition the zipper valves from one well to the other, opening the second well and subsequently shutting-in the first well, all while pumping. The transition is instantaneous[.]” [Website Exhibit***] p. 1. 

	[1.7]/[8.9]- “(e) during pumping of the fluid into the second well via the second valve, closing the first valve associated with the first well;”	Krupa further discloses “closing the first set of valves to stop pumping the fluids into the first well and isolating and continuously pumping the fluids into the second well.” [0005]. “Once injection is established and pressure has stabilized in both the first wellhead assembly 201a and the second wellhead assembly 201b, the first set of valves 221, 222 may be closed remotely to shut in the first wellhead assembly 201a.” Figure 2C (annotated) [0043]	[Website Exhibit***] p. 2. “The Freedom Series Completion System with FS iControl enables instant transitions between stages, allowing your pumps to run continuously[.]” [Website Exhibit***] p. 1. The FS iControl “automat[es] the hydraulic gate valves.” [Website Exhibit***] p. 1. “FS iControl’s proprietary algorithms integrated with the Freedom Series Completion System transition the zipper valves from one well to the other, opening the second well and subsequently shutting-in the first well, all while pumping. The transition is instantaneous[.]” [Website Exhibit***] p. 1.
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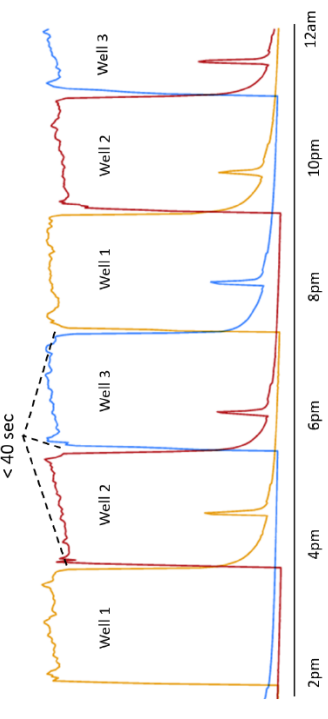
[1.8]/[8.10]- “wherein, during each of steps (a), (b), (c), (d), and (e), fluid is continuously pumped to the first valve, the second valve, or both the first valve and the second valve.”	Krupa’s fracturing plans “include instructions to perform at least one [CP] operation for ... one or more wells.” Abstract, [0005]-[0007]. With Figures 2A-G, Krupa explains, “a main valve 220 may be open to allow fluid flow (see arrow 230) from the primary manifold connection 210b to the manifold connection 210a,” where “the fluid flow (see arrow 231) may flow from one end to another.” [0040].	[Website Exhibit***] p. 2. “Pump continuously stage after stage.” [Website Exhibit***] p. 1. “The Freedom Series Completion System with FS iControl enables instant transitions between stages, allowing your pumps to run continuously[.]” [Website Exhibit***] p. 1. The FS iControl “automat[es] the hydraulic gate valves.” [Website Exhibit***] p. 1. “FS iControl’s proprietary algorithms integrated with the Freedom Series Completion System transition the zipper valves from one well to the other, opening the second well and subsequently shutting-in the first well, all while pumping. The transition is instantaneous[.]” [Website Exhibit***] p. 1. “Instant Transition Time” and “[r]educes transition time to zero.” [Website Exhibit***] p. 2.
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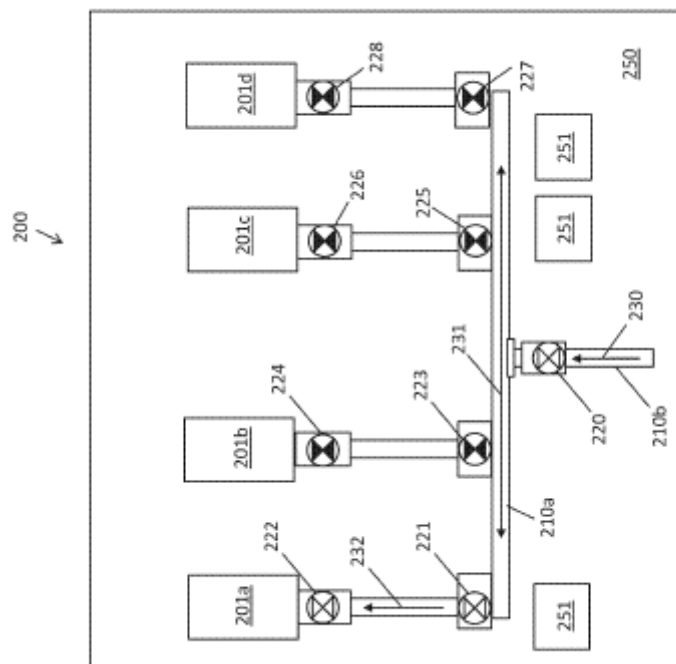
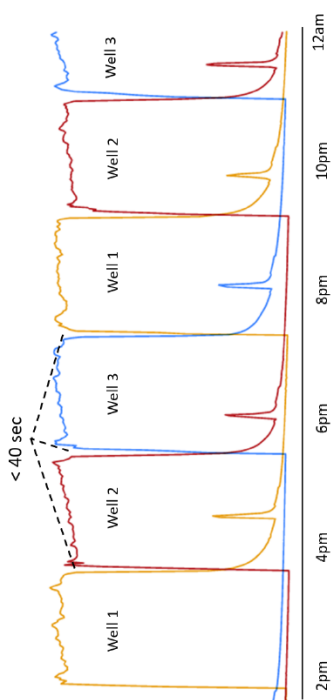


With fluid flowing continuously in the manifold connection 210a, different sets of valves (e.g., 221, 223) may be opened to allow the fluid from the manifold connection to flow into respective wellhead assemblies (e.g., 201a, 201b) to “provide continuous hydraulic fracturing pumping operations between the wellhead assemblies 201a-201d.” [0043], [0046].

Krupa discloses such CP operations “may essentially eliminate the time required to

	transition between wells,” “allow operations to not have to shut down and/or idle pumps while bleeding pressure,” and “reduce[] maintenance on pumps due to less frequent start up and shut down of the pumps.” [0058].	
[15.4]/[25.6] “(b) swapping from permitting hydraulic fracturing of the second well to permitting hydraulic fracturing of the first well, comprising: opening the first valve associated with the first well to permit pumping of fluid into the first well via the first valve;	Krupa discloses a hydraulic fracturing system may be automated to “perform [CP] processes in a hydraulic fracturing operation ... for continuous non-stop pumping for one or more wells.” [0017]. For example, fracturing operations may be transitioned “from one well to a second well.” [0038], [0046]. Hydraulic fracturing is permitted in a (first) well by opening an associated set of valves and pumping fluids into the first well from a manifold. [0005]. Hydraulic fracturing is stopped in another (second) well by closing the associated set of valves to stop fluid flow into the second well. [0005].	The FS iControl “automat[es] the hydraulic gate valves.” [Website Exhibit***] p. 1. “FS iControl’s proprietary algorithms integrated with the Freedom Series Completion System transition the zipper valves from one well to the other, opening the second well and subsequently shutting-in the first well, all while pumping. The transition is instantaneous[.]” [Website Exhibit***] p. 1.

and closing the second valve associated with the second well”		 [Website Exhibit***] p. 2.
[15.5]/[25.7] “wherein, during step (b), hydraulic fracturing fluid is continuously pumped to the first and second valves via a hydraulic manifold; and”	<i>Krupa</i> discloses flowing fluid continuously through a manifold connection (e.g., 210a in Figure 2A) to different sets of valves (e.g., first valves 221/222 and second valves 223/224). [0043]. Valves are opened to allow the fluid from the manifold to flow into respective wellhead assemblies (e.g., 201a, 201b).	“Pump continuously stage after stage.” [Website Exhibit***] p. 1. “The Freedom Series Completion System with FS iControl enables instant transitions between stages, allowing your pumps to run continuously[.]” [Website Exhibit***] p. 1. The FS iControl “automat[es] the hydraulic gate valves.” [Website Exhibit***] p. 1. “FS iControl’s proprietary algorithms integrated with the Freedom Series Completion System transition the zipper valves from one well to the other, opening the second well and subsequently shutting-in the first well, all while pumping.” [Website Exhibit***] p. 1.



Continuous hydraulic fracturing pumping operations are thereby conducted between multiple wellhead assemblies by continuously pumping hydraulic fracturing fluid from a manifold to the valves associated with each wellhead assembly. [0005], [0046].

124. For the reasons explained above, in my opinion, Downing’s October 2020 webpage on continuous pumping discloses the same subject matter the Petition relies on in Krupa for the limitations related continuous pumping, including opening a second well while a first well is still open, and subsequently closing the first well.

IX. THE ASSERTED PRIOR ART DOES NOT RENDER OBVIOUS THE CHALLENGED CLAIMS

125. The discussion below provides a detailed analysis of how each asserted ground fails to anticipate or render obvious the Challenged Claims.

126. Although I have not addressed every problem with Petitioner’s analysis of the Challenged Claims, my analysis focuses on a few primary issues that undermine Petitioner’s obviousness arguments as to every Challenged Claim.

A. Overview of the Asserted References

1. Summary of Krupa (Ex. 1003)

127. U.S. Patent Application No. 2022/0268141 to Krupa et al., entitled “Systems and Methods for an Automated and Intelligent Frac Pumping” was filed on February 18, 2022 and published August 25, 2022. Krupa describes hydraulic fracturing including “pumping fluids into a first well via at least one pump manifold by opening a first set of valves. The method may also include pumping the fluids into a second well via the at least one pump manifold while continuously pumping the fluids into the first well by opening a second set of valves. The

method further includes closing the first set of valves to stop pumping the fluids into the first well and isolating and continuously pumping the fluids into the second well.” Ex. 1003, ¶ 0005.

2. Summary of Carr (Ex. 1004)

128. U.S. Patent Application No. 2019/0233275 to Carr et al., entitled “Method and Apparatus for Metering Flow During Centralized Well Treatment,” was filed on January 31, 2018 and published August 1, 2019. Carr describes a hydraulic fracturing system for treating multiple wells from a central location. Ex. 1004, ¶ 13. Specifically, Carr describes a manifold system wherein fluid flow from the blender may be controlled and adjusted by valves in response to flow meter readings. *Id.*, ¶ 0016. As taught by Carr, the fracturing fluid flows from the first and second valve to first and second isolated flow paths to independent pump fleets that provide pressurized fluid to a first and second well. *Id.*, ¶ 0021.

3. Summary of Beuterbaugh (Ex. 1005)

129. WO2020145978 to Beuterbaugh et al., entitled “Stimulated Pulse Treatment,” was filed on January 10, 2019 and published July 16, 2020. Beuterbaugh is directed to a system for providing alternating “pressure pulses” to wells undergoing simultaneous hydraulic fracturing treatments. Ex. 1005, ¶ 0015. Specifically, Beuterbaugh describes a system that allows pressure pulses to be delivered to while pumping at a constant rate through the use of a valve

configuration that rapidly redirects flow between two wells. *Id.* According to Beuterbaugh, this system provides the benefit of reducing equipment wear during the process. *Id.*

4. Summary of Tolman (Ex. 1006)

130. U.S. Patent No. 8,490,685 to Tolman et al., entitled “Method and Apparatus Associated with Stimulation Treatments for Wells,” was filed on July 24, 2006 and issued July 23, 2013. Tolman describes “connecting multiple wells to a stimulation fluid pumping system via a pumping system manifold.” Ex. 1006, 2: 16-19. Tolman thus describes one of the early developments of the zipper fracturing manifold and method used commonly today. In line with the conventional understanding of zipper fracturing prior to the ’770 Patent, Tolman describes that the time between pumping in wells may be reduced by performing preparation activities while stimulation occurs in a first well. *Id.*, 9:49-48. Additionally, Tolman teaches the common understanding at the time that “the manipulating the manifold well valves and wellhead tree valves should not be concurrently performed.” *Id.*, 13:38-40.

5. Summary of Jackson (Ex. 1007)

131. U.S. Patent Application No. 2007/0023184 to Jackson et al., entitled “Well product recovery process,” was filed on March 30, 2006 and published February 1, 2007. Jackson is directed to hydraulic fracturing processes within a

single wellbore. Specifically, Jackson describes “a process for fracturing a formation including: introducing a supply of fracturing fluid to the formation until a first threshold is reached, adjusting the flow of the fracturing fluid to reach a second threshold, adjusting the flow to reach a third threshold and ceasing flow of the fracturing fluid to the formation, the fracturing fluid being a non-participating gas.” Ex. 1007, ¶ 0003.

132. The thresholds described by Jackson “may be defined by at least one criterion selected from a set of criteria consisting of: (a) a time period threshold; (b) a non-participating gas flow rate threshold; (c) a well bore surface or bottom hole pressure threshold; (d) a well bore surface or bottom hole rate of pressure change threshold (e) a gas quantity threshold and (f) a formation condition threshold.” Jackson, [0017]. Jackson discloses various embodiments fracturing methods intended to encourage the formation of dendric crack formations in the well, which may improve the rate of hydrocarbon production. Jackson, [0060].

B. The Krupa Grounds do not establish a reasonable likelihood of success.

133. As discussed in Section II.B, key portions of Krupa that Petitioner relies upon in every Krupa Ground are disqualified as prior art under § 102(b)(2)(B). Accordingly, the Krupa Grounds do not establish a reasonable likelihood of success.

C. The Carr Grounds do not establish a reasonable likelihood of success.

1. Ground 3: Carr does not anticipate the Challenged Claims.

134. Petitioner fails to establish that it is likely to prevail in showing that Carr anticipates the Challenged Claims. Carr discloses a multi-well system in which valves control the fluid flow to each well, but it does not discuss or contemplate swapping pumping from one well to another, let alone doing so by opening and closing valves in the particular sequence required by the claims.

135. Likewise, although Carr discloses that its system may include flow meters that can output information for use in opening and closing valves to control desired fluid properties, it does not disclose performing any particular method of swapping between wells “in response to” information from those flow meters.

136. Unable to show that Carr expressly discloses the Challenged Claims’ novel methods and systems for swapping between two wells in a particular manner based on fluid conditions, Petitioner attempts to invoke inherency by broadly asserting that “[a] POSITA would find it necessary and at least obvious” to both (i) swap between wells by manipulating the valves in the particular sequence recited in the Challenged Claims and (ii) to do so based on fluid-flow targets. Petition, 52–53. But the Petition fails to explain why Carr’s system would necessarily perform the specific steps of the Challenged claims or cite any evidence in support

of that contention. Thus, the Petition fails to show that Carr inherently discloses any of these elements.

137. Because Petitioner fails to show that Carr discloses the Challenged Claims either expressly or inherently, Petitioner cannot establish that it is likely to prevail on Ground 3.

- a) Carr does not disclose closing a first valve after opening a second valve (Limitations 1.4, 14.5, and 27.5).**

138. Carr does not disclose or discuss swapping from pumping into a first well to pumping into a second well at all, much less doing so by opening the second well's valves before closing the first well's valves, as limitations 1.4, 14.5, and 27.5 require:

opening a second valve;

communicating fluid to a second well via the second valve; and

closing the first valve after opening the second valve.

Ex.1001, claim 1; *see also id.*, claims 14, 27.

139. The only disclosures from Carr the Petition points to for these limitations state generally that first and second valves for controlling fluid flow from a manifold to first and second wells, respectively, can permit operators to stimulate the wells “alternatingly and/or simultaneously” Petition, 52 (citing Ex. 1004, ¶0033):

FIG. 5 is a flow diagram of a centralized well treatment facility that can employ the principles of the present disclosure. In some embodiments, the well treatment facility 400 can optionally include a first valve 470 disposed along the first isolated manifold path 122 and/or a second valve 472 disposed along the second isolated manifold path 124. The first valve 470 can be utilized to control the flow from the mixing blender 108 to the first well 140 and the second valve 472 can be utilized to control the flow from the mixing blender 108 to the second well 142. The first valve 470 and the second valve 472 can be disposed outside of the manifold 120 or disposed within the manifold 120. The first valve 470 and the second valve 472 can allow for the first well 140 and the second well 142 to each be stimulated individually by opening the respective first valve 470 or the second valve 472 and closing the other valve. Further, in some embodiments, the first valve 470 and the second valve 472 can be used to control the flow rate to the first well 140, the second well 142, or to both the first well 140 and the second well 142 simultaneously.

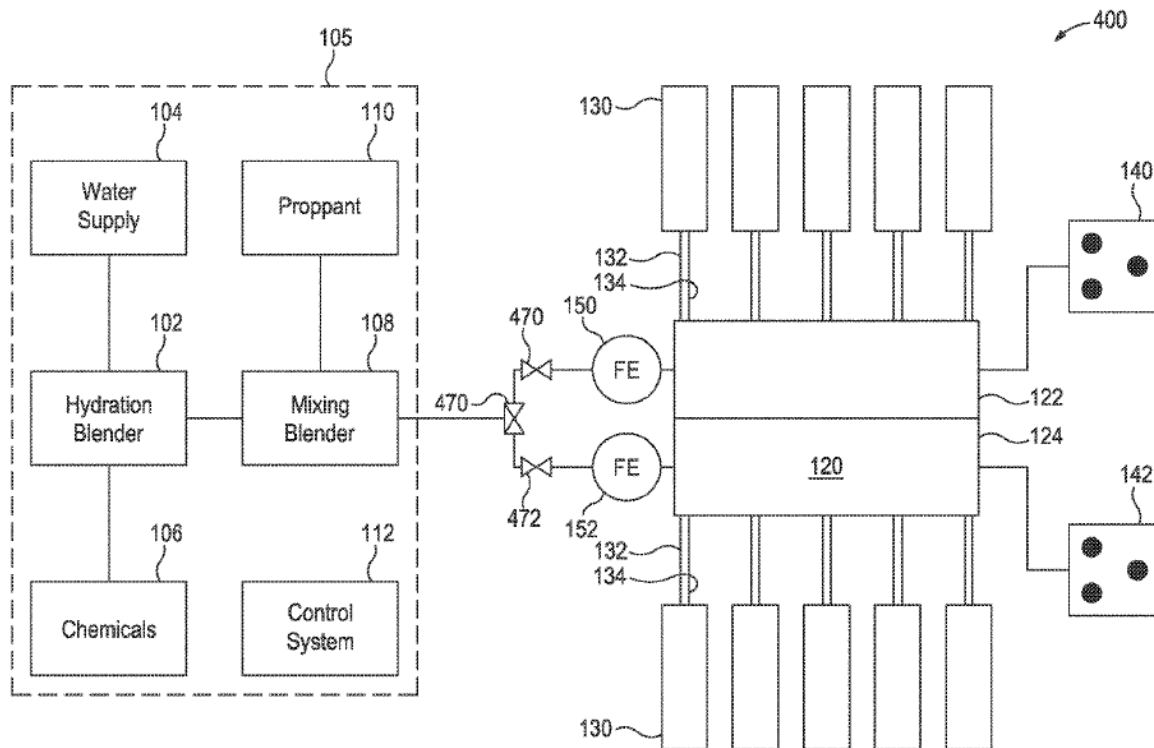


FIG. 5

140. Critically, these portions of Carr are silent as to any *transition* from treating the first well individually to treating the second well individually, much less the claimed transition that requires the specific sequence of “*opening a second valve; communicating fluid to a second well via the second valve; and closing the first valve after opening the second valve.*” *See id.*

141. The Petition asserts that Carr either discloses this step inherently or renders it obvious, but it fails to provide any support for either assertion. Its entire analysis consists of a single sentence asserting that “[a] POSITA would understand that operating the first and second valves to direct fluid into the associated first and second wells ‘individually’ and/or ‘simultaneously,’ as taught by Carr, includes closing the valve to one well (e.g., to the first well) after opening the valve to the other well (e.g., to the second well).” *Id.*

142. Petitioner’s conclusory assertion does not meet the requirements for showing inherency. I understand that inherency may not be established by probabilities or possibilities, and instead requires a showing that the prior art *necessarily* functions in accordance with, or includes, the claimed limitations.

143. Petitioner fails to establish that pumping to Carr’s first and second wells, either simultaneously or individually, necessarily requires closing the first valve after opening the second valve. *See* Petition, 52. Its sole support for its statement that a POSITA would understand that treating multiple wells

individually or simultaneously would “include” this specific valve operation is the testimony of its expert. Petition, 52 (citing Ex. 1002, ¶¶331–332). But Dr. Durham’s declaration also lacks any explanation of why Carr necessarily performs this step. Ex. 1002, ¶¶331–332. Dr. Durham instead quotes the same portions of Carr and provides the following unsupported opinion:

During simultaneous flow of fluid to both well 470 and 472, as taught by Carr, both valves 470 and 472 would be open. During this operation, Carr teaches control system 112 would close valve 470 (at least partially) in response to flow conditions such as the flow rate being higher than the fluid flow targets. Accordingly, the first valve would be closed after opening the second valve.

Ex.1002, ¶331. At the outset, this assertion is entirely unsupported by any analysis or evidence. Moreover, it fails to demonstrate inherency because it contradicts what a POSITA would understand about Carr’s disclosure.

144. First, a POSITA would not understand that Carr’s description of simultaneous or sequential fracturing necessarily requires “*opening a second valve; communicating fluid to a second well via the second valve; and closing the first valve after opening the second valve.*” For example, simultaneous fracturing may be performed consistent with Carr’s disclosure by opening both first and second valves at the same time to begin simultaneous fracturing operations and then

closing both valves at the same time at the conclusion of the simultaneous treatment.

145. Likewise, a POSITA would understand that Carr's disclosure of sequential treatment of the first and second wells could be performed by ceasing pumping into the second well and closing the second valve and subsequently opening the first valve to begin pumping into the first well. Indeed, as explained above, this is the conventional process of swapping between wells that was well understood in the art before to the invention of the claimed continuous pumping swap.

146. Second, a POSITA would not understand that Carr teaches that its control system 112 would "close" valve 470 in response to flow conditions as Petitioner's expert asserts. Carr merely states that "the control system 112 can be utilized to control the position of the first valve 470." Ex.1004, ¶0033. As Petitioner's expert acknowledges, "[d]uring simultaneous flow of fluid to both well 470 and 472, as taught by Carr, both valves 470 and 472 would be open." Ex.1002, ¶331. This is necessarily the case during a simultaneous fracturing operation.

147. In the system described by Carr, a valve may be adjusted based on measured flow rate, but a POSITA would not understand controlling the position of a valve in this manner to teach that the valve is closed. If, for example, valve

470 was controlled during simultaneous fracturing operations to reduce the flow rate to well 1, the valve might be adjusted from 100% open to 80% open. At both the beginning and end of this process, the valve is open to permit fracturing fluid to be pumped into the well.

148. Petitioner provides no evidence otherwise. Given this lack of evidence, the only explanation for why Petitioner reads Carr’s generalized disclosure as disclosing the specific valve sequence claimed by the ’770 Patent is the disclosure of the ’770 Patent itself. I understand that the use of the challenged patent as a roadmap for arriving at the claimed invention is an improper use of hindsight and is insufficient to show anticipation or obviousness.

149. Because Petitioner fails to present evidence that Carr discloses the recited sequence either expressly or inherently, it cannot establish that Carr satisfies limitations 1.4, 14.5, and 27.5.

- b) Carr does not disclose closing a first valve after opening a second valve *in response to* determining that the fluid communicated via the manifold has satisfied one or more conditions (Limitations 1.2–1.4, 14.3–14.5, 27.4–27.6).**

150. Even if Carr disclosed closing the first valve after opening the second valve, it does not disclose doing so “**in response to** *determining the fluid communicated via the manifold has satisfied one or more conditions.*” The Petition improperly treats the claimed valve sequence recited after “*determining the fluid*

communicated via the manifold has satisfied one or more conditions” as separate from and unrelated to the “*determining.*” Specifically, the claim mapping on pages 51–52 of the Petition fails to even allege that the functions it maps to the claimed valve operations in 1.3–1.4, 14.3–14.4, and 27.4–27.5 are “*in response to*” Carr’s discussion of flow meters. Petition, 51–52. But the claims require that the claimed valve sequence be performed “*in response to*” determining that the fluid has satisfied one or more conditions.

151. More specifically, to show that Carr discloses these limitations, the Petition relies on independent statements that (i) Carr’s control system can use input from flow meters to adjust valves and control the production and output of fluid to the wells “in light of fluid flow targets,” and (ii) Carr’s valves can be used to control flow to the first well, the second well, or to both wells simultaneously. Petition, 51 (citing Ex. 1004, ¶¶0023–0025, 0036). But even if these portions of Carr disclose what Petitioner says they disclose, the alleged disclosure is insufficient to meet the Challenged Claims because Petitioner fails to link them as required. The Petition points to no actual disclosure in Carr of using fluid conditions to determine whether or how to switch from pumping into a first well to pumping into a second well, much less using the specific method claimed.

152. Despite asserting that “[a] POSITA would understand that operating the first and second valves to direct fluid into the associated first and second wells

‘individually’ and/or ‘simultaneously,’ as taught by Carr, includes closing the valve to one well (e.g., to the first well) after opening the valve to the other well (e.g., to the second well),” the Petition makes no effort to show how this action would be responsive to any determination related to fluid-flow conditions.

Petition, 24–25. Nor does the Petition argue or present evidence that Carr’s system inherently performs the recited sequence in response to any determination that any fluid-flow condition is satisfied. *See id.* Accordingly, Petitioner cannot show that it is likely to prevail in showing that Carr anticipates the Challenged Claim.

2. Ground 4: Carr does not render the Challenged Claims obvious.

153. Petitioner also fails to meet its burden of showing that Carr renders the Challenged Claims obvious. Petitioner’s obviousness analysis consists of a single sentence: “A POSITA would find it necessary and at least obvious to close a first valve to a first well after opening a second valve to a second well based on the fluid flow targets to stimulate the first and second wells ‘individually’ and ‘simultaneously.’” Petition, 52–53. The Petition fails to provide any explanation either of why a POSITA would find it obvious to close the first valve after opening the second valve or why it would be obvious to do so “based on the fluid flow targets.”

154. I understand that conclusory arguments are insufficient for establishing obviousness of a claim. Instead, a patent challenger must articulate a

reason why a person of ordinary skill in the art would have combined or modified the prior art references. Petitioner does not suggest any specific modifications to Carr, much less provide a reasoned analysis of why a POSITA would make those modifications. Accordingly, Petitioner cannot satisfy its burden with respect to Ground 4.

155. The expert declaration cited by the Petition is similarly deficient and only provides a single sentence in support of Ground 4:

“To the extent the Board finds that Carr does not explicitly disclose closing the first valve after opening the second valve, such as during simultaneous flow to both wells, taking such an action would have been obvious to a POSITA in light of the teachings of Carr regarding simultaneous flow to both wells, as well as Carr’s disclosure of controlling the position of the first valve and second valve.”

Ex. 1002, ¶ 332. Like the Petition, Dr. Durham’s declaration provides no explanation or evidence in support of his conclusory opinion that Carr renders closing the first valve after opening the second valve obvious. *See id.* Such explanation and evidence are especially needed to support that opinion because it imposes on Carr a valve transition sequence contrary to the conventional thinking in the fracturing industry.

156. As I explain above with respect to Carr’s failure to inherently disclose closing a first valve after opening a second valve, a POSITA would recognize that the conventional method of swapping between wells—stopping pumping, closing the first well’s valve, and opening the second well’s valve to begin pumping—is

applicable and consistent with Carr’s disclosure. Carr does not disclose any motivation to depart from this conventional process or suggest there would be any advantages for doing so. Indeed, Carr does not provide any discussion regarding the transition between pumping into wells beyond the mere mention that wells may be treated sequentially using Carr’s described embodiments.

157. Dr. Durham similarly provides no support for Petitioner’s assertion that it would have been obvious to perform the recited valve sequence “*in response to*” a determination that the fluid communicated via the manifold satisfies one or more conditions. *See* Ex. 1002, ¶¶ 331–332.

158. Accordingly, Petitioner cannot establish that it is likely to succeed on Ground 4.

3. **Ground 5: The combination of Carr and Beuterbaugh does not render the Challenged Claims obvious.**

159. Petitioner fails to meet its burden of showing that the combination of Carr and Beuterbaugh renders the Challenged Claims obvious. Beuterbaugh does not cure Carr’s deficiencies, and even if it did, Petitioner fails to establish that a POSITA would be motivated to combine Carr with Beuterbaugh, which has a distinctly different goal than Carr—treating a plurality of wells by delivering pulses of fluid “in an alternating fashion solely to a single well [at a time] to increase efficiency and reduce wear.” Ex. 1005, ¶0015.

- a) **Beuterbaugh does not cure Carr’s failure to disclose closing a first valve after opening a second valve in response to one or more fluid conditions being satisfied.**

160. For the reasons discussed in connection with Grounds 3 and 4, Carr does not disclose or suggest the requirements of limitations 1.2–1.4, 14.3–14.5, and 27.4–27.6 of performing a specific valve sequence in response to determining that the fluid communicated via the manifold has satisfied one or more conditions. Beuterbaugh also does not disclose these limitations and the Petition does not allege that it does. Instead, the Petition relies on Beuterbaugh only for:

- (i) the one or more controllers or processors recited in limitations 14.1 and 27.3 and
- (ii) (ii) the step of “closing the first valve after opening the second valve” recited in limitations 1.4, 14.5, and 27.5.

161. *See* Petition, 62–67. It does not cite to Beuterbaugh for determining whether the fluid communicated via the manifold has met any condition or make any argument that Beuterbaugh would have made it obvious to perform the recited valve sequence in response to any such condition. Ground 5 thus necessarily fails for the same reasons as Grounds 3 and 4.

162. Even if Petitioner had attempted to remedy Carr’s lack of disclosure of performing the claimed valve sequence “in response to” fluid conditions using Beuterbaugh, it could not do so because Beuterbaugh does not disclose

determining whether the “fluid communicated via the manifold” satisfies any conditions. *See* Ex. 1005. It also does not disclose performing any valve sequence in response to any such determination. *See id.* Instead, Beuterbaugh focuses on alternating between wells based on time to deliver alternating pulses of fracturing fluid of about 100 milliseconds to 10 seconds to each well. *See id.* at ¶¶0022, 0026–0027. Beuterbaugh thus lacks any suggestion of using fluid conditions to determine how to switch between wells.

163. Because Petitioner does not show that either Beuterbaugh or Carr discloses or suggests performing the required valve sequence in response to any such conditions, it cannot demonstrate that the combination renders the Challenged claims obvious.

b) A POSITA would not have been motivated to combine Carr and Beuterbaugh

164. Even if the combination of Carr and Beuterbaugh disclosed all of the elements of the Challenged Claims, Ground 5 would still fail because Petitioner does not establish that a POSITA would have been motivated to combine Carr and Beuterbaugh. Although Petitioner asserts that a POSITA would have “found it obvious to use Beuterbaugh’s alternating valve sequences” in Carr’s system, Petitioner provides no explanation of why a POSITA would have been so motivated.

165. Indeed, Petitioner could not have shown that a POSITA would have been motivated to use Beuterbaugh’s time-based pulsing system in Carr’s flow rate-based system because no such motivation exists. As noted above, Beuterbaugh focuses on manipulating valves at specific times to deliver pulses of fracturing fluid to a plurality of wells in alternating fashion. Ex. 1005, ¶0015. Carr, on the other hand, discloses a multi-well system in which valves may be controlled using feedback from flow meters based on flow limits. *See* Ex. 1004, ¶0025.

166. A POSITA would not have been motivated to combine Beuterbaugh’s valve control teachings with Carr, and indeed, such a combination would have been impossible. Petitioner asserts that “[a] POSITA would have found it obvious as a simple substitution to use Beuterbaugh’s valve sequencing in Carr’s system to perform the same function (opening/closing valves to selectively divert fluid to a well) with predictable results.” Petition, 66–67. But Carr and Beuterbaugh disclose manipulating valves on different bases—Beuterbaugh’s valves open and close at specified time intervals to create pulses of a desired length, while Carr’s system manipulates valves based on flow rates. *See* Ex. 1004, ¶0025; Ex. 1005, ¶0015. Further, the valves described by the references are configured differently for entirely different purposes.

167. While the Petition points to Carr’s valves 470 and 472, which control flow between the blender and the pumps, Beuterbaugh describes a system wherein valves direct the flow of the pump discharge to provide timed pulses between two wells:

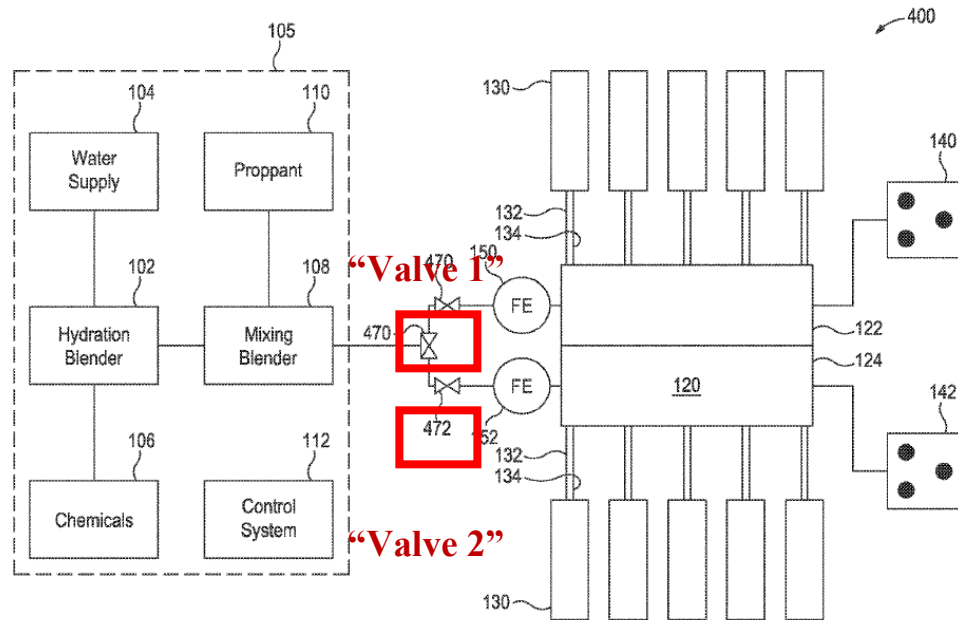


FIG. 5

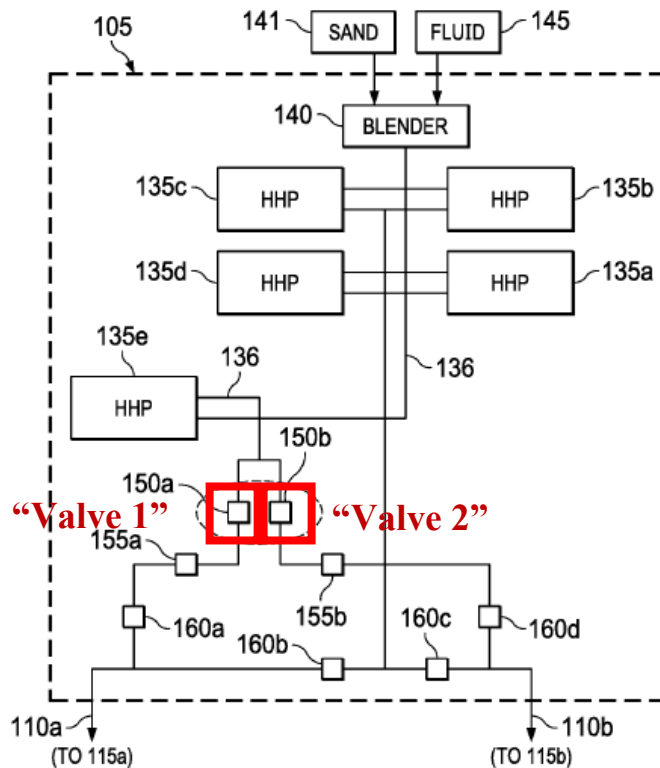


FIG. 2

168. If Beuterbaugh’s teachings were combined with the system described by Carr, it would result in a valve configuration that rapidly transitioned between providing fluid from one fleet of pumps to the next. This combination would not allow for either of the references asserted benefits—Carr’s flow rate adjustments or Beuterbaugh’s pressure pulses—and would not provide any benefit of its own. Indeed, a POSITA would find this combination unworkable because rapidly cutting off the supply of fluid to the pressure pumps would likely damage or destroy them. Thus, a POSITA would not have any motivation or expectation of success for the proposed combination.

169. Petitioner fails to explain why a POSITA looking for techniques for manipulating valves in Carr’s system would have looked to Beuterbaugh or how a POSITA would apply Beuterbaugh’s time-based system for creating pulses to Carr’s flow rate-based system. For example, Carr’s flow rate meters would be of little use in determining when or how to swap from one well to the next in executing Beuterbaugh’s pulsing method. The two references describe different ways to pump fluid to a plurality of wells, and Petitioner fails to articulate any reason why a POSITA would attempt to combine them or have a reasonable expectation of success in doing so.

170. Therefore, Petitioner has not met its burden of showing that a POSITA would have been motivated to combine Carr and Beuterbaugh to arrive at the Challenged Claims.

4. Ground 6: The combination of Carr, Beuterbaugh, and Jackson does not render the Challenged Claims obvious.

171. Petitioner does not assert that Jackson cures any of the deficiencies of Carr and Beuterbaugh discussed in connection with Grounds 4 and 5. Instead, Petitioner cites Jackson only for the flowrate thresholds recited in certain dependent claims. Petition, 69–70. Because the Petition fails demonstrate that the combination of Carr and Beuterbaugh renders any of the independent claims obvious, it also does not show that the combination of Carr, Beuterbaugh, and Jackson renders any dependent claims obvious.

D. The Tolman Grounds do not establish a reasonable likelihood of success.

5. Ground 7: Tolman does not anticipate the Challenged Claims.

172. Petitioner fails to establish that it is likely to prevail in showing that Tolman anticipates the Challenged Claims. Tolman discloses methods and systems for reducing non-pumping time between multiple wells being sequentially fractured from a single location by simultaneously fracturing one well and beginning preparations on the next well to be fractured. *See* Ex. 1006, 4:5–17, 9, 9:17–37. Tolman does not address swapping between wells while continuously pumping fracturing fluid. *See id.* On the contrary, Tolman repeatedly emphasizes that only one well connected to each pumping system is treated at a time, while other wells connected to the same system are “hydraulically isolated from the pressure and energy created by the stimulation fluid pumping system” so that operators may perform other operations, such as preparations for fracturing, on those wells. *See* Ex. 1006, 4:8–15, 9:8-15.

173. Petitioner nevertheless asserts that Tolman discloses the recited valve sequence because it discloses performing flowback in a first well while pumping fracturing fluid into a second well, which Petitioner asserts necessarily requires valves to both wells to be open for some period of time until the first well is shut in. *See* Petition, 75–76. But Petitioner ignores Tolman’s express statement that

during pumping into the second well, the manifold's valve to the first well is closed. *See* Ex. 1006, 11:16–21.

174. Even if Petitioner could show that Tolman disclosed performing the required valve sequence, Petitioner also fails to show that Tolman discloses performing that sequence “in response to” determining that the fluid communicated via the manifold satisfies one or more conditions. Although Petitioner asserts (without support) that Tolman's system necessarily evaluates fluid conditions to determine whether stimulation of a well is complete, Petitioner fails to point to any evidence that Tolman discloses opening a second valve and closing the first valve after opening a second valve in response to any such determination, as the claims require.

175. Accordingly, Petitioner fails to meet its burden of establishing that Tolman anticipates any Challenged Claim.

a) Tolman does not disclose closing a first valve after opening a second valve (Limitations 1.4, 14.5, and 27.5).

176. Tolman does not disclose closing a first valve after opening a second valve. On the contrary, Tolman repeatedly emphasizes stimulating wells sequentially while isolating wells that are not currently being fractured. *See, e.g.,* Ex. 1006, 4:5-17, 7:21–27, 8:53–56.

- i. **Tolman expressly contradicts Petitioner’s assertion that Tolman discloses the required valve sequence during concurrent flowback and fracturing operations.**

177. Petitioner does not point to any express disclosure of opening a second valve, communicating fluid to the second well, and then closing a valve associated with both a manifold and a first well. *See* Petition, 75–77. Instead, Petitioner points to the scenario in which Tolman discloses a first well being flowed back while a second well is fractured concurrently. *Id.* (citing Ex. 1006, 11:15–30). According to Petitioner, a POSITA would understand that during this operation, valves between the manifold and the first well would need to be open “to allow fluid into/out of the well,” and valves between the manifold and the second valve would also be open to permit fracturing fluid to flow into the well. *Id.* Petitioner further asserts that Tolman discloses shutting in the first well after flowback, which necessarily includes closing the first well’s valves, meaning that they would be shut after opening the second well’s valves. *Id.* at 77.

178. But not only does Tolman lack any express disclosure of these alleged valve operations, it directly contradicts Petitioner’s assertion that the first well’s valves would be open during fracturing of the second well. The disclosure Petitioner cites expressly states that during pumping into the second well, the first well is “closed”:

However, in FIG. 5, the first well 104 a is being flowed back after the placement of proppant fractures Concurrently, the

second well 104 b may be receiving the five-stage JITP hydraulic proppant fracture treatment. It should be noted that for this stimulation operation, *the main manifold valve 210 and second manifold well valve 216 are in the open position, while the first manifold well valve 214 and third manifold well valve 218 are in the closed position* to create a second well flow path.

Ex. 1006, 11:8–21. That statement is consistent with Tolman’s repeated statements that during pumping of one well, the valves between the manifold and the other wells are closed. *Id.*, 8:50–62, 10:29–35, 12:4–12; *see also id.*, 7:21–30.

179. In fact, Tolman expressly touts its manifold’s valves’ ability to isolate wells that are not currently being fractured as a key feature of its invention, explaining that isolating those wells “from the pressure and energy created by the stimulation fluid pumping system” is what allows operators to perform “other operations or activities” on them to prepare them for fracturing. *Id.* at 4:8–17. In other words, Petitioner’s interpretation would read out the express benefits of Tolman’s system and thus cannot possibly be correct.

180. Tolman further explains that simultaneously fracturing one well while performing other actions on other wells may “reduce ‘non-pumping time’ time between the first stimulation treatment of the first well and a second stimulation treatment of another well.” *Id.* at 9:11–16. But importantly, Tolman never mentions eliminating non-pumping time altogether—just reducing it. That is,

Tolman clearly contemplates that some non-pumping time will still exist. *See id.*

Thus, not only does Tolman directly contradict Petitioner’s attempt to read Tolman onto the claims, but it also specifically teaches away from having valves on two wells open simultaneously.

- ii. **To the extent that Petitioner asserts that the “first valve” is a valve on the well tree 106a, it fails to show that the valve satisfies the claim elements.**

181. Despite pointing to Tolman’s “first manifold well valve 214” for the “*first valve . . . associated with both the manifold and the first well*” recited in limitations 1.1, 14.2, and 27.1, Petitioner shifts gears in its mapping of later limitations and points to a different, hypothetical “tree valve.” *See* Petition, 71–77. Neither the “first manifold well valve 214” or Petitioner’s hypothetical tree valve, however, meets all of the claims’ requirements for the recited “first valve.” As already shown, Tolman expressly states that the first manifold valve would be closed during pumping into other wells, and Petitioner has not shown that any “tree valve” is associated the manifold, as required. Therefore, the Petition fails to point to a first valve that meets all of the claims’ requirements.

182. In more detail, in its analysis of limitations 1.1, 14.2, and 27.1, Petitioner points to “valve 214” and an unshown valve on the well tree 106a of the first well to the claimed “first valve”:

Tolman discloses a multi-well system including a manifold “configured to provide a flow path from the stimulation fluid pumping system into at least one selected well.” 2:46-50. The flow paths are selected/managed by operating valves, such as manifold well valves 214, 216, 218 associated with each well’s tree 106a-106c:

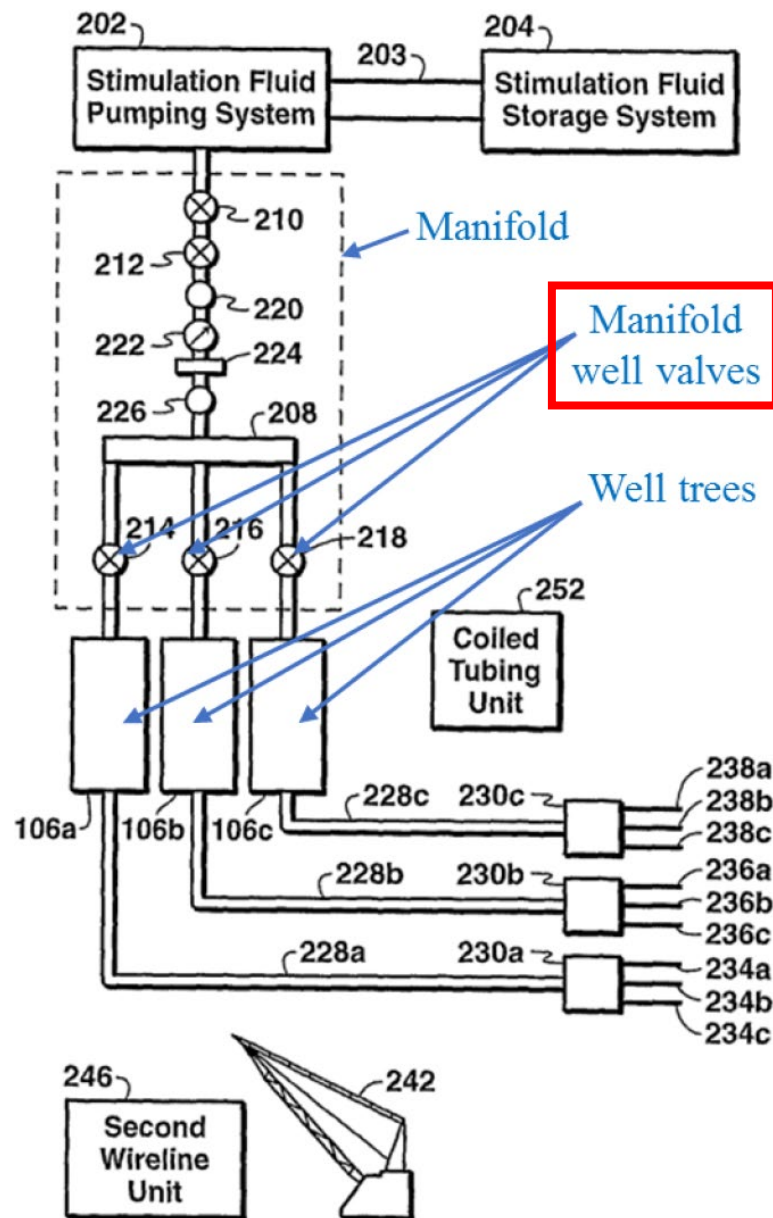


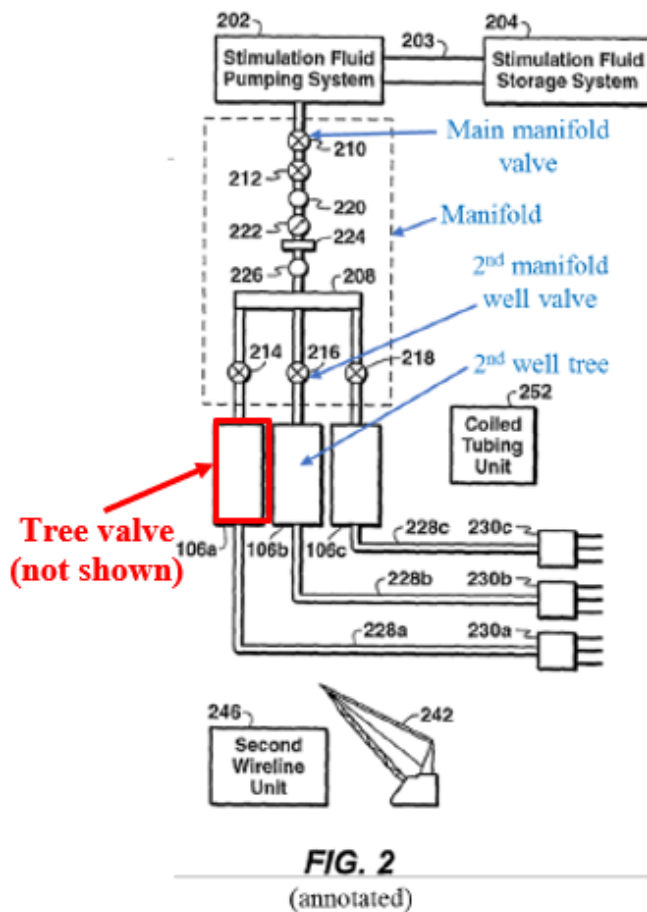
FIG. 2

Petition, 71–72 (annotated).

183. But because Tolman expressly states that the “first manifold valve 214” would be closed during fracturing of a second well, Petitioner is forced to shift the focus of its analysis of limitations 1.3, 14.4, and 27.4 to an unshown “first well tree valve,” which Petitioner asserts would be open during the concurrent flowback of the second well and fracturing of the first:

well. Ex. 1002, ¶¶ 554, 631, 669. Thus, during flowback from the first well, while a first well tree valve is open, a second well valve is opened to allow stimulation fluid to be pumped into the second well. 11:15-30.

Tolman discloses when a main manifold valve 210 and a second manifold well valve 214 are open “to create a second well flow path,” “stimulation fluid [may be] pumped down the [second] well” to fracture the second well:

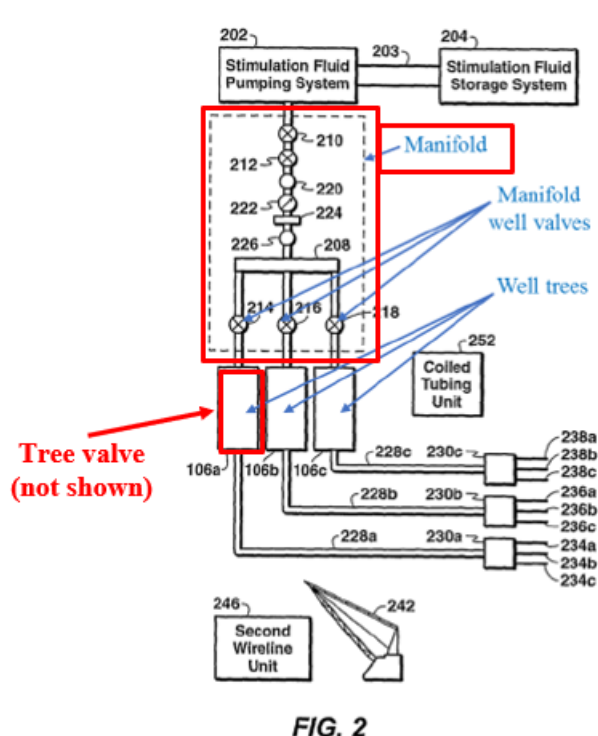


11:15-30.

184. Petition, 76 (annotated). Petitioner then asserts in connection with limitations 1.4, 14.5, and 27.5 that shutting in the first well necessarily includes closing all of the “first well’s valves.” Petition, 77.

185. Petitioner’s shift in focus is understandable because Petitioner cannot show that the “first manifold valve” would be closed after opening a second well valve and therefore cannot show that it satisfies limitations 1.4, 14.5, and 27.5. Tolman simply does not disclose that more than one of the manifold valves 214, 216, and 218 would be open at once and in fact expressly teaches otherwise. *See, e.g.,* Ex. 1006, 8:50–62, 10:29–35, 11:8–21, 12:4–12.

186. Moreover, a hypothetical valve on the well tree 106a also cannot be the recited “first valve” because it is not “associated with both the manifold and the first well,” as the Challenged Claims require. In fact, as Petitioner’s own annotations confirm, Tolman’s Figure 2 indicates that the well trees 106 are not part of the manifold 206:



Petition, 72.

187. Petitioner also does not show that a valve on tree 106a would necessarily be closed after the second valve is open, as limitations 1.4, 14.5, and 27.5 require. On the contrary, Tolman indicates that “it may be preferred that two valves, such as a manifold well valve 214-218 and a valve (not shown) on the tree 106a-106c, are closed during any given isolation from the other wells.” Ex. 1006, 7:27–30. As already noted, Tolman further explains that during pumping into one well, other wells not currently being fractured are isolated. *See, e.g., id.* at 4:7–15.

188. Therefore, to the extent that Petitioner relies on a valve in well tree 106a as disclosing the Challenged Claims’ “first valve,” Petitioner fails to show that the valve is (1) associated with a manifold or (2) closed after opening a second valve, as required. Because Petitioner cannot identify a single valve that meets all of the claims’ requirements for the recited “first valve,” it cannot satisfy its burden of showing that Tolman anticipates the Challenged Claims.

- b) Tolman does not disclose closing a first valve after opening a second valve in response to determining that the fluid communicated via the manifold has satisfied one or more conditions (Limitations 1.2–1.4, 14.3–14.5, 27.4–27.6).**

189. Even if Petitioner had established that Tolman discloses closing a first valve after opening a second valve, Ground 7 would still fail because Petitioner has

not shown that Tolman discloses doing so *in response to* determining that the fluid communicated via the manifold has satisfied one or more conditions.

i. Tolman does not disclose determining that the fluid communicated via the manifold has satisfied one or more conditions.

190. Petitioner has not shown that Tolman discloses determining that the fluid communicated via the manifold has satisfied one or more conditions. The sole “condition” the Petition asserts Tolman’s system determines in its analysis of limitations 1.2, 14.3, and 27.6 is “whether the planned stimulation treatments...are completed.” Petition, 75 (citing Ex. 1006, 9:17–19). But whether a planned stimulation treatment is complete is not a condition of fluid being communicated to a manifold, and Petitioner does not assert that it is. *See id.*

191. Instead, Petitioner attempts to invoke inherency by asserting that “[a] POSITA would have understood that determining if a stimulation treatment is complete would necessarily include determining a fluid condition of the treatment fluid to the well.” Petition, 75. But Petitioner fails to meet its burden of showing that determining that a planned treatment is complete “necessarily” includes determining that the fluid communicated via the manifold has satisfied a condition. In fact, the Petition does not identify what “fluid condition of the treatment fluid” an operator would necessarily have to determine to verify completion of a stimulation treatment, much less explain why an operator would need to determine whether the fluid satisfies that condition. *See id.*

192. Although Petition cites its expert’s declaration, Dr. Durham similarly fails to explain or provide any evidence to support his conclusion that a “POSITA would have immediately understood” that a “fluid condition” would be the basis for determining that treatment is complete. *See* Ex. 1002, ¶ 549. Thus, without any evidence to support its position or its expert’s opinion, Petitioner has not satisfied its burden of showing that Tolman inherently discloses determining whether the fluid communicated via the manifold has satisfied any condition.

193. A POSITA would not understand that determining whether a planned treatment is complete would necessarily require determining that fluid communicated via a manifold has satisfied any condition. Indeed, a pumping schedule for a hydraulic fracturing stage typically consists of pumping segments that specify a variety of pumping parameters, including a desired flow rate, expected pressure, ratio of proppant, etc. However, these parameters are intended to be maintained throughout the segment until a specified volume of fluid has pumped or a given amount of time has elapsed. In other words, fluid conditions may be evaluated throughout a hydraulic fracturing stage, but the determination that a stage is complete is made with reference to metrics that are not fluid conditions—e.g., total volume pumped or time.

194. Thus, the Petition fails to meet its burden of showing that Tolman discloses determining whether the fluid being communicated via a manifold has satisfied one or more conditions either expressly or inherently.

- ii. Tolman does not disclose closing a first valve after opening a second valve based on any determination that a planned treatment is or is not complete.**

195. Even if Petitioner had shown that determining whether a planned stimulation has completed necessarily involves making a determination about a fluid condition, Petitioner fails to show that Tolman discloses opening the second valve and closing the first valve *in response* to any such determination.

196. As discussed above, Petitioner’s primary theory for how Tolman discloses closing a first valve after opening a second valve is that performing flowback on a first well while fracturing a second—as Tolman discloses—necessarily requires leaving the first well’s valves open after beginning fracturing of the second. But the Petition fails to explain how any particular valve sequence performed in this scenario would be “*in response to*” any determination about whether a planned treatment has completed.

197. Petitioner asserts that (i) the second well’s valves are opened in response to stimulation fluid being delivered to the first well and (ii) the first well’s valves being closed in response to completion of flowback in the first well.

Petition, 77. But the claims require performing the specific ordered sequence of

closing the first valve after opening the second valve in response to a single set of one or more fluid conditions. At most, Petitioner alleges that Tolman's system opens the second valve in response to one condition—fracturing being complete in the first well—and later, independently closes the first valve in response to a different, later-occurring condition—completion of flowback in the first well. But Petitioner fails to show that Tolman discloses any single fluid condition or set of fluid conditions that triggers performance of the recited sequence, as the claims require.

198. Petitioner similarly fails to show that Tolman discloses closing a first valve after opening a second valve in response to any fluid condition under its alternative theory—that simultaneously fracturing two different wells not connected to the same manifold necessarily requires opening a second valve before closing a first valve associated with a well on a different manifold. *See* Petition, 77. Even if Petitioner is correct that the claims do not require that the recited first and second wells be connected to the same manifold, Petitioner does not even attempt to explain how Tolman discloses performing the particular sequence of closing a first well valve on one manifold after opening a second well valve on a different manifold in response to any determination that any single fluid condition or set of fluid conditions is satisfied.

199. Because Petitioner cannot show that Tolman discloses performing the recited sequence in response to determining that the fluid communicated via the manifold has satisfied one or more conditions, it cannot show that it is likely to prevail on Ground 7.

c) **Ground 8: Tolman does not render obvious the Challenged Claims.**

200. Petitioner fails to demonstrate that Tolman renders the Challenged claims obvious. Petitioner identifies three allegedly obvious modifications to Tolman for the '770 Patent's independent claims: (i) determining whether high-pressure fluid is flowing to a first well before opening other wells' valves, (ii) using flow-measuring devices to measure flow rate, and (iii) opening a second well's valves during the first well's treatment to prepare the second well for fracturing by "injecting fluids." Petition, 78–79. But Tolman's system would not meet the Challenged Claims even with all three modifications.

201. First, even if, as Petitioner asserts, a POSITA would have found it obvious to measure either pressure or flow rate in the first well before operating any valves, neither modification would cure Tolman's failure to disclose performing the claimed valve sequencing in response to these measurements. Petitioner does not point to any disclosure in Tolman that teaches or suggests closing a first valve after opening a second valve in response to either flow rate or pressure measurements. *See* Petition 78.

202. If anything, Tolman’s cited statement that “if the operations on the first well involve high pressure pumping . . . the manipulating the manifold well valves and wellhead tree valves should not be concurrently performed” teaches away from opening the second valve before finishing pumping and closing the first valve because it suggests that an operator should not manipulate valves to other wells during high-pressure pumping to a first well. *See* Ex. 1006, 13:36–40. Indeed, Tolman’s disclosure is consistent with the conventional understanding that opening valves during pumping was hazardous. As discussed above, prior to the Downing’s invention of the continuous pumping swap, the transition between pumping into wells was conventionally carried out by opening the valve to the second well only after pumping had ceased and the valve to the first well was closed. Tolman’s disclosure reflects this conventional practice and understanding. Petitioner makes no argument and presents no evidence that either this statement or Tolman’s general statement that the pumping manifold may include flow meters would have made it obvious to open a valve on a second well before closing a valve on a first well based on a fluid condition.

203. Petitioner also asserts that Tolman’s alleged disclosure of injecting fluids into second well while a first well is being treated would have made it obvious to open second well’s valves during the first well’s treatment. *See* Petition, 78 (citing Ex. 1006, 8:63-65; 9:2-6). But Petitioner fails to explain how

this sequencing would be in response to any determination that the fluid communicated via the manifold has met one or more conditions, as the claims require. *See id.* As discussed above, the only fluid condition Petitioner alleges Tolman discloses is determining is whether the first well's treatment is complete. But in Petitioner's cited scenario, the second well's valves would be opened for "fluid injections" during fracturing of the first well, *i.e.*, before the first well's treatment is complete.

204. Tolman describes the preparation activities in the second well which can be performed once isolated from the pumping manifold:

Once the pumping system manifold 206 is configured, a stimulation treatment may be pumped into the one of the wells, as shown in block 312. Concurrently, with the stimulation treatment of one of the wells, another well may be prepared for stimulation treatments, as shown in block 314, while other operations may be conducted in the remaining wells, as shown in block 316. The preparations may include using the crane 240 and wireline unit 244 to install and run the JTP perforating tools 248 and plug-setting tools 250 into the another well, performing flow-back operations, performing other wireline operations, injecting fluids or materials, and performing plug removal operations and/or other operations, as discussed further below. By preparing another well concurrently with the stimulation of a first well, the other well may be ready for the stimulation treatment when the stimulation treatment is completed in the first well.

Ex. 1006, 8:63-9:11. As Tolman describes, these preparation activities are performed while hydraulic fracturing operations take place in the first well, which is one of the benefits of conventional zipper fracturing methods. None of these

activities are commenced based on a condition of the fluid being pumped into the first well.

205. As a POSITA would understand, these activities can indeed only take place because the second well is isolated from the first well, such that the condition of any fluid being pumped into the first well is irrelevant. Thus, opening the second valve could not be “*in response*” to determining that the first well’s treatment is complete, and Petitioner does not identify any other fluid condition that would trigger performing injections on a second well while still fracturing a first. *Id.*

206. Accordingly, none of the allegedly obvious modifications to Tolman Petitioner identifies would render the Challenged Claims obvious, and Petitioner cannot meet its burden of showing that it is likely to prevail on Ground 8.

X. CONCLUSION

207. This declaration and my opinions herein are made to the best of my knowledge and understanding, and based on the material available to me, at the time of signing this declaration. I declare that all statements made herein on my own knowledge are true and that all statements made on information and belief are believed to be true, and further, that these statements were made with the knowledge that willful false statements and the like so made are punishable by fine or imprisonment, or both, under Section 1001 or Title 18 of the United States Code.

Date: March 8, 2024



John Hughett