

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 IN
SUPPORT OF PATENT OWNER'S RESPONSE**

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I, John Huggett, 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 claims 1-38 (“the Challenged Claims”) of the ’770 Patent are unpatentable in light of the prior art. It is my opinion that the Petition (and supporting evidence) does not show that the Challenged Claims are unpatentable.

4. In the preparation of this declaration, I have studied:

Exhibit	Description
	IPR Petition of U.S. Patent No. 11,560,770, (the “Petition”)
1001	’770 Patent
1002	Declaration of Dr. Robert Durham
1003	U.S. Patent Publication No. 2022/0268141 (“Krupa”)
1004	U.S. Patent Publication No. 2019/0233275 (“Carr”)

Exhibit	Description
1005	International Patent Publication No. WO2020145978 (“Beuterbaugh”)
1006	U.S. Patent No. 8,490,685 (“Tolman”)
1007	U.S. Patent Publication No. 2007/0023184 (“Jackson”)
1009	Jacobs, Trent. “The Shale Evolution: Zipper Fracture Takes Hold,” J Pet Technol 66 (2014): 60–67
1010	’770 Patent Prosecution history (“’770 File History”)
1031	Tolman, R. C., et al. (2009). Method and Apparatus for Simultaneous Stimulation of Multi-Well Pads. SPE Hydraulic Fracturing Technology Conference
2001	Wayback Machine - Downing Continuous Pumping Web Page (archived October 20, 2020)
2008	SLB Energy Glossary, “zipper manifold”
2009	SLB Energy Glossary, “missile”
2010	SLB Energy Glossary, “gate valve”
2011	Annotated Fig. 5 of US2019/0233275 (Carr)
2013	Deposition Transcript of Robert A. Durham (Aug. 15, 2024)
2014	Downing Continuous Pumping Web Page (retrieved September 16, 2024)
2030	Wayback Machine – Different Types of Pumps – Positive Displacement Pumps (archived August 12, 2020)
2031	U.S. Patent Publication 2021/0054727 (Floyd)

5. In forming the opinions expressed below, I have considered:
the documents listed above;
the relevant legal standards, including the standard for obviousness, as explained to be by counsel, 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 Ex.2007. 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.

27. In analyzing obviousness, I am informed that it is important to consider secondary considerations, which can include, for example, evidence of industry praise and awards, evidence of commercial success of the invention,

evidence of a long-felt need that was solved by an invention, evidence that others copied an invention, any evidence that an invention achieved surprising or unexpected results. I am further informed that such evidence must have a nexus, or causal relationship to the limitations of a claim, in order to be relevant.

V. BACKGROUND OF THE RELEVANT TECHNOLOGY

A. History of Hydraulic Fracture Treating

28. 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.

29. 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.

30. 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.

31. 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.

32. 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.

33. 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).

34. 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 and production 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 high-pressure hydraulic fracturing fluid to fracture the stage. The length of the well typically dictates the number of stages, with the average being anywhere between 10 and 100 stages per well. This process is costly and requires a large amount of surface equipment.

B. Shales

35. 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.

36. 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.

37. 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.

38. 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.

39. 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.

40. 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.

41. 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.

42. 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.

43. 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.

44. 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.

45. 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.

46. 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

47. 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.

48. 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

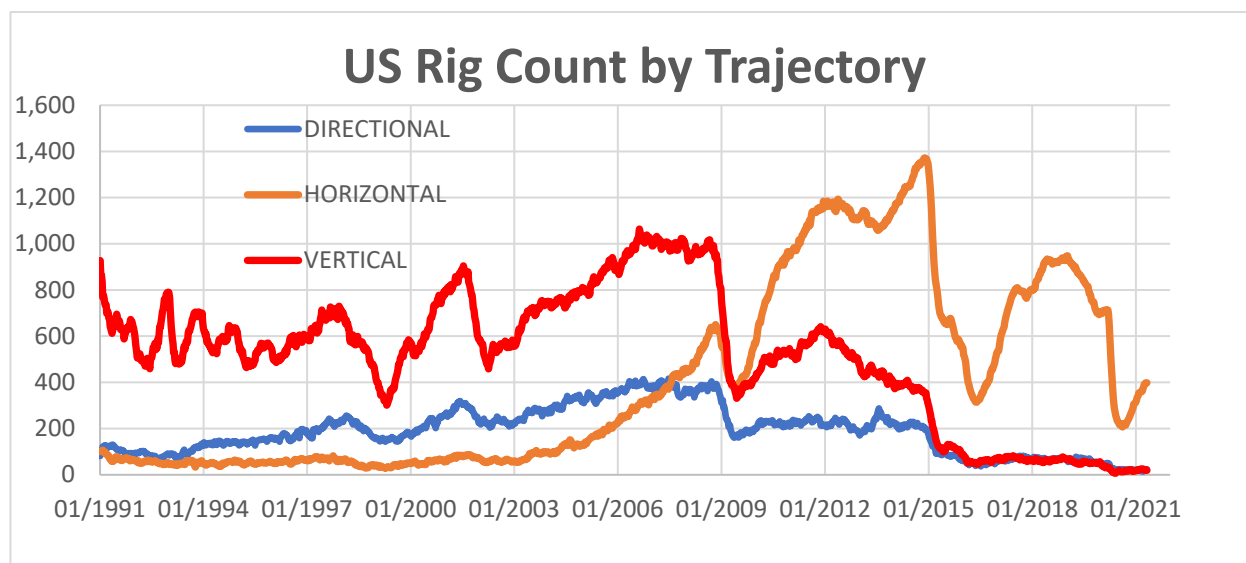
diameter drill bit that will fit inside the casing. As the well is drilled deeper, higher pressures may be encountered. Higher reservoir pressures require heavier (greater density) muds to prevent influx of reservoir fluids. However, if mud weights are too high, the pressure could exceed the rock strength 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.

49. 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), including such information as the inclination, azimuth and orientation of the drill bit.

50. 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

51. 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.

52. 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

53. 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.

54. 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. Early Hydraulic Fracturing

55. 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.

56. 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.

57. 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

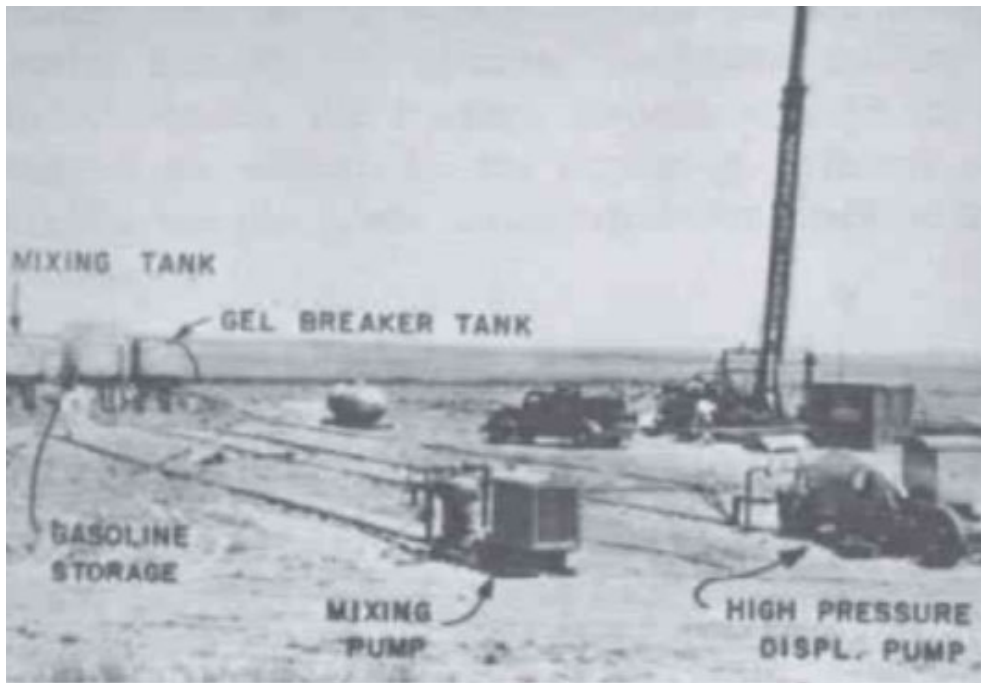
58. Although post treatment tests showed that the gas injectivity of some zones had been increased relative to others, the overall deliverability from the well was not increased. It was therefore concluded that fracturing would not replace acidizing for limestone formations. However, by the mid-1960's,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

59. 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.

60. 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.

61. 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.



62. 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.

63. 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.

64. 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.

65. 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.

66. 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 pumped 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

67. 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.

68. 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

69. 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.

70. 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.

71. 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.

72. 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.

73. 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

74. 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.

75. 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

76. 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.

77. 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

78. Most high-pressure pumps used in hydraulic fracturing are of the positive displacement 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.

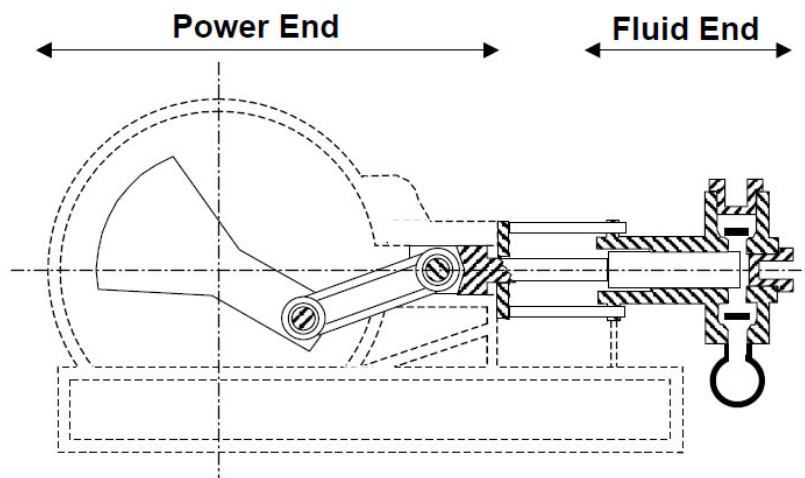


Figure 2: Schematic diagram of a generic frac pump

79. 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.

80. 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.

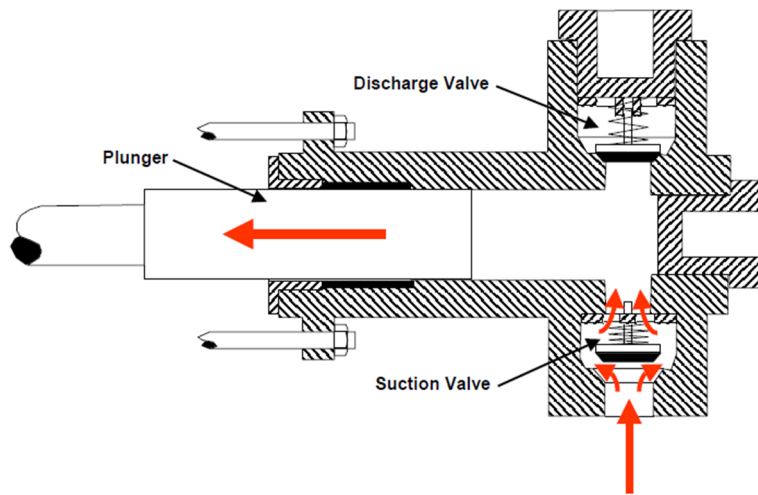


Figure 3: Generic frac pump, suction stroke

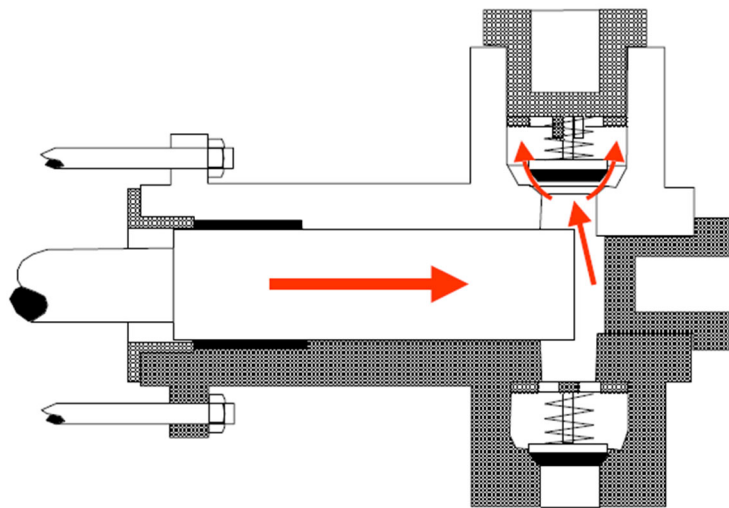


Figure 4: Generic frac pump, discharge stroke

81. 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

82. 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:

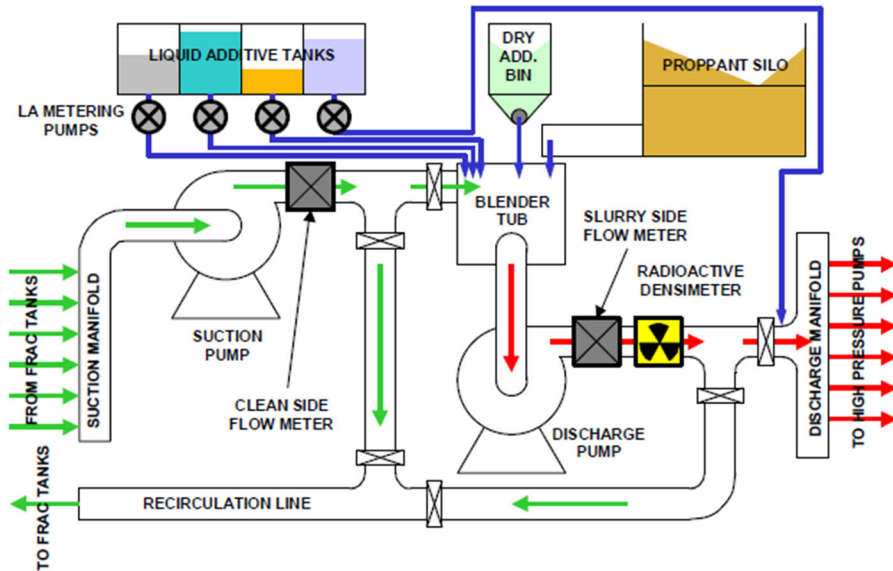


Figure 5 Generic flow diagram for a frac blender. Some blenders fitted with tub that combines the functions of the blender tub and the discharge pump.

83. 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.

84. 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

85. 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.

86. 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 valve¹ 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

¹ See Ex. 2010.

87. 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

88. 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.

89. A frac head (or goat head (**Error! Reference source not found.7**)) may be used when multiple lines are used for a frac tree or tree saver.

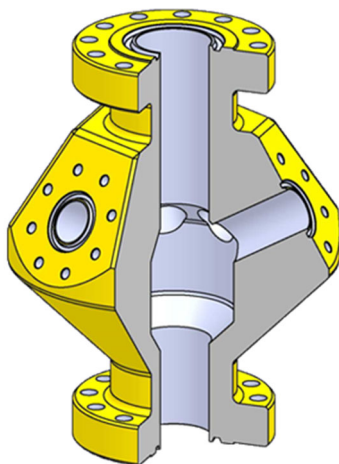


Figure 7 Example cutaway of a frac head
<http://www.qihangwellhead.com/products/API-6A-Frac-Head-Goat-Head-for-Fracturing-Wellhead-Assembly-3281453.html> or
https://img.hisupplier.com/var/userImages/2018-06/26/223100075_s.jpg

8. Manifolds

90. In general, a manifold is a pipe that connects multiple other 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

91. 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.

92. 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.

93. 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.

94. 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.

95. 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 missile’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 zipper manifold, which reduced non-productive time between stages.

96. First, by providing a flow path from the missile 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 to the time, if any, that perforation operations exceed the fracturing operation, and the time required to manipulate the valves and restart the pumps.

97. 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. Evolution in Hydraulic Fracturing

1. Overview

98. Since its origination in the early 20th Century, hydraulic fracturing has become an essential process in the production of oil and gas in North America.

99. Over time, hydraulic fracturing has continued to develop and improve. Hydraulic fracturing technology innovations have been, and will continue to be, essential for the oil and gas industry to meet growing global energy demands. Some of the more recent technological developments are describe below.

100. At its code, hydraulic fracturing is performed by (i) creating fractures in the formation with an explosive device (a “perforating gun”) and (ii) pumping high pressure fluid and sand (“proppant”) into the fractures to hold them open, which allows oil and gas to freely flow out of the fractures and into the well. Typically, hydraulic fracturing operators fracture wells in stages by plugging and perforating (“PnP”) sequential fracture zones in a formation. As previously noted,

each well may have between 10 and 100 stages depending on its length. And, traditionally, hydraulic fracturing was performed one well at a time, with all stages in a single well being completed before operations could move on to the next well, resulting in substantial non-productive time (“NPT”).

101. Eager to mitigate the NPT associated with single-well operations, operators began drilling multiple wells in close proximity so a stage in one well could be fractured while a stage in an adjacent well is prepared. However, these early versions of a multi-well method still required independent, upstream fluid sources and pump arrays for each well; or, as described in the Carr reference, could share an upstream fluid source, but still relied upon separate pump arrays to pressurize and inject an isolated and independent fluid flow into each well.²

2. Zipper Fracturing

102. As discussed above, a method known as “zipper fracturing” has since been developed to mitigate non-productive time (“NPT”) associated with the single-well PnP method. Specifically, zipper fracturing was developed to help mitigate the significant non-productive time (NPT) associated with traditional single-well PnP. Instead of perforating and hydraulically fracturing one well at a time, one zone after the other, zipper fracturing involved drilling multiple wells from a single pad site and then hydraulically fracturing a stage in one well, while

² See Ex.1004, Fig. 5, [0022].

getting ready for the next stage in another well by performing wireline and perforating operations in that well.

103. The efficiencies associated with zipper fracturing are accomplished by using a “zipper manifold.” Because of this, as of the priority date of the ’770 Patent, it was understood by a POSITA that a zipper manifold is utilized in zipper fracturing. The Jacobs article cited upon by Dr. Durham explains this concept: “In terms of extra equipment, the only added system requirement is what is called a zipper manifold.” *See* Ex.1009, 2.

104. The Schlumberger Energy Glossary defines “zipper manifold” as:

A system of frac valves that direct treatment fluid from the missile to multiple frac trees. *The zipper manifold facilitates quick redirection of fracturing pressure from one well to another, enabling pump trucks to run nearly continuously to minimize downtime.*³

Ex.2008. This definition is consistent with my understanding as a POSITA of the meaning of “zipper manifold,” including how that term was used as of May 2021. The Schlumberger Energy Glossary’s related definition of “missile” is also consistent with a POSITA’s understanding:

Flow control unit in the pressurization of fluid employed in hydraulic fracturing. Fracturing fluid enters the missile at a low pressure and is directed to the pump trucks for pressurization.

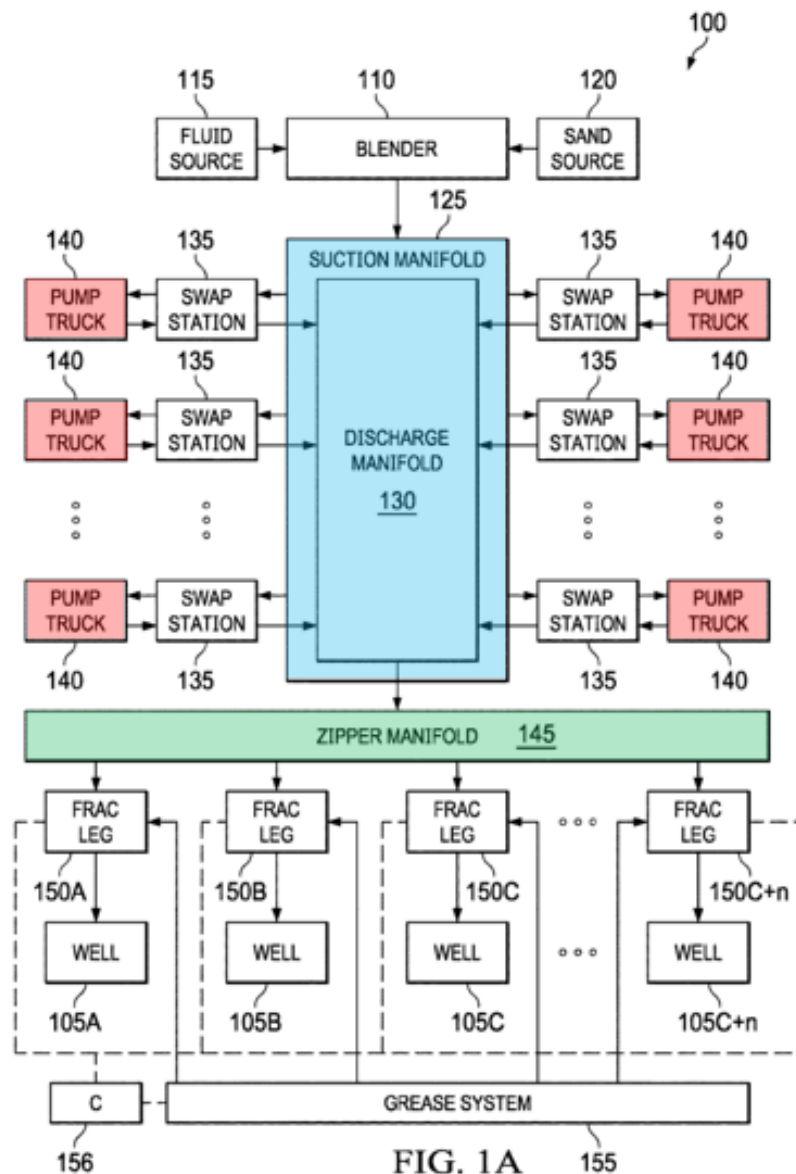
³ Ex.2008, “Zipper Manifold,” Schlumberger Energy Glossary (2024) (emphasis added).

High-pressure fluid returns to the missile and is directed to the well or, in the case of a multiwell pad, to a frac manifold.⁴

105. In other words, the pressure pumps are connected to the missile, which is connected to the zipper manifold. As described in the Schlumberger Energy Glossary, the zipper manifold receives a single input of already pressurized fracturing fluid from the missile that is then redirected by the zipper manifold to each well in a series of wells connected to the zipper manifold.

106. Figure 1A of the '770 Patent shows a diagram of a conventional zipper fracturing setup:

⁴ Ex.2009.



Ex.1001, Fig. 1A (annotated)

107. As shown above, Figure 1A includes a zipper manifold 145 (green) and an upstream manifold 130 (blue) which is connected to the pumps 140 (red). The discharge manifold 130 collects pressurized fracturing fluid from multiple pump trucks 140, combines the fluid into a common pressurized fluid flow, and

communicates the common pressurized fluid flow to the zipper manifold 145.⁵ The zipper manifold 145 then directs the common pressurized fluid flow to one of the wells 105A-C+n. Ex.1001, 5:45-65. Zipper valves 170a-b, shown in Fig. 2A, control which of the wells receive the common pressurized fluid flowing through the zipper manifold.⁶ In other words, the zipper manifold includes zipper valves corresponding to each well that can be opened or closed to redirect pressurized fluid from the zipper manifold to multiple wells. The '770 Patent uses the term “zipper valve” in the conventional manner to describe valves that redirect the common pressurized fluid flow between multiple wells on a zipper manifold. This is also consistent with Dr. Durham’s understanding and other POSITAs in the industry, with which I agree.⁷ I note that zipper manifolds and zipper valves are only utilized in zipper fracturing operations as of the priority date of the '770 Patent.

108. The development and implementation of the zipper manifold as a way to distribute pressurized fluid from a missile to a series of wells reduced the NPT associated with switching between wells. This increased efficiency and reduced

⁵ Ex.1001, 5:45-65.

⁶ Ex.1001, 6:8-9, 7:60-8:1.

⁷ Ex.2013, 81:7-23 (testifying that a zipper valve’s “[f]unction is used to direct fluid flow between the wells”); *see also* Ex.2031, 1, 3A, 3B (showing zipper valves on a zipper manifold with the function of redirecting fluid to a particular wellhead coupled to the zipper manifold).

NPT was the result of allowing one well to be isolated and fractured while the next well in the series was being perforated via wireline operations. In this manner, zipper fracturing operations could move through a series of wells in assembly-line fashion, significantly reducing NPT. Without this ability to connect a missile to a plurality of wells via a zipper manifold, which enabled fluid flow from the missile to be sequentially directed to one well and then the next, neither the zipper fracturing “assembly line” process nor the associated reduction in NPT could have been realized.

109. Because zipper fracturing substantially reduced NPT, it became widely adopted in the industry.⁸ With this widespread adoption also came the need for operators to adapt to the relatively fast-paced pumping schedule in zipper fracturing operations.⁹ Because of this “faster” schedule and relatively short amount of downtime between pumping operations as compared to the hours previously experienced with earlier methods, various industry participants referred to it as “continuous.”¹⁰ Despite the reduction in NPT, these traditional zipper fracturing operations resulted in increased wear on pumps and left little time for maintenance.¹¹

⁸ *See, e.g.*, Ex.1009, 1.

⁹ *Id.* at 2.

¹⁰ *Id.*

¹¹ *Id.*

110. While these previous zipper-based pumping operations were initially referred to as “continuous,” that was a misnomer. Traditional zipper fracturing operations still required at least a 15-minute stoppage of pumping operations during the transition between wells.¹² Transitioning between wells still required turning off the pumps, closing the valve to the first well, opening the valve to the second well, and starting the pumps back up before fracturing the second well.

111. Despite industry focus on efficiency and the reduction of NPT, traditional zipper fracturing operations still required performance of this conventional downtime sequence due to safety concerns. Traditionally, well-to-well transition downtime was necessary to safely operate the valves. For example, the Tolman article cited by Dr. Durham explains that it is “[c]ritical to maintaining safety, quality” to isolate wells not being stimulated by closing at least two valves on each isolated well.¹³ In other words, for safety purposes, only one well’s valves should be opened at any one time. That requires closing one well’s valves prior to opening another well’s valves.

3. Continuing Evolution of Zipper Fracturing Operations

112. Fracking development has been continuous and will continue to be so. The ’770 Patent is part of that continuing evolution. Simply put, the invention of

¹² *Id.* (“[W]hen doing zipper fracturing the break in stimulation operations may only last 15 minutes as workers switch from one well to another.”).

¹³ Ex.1031, 4.

the '770 Patent describes and claims a process for hydraulic fracturing that eliminates the NPT associated with stopping pumping operations when switching between hydraulically fracturing wells on a zipper manifold.

VI. OVERVIEW OF THE '770 PATENT

113. 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.”¹⁴ 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.

114. The independent claims of the '770 Patent recite a method (claim 1), an apparatus (claim 14), and a system (claim 27) that are directed to the novel CP Swap described in the specification. Claim 1 recites:

1. A method, comprising:
communicating fluid to a first well via a manifold and a first valve, the first valve being associated with both the manifold and the first well; and

¹⁴ Ex.1001, 14:43-48.

in response to determining that the fluid communicated via the manifold has satisfied one or more conditions:

opening a second valve;

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

closing the first valve after opening the second valve.

115. Figures 16D and 16E in the '770 Patent Figures 16D and 16E depict the transition from one well to the next during the CP swap. As shown, when the CP swap process is utilized, the 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).”¹⁵

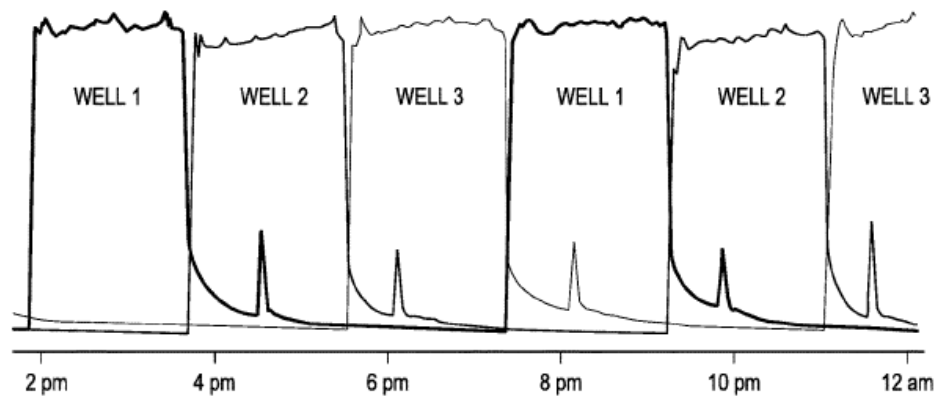
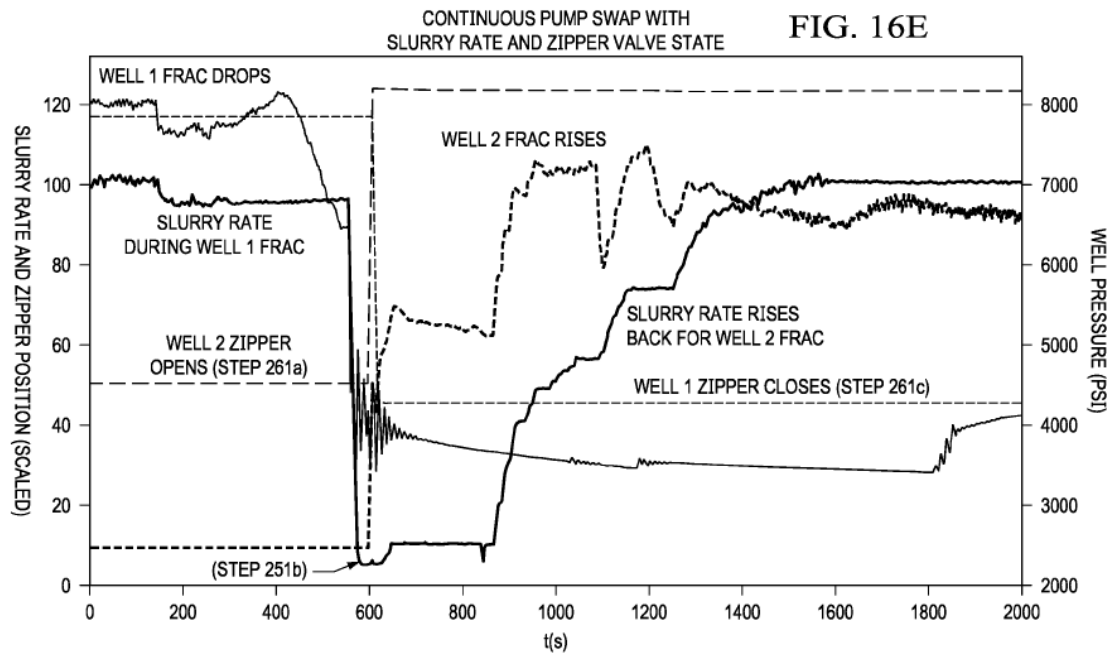


FIG. 16D

116. With respect 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

¹⁵ Ex.1001, 14:45-51, Fig. 16D-16E.

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.



117. 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

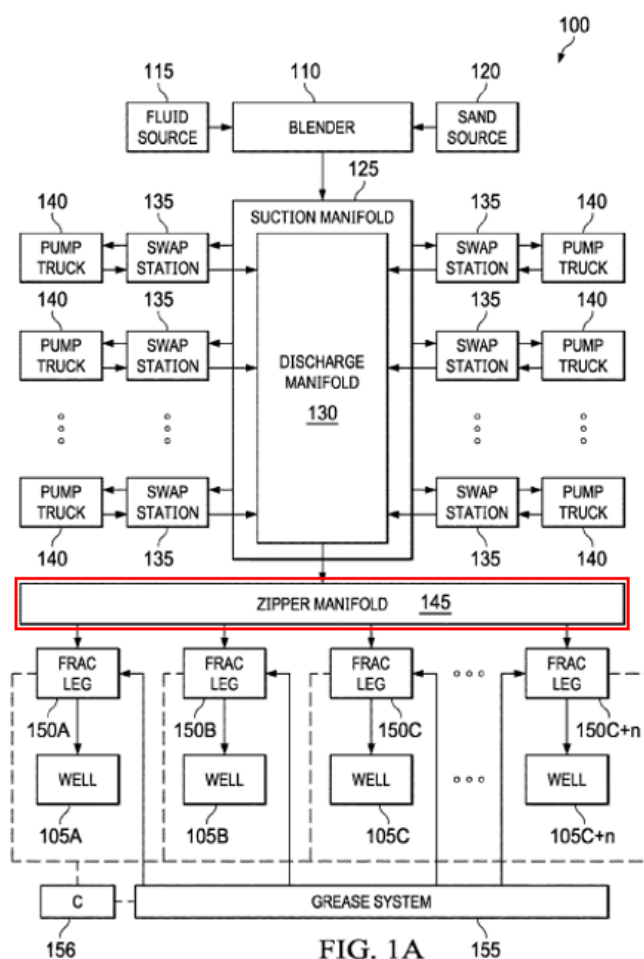
satisfied another condition, namely a pressure condition at which the fluid pressure, which corresponds to the well pressure, is below an upper threshold corresponding to the well pressure (about 5,000 psi) and above a lower threshold (about 3,000 psi). In response to determining that the one or more of these conditions have been satisfied, the zipper valve for Well 2 (well 105B) is opened.

118. 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).

119. In summary, when swapping from the first well (n_1) to the second well (n_1+1), the zipper valve associated with the second well will only be opened to initiate a CP swap when the condition of the fluid communicated to the first well (n_1) is satisfactory. The reason the condition of the fluid communicated to the first well is checked even though the zipper valve to the second well is being opened is because both wells are connected to the same zipper manifold and share a common pressurized fluid flow, as illustrated in Fig. 1A above. In traditional non-zipper systems, where each well has its own isolated fluid flow path, such a cross-well check would not be needed or logical before opening a well's valve—the fluid conditions associated with each well would be independent.

120. The claimed CP swap, and the benefits derived therefrom (e.g., reducing NPT to a mere 20 seconds), are only applicable in the context of a zipper manifold and zipper valves. Indeed, the entirety of the '770 Patent, including the specification and all drawings, refer and relate to a novel hydraulic fracturing process that must be performed during a zipper fracturing operation—specifically, with a zipper manifold and zipper valves. For example, Figure 1A (below) shows “a hydraulic fracturing system operably [sic] to execute a hydraulic fracturing plan

to hydraulically fracture a plurality of oil and gas wells,....”¹⁶ Figure 1A requires a zipper manifold (145) and zipper valves (170a-b).¹⁷



121. Similarly, Figure 1B is a “flow diagram illustrating a method for hydraulically fracturing a plurality of wells by executing a hydraulic fracturing plan *using the hydraulic fracturing system of FIG. 1A*,....”¹⁸ All subsequent figures (and corresponding description in the specification) refer to Figure 1A or

¹⁶ Ex.1001, 2:19-22.

¹⁷ Ex.1001, 5:45-6:11.

¹⁸ Ex.1001, 2:23-26.

1B. And every image depicting the claimed steps being performed, require a zipper manifold (145) and zipper valves (170a-b). *E.g.*, Ex. 1001, Figs.2A-G, 5A-C, 7A-I, 9A-G, 11, 14A-B, 16A-C, 18A-G.

122. The CP swap described and claimed 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. The claimed CP swap, and the associated efficiencies and NPT reduction, are only achieved when the claimed process is implemented in a zipper fracturing operation, with the use of a zipper manifold and zipper valves.

VII. CLAIM CONSTRUCTION

123. 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.

124. 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.

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

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

127. 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. Grounds 1 & 2: The Krupa Grounds do not anticipate or render obvious the Challenged Claims.

128. 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, 2022.¹⁹ I understand that

¹⁹ Ex.1003.

Petitioner has failed to establish that Krupa is prior art because February 18, 2022 is after May 17, 2021, the filing date of the '770 Patent. Accordingly, the Krupa Grounds cannot render the Challenged claims unpatentable and my analysis need not address Krupa or any Krupa-related grounds.

B. Grounds 3 & 4: Carr alone does not anticipate or render obvious the Challenged Claims.

1. Summary of Carr (Ex. 1004).

129. 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.

130. Carr describes a traditional hydraulic fracturing operation that improved upon older methods that required fluid preparation equipment (e.g., hydration blender, chemicals, mixing blender, proppant, etc.) to be broken down and relocated to fracture the next well after completing the first.²⁰ Carr endeavored to solve that (then-existing) problem by designing a system with a “centralized well treatment facility 105” positioned ahead the well manifolds and pump trucks. With this configuration, hydraulic fracturing fluid could be “manufactured, formed and/or mixed at a centralized location” prior to being transferred to multiple wells on a single pad, while still maintaining isolated and independent flow paths to each

²⁰ Ex.1004, [0003].

well, such that the fluid preparation equipment did not need to be broken down or relocated before moving to the next well.²¹

131. Carr Figure 5 illustrates the fluid flow paths from the fluid preparation equipment to the wells. I understand that during Dr. Durham's deposition, he annotated Carr Figure 5 (shown below) to illustrate the separate fluid flow paths for first well 140 and second well 142.²² I agree with Dr. Durham's annotations.

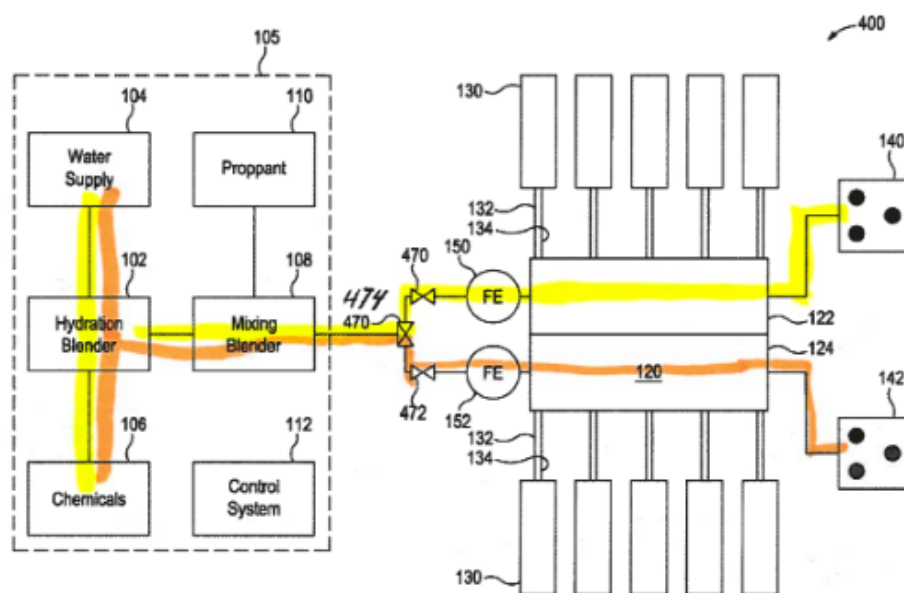


FIG. 5

132. As shown, fluid intended for first well 140 (annotated in yellow), begins at water supply 104 and chemicals 106; fluid travels through hydration blender 102 and into mixing blender 108; fluid then travels through proportion valve 474 and first valve 470 then directs fluid to first well 140 via first isolated

²¹ Ex.1004, [0013]-[0017], [0033]-[0035], Fig. 5.

²² Ex.2011.

manifold path 122; once in the first isolated manifold path 122, the fluid is pressurized by the pump array 130 and then directed into first well 142.²³ Fluid intended for second well 142 (annotated in orange) follows the same general fluid path, but second valve 472 directs the fluid into second isolated manifold path 124, where the fluid is pressurized by a separate array of pumps, and then directed into second well 142.²⁴

133. As exemplified by Dr. Durham’s annotations, fluid intended for first well 140 travels via first isolated manifold 122 and fluid intended for second well 142 travels via second isolated manifold 124. While Carr identifies each isolated manifold in Fig. 5 as being within an integrated “manifold 120,” once fluid enters its respective isolated manifold paths 122 and 124, that fluid does not mix and cannot be redirected to either well.²⁵ Based on the system and flow paths, Carr does not describe a zipper fracturing operation and Carr’s manifold 120 is not a zipper manifold—e.g., it cannot redirect fluid between first well 140 to second well 142.²⁶ Rather, Carr’s manifold 120 is more properly characterized as a “missile.”²⁷

134. Because of the Carr system’s configuration, each isolated manifold is independently pressurized and provides fluid into geologically different wells and,

²³ Ex.1004 at [0021], [0022], [0023], [0027], [0033], Claims 1, 9, 16.

²⁴ *Id.*

²⁵ Ex.1004, [0026], [0033], Claims 1, 9, 16

²⁶ *See* Ex.2008.

²⁷ *See* Ex.2009.

thus, each independent isolated manifold has independent fluid, pressure, and flow conditions. For example, the porosity and permeability of the geological formation within which a well is drilled affects the conditions of the fluid flowing to that well, as noted by Dr. Durham.²⁸ Due to these geological differences, one well may take fluid faster than the other well. Therefore, the flow conditions in each isolated manifold path must be independently monitored and controlled.²⁹ This may include monitoring flow rates, pressures, and proppant loading.

135. Carr describes utilizing one or more flow meters associated with each isolated manifold path.³⁰ For example, information from flow meter 150 associated with first isolated manifold path 122 can be used to control valve 470, which is also associated with first isolated manifold path 122, to vary the flow of fluid to the corresponding well.³¹ I agree with Dr. Durham's testimony during his deposition on this point:

A. Carr teaches a different flow meter associated with each path so that you can measure fluid flow separately and independently, as opposed to having a single meter upstream of valve 474, for example.

Q. Why would that be important?

A. So that you can measure flow independently.

²⁸ Ex.2013, 95:3-10.

²⁹ Ex.1004, [0023].

³⁰ Ex.1004, Fig. 5, [0022], [0023].

³¹ Ex.1004, Fig. 5, [0033]-[0035], [0058], [0060].

Q. Because the fluid conditions can be different, right?

A. Sure. So that you have more information.³²

136. Because each isolated manifold path 122 and 124 has its own isolated fluid flow and conditions, and because there is no exchanging or redirecting of fluid, there is no need to deploy the '770 Patent's well swapping technique. The '770 Patent's well swapping technique can only be deployed where the wells being fractured share a common, overlapping source of high-pressure fracturing fluid (i.e., where the conditions of that fluid are equally applicable to both wells). Without an overlapping source of high-pressure fracturing fluid, it is not possible to seamlessly switch from hydraulically fracturing one well to hydraulically fracturing the next, without shutting pumps down.

137. It would also make no sense to alter the position of second valve 472, which is associated with isolated manifold path 124, based on fluid flow information read by flow meter 150 associated with first isolated manifold path 122. For example, if the flow rate in the first isolated manifold path 122 was too high, only changing the position of first valve 470 based on that information would make sense—changing the position of valve 472 would have no impact at all on the flow rate in the first isolated manifold path. The system of Carr simply predates and is incompatible with that of the '770 Patent.

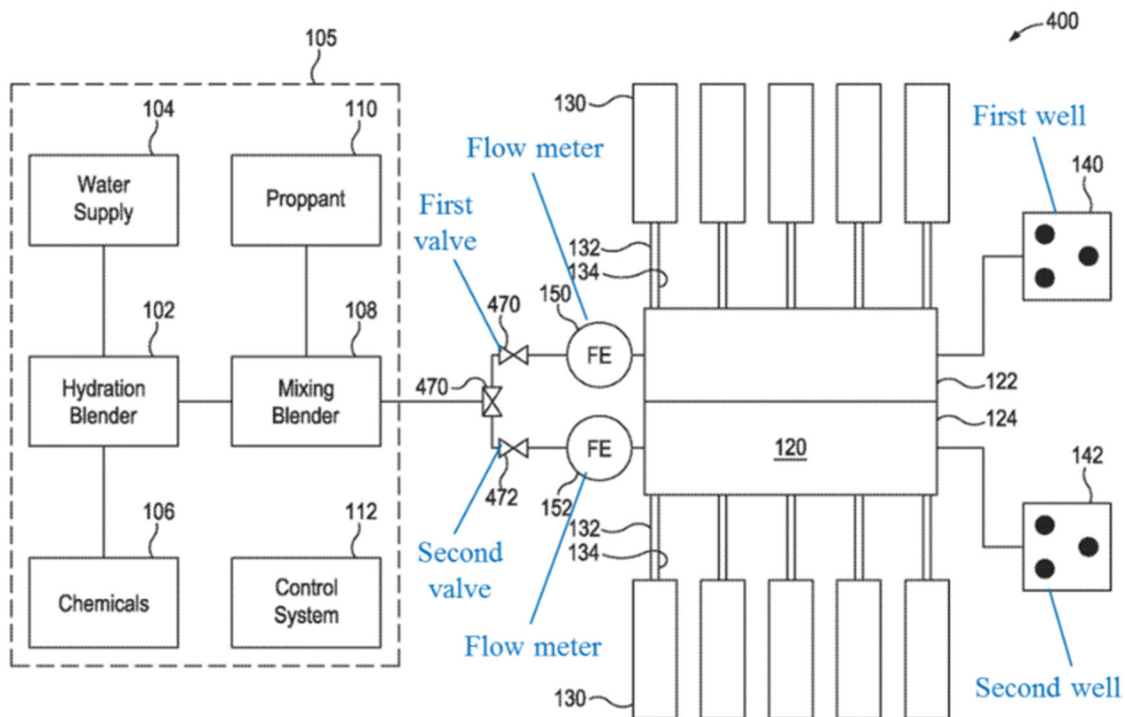
³² Ex.2013, 153:5-17.

2. Independent Claims 1, 14, and 27 are not anticipated or rendered obvious by Carr.

- a) Carr does not anticipate or render obvious performing the claimed valve sequence “*in response to determining that the fluid communicated via the manifold has satisfied one or more conditions.*”

138. Petitioner fails to establish that Carr performs the claimed valve sequence “in response to determining that the fluid communicated via the manifold has satisfied one or more conditions.” As I understand it, the Challenged Claims require “communicating fluid to a first well via a manifold” and then performing a specific valve sequence “in response to determining that the fluid communicated via the manifold has satisfied one or more conditions.” If it is determined that the fluid communicated to the first well satisfies one or more conditions, then the following specific claimed valve opening/closing sequence must be performed: (1) “opening a second valve”; (2) “communicating fluid to a second well via the second valve”; and (3) “closing the first valve after opening the second valve.” In summary, based on the language of the claims, the decision to open the *second* valve associated with the *second* well must be based on the fluid communicated to the *first* well satisfying one or more conditions. Carr’s technique of stimulating wells with independent and isolated fluid paths cannot meet this requirement.

139. The Petition maps Fig. 5 of Carr to the challenged claims as shown below on page 50 of the Petition.



140. For the claimed requirement of “*communicating fluid to a first well via a manifold and a first valve,*” Petitioner points to the fluid communicated to the first well 140 via valve 470 and the isolated manifold path 122.³³ To satisfy the claims, Carr must teach determining that the fluid communicated to the *first* well 140 via the first isolated manifold path 122 satisfies a condition and, in response, opening the *second* valve 472 and communicating fluid via the second isolated manifold path 124 to the *second* well 142.

³³ Petition, 49-50 (citing Ex.1004, [0033]).

141. Carr does not disclose that the decision to open second valve 472 is based on information received from first flow meter 150 associated with the first isolated manifold path. Instead, Carr describes that the first valve 470 can be adjusted based on fluid flow information from first flow meter 150 associated with first manifold 122, and second valve 472 can be adjusted based on fluid flow information from second flow meter 152 associated with second manifold 124.³⁴ The valves in each isolated manifold path are adjusted separately and independently of each other based on the potentially different fluid conditions in each well, as noted above and by Dr. Durham.³⁵ This is true even though the isolated manifold paths receive fluid from the same centralized source 105—the fluid flows, once split, are still “isolated” from each other and thus must be monitored separately and independently.³⁶

142. Petitioner, relying upon Dr. Durham, also alleges inherency and obviousness of the independent claims in 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.’”³⁷ I disagree with

³⁴ Ex.1004, Fig. 5, [0033]-[0035], [0023], [0058], [0060].

³⁵ Ex.2013, 153:5-17.

³⁶ Ex.1004, Fig. 5, [0033].

³⁷ Petition, 52-53 (citing Ex.1002, ¶¶331-332).

Dr. Durham's statement, which lacks any supporting evidence. Given Carr's isolated manifold paths with different fluid conditions (as explained in more detail in Section VIII.B.1), it would not have been obvious to a POSITA to open *second* valve 472 in response to determining that the fluid communicated via *first* manifold 122 has satisfied one or more conditions. Nor would a POSITA have been motivated to do so. A POSITA would have found it nonsensical to operate a valve in the second isolated manifold path 124 based on the separate and independent fluid conditions in the first isolated manifold path 122. For example, adjusting the valve in the second isolated manifold path 124 would have no impact at all on the flow rate in the first isolated manifold path 122.

143. For these reasons, the Petition fails to establish that Carr anticipates or renders obvious independent claims 1, 14, 27.

b) Carr does not anticipate or render obvious performing the claimed valve sequence in the claimed order.

144. Carr does not disclose or discuss performing the claimed valve sequence, in the claimed order. Claim 1 of the '770 Patent requires that, in response to determining that the fluid communicated via the manifold has satisfied one or more conditions:

opening a second valve;

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

*closing the first valve after opening the second valve.*³⁸

It is my opinion, based on the claim language, that these steps must be performed in the recited order. It is also my understanding that, if performed in the recited order, there is a point at which both the first valve and the second valve must be open simultaneously.

145. To establish that Carr practices the claimed sequence, the Petition relies on the following sentence from Carr: “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.”³⁹ In my opinion, the cited portion of Carr does not support performing the claimed valve sequence in the claimed order.

146. Looking at the words alone, this sentence does not specify the order in which the first valve 470 and the second valve 472 are opened and closed. Nothing in this sentence requires that first valve 470 must be opened before second valve 472 is opened. Rather, I understand this sentence to merely be explaining that when first well 140 and second well 142 are “individually stimulated” their respective valves (470, 472) are not opened at the same time, as opposed to when both first well 140 and second well 142 are stimulated simultaneously.

³⁸ Ex.1001, claim 1; *see also id.*, claims 14, 27.

³⁹ Petition, 51-52 (citing Ex.1004, [0033]).

147. In my opinion, a POSITA would not import any required valve sequence order into this sentence given the context of Carr’s system. Again, because valves 470 and 472 are on independent and “isolated” fluid flow paths that are pressurized with “separate” pumps (*see* Section VIII.B.1), each of Carr’s valves 470 and 472 may be opened and closed independently without a required ordering.⁴⁰ Such independent operation of valves 470 and 472 is necessary to achieve Carr’s goal of hitting each well’s separate “fluid flow targets.”⁴¹ A POSITA would find it inappropriate to read the claimed valve sequence that requires valve *interdependence* into Carr’s system that requires valve *independence*.

148. If a POSITA were to read any ordering into the sentence pointed to by Petitioner, it would be the conventional valve sequencing utilized in the hydraulic fracturing industry when individually and sequentially fracturing two wells: closing the valve of the first well and then opening the valve of the second well. As mentioned above, this traditional sequence was described as being “critical” for safety purposes.⁴² For example, the Tolman article explains that only one well’s valves should be opened at any one time for safety reasons, thus requiring closing

⁴⁰ Ex.1004, [0033], [0022].

⁴¹ Ex.1004, [0035] (“utilizing flow data from the first flow meter 150 and the second flow meter 152 in light of fluid flow targets for the first well 140 and/or the second well 142”).

⁴² *See* Ex.1031, 4.

one well's valves prior to opening another well's valves.⁴³ Similarly, the Jacobs article describes a "break in stimulation operations" of 15 minutes, during which the pumps would be stopped and both wells' valves would be closed.⁴⁴

149. Carr's ability to stimulate wells simultaneously similarly does not teach (expressly or impliedly) performing the claimed valve sequence, as alleged.⁴⁵ When wells are stimulated simultaneously, the valves are opened and closed simultaneously. In the context of Carr, valves 470 and 472 would be opened/closed simultaneously during simultaneous stimulation of wells 140 and 142.

150. A POSITA would also not find the recited valve sequence inherent or obvious based upon Carr. I note that even if Carr is "capable of" performing the recited valve sequence, neither Petitioner nor Dr. Durham has explained why a person of ordinary skill in the art would have been motivated to use such a sequence.

151. Further Dr. Durham's speculation in paragraph 331 that Carr would "close valve 470" in response to flow conditions while simultaneously stimulating both wells is nonsensical. To achieve simultaneous stimulation, both valves would need to be opened and remain open during stimulation operations. Carr instead says that "the control system 112 can be utilized to control the position of the first

⁴³ *Id.*

⁴⁴ *See* Ex.1009, 2.

⁴⁵ Petition, 51-52 (citing Ex.1004, [0033]).

valve 470.”⁴⁶ Controlling the position of valve 470 during treatment cannot mean completely closing it because doing so would potentially deadhead the pumps. “Deadheading” is when a positive displacement pump operates against a closed valve.⁴⁷ Specifically, “[w]ith the pump operating against a closed discharge valve, it will continue to produce flow and the pressure in the discharge line will increase until the pipeline can either fracture or the pump can become severely damaged, or both.”⁴⁸ For these reasons, a POSITA would not understand that performing *simultaneous* stimulation of wells would render obvious the claimed valve sequence.

152. In my opinion, the only explanation for why Petitioner reads Carr’s generalized disclosure as disclosing the claimed valve sequence is the disclosure of the ’770 Patent itself. However, I understand that the use of the Challenged Claims as a roadmap for arriving at the claimed invention is an improper use of hindsight and is insufficient to show anticipation or obviousness.

153. Given Petitioner’s lack of evidence, and for these additional reasons, the Petition fails to establish that Carr anticipates or renders obvious independent claims 1, 14, 27.

⁴⁶ Ex.1004, [0033].

⁴⁷ See Ex.2030, 1.

⁴⁸ *Id.*

3. Dependent Claims 2, 15, and 28 are not anticipated or rendered obvious by Carr.

154. Dependent claim 2 (which is representative of dependent claims 15 and 28) recites:

2. The method of claim 1, further comprising:

communicating fluid to *a third well* via the manifold and a third valve, the *third valve being associated with both the manifold and the third well*; and

in response to determining that the fluid communicated via the manifold has satisfied one or more conditions:

opening a fourth valve;

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

closing the third valve after opening the fourth valve.

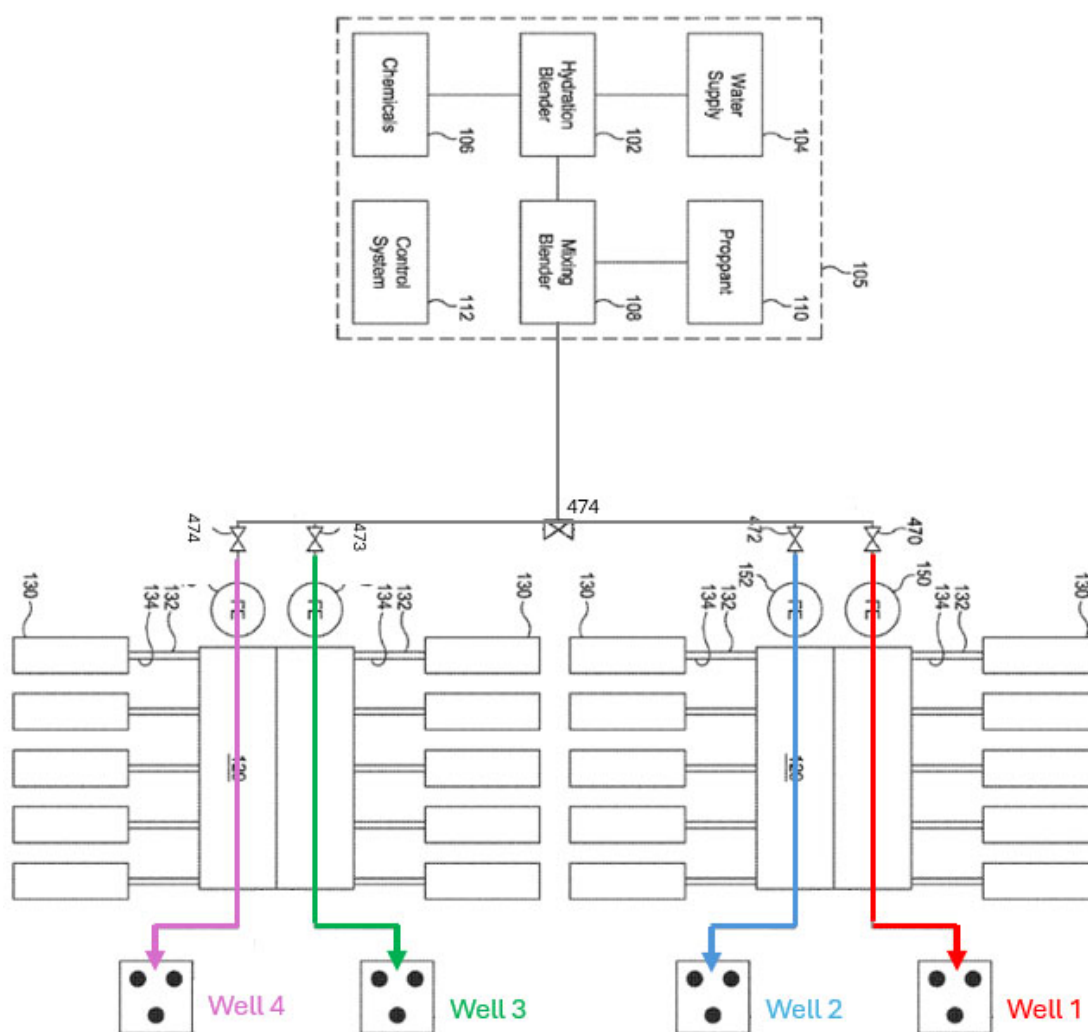
155. As shown above, dependent claims 2, 15, and 28 require: (1) the addition of a “*third well*” with associated “*third valve*” and a “*fourth well*” with associated “*fourth valve*”; (2) that the third valve and third well be associated with “the manifold”; and (3) that the third and fourth valves must be opened and closed in response to satisfying a condition of the fluid via the manifold (i.e., the same manifold that communicates fluid to the first well). It is my understanding that, based on the concept of antecedent basis, that the claimed “manifold” must therefore be associated with both the first valve and first well as well as the third valve and third well.

156. While Carr does disclose a system and method for simultaneously treating multiple wells from a centralized location⁴⁹, every description and figure in Carr describes and depicts only a two-well system. Accordingly, it is my opinion that Carr only expressly discloses a two-well system.

157. Additionally, even if Carr could accommodate a four-well system, Petitioner does not explain *how* a POSITA would deploy a four-well system in Carr, which necessarily requires four wells, each having its own isolated manifold path, flow meter(s), valve(s), and pump array, but combined into a single integrated manifold 120. As shown in the below mockup of a four-well system in Carr, doing so would be physically impractical if not impossible given the space needed to accommodate four sets of pump arrays.

158. For exemplary and discussion purposes, below is a hypothetical depiction of the Carr system with four wells.

⁴⁹ Ex.1004, [0001].



159. As shown above, if Carr did deploy a four-well system, I agree with Dr. Durham that each additional well would be deployed in the same way that Carr discloses deploying the first and second well setups. Namely, the third well (shown in green) and fourth well (shown in purple) would each be associated with its own isolated manifold path, flow meter, valve, and pumps.⁵⁰ Further, the third valve and third well (shown in green) would not be associated with the same

⁵⁰ Ex.2013, 1589-21.

manifold as the first valve and first well (shown in red), and fluid would not be communicated to the third well (shown in green) via the same manifold that communicates fluid to the first well (shown in red).

160. Additionally, Carr's hypothetical third valve (shown in green) and fourth valve (shown in purple) would each be opened and closed in response to a fluid condition in their own associated isolated manifold path, and not in response to a fluid condition in any other isolated manifold path, as claims 2, 15, and 28 require. Again, in my opinion, and as shown above, because each isolated manifold path has its own pressurization source and fluid conditions, a POSITA would not have been motivated to make the valve actions in one isolated manifold path dependent on the independent conditions of any other isolated manifold path.

4. Dependent Claims 3, 16, and 29 are not anticipated or rendered obvious by Carr.

161. Dependent claim 3 (which is representative of dependent claims 16 and 29) recites:

2. The method of claim 2, wherein:

the first valve is closed after opening both the second valve and the fourth valve; and/or

the third valve is closed after opening both the second valve and the fourth valve.

162. As shown above, dependent claims 3, 16, and 29 recite a specific valve sequence that must be performed with four valves within a four-well system. As

noted above in Section VIII.B.3, Carr describes only a two-well system. Therefore, it is my opinion that Carr does not anticipate dependent claims 3, 16, and 29.

163. It is also my opinion that Carr does not render obvious dependent claims 3, 16, and 29. I disagree with Petitioner's assertion that "a POSITA would have found such valve sequencing obvious 'in light of fluid flow targets.'"⁵¹ As previously discussed (*see* Sections VIII.B.1, VIII.V.2.a-b), the fluid flow targets described in Carr are specific to each well and are achieved by monitoring information from the flow meter associated with that well and adjusting the valve associated with that well.⁵² As a result, Carr expressly teaches that each well, its associated valve(s), flow meter(s), and isolated manifold path are independent of the other wells.⁵³ Accordingly, in my opinion, it would not be obvious nor would a POSITA be motivated to imply interdependence between the wells where none exists.

5. Dependent Claims 11, 24, and 36 are not anticipated or rendered obvious by Carr.

164. Dependent claim 11 (which is representative of dependent claims 24 and 36) recites:

2. The method of claim 1, wherein:

the first valve is a *zipper valve*; and/or

⁵¹ Petition, 54.

⁵² Ex.1004, Fig. 5, [0033]-[0035], [0023], [0058].

⁵³ *Id.*

the second valve is a *zipper valve*.

165. As shown above, dependent claims 11, 24, and 36 require that the first valve and/or the second valve is a “zipper valve.” Petitioner alleges that this term is meaningless, and that “‘zipper valves’ are not distinguished from any other valve capable of allowing fluid flow into a well.”⁵⁴ Petitioner is wrong. As described in Section V.H.2, a “zipper valve” is not a meaningless term and is distinguishable from other valves, including in a zipper fracturing operation. The term “zipper valve” has a specific meaning and function to a POSITA in hydraulic fracturing and is used in this conventional way in the ’770 Patent.⁵⁵ As I discuss above, a “zipper valve” redirects common pressurized fluid flow between multiple wells attached to the manifold.⁵⁶ A conventional “zipper valve” is illustrated in every embodiment of the ’770 Patent.⁵⁷

166. For example, ’770 Patent, Figure 1A shows a zipper manifold 145 that redirects pressurized flow between wells 105A-C+n.⁵⁸

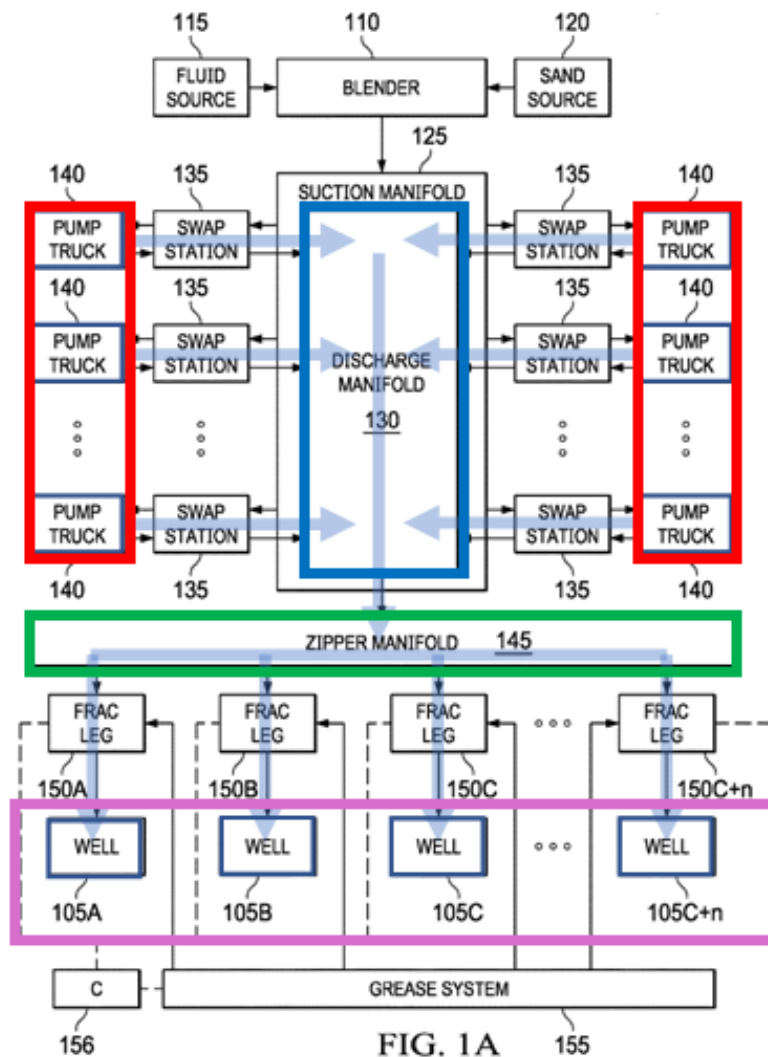
⁵⁴ Petition, 59.

⁵⁵ See Ex.2031.

⁵⁶ *Id.*

⁵⁷ See, e.g., Ex.1001, Figs. 1A-20 (depicting and/or describing a zipper fracturing operation utilizing a zipper manifold and zipper valves).

⁵⁸ Ex.1001, Fig. 1A, 2:19-22, 5:45-65; *see also* Ex.2009 (Schlumberger definition of “zipper manifold”).



167. Zipper valves 170a-b, shown below in Fig. 2A, control which of the wells 105A-C+n receive the common pressurized fluid flowing through the zipper manifold—i.e., they allow the zipper manifold to redirect fluid to a specific well.⁵⁹ The other valves depicted in Fig. 2A are not zipper valves.⁶⁰

⁵⁹ Ex.1001, Fig. 2A, 6:8-9, 7:60-8:1.

⁶⁰ *E.g.*, Ex.1001, 6:5-11 (describing pump-down valves 160a-b, master valves 165a-b, and zipper valves 170a-b).

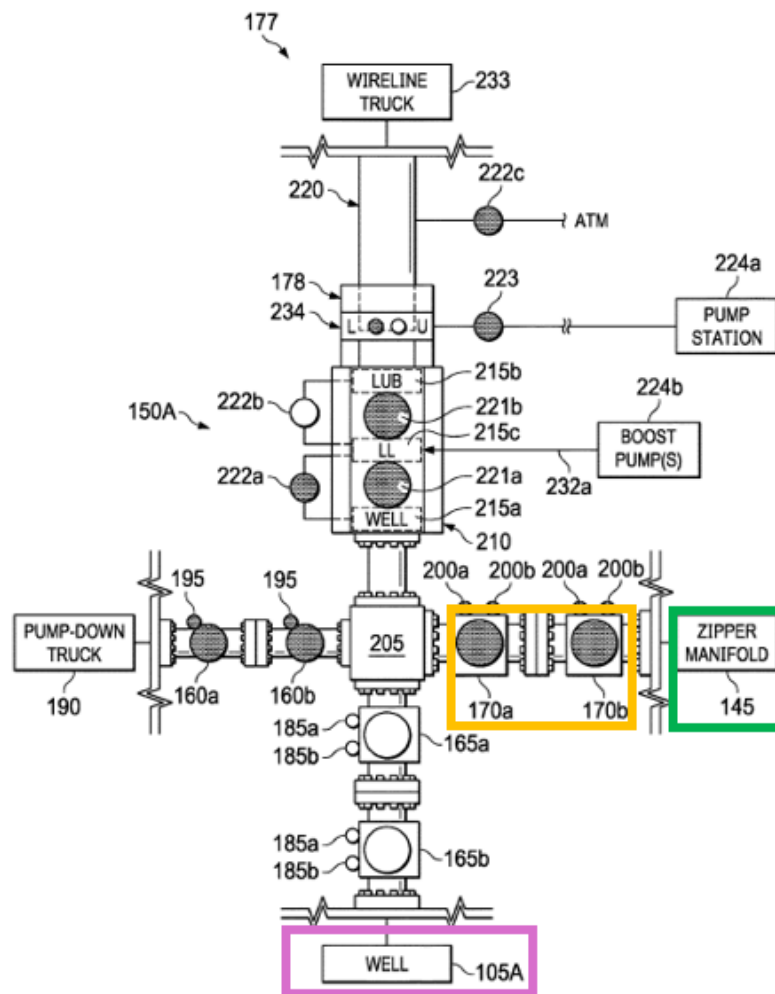


FIG. 2A

168. I disagree with Petitioner’s assertion that valves 470 and 472 in Carr are “zipper valves.”⁶¹ First valve 470 and second valve 472 in Carr do not redirect pressurized fluid flow between multiple wells attached to a zipper manifold. Specifically, as shown in Carr Fig. 5 (*see* Section VIII.B.2), first valve 470 controls fluid flow to first well 140 and second valve 472 controls fluid flow to second well 142.⁶² Once fluid has entered each isolated manifold path, neither first

⁶¹ Petition, 50.

⁶² Ex.1004, [0033], Fig. 5.

valve 470 nor second valve 472 has the capability to redirect fluid between wells 140 and 142.

169. Accordingly, in my opinion, Carr fails to anticipate or render obvious dependent claims 11, 24, and 36.

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

1. Summary of Beuterbaugh.

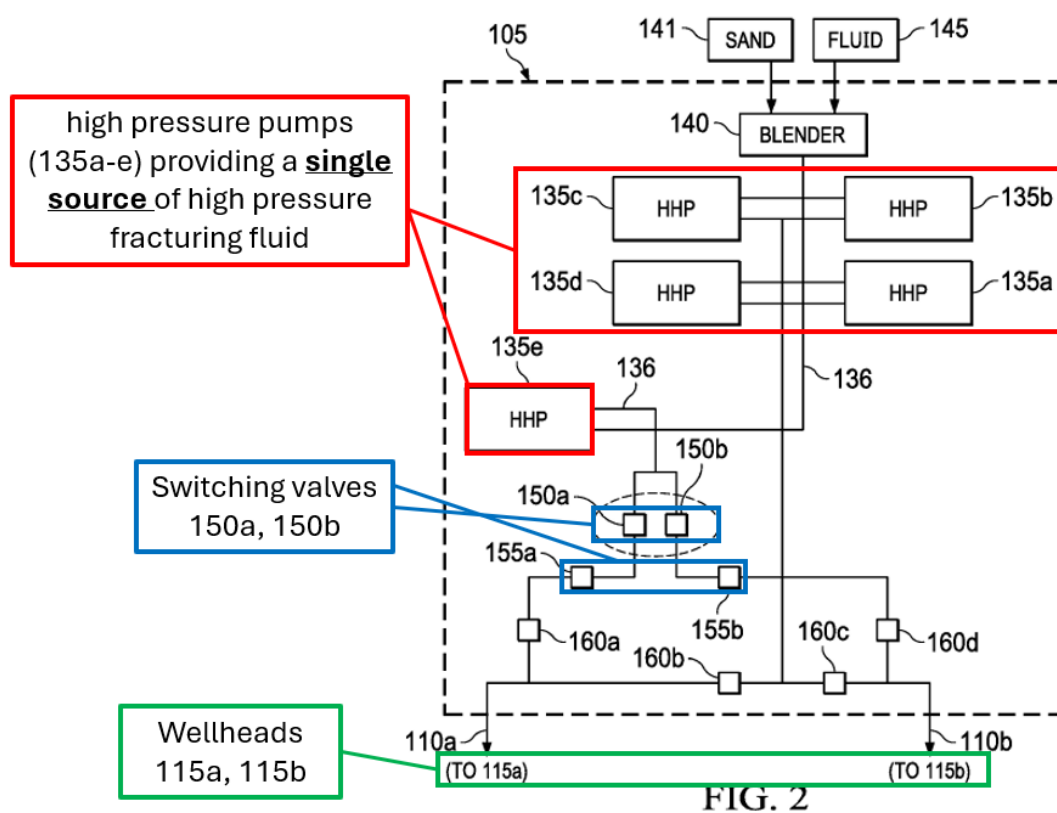
170. Beuterbaugh describes a system and method for increasing efficiency and well production in traditional zipper fracturing operations by rapidly switching back and forth between wells being stimulated on the same zipper manifold.⁶³

Using the system and method in Beuterbaugh, it is possible to perform a “near instantaneous switching of a single-mode high pressure fracturing fluid to allow two or more wells to be pulsed simultaneously.”⁶⁴

171. An annotated version of the Beuterbaugh system is shown below in Figure 2:

⁶³ Ex.1005, Abstract, Fig. 2.

⁶⁴ Ex.1005, [0015].



172. Beuterbaugh describes utilizing the system shown in Fig. 2 to reduce wear and tear on surface equipment, including the high pressure pumps by locating a single source of fracturing fluid and the pumps (135a-135e) ahead of the switching valves 150a-150b, 155a-155b.⁶⁵ When this configuration is deployed, pulses of substantially constant high pressure stimulation fluid is directed to each wellhead 115a, 115b, even with switching valves 150a-150b, 155a-155b fully closing (with the “absolute shut off of fracturing fluid” when closed) between pulses.⁶⁶ Beuterbaugh is able to effectuate these pulses without dead heading the

⁶⁵ Ex. 1005, [0015], [0018].

⁶⁶ *Id.*

pumps because the stimulation fluid source and the high pressure pumps are located ahead of switching valves 150a-150b, 155a-155b.

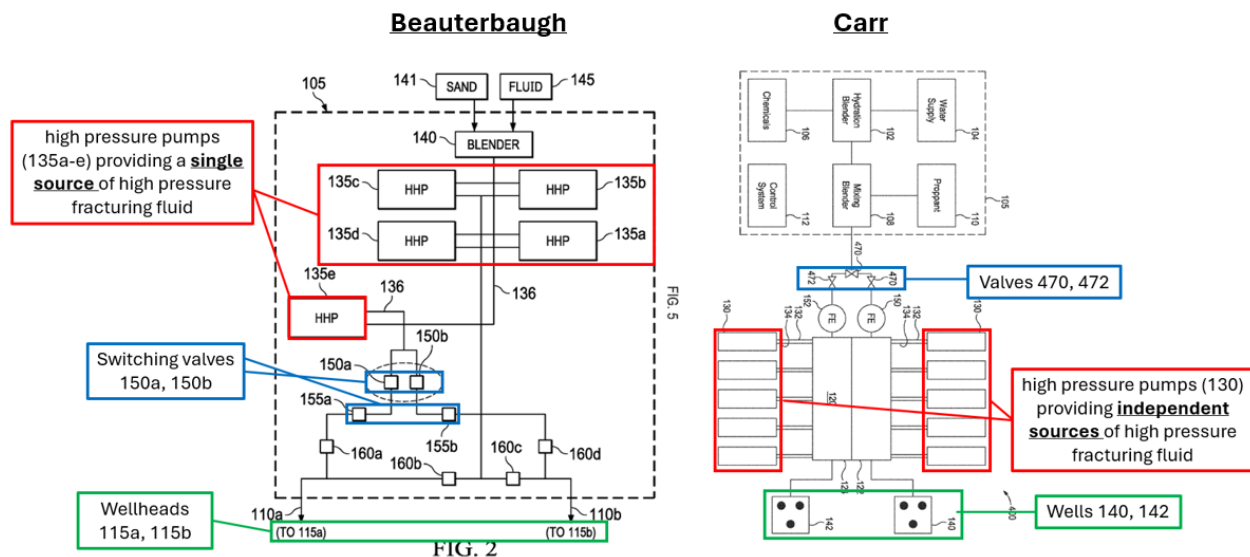
173. As shown above and described in Beuterbaugh, to achieve the claimed efficiencies and reduction in equipment wear and tear (including on the pumps), the Beuterbaugh system and method requires that: (1) the wells share “a single source of high pressure fracturing fluid” (i.e., the pressure pumps (135a-135e) are positioned ahead of switching valves (150a-150e)); (2) the pressure pumps 135a-135e run at a constant rate and provide substantially constant pressure to the switching valves (150a-150e); (3) there be an “absolute shut off of fracturing fluid flow after one of the switching valves 150a, 150b shifts to a closed position;” and (4) the sequence for pulsing between switching valves 150a-150e is based on a predetermined amount of time.⁶⁷

174. In my opinion, the Beuterbaugh system is distinct from traditional non-zipper fracturing systems (i.e., Carr), where each wellhead has its own associated pumps and isolated fluid flow path. *See* Section VIII.B.1. Unlike Carr where each well has its own pressurization source and independent fluid flow path that cannot be redirected between wells, Beuterbaugh’s wells share a single common source of high-pressure fluid that is provided at a substantially constant

⁶⁷ Ex. 1005, [0015], [0018], [0019], claims 1, 12, 14, 19.

pressure fluid and, thus, fluid can be selectively (and repeatedly) directed between wells to create the described “pulses” in each well.⁶⁸

175. Below is a side-by-side comparison of the Beuterbaugh (Fig. 2) and Carr (Fig. 5) systems. As shown below, the traditional system of Carr could not realize the benefits of Beuterbaugh without completely restructuring Carr’s system.



2. A POSITA would not have been motivated to add Beuterbaugh’s valve sequencing to Carr.

176. I disagree with Petitioner and Dr. Durham that a POSITA would have been motivated to deploy Beuterbaugh’s valve sequencing into the Carr system.⁶⁹ To start, Petitioner’s reasons for why a POSITA would deploy Beuterbaugh’s valve sequencing into the Carr system is based on benefits specific to the Beuterbaugh system, which are not compatible with the Carr system.

⁶⁸ *Id.*

⁶⁹ Petition, 66 (citing Ex.1005, [0024], [0019]).

177. I disagree with Petitioner’s allegation that a POSITA would have been motivated to substitute Beuterbaugh’s valve sequencing into Carr because (i) “Beuterbaugh’s valve sequencing allows the ‘overlap of fluid flows to each well [to] be controlled to optimize the downhole pressure waves and to minimize the surface impacts.’”⁷⁰ Both alleged motivations are based on benefits specific to Beuterbaugh’s system that are not compatible with Carr’s different system in which wells are fed by isolated manifold paths.

178. First, the system of Carr does not have any “overlap of fluid flows to each well” that can be controlled an optimized, as Beuterbaugh does. As described in Sections VIII.B.1 and VIII.B.2.a-b, Carr’s wells are isolated and once hydraulic fracturing fluid is communicated into each well’s respective isolated manifold path, the fluid flow is independently pressurized, does not overlap, and cannot be redirected.⁷¹ And the system of Carr cannot provide a substantially constant pressure of hydraulic fracturing fluid to two wells at a constant rate, as Beuterbaugh does.⁷²

179. I also disagree with Petitioner’s second alleged motivation for implementing Beuterbaugh’s valve sequence in Carr. Petitioner alleges that a POSITA would have been motivated to implement Beuterbaugh’s valve sequence

⁷⁰ *Id.*

⁷¹ *See* Ex.1004, Fig. 5, [0026], [0033], Claims 1, 9, 16; Ex.2011.

⁷² Ex.1005, [0018].

in Carr because Carr would allow for “‘absolute shut off of fracturing fluid’ by the plug valves.”⁷³ However, the “absolute shut off of fracturing fluid” is not a benefit of Beuterbaugh’s valve sequence; rather, it is a benefit of Beuterbaugh’s plug valves.⁷⁴ As described in Beuterbaugh, “[t]he plug valves 155a, 155b allow absolute shut off of fracturing fluid flow after one of the switching valves 150a, 150b shifts to a closed position in case there is some leakage flow.”⁷⁵ Conversely, Carr’s system does not have “plug valves” and it is my understanding that Petitioner does not propose adding such valves to Carr.

180. Even if Beuterbaugh’s valve sequence were to be implemented in Carr, it is my opinion that, for the same reasons explained in Section VIII.B.2.a, deploying the claimed valve sequence in Carr would still not be performed “in response to determining that the fluid communicated via the manifold has satisfied one or more conditions,” as the Challenged Claims require.

181. Given the vast structural and operational differences between the Beuterbaugh and Carr systems, it is my opinion that a POSITA would not have been motivated to implement Beuterbaugh’s valve sequence in Carr. The systems of Beuterbaugh and Carr have fundamentally different structures, functions, and operational goals. In my opinion, a POSITA considering the entirety of each of

⁷³ Petition, 66 (citing Ex.1005, [0019]).

⁷⁴ Ex.1005, [0019].

⁷⁵ *Id.*

Carr and Beuterbaugh would not be motivated to implement Beuterbaugh's valve sequence in Carr.

3. Dependent Claims 2, 15, and 28 are not rendered obvious by the combination of Carr and Beuterbaugh.

182. For the same reasons as stated with respect to Carr alone (*see* Section VIII.B.3), the combination of Carr and Beuterbaugh similarly does not render obvious dependent claims 2, 15, and 28.

4. Dependent Claims 3, 16, and 29 are not rendered obvious by the combination of Carr and Beuterbaugh.

183. For the same reasons as stated with respect to Carr alone (*see* Section VIII.B.4), the combination of Carr and Beuterbaugh similarly does not render obvious dependent claims 3, 16, and 29.

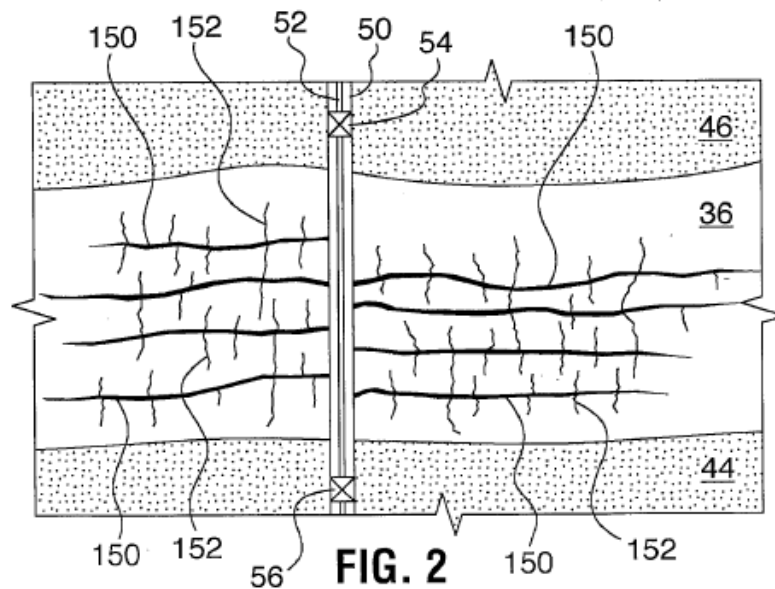
D. Ground 6: The combination of Carr, Beuterbaugh, and Jackson does not render the Challenged Claims obvious.

1. Overview of Jackson.

184. 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, 2007.⁷⁶ As shown below in Jackson Fig. 2, Jackson is directed to a single-well hydraulic fracturing processes.⁷⁷

⁷⁶ Ex.1007. Petitioner inadvertently labeled the filed copy of the Jackson Reference as Exhibit 1005; however, the Jackson reference is actually Exhibit 1007.

⁷⁷ Ex.1007, Abstract.



185. 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.”⁷⁸ More simply put, Jackson describes moving between *fracking stages in a single well* based on flowrate thresholds.⁷⁹

2. Carr, Beuterbaugh, and Jackson are fundamentally different systems.

186. Petitioner adds Jackson to the combination of Carr and Beuterbaugh to cure the deficiency related to flowrate thresholds limitations recited in

⁷⁸ Ex.1007, ¶ 0003, 0012.

⁷⁹ *Id.*

dependent claims 5, 6, 9, 18, 19, 22, 31, and 32. *See* Petition, 69-70. In my opinion, adding Jackson to the combination of Carr and Beuterbaugh does not render the Challenged Claims obvious, including because they are all fundamentally different systems that solve fundamentally different problems.

187. As explained in Section VIII.B.1, Carr relates to a ***two-well*** hydraulic fracturing operation with a “centralized well treatment facility 105” positioned ahead the well manifolds and pump trucks such that the wells can be hydraulically fractured either independently or simultaneously with ***no interdependence*** between wells. As explained in VIII.C.1, Beuterbaugh relates to delivering alternating rapid pulses of hydraulic fracturing fluid to ***two or more wells based on time***. Conversely, Jackson relates to moving between ***fracking stages in a single well based on flowrate thresholds***.

188. While Jackson does disclose “adjusting fluid flow into a single well to meet certain pressure thresholds,” because Jackson is a single-well system, this disclosure is directed to transitioning ***between stages in a single well***. Jackson does not describe how such thresholds would be used to determine when to transition ***between wells***. I have reviewed the Petition and Dr. Durham’s declaration (Ex. 1002) and neither provide any explanation as to ***how or why*** Jackson’s threshold for transitioning between stages in a single well is relevant to determining when to transition between wells.

3. Jackson’s thresholds would serve no purpose in Carr.

189. A POSITA would not have been motivated to combine Jackson’s single-well thresholds with Carr because Carr would not benefit therefrom.

190. As explained in Section VIII.B.1, Carr describes a two-well hydraulic fracturing operation that allows the hydraulic fracturing operations in each well to occur *independent* of what is occurring in the other well. Because Carr’s system has a “centralized well treatment facility 105” positioned ahead the well manifolds and pump trucks, and each well has its own associated valves, flow meters, isolated manifold, and pressurization source, first well 140 and second well 142 can be hydraulically fractured independently or simultaneously without any interdependence. Adding Jackson’s flow rate thresholds into Carr would necessarily import into Carr *dependence*, in direct contravention of Carr’s goals.

191. For these reasons, in my opinion, a POSITA would not have been motivated to combine Jackson with Carr.

E. Ground 7 & 8: Tolman does not anticipate or render obvious the Challenged Claims.

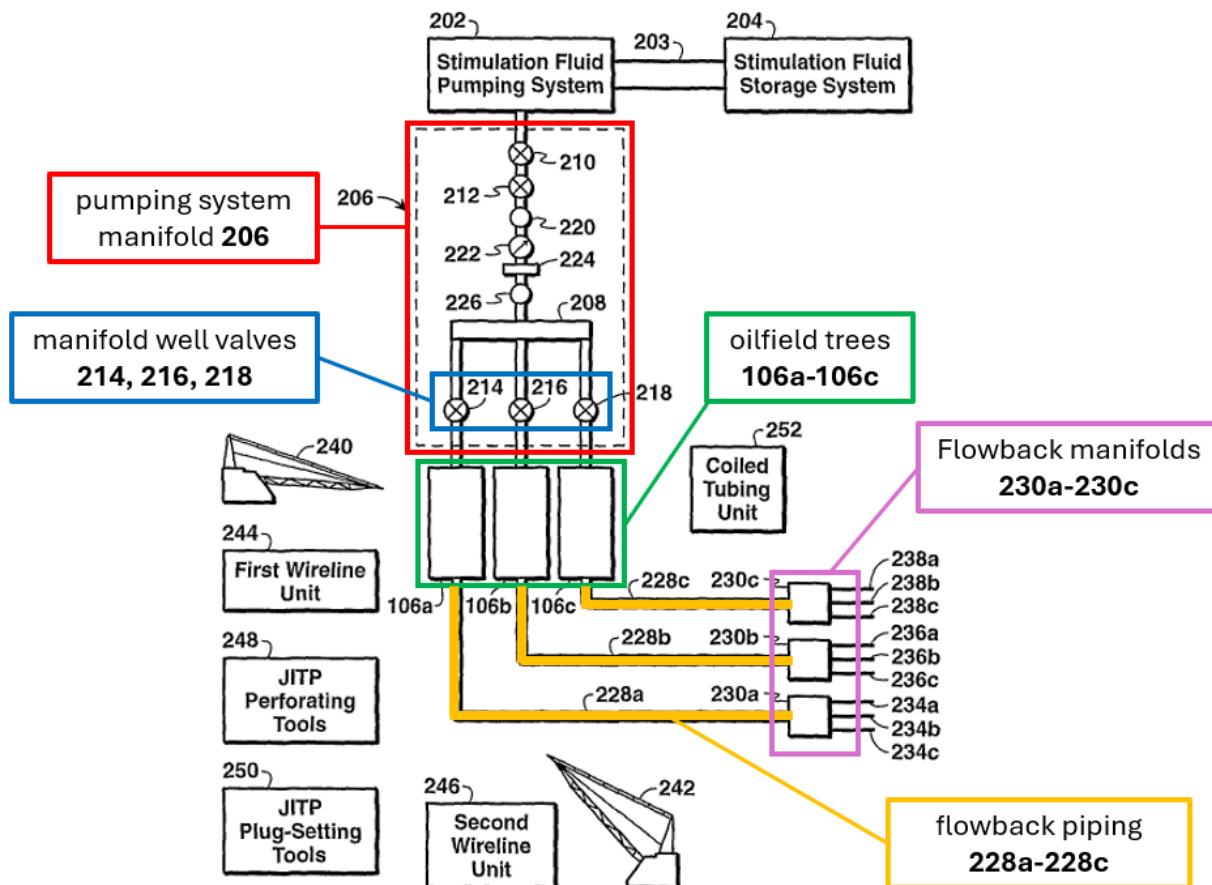
1. Summary of Tolman.

192. Tolman is one of the earliest references that describes what is now a traditional zipper fracturing operation, where multiple wells are connected to a zipper manifold.⁸⁰ At the time, Tolman sought to improve upon the traditional

⁸⁰ Ex.1006, Abstract.

single-well stimulation operations were all stages in a single well were completed before initiating preparation operations in a second well. Tolman does not, however, teach or suggest the continuous pumping swap claimed by the '770 Patent.⁸¹

193. Below is an annotated image of Tolman Fig. 2:



Ex. 1006, Fig. 2 (annotated).

194. Despite Tolman's improvements to then-existing systems and methods, Tolman is still suffers from the NPT associated with having to shut its

⁸¹ See e.g., Ex.1006, 1:50-2:4, 8:63-9:16; 10:30-59.

pumps down when transitioning between stimulating wells. *See supra*, Section V.H.2. Indeed, Tolman only describes treating one well at a time and that, while treating that well, all other wells connected to the same pumping system are “hydraulically isolated from the pressure and energy created by the stimulation fluid pumping system” so that operators may perform other operations on those isolated wells.⁸² Tolman’s requirement that wells not being stimulated be isolated also requires that the common pumping system 202 be shut down when transitioning from one well to the next to prevent dead heading the pumps.⁸³ So, while Tolman’s technique may “reduce ‘non-pumping time’ time” between well stimulations, [] it does not eliminate it.⁸⁴

2. Petitioner does not identify with particularity which valve in Tolman is the claimed “first valve” of Claims 1, 14, 27.

195. Based on my review of the Petition, Petitioner does not consistently, or with particularity, identify what valve in Tolman is the claimed “first valve.” Specifically, for elements 1.1, 4.2, and 27.1, the Petition points to both “manifold well valve 214” and an unspecified “tree valve” on the wellhead tree 106a as the claimed “first valve.”⁸⁵ In later elements, however, the Petition’s claim mapping does not point to the first manifold valve 214 as the claimed “first valve.” Instead,

⁸² Ex.1006, 4:8-15, 9:8-15.

⁸³ *See* Ex.2030, 1.

⁸⁴ Ex.1006, 9:11-16.

⁸⁵ Petition, 71-72.

all subsequent elements point only to various versions of “tree valve(s), including: (i) an unspecified “well tree valve,” (ii) plural “well tree valves,” (iii) “a first well tree valve,” or (iv) generic “first well’s valves.”⁸⁶ Despite Tolman’s well head trees having multiple valves, Petitioner never specifies which tree valve it believes is the claimed “first valve.”⁸⁷

196. Petitioner’s (and Dr. Durham’s) inconsistent reference to one or more tree valve(s) makes it impossible to determine which valve Petitioner contends is the claimed “first valve.”⁸⁸ The inconsistencies in Petitioner’s positions as to which Tolman valve is the claimed “first valve” stems from the fact that no valve in Tolman meets each and every limitation of the claimed “first valve.”

197. Included in the Petition is an annotated version of Tolman, Fig. 2 (shown below).⁸⁹ Petitioner points generally to well trees 106a-c, which are depicted as generic boxes without any valves as evidence of Tolman’s “tree valve(s).”⁹⁰

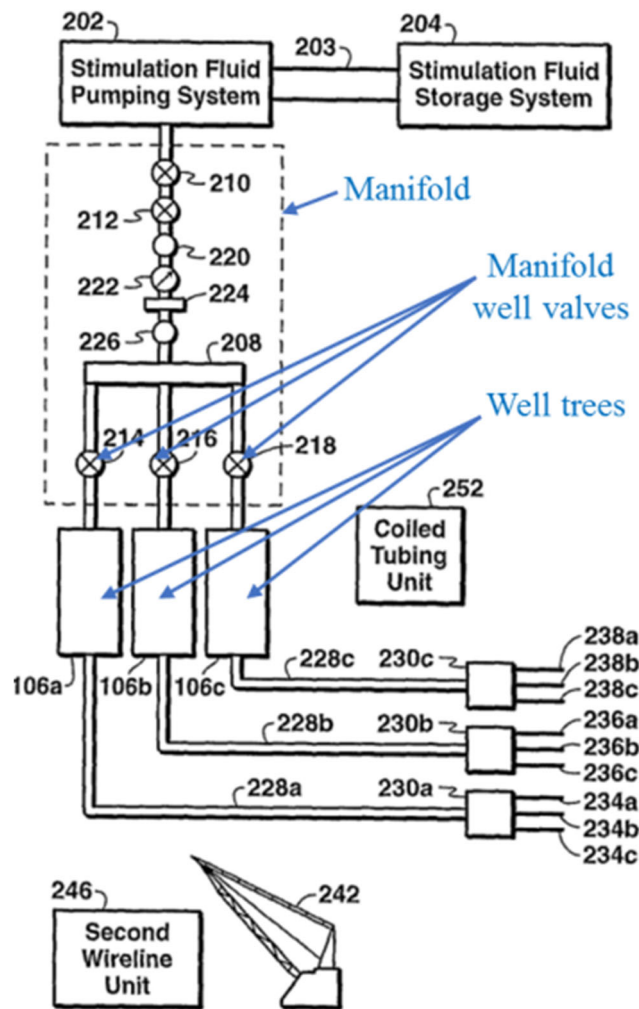
⁸⁶ See Petition, 75-76.

⁸⁷ Ex.1006, 8:13 (referencing “wellhead tree valves”); *see also* Petition, 75 (“Tolman discloses well tree valves are closed during isolation and open during stimulation.”).

⁸⁸ Ex.1002, ¶548 (referring to *the “tree valve”* associated with first well), ¶548 (“a POSITA would have known that a ‘tree’ is a structure located above a wellbore that contains *valves* used for allowing or preventing flow into and/or out of the well.”).

⁸⁹ Petition, 72 (annotating Ex.1006, Fig. 2).

⁹⁰ *Id.*



Tolman’s description of well trees 106a-c is similarly limited (though a POSITA would understand that a well tree has more than one valve). Tolman only describes “a valve (not shown) on the tree 106a-106,” “one or more valves be installed on trees 106a-106c,” and “wellhead tree valves.”⁹¹ Tolman’s lack of disclosure coupled with Petitioner’s and Dr. Durham’s inconsistent identification

⁹¹ Ex.1006, 7:29-33, 8:13, 13:39.

of “tree valves” or “tree valve,” makes it impossible to determine and evaluate which valve Petitioner contends is the claimed “first valve.”

3. Petitioner does not point to a single “valve” in Tolman that meets all limitations of the claimed “first valve.”

198. In my opinion, neither of the valves identified in the Petition’s mapping—first manifold valve 214 and a “tree valve(s)” associated with flowback—meets all limitations required of the claimed “first valve.”

a) Tolman’s “manifold valve 214” does not meet the requirements of the claimed “first valve.”

199. In my opinion, Tolman’s first manifold valve 214 does not meet the limitations of the claimed “first valve” because first manifold valve 214 must be closed when second manifold valve 216 (the alleged “second valve”) is open. This directly contradicts claim elements 1.4, 14.5, and 27.5, which require: “closing the first valve *after* opening the second valve” and “close the first valve *after* opening the second valve.”

200. Tolman is very clear that when one well is being stimulated, the other wells must be isolated (i.e., their valves closed). For example, Tolman explains that when first manifold well valve 214 is open and well 104a is being stimulated, second and third manifold valves 216 and 218 are closed, isolating the second and third wells:⁹²

⁹² Ex.1006, 8:56-62; *see also id.*, 4:5-16, 7:4-7, 7:21-30, 10:30-35; 13:35-40.

As an example, for the stimulation treatment to flow into the first well 104a, the main manifold valve 210 and *first manifold well valve 214* may be placed in the **open** position, while the *second manifold well valve 216* and *third manifold well valve 218* may be placed in the **closed** position to isolate the second and third wells 104b and 104c.

201. And when second manifold well valve 216 (alleged to be the claimed “second valve”) is opened to stimulate well 104b (the claimed second well), first and third manifold well valves 214 and 218 are closed, isolating the first and third wells:⁹³

It should be noted that for this stimulation operation [in second well 104b], 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.

202. Accordingly, a POSITA would not understand that first manifold well valve 214 could be the claimed “first valve” because first manifold well valve 214 is not open when second manifold well valve 216 (the claimed “second valve” is opened).

⁹³ Ex.1006, 11:15-21.

b) Tolman’s alleged “tree valve(s)” associated with flowback do not meet all limitations of the claimed “first valve.”

i. Tolman’s “tree valve(s)” associated with flowback do not communicate fluid *to the first well*.

203. In my opinion, Petitioner’s identification of an unspecified “tree valve(s)” through which fluids are flowed back does not meet the limitations of the claimed “first valve.”⁹⁴ Specifically, Petitioner alleges that “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.”⁹⁵ In my opinion, Tolman’s tree valve associated with flowback also fails to meet every limitation of the claimed “first valve.”

204. In my opinion, Tolman’s tree valve(s) associated with flowback operations fail to “communicat[e] fluid *to a first well* via a manifold,” as claim elements 1.1, 14.2, and 27.1 require. As in Tolman (and in any standard fracturing operation), tree valves used during flowback operations communicate fluid *out of a well*—not *to* a well.⁹⁶ For example, Tolman states: “flowback operations may be

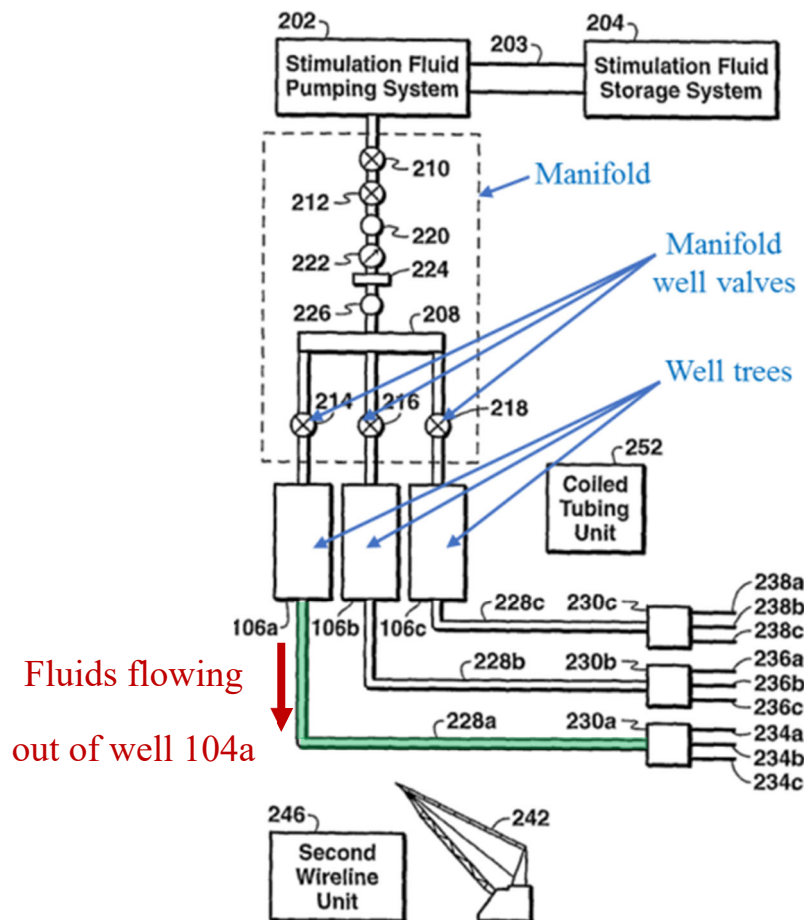
⁹⁴ Petition, 75-76.

⁹⁵ Petition, 76; Ex.1006, 6:58-61.

⁹⁶ See Ex.1006, 6:33-35 (“[T]he hydrocarbons *from the wells* 104a-104c typically flow *through the flowback manifolds* 230a-230c for further processing or sales), 8:21-23 (“Flowback operations” include “flowing back the well, manipulating choke manifold valves; producing gas to the sales line; and/or venting and flaring gas to the atmosphere.”), 11:15-30, 13:51-56.

performed to force close the proppant fractures...and recover the stimulation fluid used to form the proppant fractures...and produce hydrocarbons to the sales lines.”⁹⁷

205. In Tolman’s Fig. 2, flowback line 228A is the line through which hydrocarbons and other fluids flow out of well 104a, as illustrated below.



Ex.1006, Fig. 2 (annotated); Petition, 72

⁹⁷ Ex.1006, 10:65-11:3

206. Tolman’s “flowback” operations in Fig. 2 are consistent with how a POSITA would understand flowback operations to typically occur. For example, Tolman describes that “the wells 104a-104c produce hydrocarbons through piping 228a-228c [flowback line 228a] that is coupled between the respective oil field trees 106a-106c and the flowback manifolds 230a-230c.”⁹⁸ Accordingly, because Tolman’s tree valve associated with flowback communicates fluid *out of the first well*, it fails to meet recited “*first valve*” that communicates fluid “*to*” the first well.

ii. Petitioner fails to prove that Tolman’s controller/computer system controls the “tree valve(s).”

207. Additionally, Petitioner has not identified any controller or computer in Tolman that controls Tolman’s tree valve(s). For example, for claim elements 1.2, 14.1, 14.3, 27.3, and 27.6, Petitioner relies exclusively on evidence directed to Tolman’s *manifold well valves 214, 216, and 218*—not the tree valves.⁹⁹ However, this is not immediately clear given the Petition’s selective quoting of Tolman.

208. For claim elements 14.1 and 27.3, the portion of Tolman that the Petition relies on is quoted in full below:¹⁰⁰

⁹⁸ Ex.1006, 6:23-26.

⁹⁹ See Petition 70-77.

¹⁰⁰ Ex.1006, 14:11-22; *see also* Petition, 70-71, 73-74.

Also, the pumping system manifold **206** may include a processor based device, such as a computer system, as well. The computer system for the pumping system manifold **206** may include mechanisms to adjust the valves **210**, **214**, **216** and **218** between the open and closed positions, and communicate with the various gauges **220**, **222** and **226** and ball-sealer injector **224**. In fact, the computer systems of the stimulation fluid pumping system **202** and the pumping system manifold **206** may be configured to interact with each other to manage the pumping stimulation treatment process for the plurality of wells **104a-104c**.

209. Similarly, for claims elements 1.2, 14.3, and 27.6, the portion of Tolman that the petition relies on is quoted in full below:¹⁰¹

The pumping system manifold **206** may be coupled to any number of wells with the appropriate valves, flow measurements devices, flow control devices. With the equipment in place, the pumping system manifold **206** may be adjusted to prepare a specific well to receive the stimulation treatment, while the other wells are isolated from the stimulation treatment, as shown in block **310**. As an example, for the stimulation treatment to flow into the first well **104a**, the main manifold valve **210** and first manifold well valve **214** may be placed in the open position, while the second manifold well valve **216** and third manifold well valve **218** may be placed in the closed position to isolate the second and third wells **104b** and **104c**.

210. When read in their full context, a POSITA would understand both paragraphs reproduced above to be describing Tolman's functions and capabilities as to the *manifold valves 210, 214, 216, and 218*, and not any functionality or capability related to Tolman's "tree valve(s)."

¹⁰¹ Ex.1006, 8:50-62; *see also* Petition, 74.

211. In my opinion, Petitioner has not established that Tolman's tree valve(s) meet all elements of the claimed "first valve."

4. Tolman does not disclose that each step in the claimed valve sequence is performed "in response to determining that the fluid communicated via the manifold has satisfied one or more conditions."

212. In additions to the items noted above, the Petition also fails to show that even if Tolman described the claimed valve sequence, which it does not, that Tolman performs each of those steps "*in response to*" determining that that a single fluid condition or set of conditions has been satisfied.

213. Instead, Petitioner relies on two different "conditions" for opening the second valve and closing the first valve. For example, Petitioner contends that Tolman discloses opening a second valve (manifold well valve 216) in response treatment being complete on the first well.¹⁰² Conversely, Petitioner contends that Tolman discloses closing the first valve (tree valve) in response to flowback being complete on the first well and the first well being ready to be shut in.¹⁰³

214. In my opinion, a POSITA would not understand that Petitioner's allegations as to performing the two different valve sequences in response to two different conditions would satisfy the limitation that each of the claimed valve

¹⁰² Petition, 75-77 (claim elements 1.2-1.4, 14.3-14.5, 27.4-27.6).

¹⁰³ *Id.*

sequences be performed “in response to determining that the fluid communicated via the manifold has satisfied one or more conditions.”

5. Tolman does not teach or suggest “*closing the first valve after opening the second valve.*” (elements [1.4]/[14.5]/[27.5])

215. Petitioner identifies a flowback tree valve on Tolman’s first well 106c as the recited “*first valve.*” For the recited “*second valve,*” Petitioner identifies Tolman’s second manifold well valve 216 associated with second well 106b. Petition, 72-73. Accordingly, to meet claim elements [1.4]/[14.5]/[27.5], Tolman would have to teach or suggest *closing the first well’s tree valve after opening the second well’s manifold well valve 216*. Petitioner’s own explanation of Tolman does not demonstrate this required sequence.

216. Specifically, in the mapping of these elements, Petitioner states: “When fracturing operations are completed in the second well and fluids are flowed back through the second well, the first well is shut-in.”¹⁰⁴ However, when “fluids are flowed back in the second well,” the second well’s manifold well valve 216 (alleged “*second valve*”) must *already be closed*, as explained in the portions of Tolman cited by Petitioner.¹⁰⁵ Specifically, Tolman states that as “the second well 104b is flowed back,” and the third well 104c is being stimulated in a “concurrent operation,” the “*second manifold well valve 216 [is] in the closed*

¹⁰⁴ Petition, 77 (citing Ex.1006, 11:63-67, 46-49).

¹⁰⁵ Ex.1006, 11:63-12:13.

position to create a third well fluid flow path.”¹⁰⁶ Thus, if the first well’s tree valve (alleged “*first valve*”) is closed during shut in, which occurs when the second well is being flowed back, then the second manifold well valve 216 (alleged “*second valve*”) must necessarily already be closed—i.e., it is not closed *after* the tree valve is closed. Accordingly, Petitioner fails to establish “*closing the first valve after opening the second valve.*”

6. Petitioner’s alternative “two system” theory fails to anticipate or render obvious claim elements 1.3, 14.4, 27.4.

217. I understand that, in the Petition, the Petitioner makes an alternative argument that two or more of the Tolman systems shown in Figure 2 could be used to meet the limitation of “opening a second valve; communicating fluid to a second well via the second valve.”¹⁰⁷ Petitioner argues that “the Claims do not require ‘the second valve’ to be associated with the same manifold as ‘the first valve.’”¹⁰⁸ In my opinion, a POSITA would not read the ’770 Patent specification and claims and arrive at the understanding that two entirely separate and independent hydraulic fracturing systems, with no interdependence, could be utilized to meet the challenged claims. Such a suggestion, especially in view of the entirety of the ’770 Patent, is nonsensical.

¹⁰⁶ *Id.*

¹⁰⁷ Petition, 77.

¹⁰⁸ Petition, 77.

218. In addition to being a nonsensical hypothetical, even assuming Petitioner’s “two system” hypothetical held water (which it doesn’t), Petitioner has not provided any evidence that such a system (or combination of systems) would meet any other limitation(s) of the Challenged Claims. For example, Petitioner does not explain how or why a POSITA would be motivated to make its decision to open a second valve on second system dependent on the satisfaction of a fluid condition in the first system. In my opinion, a POSITA would not understand such a system (or combination of systems) would perform the limitations of the Challenged Claims or that a POSITA would be motivated to perform the limitations of the Challenged claims in such a way.

7. Petitioner’s alternative “injecting fluids” theory also fails to anticipate or render obvious the Challenged Claims.

219. Petitioner makes another “alternative” argument that Tolman’s disclosure of “injecting fluids” into the second well while stimulating the first well would render obvious the claimed valve sequence.¹⁰⁹ I disagree.

220. In my opinion, Petitioner’s “injecting fluids” theory does not anticipate or render obvious the Challenged Claims because it ignores that the limitation of “opening a second valve” must be performed “*in response to*” determining a condition of the fluid communicated to the first well. I have

¹⁰⁹ Petition, 78-79.

reviewed the Petitioner and Dr. Durham’s declaration and am not aware of any such evidence.

221. In my opinion Petitioner’s “injecting fluids” theory also fails on the merits. Petitioner’s reliance on “determining if a stimulation treatment is complete” on the first well for the “in response to” limitation does not apply to Petitioner’s “injecting fluids” theory.¹¹⁰ Indeed, Petitioner points to “opening a second well’s valve *during* the first well’s stimulation to allow fluid injected into the second well.”¹¹¹ However, it is logically impossible to open a second well’s valve “*during*” the first well’s stimulation in response to the first well’s stimulation being “complete.”

222. Accordingly, Petitioner’s alternative “injecting fluids” theory also does not anticipate or render obvious the Challenged Claims.

223. In my opinion, for each of the forgoing reasons, independently and collectively, Petitioner’s Grounds 7 and 8 fail to render the Challenged Claims unpatentable.

8. Dependent Claims 3, 16, 29 are not anticipated or rendered obvious by Tolman.

224. Dependent claim 3 (which is representative of dependent claims 16 and 29) recites:

¹¹⁰ See Petition, 74-75.

¹¹¹ Petition, 78-79.

2. The method of claim 2, wherein:

the first valve is closed after opening both the second valve and the fourth valve; and/or

the third valve is closed after opening both the second valve and the fourth valve.

225. In my opinion, Tolman teaches only a three well system and, thus cannot anticipate the Challenged Claims.

226. In my opinion, Tolman also does not render the Challenged Claims obvious. Like many other of Petitioner's arguments, Petitioner again fails to assert that the performed valve sequence (in this case, on a four-well system) would be performed in response to determining that any fluid condition being meet, as the Challenged Claims require.¹¹²

227. I also disagree with Petitioner's assertion that it would have been obvious to manipulate four different valves "for simultaneous and concurrent operations." Because Tolman expressly warns that an operator should *not* manipulate valves of other wells when pumping to a first well, a POSITA would understand that an operator would not operate Tolman valves in the claimed sequence.¹¹³

¹¹² Petition, 79-80.

¹¹³ See Ex.1006, 13:36–40 ("[I]f 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").

228. Accordingly, in my opinion, Tolman does not anticipate or render obvious dependent claims 3, 16, or 29.

9. Dependent Claims 5, 6, 9, 18, 19, 22, 31, and 32 are not anticipated or rendered obvious by Tolman.

229. Dependent Claims 5, 6, 9, 18, 19, 22, 31, 32 require that satisfying the one or more “flow rate conditions” requires consideration of one or more “*thresholds*” Tolman does not describe (expressly or inherently) any flow rate “threshold(s)” as understood by a POSITA.

230. For example, the determination in Tolman step 318 (“Are Planned Stimulation Treatments Complete”) is not related to the evaluation of any fluid condition (or threshold) of any individual well (let alone comparing a flow rate to any threshold). Rather, the determination in step 318 is simply whether the entire fracturing plan is complete—i.e., if the plan was to fracture 5 wells, the determination is whether all 5 wells were fractured.¹¹⁴ If complete, “then the equipment associated with the stimulation treatments may be rigged-down and moved off the surface pad 102.”¹¹⁵ And if not complete, “the pumping system manifold 206 may be adjusted to prepare for the next well.”¹¹⁶

¹¹⁴ Ex.1006, 9:17-19.

¹¹⁵ *Id.* 9:39-42.

¹¹⁶ *Id.*, 9:17-22.

231. Dr. Durham argues that it would be obvious to a POSITA that the “determining” step relates to a flow rate threshold—i.e., determining if stimulation fluid flow into the first well had stopped.¹¹⁷ But Dr. Durham provides no evidence or explanation in support of his theory. Tolman also directly contradicts Dr. Durham’s theory—Tolman’s step 318 determination is *not made on a well-by-well basis*; rather, it is simply a project-based question: are we “done” or “not done” with the overall fracturing plan?¹¹⁸

232. Accordingly, Tolman does not anticipate or render obvious claims 5, 9, 18, 22, and 31.

IX. SECONDARY CONSIDERATIONS OF NON-OBVIOUSNESS

A. Downing’s Freedom Series Completion System implements the claimed invention.

233. I understand that Patent Owner (“Downing”) has a commercial completion system called the Freedom Series Completion System (“Freedom Series”). Based on my review of Downing’s two webpages—an initial webpage from October 2020 and a current webpage from September 2024¹¹⁹—describing the Freedom Series’, and my conversation with Tim Marvel, Vice President of

¹¹⁷ Ex.1002, ¶591.

¹¹⁸ Ex.1006, 9:17-48.

¹¹⁹ Ex.2001; Ex.2014.

Business Development and Technology at SEF Energy, it is my opinion that the Freedom Series implements the CP swap feature claimed in the '770 Patent.

234. Downing's October 2020 webpage describes the Freedom Series' ability to enable continuous pumping operations. In describing the Freedom Series, Downing's webpage describes:

[T]he 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 and the total time between stages measured at treatment pressure is as fast as 40 seconds.¹²⁰

235. The '770 Patent contains a nearly identical disclosure. When describing the CP swap feature, the '770 Patent specification describes:

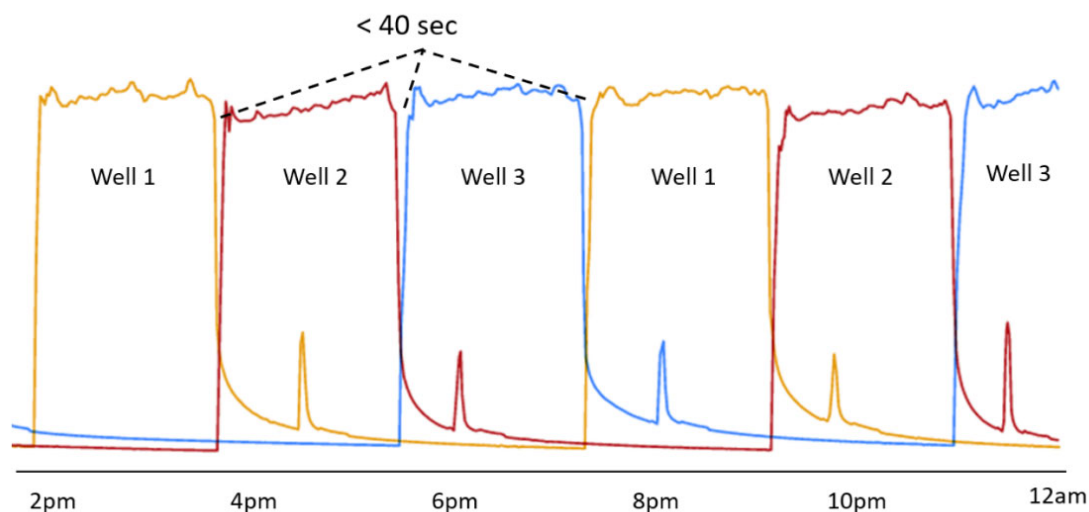
“[E]xecuting the CP swap from hydraulically fracturing [] the n1 well [] to hydraulically fracturing [] the n1+1 well [] transitions the zipper valves from one well to the other, opening the second well and subsequently shutting-in the first well, all while pumping. The transition is instantaneous and the total time between stages measured at treatment pressure is less than 20 seconds (as fast as 19 seconds in some instances).”¹²¹

236. Similarly, the '770 Patent and Downing's webpages display nearly identical figures representing fluid condition data generated from an actual CP

¹²⁰ Ex.2001, 1.

¹²¹ Ex.1001, 14:43-50.

swap being performed. Below is a color figure from Downing's October 2020 webpage showing the transition from one well to the next during, what I understand was, the Freedom Series performing an actual CP swap:¹²²



And below is Figure 16D from the '770 Patent, showing the same thing:¹²³

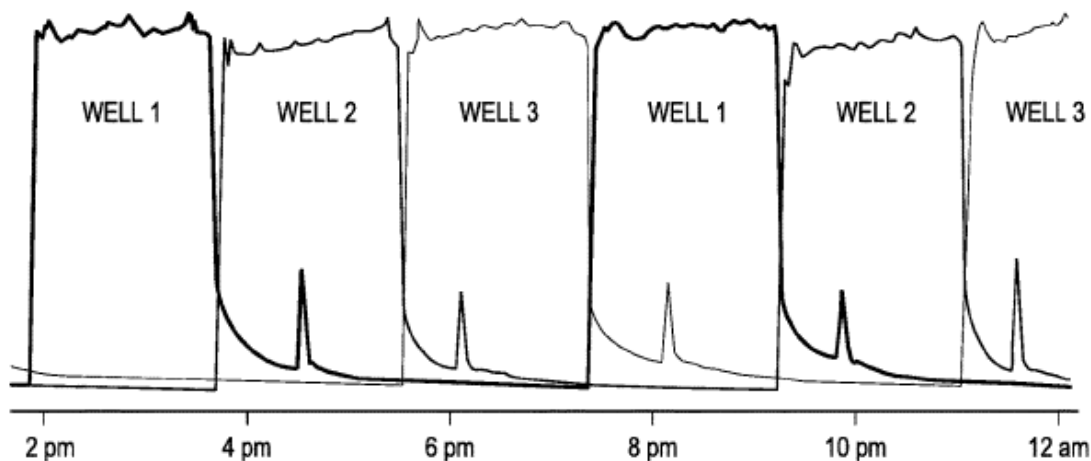
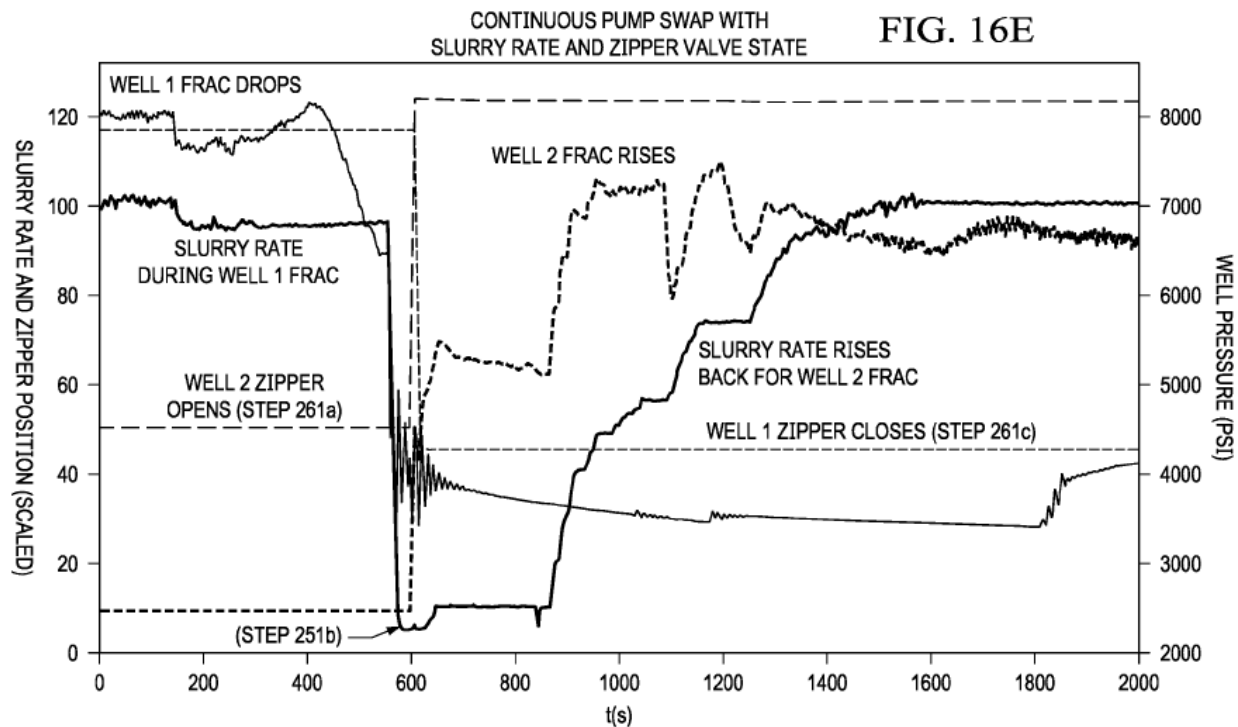


FIG. 16D

¹²² Ex.2001, 2.

¹²³ Ex.1001, Fig. 16D.

237. '770 Patent Figure 16E is a zoomed in version of Figure 16D (focusing on the transition between well 1 and well 2) showing each of the claimed steps being performed, including the claimed valve sequence in response to a fluid condition (e.g., flow rate) being satisfied:¹²⁴



238. Downing’s October 2020 website further confirms that the Freedom Series performs the claimed CP swap. For example, as mentioned above, Downing’s website describes that during hydraulic fracturing operations, the Freedom Series “transition[s] the zipper valves from one well to the other, opening the second well and subsequently shutting-in the first well, all while pumping.”¹²⁵

¹²⁴ Ex.1001, Fig. 16E.

¹²⁵ Ex.2001, 1.

Further, the figures in the '770 Patent and Downing's website illustrate that the fluid conditions associated with a first well (e.g., "Well 1") determine when a valve on a second well (e.g., "Well 2") can open. In each transition, the second well's valve opens when the fluid pressure in the first well drops.

239. Based on my review of the '770 Patent, Downing's webpages, and my conversation with Mr. Marvel, it is my opinion that the Freedom Series implements the CP swap feature claimed in the '770 Patent.

B. The claimed CP swap feature enables continuous pumping in the Freedom Series and provides significant benefits.

240. In my opinion, it is also the claimed CP swap feature that enables continuous pumping in the Freedom Series. The process of having the first valve open, then opening the second valve and closing the first valve in response to satisfying a fluid condition in the manifold, allows the pumps to keep running when transitioning between wells. As I previously discussed, performing the traditional method of transitioning between wells by opening and then closing a first valve, and then opening and closing a second valve, requires shutting down the pumps for safety and equipment preservation reasons.¹²⁶ The Freedom Series' continuous pumping capability cannot occur without performing the claimed CP swap.

¹²⁶ See *supra* ¶¶ 110–111, 151.

241. Indeed, as recognized by Downing's webpages, it is the CP swap feature that enables "instantaneous" transitions when switching wells, effectively eliminating NPT.¹²⁷ If a typical zipper fracturing operation has 5 wells, with an average of 60 stages per well, implementing the CP swap feature can save as much as 15 hours per well and 75 hours of NPT per project, resulting in more efficient operations and faster completions.

X. CONCLUSION

242. 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: September 19, 2024


John Hughett

¹²⁷ Ex.2001, 1; Ex.2014, 1.