

**IN THE UNITED STATES PATENT AND TRADEMARK OFFICE
BEFORE THE PATENT TRIAL AND APPEAL BOARD**

In re U.S. Patent No. 11,373,058 B2

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Assignee: Halliburton Energy Services, Inc.

Title: System and Method for Treatment Optimization

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I, Michael Nikolaou, make this declaration in connection with the petition for post grant review submitted by Petitioners for U.S. Patent No. 11,373,058. All statements made herein of my own knowledge are true, and all statements made herein based on information and belief are believed to be true. Although I am being compensated for my time in preparing this declaration, the opinions expressed herein are my own, and I have no stake in the outcome of this proceeding or any related litigation or administrative proceedings.

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I. INTRODUCTION

1. I am making this declaration at the request of ProFrac Holding Corp. and U.S. Well Services, LLC (collectively, “Petitioners”) in the matter of the Post Grant Review of U.S. Patent No. 11,373,058 (the “’058 patent”) to Jaaskelainen et al., assigned to Halliburton Energy Services (“Patent Owner” or “Halliburton”). I understand that Petitioners have been sued by Patent Owner in *Halliburton Energy Services et al. v U.S. Well Services, LLC, Profrac Holding Corp.*, Case No. 6:22-cv-00906 (W.D. Tex.), where it has accused Petitioners of infringing the ’058 patent.

2. In the preparation of this declaration, I have reviewed the following documents:

Exhibit No.	Description
1001	U.S. Patent No. 11,373,058
1002	File History of U.S. Patent No. 11,373,058
1004	Curriculum Vitae of Dr. Michael Nikolaou
1005	U.S. Patent App. Pub. No. 2018/0230782 to Pankaj et al.
1006	U.S. Patent App. Pub. No. 2016/0258267 to Payne et al.
1007	S. Dalvi, Fundamentals of Oil & Gas Industry for Beginners (Notion Press 2015) (excerpts)
1008	U.S. Patent App. Pub. No. 2013/0306322 to Sanborn et al.
1009	U.S. Patent No. 9,410,410 to Broussard et al.
1010	U.S. Patent App. Pub. No. 2012/0255734 to Coli et al.
1011	U.S. Patent No. 10,020,711 to Oehring et al.
1012	U.S. Patent App. Pub. No. 2008/0236818 to Dykstra et al.
1013	U.S. Patent App. Pub. No. 2006/0015310 to Husen et al.
1014	U.S. Patent App. Pub. No. 2016/0061003 to Gottumukkala et al.
1015	U.S. Patent No. 10,280,722 to Bello et al.

Exhibit No.	Description
1016	Print-Out from the Internet Archive at: https://web.archive.org/web/20180728025208/https://www.mayoclinic.org/tests-procedures/allergy-tests/about/pac-20392895
1017	U.S. Patent No. 5,809,428 to Garahi et al.
1018	U.S. Patent App. Pub. No. 2006/0015310 to Rashid et al.
1019	U.S. Patent No. 8,352,227 to Klumpen et al.
1020	U.S. Patent No. 7,953,585 to Gurpinar et al.
1021	U.K. Patent App. GB 2443051 to Varadarajan et al.
1022	Did not review
1023	PCT International Pub. No. WO 2018/084871 to Madasu et al.
1024	U.S. Patent No. 10,378,333 to Dawson et al.
1025	Did not review
1026	Did not review
1027	U.S. Patent No. 10,087,722 to Lecerf et al.
1028	T. Jacobs, These Five Companies are Reinventing the U.S. Frac Fleet, <i>Journal of Petroleum Technology</i> (July 31, 2019)
1029	Website Printout, Internet Archive (U.S. Well Services) at: https://web.archive.org/web/20151121102607/http://uswellservices.com/
1030	Excerpt from <i>Petrophysics Theory and Practice of Measuring Reservoir Rock and Fluid Transport Properties</i> , Gulf Professional Publishing, 2015.

3. In forming my opinions expressed below, I have considered the documents listed immediately above and my knowledge and experience based on my work in this area as described below.

4. The earliest application that resulted in the issuance of the '058 patent was filed on September 17, 2019. Ex. 1001, Cover. I am familiar with the technology at issue and am aware of the state of the art around this time. It is my opinion that, as of September 17, 2019, a person of ordinary skill in the art

(“POSITA”) pertinent to the subject matter of the ’058 patent would have had at least a bachelor of science in chemical engineering, mechanical engineering, materials science, or metallurgical engineering or an equivalent field and at least two years of academic or industry experience in the oil and gas industry, including experience with process control systems. Further, it is my opinion that someone with additional education but less professional experience, and vice versa, may qualify as a POSITA. My analysis and opinions below are given from the perspective of a POSITA in this technological field in the relevant time frame, unless stated otherwise.

II. QUALIFICATIONS AND COMPENSATION

5. I am a Professor and Associate Chair of Chemical and Biomolecular Engineering in the Cullen College of Engineering at the University of Houston.

6. I graduated with a diploma in chemical engineering from the National Technical University in Athens, Greece in 1984. I then earned a Ph.D. in chemical engineering at the University of California, Los Angeles in 1989. Prior to coming to the University of Houston, I was an Assistant (and then Associate) Professor at Texas A&M University for eight years. After my promotion to Associate Professor and tenure at Texas A&M, I took a sabbatical leave as a Visiting Scientist at MIT. I have taught at the University of Houston for over 20 years.

7. In my role as a professor at the University of Houston I teach both undergraduate and graduate courses every year. At the undergraduate level, these courses include Analytical Methods for Chemical Engineers, Numerical Methods for Chemical Engineers, Plant Economics, Plant Design, Thermodynamics, Statistical Methods in Chemical Engineering, Statistical Quality Control Methods, and Chemical Process Control. At the graduate level, I teach Mathematical Methods in Chemical Engineering, Advanced Process Control, and Natural Gas Engineering. I also routinely advise both undergraduate and graduate (master and Ph.D.) students.

8. I have extensive experience in process systems engineering and mathematical modeling. My research interests are in computer-aided systems engineering, i.e., development and use of computer-based methods for the design, optimization, monitoring, and automatic control of various kinds of systems, in a diverse array of industries, including the oil and gas industry.

9. In my 30 years of academic and industrial consulting experience I have worked on problems in several industries, including the oil and gas industry and oil refining and petrochemicals. Much of my work tackles fundamental research issues and is described in a number of publications, as discussed below. A substantial portion of my work is directed to concrete solutions to problems faced by industrial partners and has resulted in specific commercial products (e.g., for

Lam Research, <https://www.lamresearch.com/>), patents, and the formation (by the corresponding project's managers) of a small company that was eventually bought by Schlumberger, a major global oilfield services company (http://www.slb.com/services/drilling/drilling_services_systems/directional_drilling/slider.aspx).

10. In addition to teaching, I have also served as a consultant for various oil and gas companies over the past 27 years, working with both major companies and smaller, independent companies, both “upstream” (i.e., oil and gas exploration and production) and “downstream” (oil and gas transportation, oil refining, and chemicals). I have consulted on a variety of matters for ENI, Schlumberger, WildHorse / RotoSlide, Synergy Fluid Services, XGas/EPT, IQPC Oil & Gas, Intelligent Agents Corporation, Landmark, ECOPETROL, Lam Research, Shell Global Solutions, Noble Drilling, AspenTech, General Electric, Simulation Sciences, Bryan Research & Engineering, Frito-Lay, Shell Development, and Union Pacific Resources.

11. I have published over 150 peer-reviewed publications in journals and conference proceedings in the area of computer-aided systems engineering. My publications focus on applications to the design, optimization, monitoring, and automatic control of various kinds of systems, in oil and gas, oil refining and petrochemicals, snack food production, semiconductor manufacturing, and

development and administration of antibiotics against resistant infections. Three of my refereed journal publications have been featured on the cover of high-impact journals (*AIChE Journal*, 2011; *IEEE Control Systems Magazine*, 2006; *PLoS Computational Biology*, 2011).

12. I have also presented my work as a speaker at numerous academic conferences, whether in regular sessions, invited sessions, or as a keynote speaker. As an example, I have been invited twice (in 1996 and 2011) to give presentations in the flagship conference on Chemical Process Control, held every five years (CPC-V and CPC-VIII), and was a keynote speaker at the 2017 International Petroleum & Petrochemical Technology Conference (IPPTC) in Beijing, China. I have also published five book chapters on various aspects of computer-aided systems engineering. Finally, I serve regularly as a peer reviewer at several major engineering and scientific journals (including *Automatica*, *PLoS*, *AIChE Journal*, *SPE Journal*, *Journal of Process Control*, *Computers & Chemical Engineering*) as well as at federal and international funding agencies, including National Science Foundation (NSF), Petroleum Research Fund (PRF), National Institutes of Health (NIH), and the Qatar National Research Fund (QNRF).

13. I am a member of the American Institute of Chemical Engineers, the Society of Petroleum Engineers, and Omega Chi Epsilon. I serve as a co-organizer

or co-chair of several major international conferences, including the AIChE Annual Meeting and the AIChE Spring Meeting.

14. I have received numerous teaching awards from both Texas A&M and University of Houston, including the Dow Excellence in Teaching Award, and the Cullen College of Engineering Teaching Award. I have also been named a Top Reviewer by *Automatica*, and, in 2007, I received the Computing & Systems Technology (CAST) Directors Award from the American Institute of Chemical Engineering. In 2017, I received the Abraham E. Dukler Distinguished Engineering Faculty Award at the University of Houston, which is given to a faculty that has made significant contributions to society and whose accomplishments and careers have brought credit to the University of Houston Cullen College of Engineering. In 2019, I received the Fluor Corp. Faculty Excellence Award at the Cullen College of Engineering. This award is the highest distinction bestowed to faculty of this college.

15. My curriculum vitae, which includes a complete list of my publications, is included as EX-1004.

16. I have previously given testimony in the following cases:

a) *Eurecat United States, Inc. v. Soren Marklund, Douglas Wene, and Chem 32 LLC*, Trial Ct. Cause No. 2012-5700, Harris Cty. Ct. (Tex.).

b) *TDE Petroleum Data Solutions, Inc. v. AKM Enterprise, Inc. DBA Mobilize, Inc.*, Case No. 4:15-cv-01821 (S.D. Tex. 2015).

c) *Arrona et al. v. Bluestone Natural Resources, LLC*, Case No. 4:15-cv-02680 (S.D. Tex. 2017).

d) *Sunoco Partners Marketing & Terminals L.P. v. Powder Springs Logistics, LLC, et al.*, Case No. 1:17-cv-01390 (D. Del. 2017).

e) *Magellan Midstream Partners L.P. v. Sunoco Partners Marketing & Terminals*, Case No. IPR2019-00024 (U.S. Patent No. 9,494,948).

f) *Magellan Midstream Partners L.P. v. Sunoco Partners Marketing & Terminals*, Case No. IPR2019-00025 (U.S. Patent No. 9,606,548).

17. I am being compensated in this matter at my standard consulting hourly rate of \$700 per hour. My compensation is not dependent on the substance of my statements in this declaration.

18. I am over the age of 18 and am competent to write this declaration. I have personal knowledge, or have developed knowledge, of the technologies discussed in this declaration based upon my education, training, or experience with the matters discussed herein.

III. RELEVANT LEGAL STANDARDS

A. Obviousness

19. I understand that obviousness is analyzed from the perspective of a POSITA at the time of the alleged invention. I also understand that a POSITA is presumed to have been aware of all pertinent prior art at the time of the alleged invention.

20. I understand that an obviousness analysis involves comparing a claim to the prior art to determine whether the claimed invention as a whole would have been obvious to a POSITA in view of the prior art and in light of the general knowledge of the art at the time the invention was made. I also understand that the invention may be deemed obvious when a POSITA would have reached the claimed invention through routine experimentation.

21. I understand that obviousness can be established by combining or modifying the disclosures of the prior art to achieve the claimed invention. It is also my understanding that where there is a reason to modify or combine the prior art to achieve the claimed invention, there must also be a reasonable expectation of success in so doing to render the claimed invention obvious. I understand that the reason to combine prior art references can come from a variety of sources, not just the prior art itself or the specific problem the patentee was trying to solve. I also understand that the references themselves need not provide a specific hint or

suggestion of the alteration needed to arrive at the claimed invention; the analysis may include recourse to logic, judgment, and common sense available to a POSITA.

22. I understand that when there is some recognized reason to solve a problem, and there are a finite number of identified, predictable solutions, a POSITA has good reason to pursue the known options within his or her technical grasp. If such an approach leads to the anticipated success, it is likely the product not of innovation but of ordinary skill and common sense. In such a circumstance, when a patent simply arranges old elements with each performing the same function it had been known to perform and yields no more than one would expect from such an arrangement, the combination is obvious.

23. I understand that when considering the obviousness of an invention, one should also consider whether there are any objective indicia that support the non-obviousness of the invention. I further understand that objective indicia of non-obviousness, also known as “secondary considerations,” include failure of others, copying, unexpected results, information that “teaches away” from the claimed subject matter, perception in the industry, commercial success, and long-felt but unmet need. I also understand that for objective indicia of non-obviousness to be applicable, the indicia must have some sort of nexus to the subject matter in the claim that was not known in the art. I understand that this nexus includes a

factual connection between the patentable subject matter of the claim and the objective indicia alleged. I also understand that an independently made invention that is made within a comparatively short period is evidence that the claimed invention was the product of ordinary skill.

24. Finally, I understand that patent examiners at the U.S. Patent and Trademark Office (“PTO”) rely upon certain exemplary rationales in reviewing patent applications to understand whether the subject matter of the claims is obvious. I understand that the following is the list of exemplary rationales relied upon by patent examiners at the PTO: (i) combining prior art elements according to known methods to yield predictable results; (ii) simple substitution of one known element for another to obtain predictable results; (iii) use of a known technique to improve similar devices (methods, or products) in the same way; (iv) applying a known technique to a known device (method, or product) ready for improvement to yield predictable results; (v) “obvious to try”—choosing from a finite number of identified, predictable solutions, with a reasonable expectation of success; and (vi) known work in one field of endeavor may prompt variations of it for use in either the same field or a different one based on design incentives or other market forces if the variations are predictable to one of ordinary skill in the art.

B. Construing the Meaning of Claim Terms

25. I understand that a post grant review (“PGR”) is a proceeding before the PTO for evaluating the validity of issued patent claims. I understand that, in a PGR, a claim term is interpreted in a manner consistent with the standard used in patent litigation, as set forth in a case known as *Phillips v. AWH Corp.*, 415 F.3d 1303 (Fed. Cir. 2005) (en banc). That standard generally construes the claims according to their “ordinary and customary” meaning in view of the claim language, specification, file history, and, where applicable, relevant other evidence.

26. I understand that a patent’s “specification” includes all the figures, written descriptions, and claims within the patent. I understand that the PTO will look to the specification and prosecution history to see if there is a definition for a given claim term and, if not, will apply the ordinary and customary meaning from the perspective of a POSITA at the time in which the alleged invention was made.

27. As discussed above and detailed in my curriculum vitae, I was very familiar with hydraulic fracturing processes at both the individual well and oil-field level, as well as control systems for such processes and well treatment methods, technologies and was aware of the state of the art as of the earliest claimed priority date of the ’058 patent. I believe that I would qualify as understanding the knowledge and skill of a POSITA as of September 17, 2019, and I have a sufficient

level of knowledge, experience, and expertise to provide an expert opinion in the field of the '058 patent.

IV. BACKGROUND OF THE TECHNOLOGY

28. The following paragraphs regarding hydraulic fracturing are based on prior art to the '058 patent. For purposes of this declaration, I have been asked to assume that the earliest priority date of the '058 patent is September 17, 2019.

29. The specification of the '058 patent acknowledges that electric frac pumps were known prior art in the background section: “[i]n the oil and gas industry, electric frac pumps are often controlled in order to achieve certain downhole environment responses.” Ex. 1001, 1:11–13. After describing how electric frac pumps were typically used in the industry, the '058 patent states “[i]t is with these observations in mind, among others, that aspects of the present disclosure were concerned and developed.” *Id.*, 1:27–29. It is, therefore, appropriate to examine the state of the art regarding the following three sections—that is, (i) Oil and Gas Extraction from Wells, (ii) Hydraulic Fracturing, and (iii) Control Systems for Hydraulic Fracturing Operations—before the assumed September 17, 2019 priority date of the '058 patent.

A. Oil and Gas Extraction from Wells

30. Retrieving hydrocarbons, such as oil and gas, from the earth has been done for centuries. *See* S. Dalvi, *Fundamentals of Oil & Gas Industry for*

Beginners (Notion Press 2015) (“Dalvi”) (EX-1007.013) (disclosing that oil drilling began in Azerbaijan in 1848, and two large pipelines hundreds of kilometers long were built to transport oil from the wellsites). The process starts with searching for potential petroleum reservoirs. These oil and gas reservoirs are subsurface pools of hydrocarbons contained in porous rock formations. They formed when the naturally occurring hydrocarbons were trapped among rock formations with lower permeability. Oil and natural gas are contained in the tiny pore spaces in these rocks similar to how water is contained in a sponge. *Id.*, 029.

31. Most reservoirs generally contain oil, gas, and water. Because of gravity, these fluids separate according to their density—that is, gas on top, followed by oil, and then water. *Id.*, 030. After discovering a reservoir, the rock formation is punctured by drilling a bore through it followed by tubing being inserted into the rock to extract the hydrocarbons. *Id.*; *see id.*, 056 (“An oil well can also be described as a hole pierced through reservoir rock and pipes inserted to extract the hydrocarbon content of the reservoir.”). Early on, oil wells were drilled by hammering a cable tool into the earth. But these were soon replaced by rotary drills, which could drill boreholes to much greater depths in less time. *Id.*, 057. Drilling equipment on a wellsite is referred to as a rig. *Id.*

32. Oil wells are nowadays typically drilled at an angle other than vertical to reach different parts of the formation, which is referred to as deviation drilling.

Id., 067. Drilling this way makes it possible to reach subsurface areas laterally remote from the point where the drill bit enters the earth. A well that has sections more than 80 degrees from vertical is called a horizontal well, which can extend for a number of kilometers and thus achieve higher production. *Id.* The image below illustrates deviation drilling:

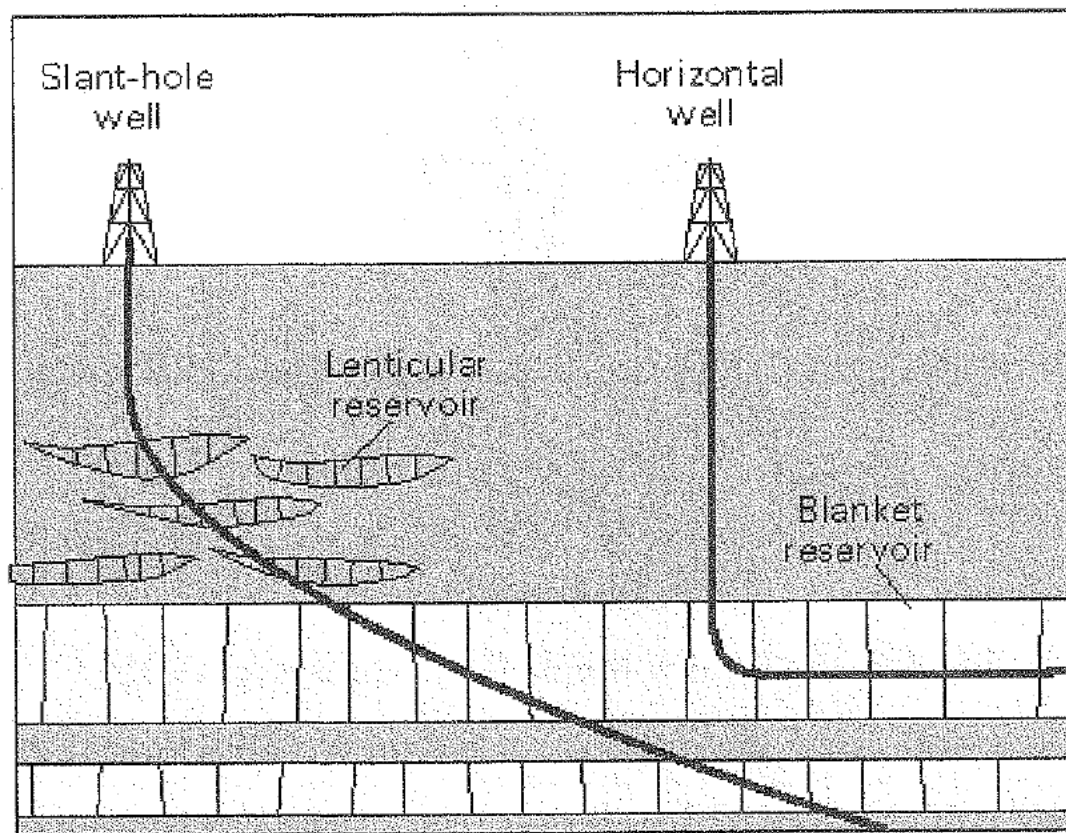


Fig.3.9: 37p Deviation Drilling for drilling at an angle

Dalvi, Fig. 3.9.37 p – Drilling at an Angle (EX-1007.067)

33. After the well is drilled, it needs to be cased. Part of this process includes reinforcing and providing structural integrity to the well, creating a barrier

to debris falling into the well. *Id.*, 059. At this point, underground formations have sufficient pressure to cause the hydrocarbons to come to the surface on their own. *Id.*, 074. Once the well is cased, the well opening is closed at the surface by installing the wellhead and production tree, which control the formation pressure and flow. *Id.* The production tree is connected to a network of pipes that carries the oil/gas to a metering station, and from there to tanks for supplying product to refineries or natural gas compressor stations. *Id.*, 075.

34. Next, a well engineer measures data from the well to determine the maximum amount of hydrocarbons that the well can produce in a 24-hour period. *Id.*, 074. This data is used to determine the “most efficient recovery rate,” or “MER.” As hydrocarbons are extracted, the MER will decline because the reservoir will lose its pressure. This is known as the “decline rate.” *Id.* Using this information, calculations can be made to determine when the well will need enhanced recovery methods in its lifespan. *Id.* A well will also need “treatment” to ensure a smooth flow of hydrocarbons. The treatment may include injecting acid, water, or gases into the well to open up the formation and allow the petroleum to flow through the formation more easily. *Id.*

B. Hydraulic Fracturing

35. Hydraulic fracturing—commonly called “frac’ing”—is a process for increasing the flow of oil or gas from a well. U.S. Patent Appl. Publ’n

No. 2013/0306322 (“Sanborn”), ¶ 0003 (EX-1008). This process has been in use for decades. U.S. Patent No. 9,410,410 [1:8–14] (“Broussard”) (EX-1009).

Frac’ing involves pumping fluid into a well under high enough pressures to fracture the rock formation and form fissures therein. Sanborn, EX-1008, ¶ 0003; Broussard, EX-1009 [1:14-21]. Fissures or openings create space to allow oil and gas to move through the wellbore to the surface. Sanborn, EX-1008, ¶ 0003.

Sanborn describes this process as follows:

A hydraulic fracture is typically formed by pumping the fracturing fluid into the wellbore at a rate sufficient to create a downhole pressure that exceeds the fracture gradient of the surrounding rock. The rock cracks, and the fracture fluid continues farther into the rock, extending the crack into the depth of the well. Often, a proppant . . . is added into the injected fluid, to prevent the fractures from closing when the injection is stopped. The fracture that remains open is permeable enough to allow the flow of the desired gas or oil to the well, and eventually, to the surface for collection.

Id., ¶ 0004. One commonly-used example of a proppant is sand. *Id.*, ¶ 0026; Broussard, EX-1009 [4:46-50].

36. The proppant and fluid are typically mixed together (along with other additives) using a blender to form a “slurry” or “fracturing fluid.” This slurry or fracturing fluid is then pumped into the wellbore. Broussard, EX-1009 [2:48-54], [4:48-67], [6:54-58]; Sanborn, EX-1008, ¶ 0005 (describing the “injection and movement of the slurry (water, proppants, and chemical additives), through

thousands of feet of earth and rock”); ¶ 0036 (“Pre-selected proportions of the fracturing fluid components (including chemical additives) and proppants are directed into at least one blender/mixing unit. . . .”); *see* U.S. Patent Appl. Publ’n No. 2012/0255734 (“Coli”), EX-1010, ¶ 0035 (“In a conventional fracturing operation, a ‘slurry’ of fluids and additives is injected into a hydrocarbon bearing rock formation at a wellbore to propagate fracturing. . . . The majority of the fluids injected will be flowed back through the wellbore and recovered, while the sand will remain in the newly created fracture, thus ‘propping’ it open and providing a permeable membrane for hydrocarbon fluids and gases to flow through so they may be recovered.”).

37. Hydraulic fracturing operations require large-scale equipment and massive amounts of fracturing fluid components, such as water, proppants, and other additives, on-site at the well. Sanborn describes equipment typically used during hydraulic fracturing operations:

Hydraulic fracturing equipment that is used in oil and natural gas fields includes a large number of components. Blenders, high-volume fracturing pumps, monitoring units, material tanks, hoses, electronics systems, and power units are just some of the components required for these operations. In a typical fracturing operation currently practiced, a large number of tractor trailers are used to support individual sets of diesel engines and fracturing pumps, along with associated equipment, such as transmission systems.

Sanborn, EX-1008, ¶ 0005; *see also* ¶¶ 0025-0031 (describing in detail the equipment and materials needed at a fracturing site). For fracturing fluid materials, Sanborn describes that hydraulic fracturing operations need “supply containers for fracturing fluid components” (¶ 0026) and “blending equipment for blending the fracturing fluid/solid components” (¶ 0027); *see* Broussard, EX-1009[6:4-10] (describing the need for “sand transporting vehicles,” “acid transporting vehicles,” “hydration units,” “blenders,” “water tanks,” “conveyor belts,” and other equipment). Both Sanborn and Broussard include figures illustrating some of the trucks and equipment needed on a typical hydraulic fracturing wellsite. Figure 1 of Sanborn shows as much and is reproduced below:

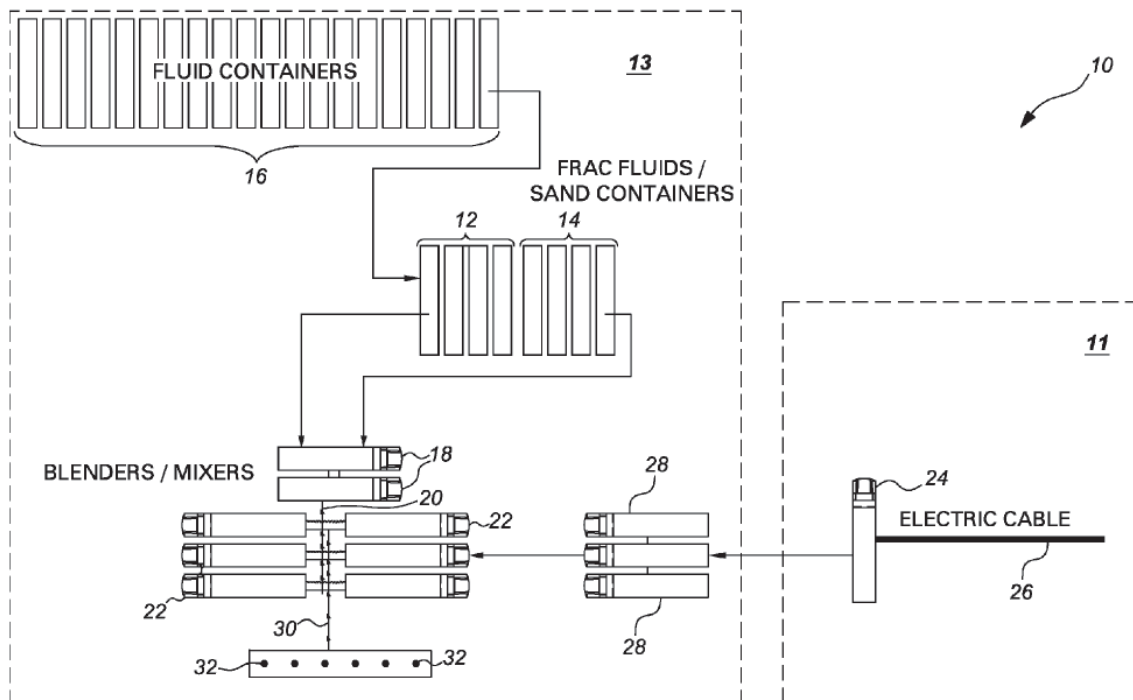


Fig. 1

Sanborn, Fig. 1 (EX-1008)

As shown in Figure 1 above, Sanborn discloses that a wellsite includes multiple tractor trailers (18, 22, 28) and containers (12, 14, 16) holding the equipment and fluid components, with the wellheads represented by element 32. *Id.*, ¶¶ 0034, 0036, 0038, 0040, 0043.

38. Broussard similarly shows a representative hydraulic fracturing site in Figure 1, reproduced below:

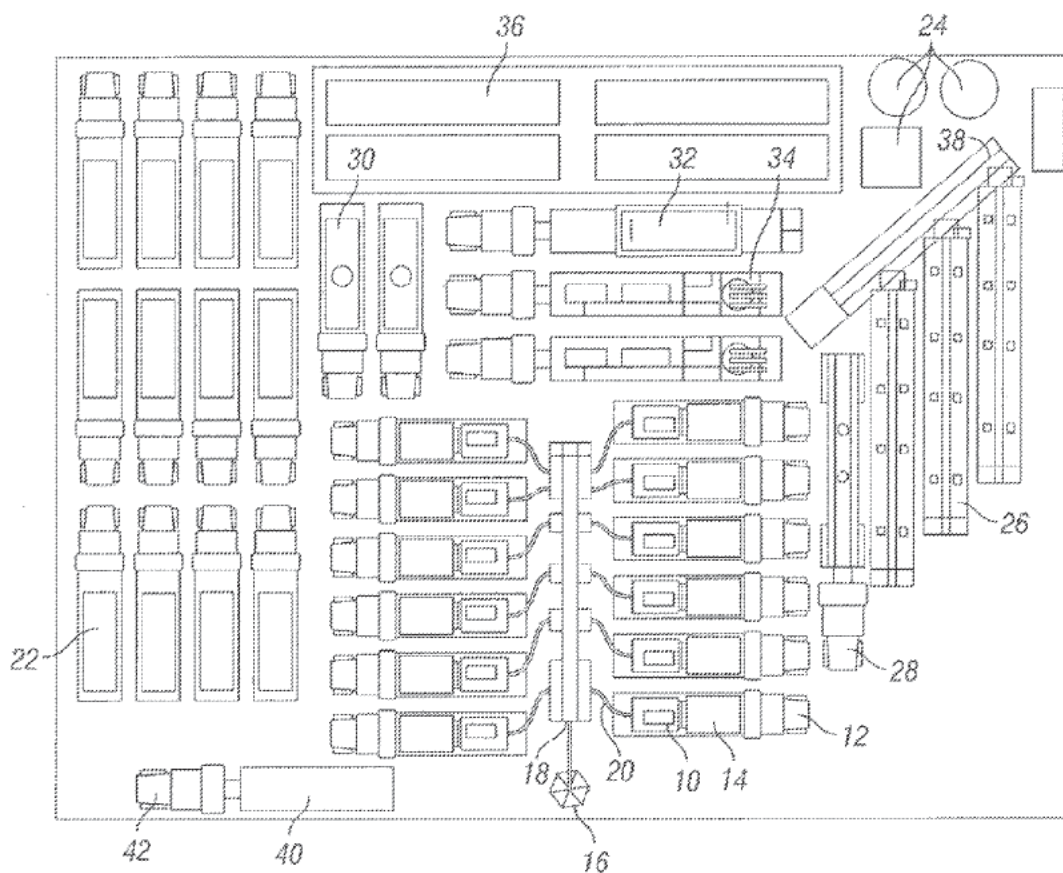


FIG. 1

Broussard, Fig. 1 (EX-1009)

In describing the above figure, Broussard states, “[T]here is shown a plurality of pumps 10 mounted to pump vehicles 12. The pump vehicles 12 can be trucks

having at least five axles. . . . The pumps 10 are fluidly connected to the wellhead 16 via the missile 18. . . . The missile 18 is then connected to the wellhead 16 and configured to deliver fracturing fluid provided by the pumps 10 to the wellhead 16.” *Id.* [3:19-30]. In addition, Broussard explains that Figure 1 depicts “sand transporting vehicles 26, an acid transporting vehicle 28, vehicles for transporting other chemicals 30, and a vehicle carrying a hydration unit 32, such as, for example, a water pump. Also shown are fracturing fluid blenders 34, which can be configured to mix and blend the components of the hydraulic fracturing fluid, and to supply the hydraulic fracturing fluid to the pumps 10.” *Id.* [4:60-67].

39. Hydraulic fracturing operations also require powerful pumps. Typically, multiple pumps are used at each wellsite. Sanborn provides as “one example, 16 tractor trailers may support 16 diesel-powered, 2000 hp fracturing pumps. . . . High-capacity, high-power hydraulic pumps (e.g., triplex or quintuplex types) are commercially available from a number of sources.” Sanborn, EX-1008, ¶ 0005; *see* Coli, EX-1010, ¶ 0007 (stating that “average fracturing operations” may require “as many as fifty fluid pumps”). These high-power pumps require commensurately high-power motors, or “prime movers,” to drive them. Conventional systems typically used diesel fueled motors for this purpose. Coli, EX-1010, ¶ 0005 (stating that “pumping systems are typically mobilized on skids or tractor-trailers and powered using diesel motors”), ¶ 0035 (describing in

conventional fracturing operations using “multiple high pressure, plunger style pumps driven by diesel fueled prime movers”); Sanborn, EX-1008, ¶ 0005 (“In a typical fracturing operation currently practiced, a large number of tractor trailers are used to support individual sets of diesel engines and fracturing pumps. . . .”).

40. Diesel-powered fracturing systems, however, had a “number of drawbacks.” *Id.*, ¶ 0006. As Sanborn explains, the “mechanical collection of many diesel engines and many pumps can lead to high inefficiencies in the overall pumping operation. Part of this inefficiency is due to maintenance requirements for each of a multitude of engines, and the potential for engine break-downs.” *Id.* These systems further require “large amounts of diesel,” which led to “potential safety, noise, and environmental problems.” *Id.*, ¶ 0007. For example, the number of tractor-trailers required for diesel-powered systems created a “large and undesirable ‘footprint’ at the drilling/fracturing site. (Since the use of diesel engines mandates the use of diesel fuel, additional space is required for diesel fuel tankers). This . . . also has significant ‘community impact’, in terms of traffic congestion and road-surface wear and tear.” *Id.*; Coli, EX-1010, ¶ 0007 (noting the “footprint” to accommodate diesel-powered fracturing operations is “massive,” and the “operational infrastructure require[ed] to support these fracturing operations is extensive”), ¶ 0008 (“[O]ne major logistical concern is the availability of diesel fuel. The excessive volumes of diesel fuel required necessitates constant

transportation of diesel tankers to the site, and results in significant carbon dioxide emissions.”).

41. U.S. Patent No. 10,020,711 (“Oehring”)(EX-1011) described known issues with diesel-powered systems:

[T]he fracturing equipment is powered by large diesel motors. . . . Such engines may be very powerful, but have certain disadvantages. Diesel is more expensive, is less environmentally friendly, less safe, and heavier to transport than natural gas. For example, diesel engines are very heavy, and so require the use of a large amount of heavy equipment, including trailers and trucks, to transport the engines to and from a well site. In addition, such engines are not clean, generating large amounts of exhaust and pollutants that may cause environmental hazards. . . . Onsite refueling, especially during operations, presents increased risks of fuel leaks, fires, and other accidents. The large amounts of diesel fuel needed to power traditional fracturing operations require constant transportation and delivery by diesel tankers onto the well site, resulting in significant carbon dioxide emissions.

Oehring, EX-1011 [1:43-59].

42. Based on the above disclosures, a POSITA would have understood that the industry was looking for ways to reduce the reliance on diesel fuel. One proposed solution was to “decrease fuel consumption and emissions by running large pump engines on ‘Bi-fuel’, blending natural gas and diesel fuel.” Coli, EX-1010, ¶ 0008; Oehring, EX-1011 [1:60-61] (“Some systems have tried to eliminate partial reliance on diesel by creating bi-fuel systems.”). Another now

well-known solution was to substitute electric motors for diesel ones. Broussard, EX-1009 [1:8-11] (“This technology relates to hydraulic fracturing in oil and gas wells. In particular, this technology relates to pumping fracturing fluid into an oil or gas well using pumps powered by electric motors.”); Sanborn, EX-1008, Abstract (“A fracturing system is described. The system includes an electric motor-driven pumping sub-system, configured to pump a pressurized fracturing fluid into at least one wellbore. . . .”); Coli, EX-1010, ¶ 0003 (“This invention relates generally to hydraulic stimulation of underground hydrocarbon-bearing formations, and more particularly, to the generation and use of electrical power to deliver fracturing fluid to a wellbore.”).

43. Using electrically powered motors to drive the pumps had several known advantages. This solution obviated “the need for a constant supply of diesel fuel to the site and reduc[ed] the site footprint and infrastructure required for the fracturing operation.” Coli, EX-1010, ¶ 0036, ¶ 0039 (claiming that the “physical footprint of the on-site area” could be “about 80% less than the footprint for the conventional [diesel] system” by “removing diesel prime movers”). One reason for this was that “diesel engines are very heavy, and so require the use of a large amount of heavy equipment . . . to transport the engines to and from a well site.” Oehring, EX-1011 [1:48-51]. Sanborn notes that with the substitution of electric motors for diesel ones, “the number of trailers on the site can be greatly reduced,”

and, further, the electric motors were also “generally cleaner and more reliable”. Sanborn, EX-1008, ¶ 0042, ¶ 0049. Sanborn explains that the electric motors may be driven by, for example, a natural gas fueled turbine generator. *Id.*, Abstract.

44. It was therefore well-known to a POSITA that hydraulic fracturing operations at wellsites typically employed either electric-powered pumps (such as those driven by gas turbines) or traditional diesel-powered pumps years before the filing date of the ’058 patent. *See* U.S. Pat. App. Pub. No. 2008/0236818 (“Dykstra”) (EX-1012), ¶¶ 0018, 0020 (disclosing that a “pumping grid 111” directs fracturing fluid to “multiple wells 110” and that the pumps in the grid 111 “can be electric, gas, diesel, or natural gas powered”).

C. Control Systems for Hydraulic Fracturing Operations

45. Computer-based control systems were commonplace in hydraulic fracturing operations before the ’058 patent filing date. In Coli, for example, “[a] control system can be provided for regulating various equipment and systems within the electric powered fractioning [sic, fracturing] operation.” Coli, EX-1010, ¶ 0065; *see id.*, ¶ 0072 (“Suitable controls and computer monitoring for the entire fracturing operation can take place at a single central location, which facilitates adherence to pre-set safety parameters.”). Similar control systems were used in both Sanborn and Dykstra. Sanborn, EX-1008, ¶ 0030 (disclosing that the system includes “an operations and control unit, usually computer-based, and containing

monitoring, data-recording, and communication equipment, as well as remote pumper controls to monitor and control each stage of the fracturing process, and to record data for each phase”); *see id.*, ¶ 0050; Dykstra, EX-1012, ¶ 0021 (disclosing a “central control system” that may be an “electronic computer system” for monitoring, coordinating, and controlling the “operations of the chemical storage system, proppant storage system, blending unit, pumping grid, power unit, and manifolds”).

46. It was also well-known to a POSITA that such control systems relied on models to optimize well performance. In U.S. Pat. Pub. No. 2006/0015310 (“Husen”) (EX-1013), for example, it was known to “create models for simulating the operation of oil, gas or geothermal wells and more particularly . . . for fracturing subterranean formations and determining characterizing information about the fractures. . . .” *Id.*, ¶ 0004. These known modeling methods included “determining characteristics of subterranean structures by obtaining and evaluating signals created in the well in response to one or more excitation events.” *Id.* Information that may be obtained through evaluation of such signals included “structural information (e.g., what objects are downhole, locations of what is downhole, and events that occur downhole) and parametric information (e.g., pressure, temperature and flow rate).” *Id.*, ¶ 0018.

47. Based on the above disclosures, a POSITA would have understood Husen to disclose generating an optimized model that starts with a base model, inputting actual well performance data, and modifying the model to generate a performance prediction that “matches the actual performance for producing an optimized model.” *Id.*, ¶ 0035. The model may be repeatedly optimized as actual performance data for multiple wellsite zones is collected. *Id.*, ¶ 0036. As Husen explains, such models may be used “in monitoring or controlling the fracturing process or in performing subsequent fracturing jobs.” *Id.*, ¶ 0004; *see* U.S. Pat. Pub. No. 2016/0061003 (“Gottumukkala”) (EX-1014), ¶ 0015 (“Embodiments of the present disclosure include the use of analytical well modeling tools and integrated workflows which can be used ‘on-the-fly’ and in real time to manipulate and optimize flow control valve settings.”). Gottumukkala similarly discloses methods for controlling valve settings on a well using a system model (“network model”) that:

utilizes workflows which perform data analysis and integrate accurate inputs of reservoir properties, pressures, fluid data, and/or other data to the model. The network model is then updated/calibrated for running optimization scenarios and for validating results for implementation of those optimization scenarios. Once flow control valve settings are implemented based on the validated optimization scenarios, the network model may be continually recalibrated which effectively continues the optimization loop.

Gottumukkala, EX-1014, ¶ 0023; *see id.*, ¶ 0025 (disclosing use of an “optimization algorithm” to “determine optimized scenarios for a given objective function, e.g. maximum well production, reduced water cut, gas control, or other objective function”).

48. In another example, U.S. Patent No. 10,280,722 (“Bello”) (EX-1015) discloses that a model may be “automatically and periodically updated using measured values determined from surface and/or downhole sensors, e.g. single and distributed well sensor measurements.” *Id.* [13:66-14:2]. This “adjustment process includes automatically determining or adjusting the values of a set of model parameters that result in the best matching of . . . simulated and measured data. . . . The system provides an automatic updating and adjusting capability without requiring the availability of human intervention. The system functions in the background, updating and adjusting the model without intervention by the user so that the model continuously remains accurate as needed.” *Id.* [14:22-33].

49. Optimized well operation models were therefore known and available for use by wellsite operators years before the ’058 patent filing date. For example, Bello discloses a “production data hub” that receives and processes data from multiple sources such as “production wells, drilling platforms, and measurement or formation evaluation systems.” *Id.* [6:48-52]. The data hub may be employed as a server accessible over a network such as the internet. *Id.* [6:52-53, 7:4-9]. Users

(“clients”) can “access the data hub . . . to receive software, data (raw and computed) and modeling or prediction results.” *Id.* [7:6-9, 16:20-24].

V. U.S. Patent No. 11,373,058

50. In this Section, I consider the disclosure in the '058 patent along with relevant information from the prosecution history of the '058 patent.

A. Background

51. The '058 patent is directed toward “well treatment plan optimizations.” EX-1001, [1:6–7]. Figure 1B illustrates a wellbore environment, shown below:

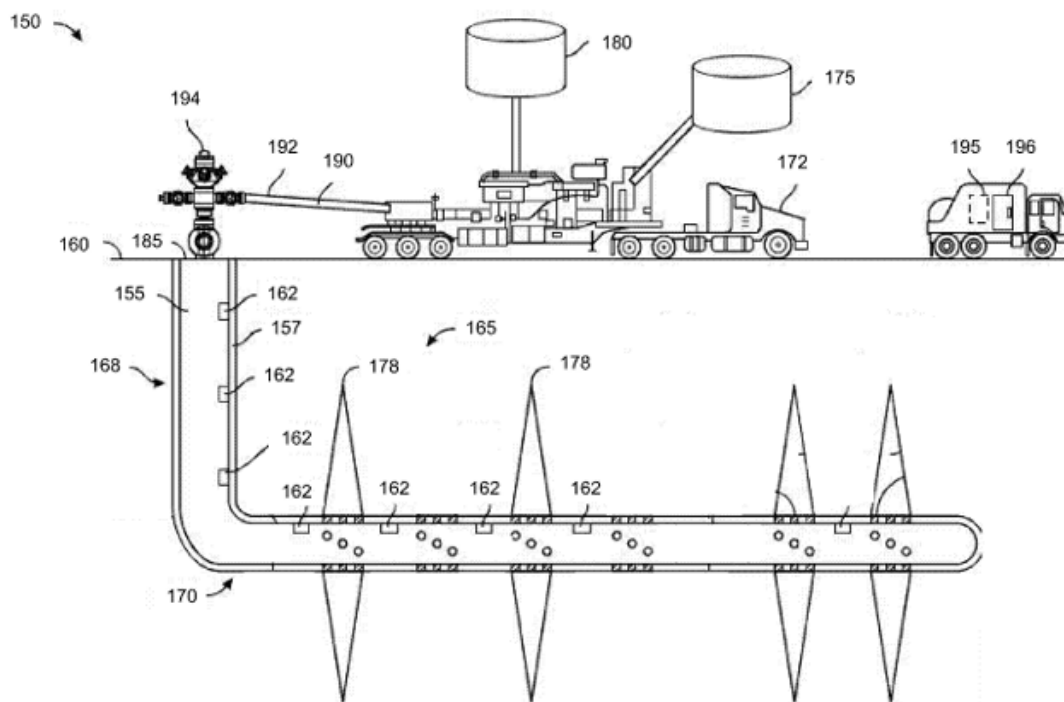


FIG. 1B

'058 Patent, EX-1001, Fig. 1B.

In describing the above figure, the '058 patent explains that “wellbore 155 extends from the surface 160 of the earth through the formation 165 formed by a drilling device from a previous drilling operation (not shown).” *Id.* [5:39–42]. Sensors 162, placed throughout the wellbore, are “used to generate and execute a data synthesis model” by measuring “temperature, pressure, strain, vibration or flow rate.” [5:46–52]. Adjusting the pump settings during fracturing, such as pump rate and/or mixture of carrier fluid 175 and proppant 180 for treatment fluid 190, affects the measurements received from the wellbore sensors 162. *See* [5:58–64].

52. The '058 patent explains that at the time of the alleged invention (September 17, 2019), “electric frac pumps [we]re often controlled . . . to achieve certain downhole environment responses.” EX-1001 [1: 11–13]. Conventional systems relied on technicians manually adjusting the pump settings according to “appraised information retrieved from [sensors in] the downhole environment.” *Id.* [1:13–15]; *see id.*, [1:16–19] (“For example, a technician may review sensor data and, based on experience, adjust various settings such as flow rate, pressure values, chemical compositions, etc., on an electric frac pump.”). Conventional systems also relied on representative system models—that is, models that technicians select to best represent downhole environment measured by sensors—to determine pump settings. *See id.* [1:19–26]. The '058 patent, however, does not explicitly mention any improvement in these conventional systems themselves. *Id.* [1:17–28] (“It is

with these observations in mind, among others, that aspects of the ['058 patent] were concerned and developed.”).

53. To supposedly optimize this conventional process, the '058 patent describes a process using system models and sensor data depicted in a flow chart in Figure 4, reproduced below.

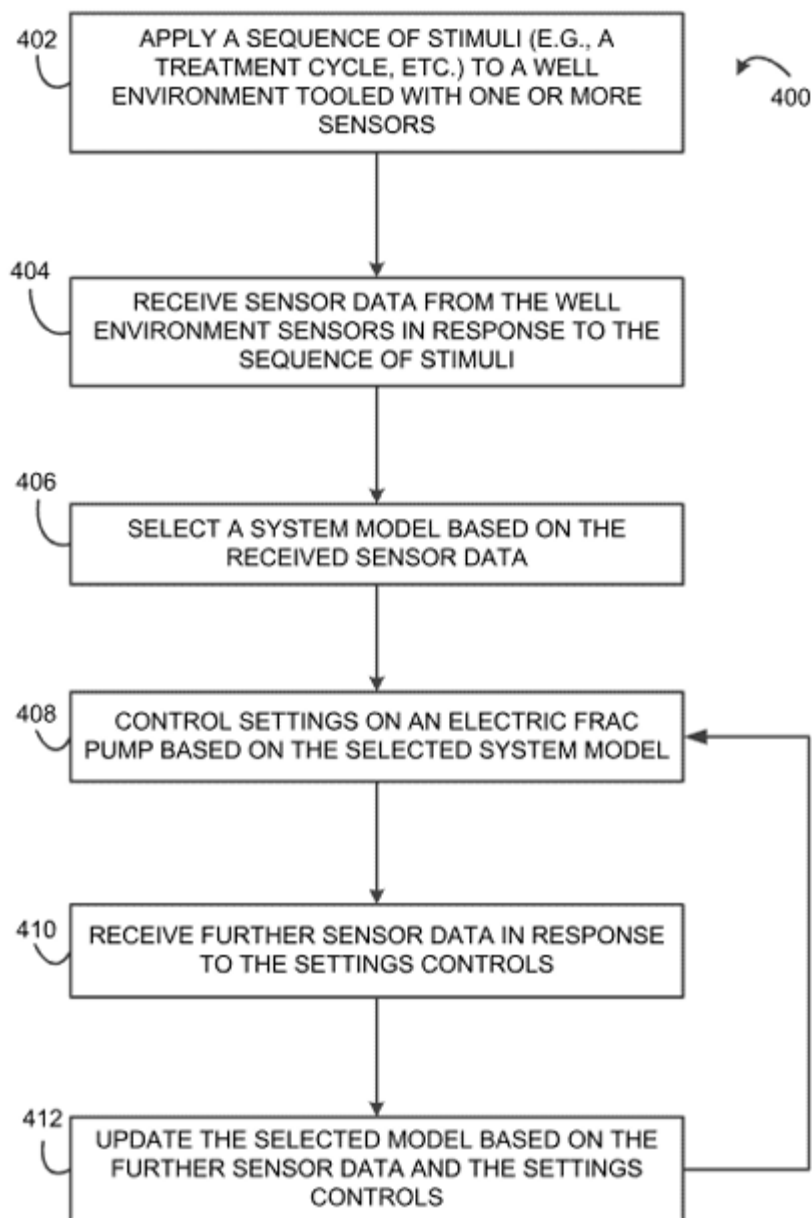


FIG. 4

'058 Patent, EX-1001, Fig. 4.

54. As shown above, Figure 4 illustrates several steps “for selecting and executing a representative system model.” *Id.* [8:22–23]. First, and in step 402, “a sequence of stimuli is applied . . . to well environment tooled with one or more

sensors.” [8:26–28]. Next, in steps 404 and 406, sensor data is collected and used to select a representative system model. [8:19–30, 8:37–38]; *see id.* [8:19–44]. In step 408, “settings on an electric frac pump are controlled based on the selected representative system model.” [8:45–46]. And, finally, and optionally, in steps 410 and 412 additional sensor data is measured and used to update the selected model and/or settings on the electric frac pump. *See id.* [8:49–55].

B. The Prosecution History

55. The application that led to the ’058 patent was filed as U.S. Patent Application No. 16/573,448 on September 17, 2019. EX-1002.

56. I understand that the ’058 patent claims were never rejected. *See generally id.* Instead, I understand that the examiner allowed the patent for the following:

Reasons For Allowance

4. The cited references do not disclose generating a sequence of stimuli for application to a well environment, the sequence of stimuli comprising one or more of particulate concentrations, chemical concentrations, or a pump rate control, selecting a representative system model based on the received formation response data from downhole or surface sensors and sequence of stimuli, and controlling an electrical fracturing pump based on the representative system model.

5. After a thorough search, and in light of the prior art of record, claims 1-20 are allowed.

EX-1002.024. I also understand that neither Pankaj (EX-1005), Dawson (EX-1024), Lecerf (EX-1027), nor Klumpen (EX-1019) were considered by the examiner.

C. The Challenged Claims

57. I understand that for purposes of this proceeding, Petitioners are challenging the validity of claims 1–20 of the '058 patent.

58. Claim 1 of the '058 patent is representative of the challenged claims and shown below:

1. A computer-implemented method for controlling electrical fracturing equipment for fracturing a well, the method comprising:

generating a sequence of stimuli for application to a well environment, the sequence of stimuli comprising one or

more of particulate concentrations, chemical concentrations, or a pump rate control;

receiving formation response data comprising data from one or more downhole sensors or surface sensors;

selecting a representative system model based on the received formation response data and sequence of stimuli; and

controlling an electrical fracturing pump based on the representative system model.

VI. CLAIM CONSTRUCTION

59. I understand that Petitioners reserve the right to assert in litigation that certain claim constructions are proper and that certain terms are indefinite, and I do not concede, by providing my opinions herein, that the challenged claims are of definite scope or properly described.

60. For purposes of this declaration, I will apply the plain and ordinary meaning for every term. However, I reserve the right to supplement my opinions if Patent Owner offers a construction of any term in the '058 patent.

VII. GROUNDS OF INVALIDITY

A. GROUND 1: Claims 1–4, 6–7, 9–12, 14, and 16–19 of the '058 Patent Are Obvious Based on Pankaj (EX-1005) in View of Payne (EX-1006)

61. It is my opinion that a POSITA would have found claims 1–4, 6, 7, 9–12, 14, and 16–19 of the '058 patent obvious over U.S. Patent Application Publication No. 2018/0230782 to Pankaj et al. (“Pankaj”) (EX-1005) in view of U.S. Patent Application Publication No. 2016/0258267 to Payne et al. (EX-1006). I

briefly describe Pankaj and Payne next, followed by a detailed explanation of how the combination of these two references renders obvious each limitation found in those claims.

1. Overview of Pankaj

62. The application leading to Pankaj was filed on August 8, 2016 and published on August 16, 2018, nearly one year before the filing of the '058 patent. EX-1005, Cover.

63. Pankaj is directed toward a method and system for “performing wellsite operations.” *Id.* [0001]. Figure 3.1 of Pankaj illustrates such an example fracture operations performed at a wellsite, shown below:

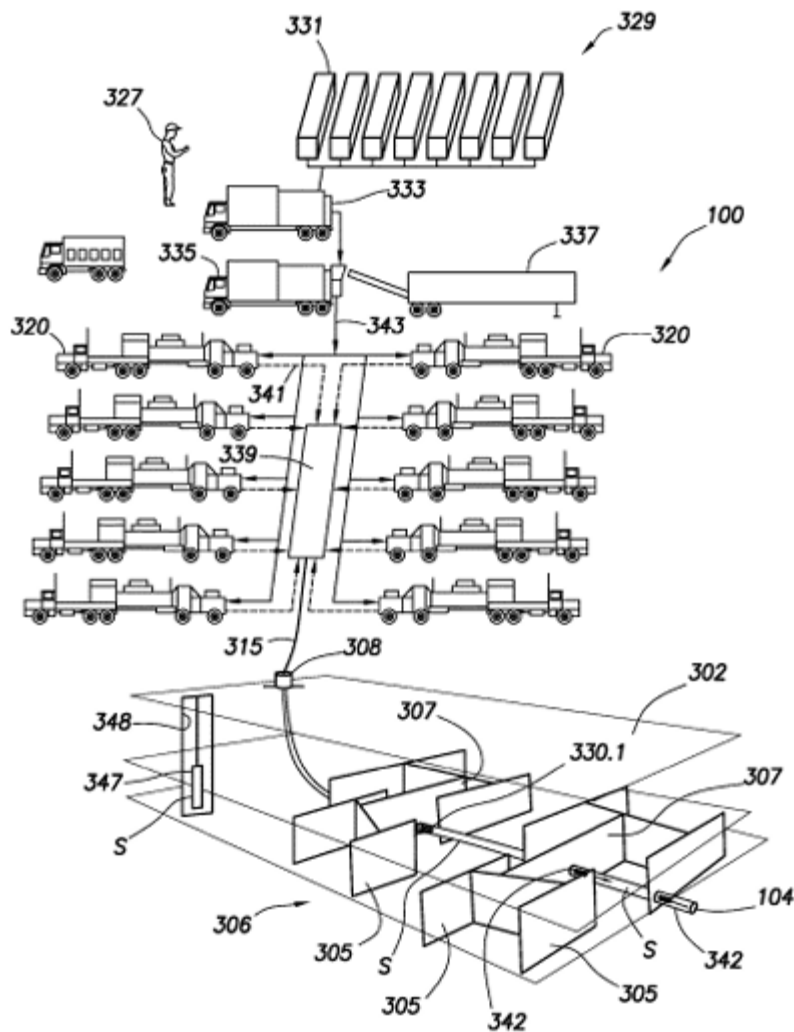


FIG. 3.1

Pankaj, Fig. 3.1 (EX-1005) [0054]

Pankaj, in describing the above figure, explains that the “fracture operation at the wellsite 100 [involves] the injection of fluids into the wellbore 136 in the subterranean formation 302 to expand the fracture network 306 propagated therein.” [0054]. Sensors (depicted as S in Figure 3.1) are placed throughout the wellbore. *Id.*, [0062] (“Various sensors (S) may be located at various positions

along the wellbore and/or the monitoring tools to collect and/or monitor the desired data.”). These sensors “measure wellsite parameters, such as formation parameters (e.g., mechanical properties, petrophysical properties, geological structure, stresses, in situ stress distribution, permeability, porosity, natural fracture geometry, etc.), fracture parameters (e.g., pump rate, volume (e.g., pad fluid and slurry), fracture geometry (e.g., propped fracture length), concentration of the proppant etc.), fluid parameters (e.g., viscosity, composition, proppant, temperature, density, etc.), reservoir parameters (e.g., pressure, temperature, viscosity), equipment parameters, and/or other parameters as desired.” *Id.*, [0062]. Adjusting “fracturing treatment parameters may be optimized” based on wellsite data from these sensors. *Id.*, [0141].

64. To optimize these parameters, Pankaj describes a method 1100 using mechanical earth models and sensor data shown in Figure 11, below:

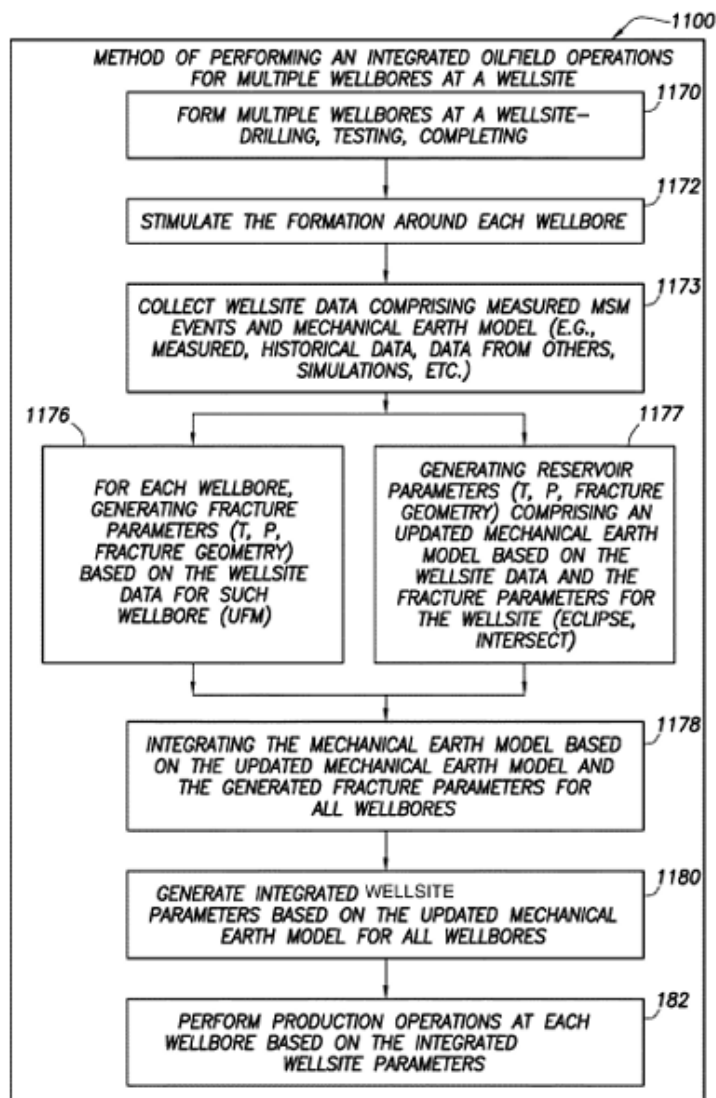


FIG.11

Pankaj, Fig. 11 (EX-1005)

Figure 11, shown above, includes several steps for “performing integrated oilfield operations” using wellsite (sensor) data and models. *Id.*, [0097]. First, and in steps 1172–1173, the method involves “1172 stimulating the formation around each wellbore (e.g., perforating, injecting)” and “1173 collecting wellsite data” from sensors “before, during, and after one or more oilfield operations.” *Id.* The

measured wellsite data from sensors is used to generate fracture parameters using modeling. *Id.*, [0100], [0103] (“Simulation techniques, such as unconventional fracture models, may be applied using input parameters from a wellsite to predict equivalent behavior of rock deformation causing the hydraulic fracture propagation.”). Using reservoir simulations, reservoir parameters are generated 1177 from both wellsite data and the generated fracture parameters. *Id.*, [0119]. In step 1178, Pankaj’s method uses generated fracture parameters to update the mechanical earth model used by the reservoir simulator. *Id.*, [0126]. Finally, new wellsite parameters are generated from the updated mechanical earth model (step 1180) and used to perform fracture and/or production operations (step 1182). *See Id.*, [0140]–[0141].

2. Overview of Payne

65. The application leading to Payne was filed on March 3, 2016 and published on September 8, 2016, which is years before the filing of the ’058 patent. EX-1006, Cover.

66. Payne discloses a well fracturing system that uses electrical motors. *Id.*, [0042] (“FIG. 1 illustrates an example of a hydraulic fracturing fleet layout for a well fracturing system using electrical motors.”). Figure 1 of Payne illustrates such a system:

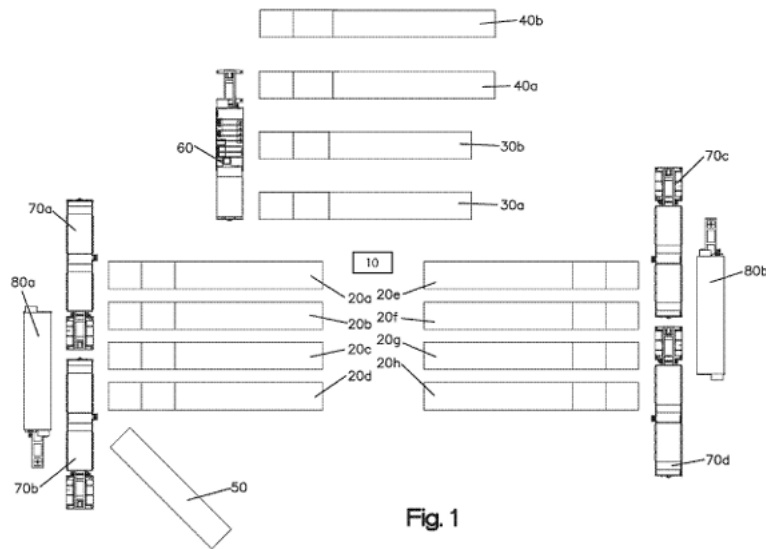


Fig. 1

Payne, Fig. 1 (EX-1006)

Payne’s fracturing system may include “electrical pump motors” and “electrical fracturing motors.” *Id.*, [0014]–[0015]. Payne explains that using electrical motors provides “numerous advantages” over conventional diesel engine-driven pumps, such as having “more precise, continuous speed control” and having no need to supply fuel. *Id.*, [0008]–[0009]; *see id.*, [0037]–[0040].

3. It Would Have Been Obvious to a POSITA to Combine Payne’s Teaching Concerning Electronic Fracturing Equipment and Pump With Pankaj’s Teachings

67. A POSITA would have found it obvious to combine the teaching in Payne extolling the use of electrical fracturing pumps with Pankaj’s teachings regarding improved methods for oilfield operations involving fracturing. Put another way, a POSITA would have readily understood that Pankaj’s systems and

methods would benefit from use of Payne’s electrical fracturing pump for the reasons below.

68. Both Pankaj and Payne are analogous art to the ’058 patent for two reasons. First, Pankaj and Payne are both directed toward the same field of endeavor of the ’058 patent—that is, fracturing operations. EX-1001, Abstract, [4:31–50]; EX-1005, [0002] (“More particularly, this disclosure is directed to methods and systems for performing fracture (or stimulation) operations and/or production operations at a wellsite.”); EX-1006, [0003] (“The following description relates to remotely monitoring and controlling electrical motors in oil and gas well stimulation hydraulic fracturing applications.”). Second, both Pankaj and Payne are reasonably pertinent to a problem described by the ’058 patent: optimizing conventional fracturing operations. *See* EX-1001, [1:11–26, 7:1–61]; EX-1005, [0042] (“In this manner, operations may be selectively adjusted based on the data collected [from sensors]. Portions of the operation, such as controlling drilling, weight on bit, pump rates or other parameters, may be optimized based on the information. These adjustments may be made automatically based on computer protocol, and/or manually by an operator. In some cases, well plans may be adjusted to select optimum operating conditions, or to avoid problems.”), [0067], [0069], [0078], [0090], [0141]; EX-1006, [0010]–[0011] (“AC motors require virtually no maintenance and are preferred for applications where reliability is

critical. Additionally, AC motors are better suited for applications where the operating environment may be wet, corrosive or explosive.”); Abstract (noting that the disclosed system includes “a system control unit [which] may control the operational parameters of the system”). For either reason, a POSITA would have understood that both Pankaj and Payne are analogous art.

69. In its fracturing operations, Pankaj discloses using fracturing equipment including pumps. Figure 3.1 of Pankaj illustrates this fracturing equipment and pump system 329, shown below:

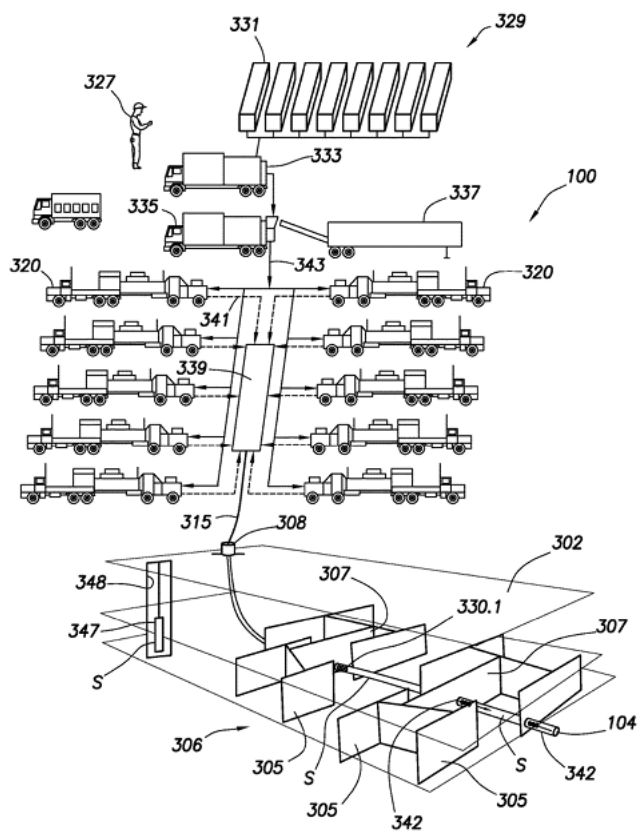


FIG.3.1

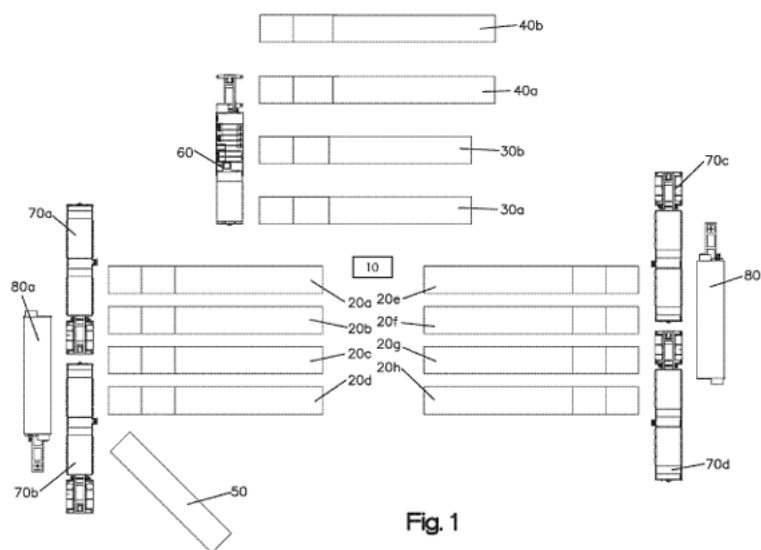
Pankaj, Fig. 3 (EX-1005)

Pankaj further explains that “[f]racturing is performed by pumping fluid into the formation using a pump system 329. The pump system 329 is positioned above the wellhead 308 for passing fluid through a fracture tool (e.g., tubing) 342.” *Id.*, [0055]; [0101] (“The missile manifold carries the fracturing fluid into the high pressure pumps and the field operator uses these high pressure pumps on surface to pump the fracturing fluids to the wellhead...”). A POSITA would have understood that Pankaj therefore discloses fracturing equipment that includes fracturing pumps, as a POSITA would have expected. Further, Pankaj does not specify or require any specific pump type. A POSITA would therefore understand that the choice of pumps was an implementation detail, and a POSITA would have naturally looked to known pump systems in the field for this choice.

70. As I explained above, there were a limited number of well-known choices for pumps used in hydraulic fracturing operations. For example, Dykstra explained that a “pumping grid 111” directs fracturing fluid to “multiple wells 110” and that the pumps in the grid 111 “can be electric, gas, diesel, or natural gas powered.” EX-1012, [0018], [0020]. While diesel pumps were more commonly used, a POSITA would have understood that by the filing date of the 058 patent, well operations using electrical pumps were well-known and in use in the industry. A POSITA also would have understood the advantages of electrical pumps over

the traditional diesel ones. *See ¶¶ _____, supra.* Payne is one reference teaching those advantages and disclosing the use of electrical pumps.

71. Payne, like Pankaj, discloses a well fracturing system. Payne's system uses electrical motors to drive the pumps. EX-1006, [0042] ("FIG. 1 illustrates an example of a hydraulic fracturing fleet layout for a well fracturing system using electrical motors."). Figure 1 of Payne illustrates such a system:



Payne, Fig. 1 (EX-1006).

Payne's fracturing system may include "electrical pump motors" and "electrical fracturing motors." EX-1006, [0014]–[0015]. Payne addresses in detail the benefits of using electrical motors for the fracturing pumps over the traditional diesel ones. *Id.*, [0008] (stating among other things that using "diesel engines has serious disadvantages, including the relative inefficiency of the internal combustion engine and the fact that its operation is costly"). Thus, Payne promotes the use of

electrical motors for driving the pumps and provides a lengthy explanation of the advantages of doing so. *Id.*, [0009] (stating, for example, that the “use of electrical motors obviates the need for supplying diesel fuel to more traditional fracturing pumps, and reduces the footprint of the site, and its environmental impact”).

72. A POSITA would have therefore been motivated to apply Payne’s teachings concerning the benefits of using “*electrical fracturing equipment*” and “*electrical fracturing pumps*” when considering Pankaj’s methods and systems for at least six reasons.

73. Payne provides four reasons to use electrical motors over conventional fracturing motors, such as diesel-driven motors. First, Payne explains that “[e]lectrical motors are lighter, have fewer moving parts, and can more easily be transported” over conventional motors. EX-1006, [0009]. Second, Payne also explains that “the control of electrical motors provides many advantages over traditional diesel-driven, variable gear ratio powertrains, for example, through more precise, continuous speed control . . . allow[ing] for the most efficient distribution of power throughout the entire system.” *Id.*; *see id.*, [0037]. Third, Payne additionally explains that the “use of electrical motors obviates the need for supplying diesel fuel to more traditional fracturing pumps, and reduces the footprint of the site, and its environmental impact.” *Id.*, [0009]. Fourth, Payne

explains that, unlike conventional motors, electrical motors provide “the ability to independently control and operate ancillary sub systems.” *Id.*; *see also id.*, [0040].

74. In addition, as I stated previously, Pankaj is agnostic concerning the type of pumps used in the disclosed system, leaving that implementation detail to the POSITA. Such a POSITA would have understood that Payne’s teachings concerning the use of electrical fracturing equipment and pumps would have been the mere application of a known technique to Pankaj’s teachings, and would have recognized the benefits and advantages of applying Payne’s teachings in that way. Payne shows that electrical fracturing equipment and pumps were known years before the filing of the ’058 patent, making it a known technique. EX-1006, Cover. Payne also discloses reasons why electrical fracturing equipment and pumps provide “advantages over traditional diesel-driven” equipment. *Id.*, [0037]; *see id.*, [0009]. A skilled artisan would have recognized that the system described in Pankaj would have benefited from the same improvements as the conventional systems described in Payne. EX-1005, Fig. 3.1, [0055]; EX-1006, [0037]; *see id.*, [0009].

75. A POSITA would have also recognized that using Payne’s electrical fracturing equipment and pumps would have been a design choice. As I explained above, *see* § IV.B, there were only a limited number of identified predictable solutions for pumps used in a fracturing operation. Diesel-driven pumps and

electric pumps were two options. A POSITA would have weighed the trade-offs and advantages of each of these choices. For example, Payne explains that “[e]lectrical motors are lighter, have fewer moving parts, and can more easily be transported” over conventional motors. Ex. 1006, [0009]. This trade-off would be very important if a wellsite was located in a remote area difficult to reach. Such a design need would have motivated a POSITA to choose a fracturing operation that uses electrical motors rather than the harder to transport diesel-driven solution.

76. Further, a POSITA would have had a reasonable expectation of success in combining Payne’s teachings regarding using electrical fracturing equipment and pumps with Pankaj’s teachings. The use of such electrical equipment and pumps in the hydraulic fracturing industry was, by September 2019, commonly known. In addition to Payne, filed in 2016, other references teaching the use of such equipment included Broussard (EX-1009), Sanborn (EX-1008), and Coli (EX-1010), all filed in 2012. Further, while I am aware that Payne states that “the use and control of hydraulic fracturing operations using electrical motors has not been successfully implemented in practice” (EX-1006, [0012]), even if that statement is taken as true at the time Payne’s application was filed (which it was not), it was not true as of September 2019, the filing date of the 058 patent. By then, so-called “e-fracturing” operations using electric motors to drive pumps were deployed and in public use. *See* EX-1029 (website printout from November 21,

2015 showing that U.S. Well Services was employing “electric hydraulic fracturing fleets ... to meet the demanding pressure and pump requirements associated with unconventional reservoirs”); EX-1028 (July 31, 2019 article from the *Journal of Petroleum Technology*, disclosing a company utilizing “electric motors as the prime movers” of its “e-fleet” equipment, including pumps and stating that the first e-fleet was deployed in 2016). By September 2019, a POSITA would have understood that electrical fracturing equipment had been in use for a number of years and as such would have had a reasonable expectation of success in combining the Payne’s teachings of using electrical fracturing equipment and pumps driven by electric motors with Pankaj’s teachings.

77. For the reasons above, it would have been obvious for a POSITA to combine the teachings in Payne of using an electrical fracturing pump with the teachings concerning Pankaj’s systems.

B. The Combination of Pankaj and Payne Renders Obvious Claims 1–4, 6–7, 9–12, 14, and 16–19

78. As I explain below, the combination of Pankaj and Payne renders obvious all limitations of claims 1–4, 6–7, 9–12, 14, and 16–19.

1. Independent Claim 1

- i. [1pre] “A computer-implemented method for controlling electrical fracturing equipment for fracturing a well, the method comprising:”

79. To the extent that the preamble of claim 1 is a limitation, Pankaj discloses it. Specifically, Pankaj discloses a “*method of performing oilfield operations at a wellsite.*” EX-1005, Abstract (“The method involves generating fracture parameters including a hydraulic fracture network of a fracture grid for each of the multiple wellbores based on wellsite data. . . .”). Figure 11 of Pankaj shows a “method for performing an integrated oilfield operation[],” which includes the following steps:

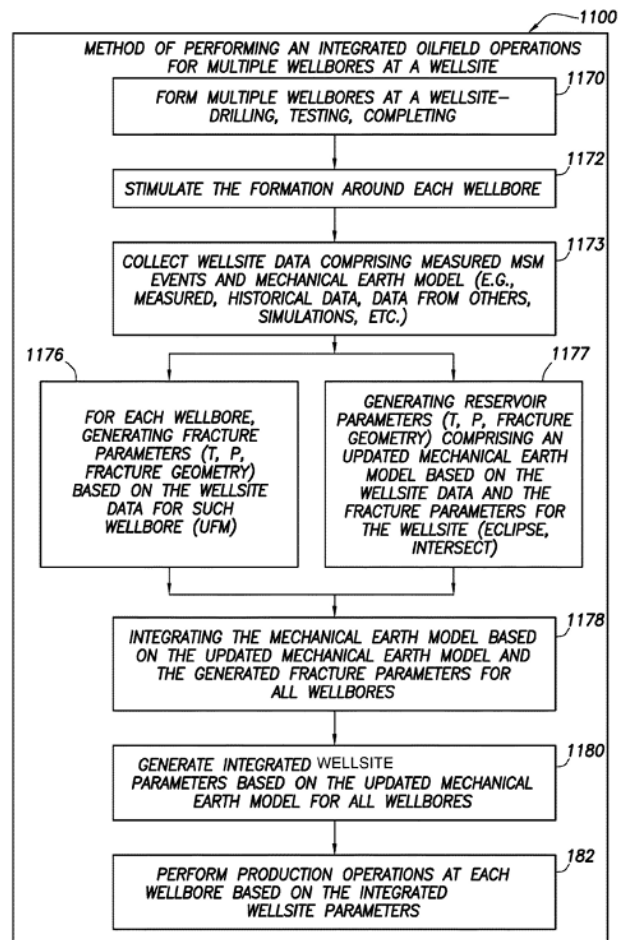


FIG. 11
Pankaj, Fig. 11 (EX-1005)

Pankaj also discloses that the method above may be implemented by a computer processor. Ex. 1005, [0031], [0042], [0064]–[0066], [0113], [0099] (explaining that the “MEM may be built using geomechanical oilfield software . . . or other geomechanical techniques using conventional software as is understood by those of skill in the art”). Based on above disclosures, a POSITA would have understood that Pankaj discloses “[a] *computer-implemented method for controlling . . . fracturing equipment for fracturing a well.*”

80. Pankaj, however, does not expressly disclose “*electrical fracturing equipment.*” As I explained above, *see* § VII.A.3, using Payne’s electrical fracturing equipment and pumps in the system of Pankaj would have been obvious to a POSITA in view of Payne. Thus, the combination of Pankaj and Payne discloses “[a] *computer-implemented method for controlling electrical fracturing equipment for fracturing a well.*”

81. For these reasons, it is my opinion that a POSITA would understand that the combination of Pankaj and Payne renders obvious the preamble of claim 1 to the extent that it is limiting.

- ii. [1A] “generating a sequence of stimuli for application to a well environment, the sequence of stimuli comprising one or more of particulate concentrations, chemical concentrations, or a pump rate control;”

82. Pankaj discloses or at a minimum renders this limitation obvious.

Figure 11 of Pankaj discloses generating and monitoring a sequence of stimuli for application in a well environment, shown below:

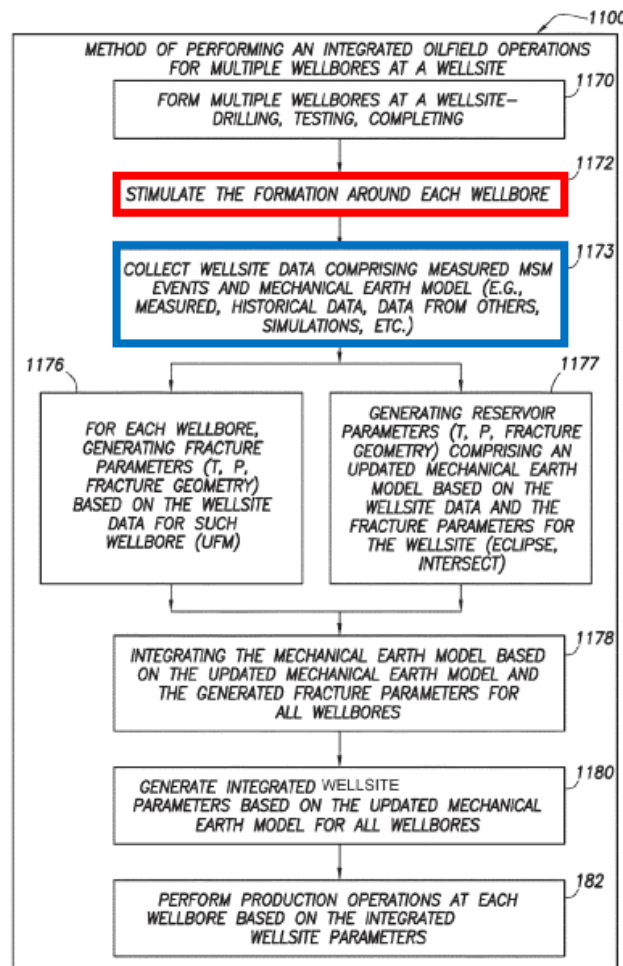


FIG. 11

Pankaj, Fig. 11 (EX-1005) (annotated).

In step 1172, shown above, the process involves “*stimulating* the formation around each wellbore (e.g., perforating, injecting).” Ex. 1005, [0097] (emphasis added).

83. A POSITA would understand “perforating” and “injecting” refer to fracturing treatment processes. EX-1005, [0059] (“Various fluids, such as conventional stimulation fluids with proppants (slurry) may be pumped into the

formation through perforations along the wellbore to create fractures.”); [0061] (stating that “injection may be manipulated by adjusting the material being injected and/or the way it is injected to achieve the fractures...”); [0055] (referring to forming a “fracturing (or injection) fluid”); [0086] (“Fig. 6.2 is a plot of a fracture model ... generated about each of the wellbores ... by injection of injection fluid into the formation (i.e., stimulation”); [0100] (disclosing “fracture parameters” such as “*pump rate*, volume (e.g., pad fluid and slurry), fracture geometry (e.g., propped fracture length), *concentration of the proppant etc., injection fluid parameters (e.g., viscosity, composition, proppant, temperature, density, etc.).*”) (emphasis added). Such a person would have understood that these teachings in Pankaj to disclose applying a sequence of stimuli to the well (“stimulate the formation”) by adjusting one or more properties of the fracturing fluid such as the volume of fluid and/or concentration of proppant (“adjusting the material being injected”) or its pumping rate (“the way it is injected”). A POSITA would have thus understood these teachings in Pankaj to disclose (or render obvious) “*generating a sequence of stimuli ... comprising one or more of particulate concentrations, chemical concentrations, or a pump rate control.*”

84. For these reasons, I believe a POSITA would have understood that Pankaj discloses this limitation.

iii. [1B] “receiving formation response data comprising data from one or more downhole sensors or surface sensors”

85. Pankaj discloses “*receiving formation response data comprising data from one or more downhole sensors or surface sensors.*”

86. Figure 11 of Pankaj discloses steps of generating both the “fracture parameters” 1176 and “reservoir parameters” 1177 using wellsite data from wellbore sensors (“*formation response data*”):

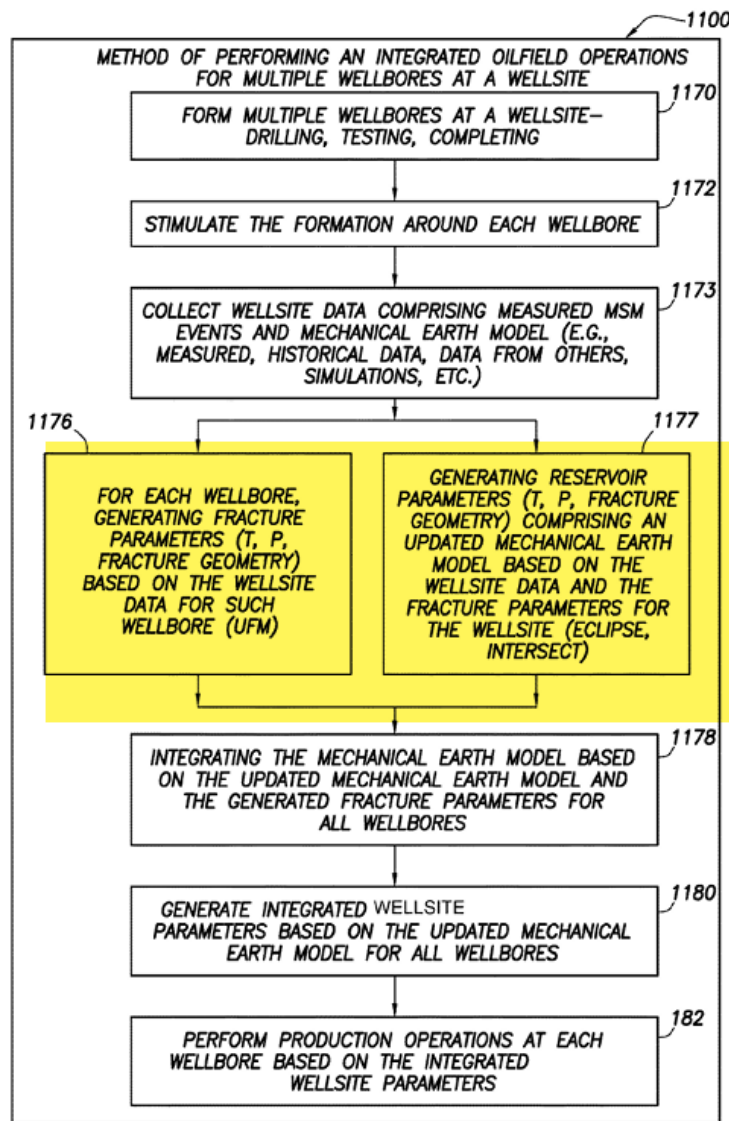


FIG. 11

Pankaj, Ex. 1005, Fig. 11 (annotated);,

see id., [0100], [0119]. For each wellbore, Pankaj further explains that fracture parameters in step 1176 are “based on wellsite data” collected from sensors. Ex. 1005, [0100].

87. Pankaj’s sensors “measure wellsite parameters, such as formation parameters (e.g., mechanical properties, petrophysical properties, geological structure, stresses, in situ stress distribution, permeability, porosity, natural fracture

geometry, etc.), fracture parameters (e.g., pump rate, volume (e.g., pad fluid and slurry), fracture geometry (e.g., propped fracture length), concentration of the proppant etc.), fluid parameters (e.g., viscosity, composition, proppant, temperature, density, etc.), reservoir parameters (e.g., pressure, temperature, viscosity), equipment parameters, and/or other parameters as desired.” Ex. 1005, [0062]. A POSITA would have understood that this data includes “*formation response data*” measured using downhole sensors. *See id.*, [0062], [0102] (“The generating 1176 may involve measuring the fracture parameters at the wellsite, for example, by deploying a downhole tool into the wellbore to perform measurements of subsurface formations.”). Alternatively, Pankaj discloses that sensors may “be located at various positions along the wellbore.” *Id.*, [0062] (“Various sensors (S) may be located at various positions along the wellbore and/or the monitoring tools to collect and/or monitor the desired data.”). Pankaj’s fracture parameters are therefore based on wellsite data from downhole sensors (“*received formation response data comprising data from one or more downhole sensors.*”). *See id.*, [0062], [0102].

88. In addition, Pankaj discloses that reservoir parameters in step 1177 are likewise “based on wellsite data,” *Id.*, [0119], that include, for example “borehole imaging logs, evaluating seismic measurements, ant tracking, sonic measurements, geological measurements, etc.” *Id.*, [0120]; *see id.*, [0123]–[0124]. A POSITA

would have recognized that these wellsite data examples are from surface sensors. *Id.*, [0121] (“The reservoir simulator may generate reservoir parameters (e.g., permeability of the reservoir rock, porosity of the reservoir, saturations of fluid present in the reservoir, reservoir compressibility, etc.) from the fracture parameters and the wellsite data (e.g., production that is governed by the choke size at the wellhead).”); *see id.*, [0120] (describing certain seismic and imaging logs that result from surface measurement techniques). Pankaj therefore discloses reservoir parameters are based on wellsite data from surface sensors (“*received formation response data comprising data from one or more. . . surface sensors.*”).

89. For these reasons, I believe a POSITA would have understood that Pankaj discloses this limitation.

iv. [1C] “selecting a representative system model based on the received formation response data and sequence of stimuli;”

90. Pankaj discloses “*selecting a representative system model based on the received formation response data and sequence of stimuli.*”

91. In Pankaj, fracture parameters are modeled using wellsite data and the stimulation step. *Id.*, Fig. 11, [0102], [0105]. Using the received parameters, step 1176 also involves simulation techniques, such as an Unconventional Fracture Model, that “help predict the equivalent behavior of rock deformation causing the hydraulic fracture propagation.” *Id.*, [0103]; *see id.*, at [0112] (“The generating

1176 may involve modeling the smooth fracture behavior to solve the governing equations and determine the smooth fracture parameters.”). Using wellsite data (“*received formation response data*”), existing models are selected which best represents the subsurface fracture networks (“*selecting a representative system model*”):

[Unconventional hydraulic Fracture Models (“UFMs”)] have been developed to understand subsurface fracture networks. ***Existing models may be used to simulate the governing equations for cases involving smooth fractures.*** These models may be used, for example, to simulate complex fracture network propagation in a formation with pre-existing natural fractures.

Id., [0112] (emphasis added); *see id.*, at [0075], [0103] (“The generating 1176 may involve modeling fracture parameters by solving governing equations for the wellsite data for the formation to be fractured. Simulation techniques, such as the Unconventional Fracture Model (UFM using UFM™ or other simulator), may be applied to these input parameters from the wellsite to predict the equivalent behavior of rock deformation causing the hydraulic fracture propagation.”). This selection is based on both wellsite data (“*received formation response data*”), *Id.*, [0102], [0105] and fracture parameters (“*sequence of stimuli*”), *id.*, [0105] (“Using one or more of these techniques, the hydraulic fracture geometry and the fracture parameters, such as conductivity, pressure in fractures, temperature, may

be modeled from the wellsite data collection.”). *See id.* at [0062] (explaining that wellsite data measured by sensors includes fracture parameters).

92. Moreover, as shown in Fig. 11, the wellsite data is collected at least in response to the step of “*stimulat[ing] the formation around each wellbore.*” *See id.*, Fig. 11, [0055], [0059], [0061], [0086], [0098], [0100], [0102]–[0103], [0112], [0116]–[0117]. A POSITA would have understood from Pankaj that the fracture parameters and reservoir parameters are generated in response to both the wellsite data and the stimulation step. *See* Ex-1005, [0055], [0059], [0061], [0086], [0098], [0100], [0102]–[0103], [0112], [0116]–[0117].

93. Additionally, reservoir simulations also use models determined from generated fracture parameters (“*sequence of stimuli*”) and wellsite data (“*the received formation response data*”). *Id.*, [0119] (“The reservoir parameters (e.g., pressure, flow rate, permeability, viscosity etc.) may be determined based on the wellsite data and the generated fracture parameters 1176.”). Pankaj further provides an example of each of these parameters:

The reservoir simulator may generate reservoir parameters (e.g., permeability of the reservoir rock, porosity of the reservoir, saturations of fluid present in the reservoir, reservoir compressibility, etc.) from the fracture parameters and the wellsite data (e.g., production that is governed by the choke size at the wellhead).

Id., [0121]. These fracture parameters and reservoir parameters values are then integrated into an updated mechanical earth model. *Id.*, Fig. 11, step 1178, [0126]

(“The method continues with 1178—integrating the updated mechanical earth model by integrating the fracture parameters for all of the wellbores into the updated earth model of the reservoir simulator. The integrating may involve selecting aspects from the fracture parameters of one or more of the wellbores and gridding such fracture parameters to the reservoir model as shown in FIGS. 6.1-8.2.”); *see id.*, [0138]–[0139]. Based on these disclosures, a POSITA would have understood that the updated mechanical earth model is selected (“*selecting a representative system model*”) based on both the wellsite data (“*the received formation response data*”) and fracture parameters/stimulating step (“*sequence of stimuli*”).

94. For these reasons, I believe a POSITA would have understood that Pankaj also discloses this limitation.

- v. [1D] “controlling an electrical fracturing pump based on the representative system model.”

95. Pankaj discloses “*controlling a[n] . . . fracturing pump based on the representative system model.*”

96. Figure 11 of Pankaj discloses three steps that include generating fracturing parameters based on the updated model 1180 and then, using those updated parameters, operating a fracturing pump at a wellbore 1182, shown below:

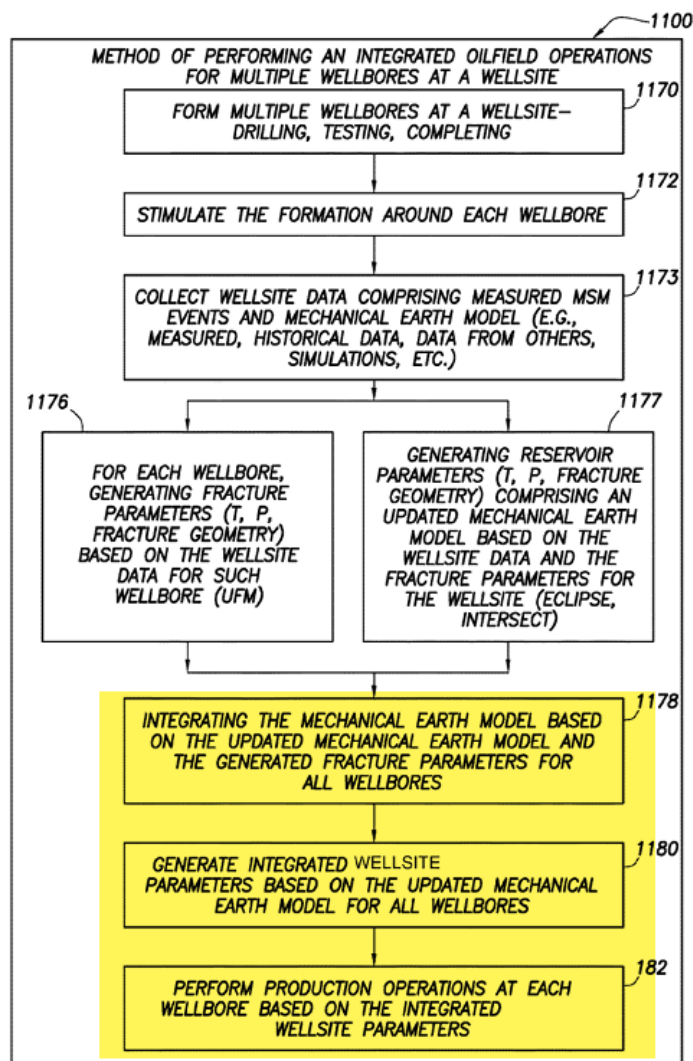


FIG. 11

Pankaj, Ex. 1005, Fig. 11 (annotated).

see id., [0140] (“The method 1100 may also involve additional applications, such as generating integrated wellsite parameters 1180 for the multi-wellbore wellsite, and performing fracture and/or production operations 1182.”). The updated mechanical earth model includes data from the UFM, such as production forecasts of production parameters, to provide integrated dynamic wellsite parameters. *Id.*, [0105] (using UFM allows “the hydraulic fracture geometry and the fracture

parameters, such as conductivity, pressure in fractures, temperature, may be modeled from the wellsite data collection.”), [0140] (“The integrated dynamic wellsite parameters may include, for example, production forecasts of production parameters (e.g., pressure, flow rate, permeability, etc.). . . .”). Using these wellsite parameters generated from the updated mechanical earth model (shown in step 1180 above), Pankaj further explains “the method performing 1182 may involve performing fracture and/or production operations at one or more of the wellbores of the wellsite.” *Id.*, [0141].

97. Pankaj explains that step 1182 (shown above) includes optimizing “fracturing treatment parameters” “to achieve the desired stimulation objectives to maximize well production.” *Id.*, [0141]. Pankaj discloses that fracture treatment parameters—that is, parameters for “*controlling an . . . fracturing pump*—are updated based on the resulting model. *Id.*, [0126] (“The method continues with 1178—integrating the updated mechanical earth model by integrating the fracture parameters for all of the wellbores into the updated earth model of the reservoir simulator. The integrating may involve selecting aspects from the fracture parameters of one or more of the wellbores and gridding such fracture parameters to the reservoir model as shown in FIGS. 6.1-8.2.”); *see Id.*, [0076] (“The matching exercise may require changing the reservoir properties in the geological model and/or changing the fracture design parameters and fluid properties.”). A

POSITA would have recognized that a fracturing pump is controlled via these updated fracture parameters from using the model. *See id.*, [0140]–[0141].

98. Pankaj does not expressly disclose an “*electrical fracturing pump*,” but as explained above, *see* § VII.A.3, such a modification to Pankaj to use Payne’s “*electrical fracturing pumps*” would have been obvious. The combination of Pankaj and Payne renders obvious “*controlling an electrical fracturing pump based on the representative system model*.”

99. For these reasons, it is my opinion that this limitation would have been obvious to a POSITA reviewing Pankaj in view of the Payne.

2. Dependent Claim 2

100. Claim 2 depends from claim 1 and further recites “*wherein the representative system model is retrieved from a data store based the received formation response data*.” The 058 patent specification explains that a data store is simply a form of computer memory. EX-1001 [7:17-21].

101. Pankaj discloses this limitation. Pankaj explains that simulators “may have built-in unconventional hydraulic fracture models like UFM™ (or other unconventional fracture models).” EX-1005, [0075]. Pankaj further explains that pre-existing UFM models help simulate the governing equations:

UFMs have been developed to understand subsurface fracture networks. Existing models may be used to simulate the governing equations for cases involving smooth fractures. These models may be used, for

example, to simulate complex fracture network propagation in a formation with pre-existing natural fractures.

Id., [0112]. Based on these disclosures, a POSITA would have understood that Pankaj's pre-existing UFM's were stored in a data store, e.g., computer memory, so that they can be used, if needed. As explained above, existing UFM models are selected that best represent the subsurface fracture networks using wellsite data. Accordingly, a POSITA would have understood that Pankaj discloses that its UFM (a "*representative system model*") is selected from a group of pre-existing UFM's based on which model best represents wellsite data ("*retrieved from a data store based the received formation response data.*")

102. Additionally, and as explained above, a POSITA would have understood that Pankaj's updated mechanical earth model is selected based on both the wellsite data and generated fracture parameters. Pankaj explains that these mechanical earth models may be "a model that is provided, or may be calculated from the other wellsite data." *Id.*, [0099]. Pankaj also explains that these models may be created using existing definitions. *Id.*, [0071] ("In the hydraulic fracturing workflow 400.2, a geological model (or MEM) may be created with a definition of the structural lithology and reservoir parameters, such as permeability, porosity, fluid saturation distribution, and rock properties, such as minimum in-situ stress, Young's modulus, etc."). A POSITA would have understood that Pankaj's

“provided” mechanical earth models are retrieved from computer memory (“a *data store*”). Based on these disclosures, a POSITA would have understood that Pankaj’s representative mechanical earth models are retrieved from memory. *See id.* [0037] (explaining that the system includes “computer facilities for receiving, storing, processing, and/or analyzing data from the operation”); *id.* [0042], [0058], [0113].

103. For these reasons, I believe a POSITA would have understood that Pankaj also discloses this limitation, expressly, inherently, or both.

3. Dependent Claim 3

104. Dependent claim 3 depends from claim 1. This claim further recites “wherein the representative system model is generated based on data created through simulation with uncertainty parameters.”

105. Pankaj discloses this limitation. Pankaj explains that “fracture simulation software, such as MANGROVE, may be used to simulate fracture operations (or engineered stimulation design) alone or within the software platform.” *Id.*, [0065]. Such simulation software, as Pankaj explains, includes workflows like that shown in Figure 4.2 of Pankaj below:

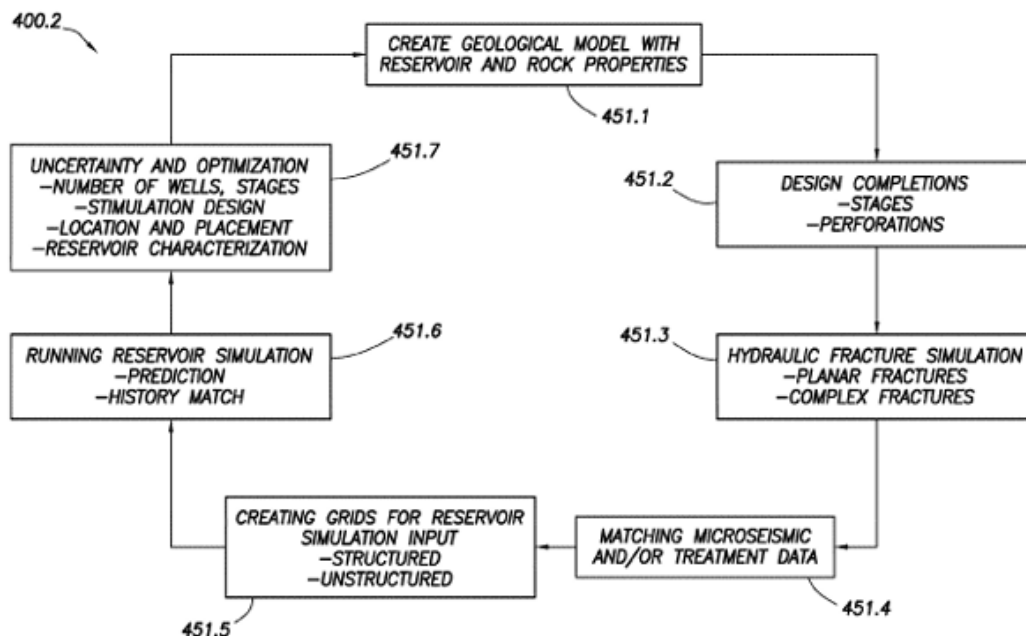


FIG.4.2

Pankaj, Ex. 1005, Fig. 4,

see *id.*, [0069] (“FIG. 4.2 shows another example workflow 400.2. As schematically shown, the workflow 400.2 includes events 451.1-451.7 of a hydraulic fracture workflow, such as one used in MANGROVE™. The events include 451.1 creating a geological model with reservoir and rock properties, 451.2 designing completions (e.g., stages, perforations), 451.3 performing hydraulic fracture simulations (e.g., for planar and complex fractures), 451.4 matching micro seismic and/or treatment data, 451.5 creating grids for reservoir simulation input (e.g., structure and unstructured grids), 451.6 running reservoir simulation (e.g., prediction and history match), and 451.7 *performing uncertainty optimization* (e.g., number of wells, stages, stimulation design, location and placement, reservoir

characterization).”) (emphasis added). As shown above, event 451.7 of the simulation software workflow performs uncertainty optimization. *Id.*, Fig. 4.2, [0069]. A POSITA would have understood that this event optimizes several “*uncertainty parameters*,” “such as number of wells, stages, stimulation design, location and placement, reservoir characterization.” *Id.*

106. In addition, a POSITA would have understood from Pankaj that “*data created through simulation with uncertainty parameters*” is used to generate the “*system model*” as claimed. The initial step shown in Figure 4.2 of Pankaj discloses includes “451.1 creating a geological model with reservoir and rock properties.” Ex-1005, [0069]. After this model is created, Figure 4.1 performs uncertainty optimization on that model, as shown in step 451.7 of Figure 4.1 EX-1005, Fig. 4.1 [0069]. A POSITA would have understood that these models, which uncertainty parameters, are then used to generate the system model that ultimately is used for operations. Ex-1005, [0069], [0072] (“After the geological model is ready, well completion may be designed which may be apt and useful for the treatment execution for the conditions defined by the geological model.”); [0074] (“The design of the hydraulic fracture in the workflow involves creating treatment design scenarios with actual treatment fluid and proppant schedules. The simulation models may then run on these schedules to predict the fracture

propagation, fluid and proppant placement and the ultimate fracture geometry achieved.”

107. For these reasons, I believe a POSITA would have understood that Pankaj also discloses this limitation.

4. Dependent Claim 4

108. Dependent claim 4 depends from claim 1. This claim has two parts: (i) “selecting the representative system model further comprises: determining one of a linear or a non-linear relationship between the sequence of stimuli and received formation response data”; and (ii) “updating the one of the linear or the non-linear relationship based on multiple iterations of the generated sequence of stimuli.” Below, I explain how Pankaj discloses both parts of this claim.

a. selecting the representative system model further comprises: determining one of a linear or a non-linear relationship between the sequence of stimuli and received formation response data

109. Pankaj discloses that the selection of the “representative system model” “further comprises: determining one of a linear or a non-linear relationship between the sequence of stimuli and received formation response data.”

110. Pankaj discloses that UFM’s are used to “simulate governing equations for cases involving smooth fractures.” *Id.*, [0112]. Pankaj also mentions several governing equations used by these UFM’s, such as equations 1-5. *See Id.*, [0106]–[110] (describing multiple linear equations). A POSITA would have understood

that each of equations 1-5 is a linear equation that represents a mathematical relationship between fracture parameters (“*sequence of stimuli*”) and modeled wellsite data (“*formation response data*”). Such a person would typically consider q (flow rate) at the injection point $n(s = 0)$ as an input (“*sequence of stimuli*”) and derive as outputs, including “*formation response data*,” from solution of eqns. (1)-(5) the remaining variables: $(H_{fL}, \bar{w}(s, t), q_L, q(s, t), p(s, t), w(x, y, z), H(s, t))$. A POSITA would have thus understood equations 1–5 in Pankaj to represent “*a linear. . . relationship between the sequence of stimuli and received formation response data.*”

111. In addition, Pankaj explains that “nonlinear system of equations” may be used by “[c]ombining these equations and discretizing the fracture network into small elements.” *Id.*, [0111]. Pankaj further explains that these nonlinear equations—also representing mathematical relationship fracture parameters (“*sequence of stimuli*”) and modeled wellsite data (“*formation response data*”)—can be solved “using a damped Newton-Raphson method.” Pankaj therefore discloses “*determining. . . a non-linear relationship between the sequence of stimuli and received formation response data,*” as well.

112. For these reasons, I believe a POSITA would have understood that Pankaj also discloses this limitation.

b. updating the one of the linear or the non-linear relationship based on multiple iterations of the generated sequence of stimuli

113. Pankaj discloses “updating the one of the linear or the non-linear relationship based on multiple iterations of the generated sequence of stimuli.”

114. Using the updated models, Pankaj discloses that “integrated dynamic wellsite parameters may then be generated 1180.” *Id.*, [0140]. Pankaj continues, “[t]he integrated dynamic wellsite parameters may include, for example, production forecasts of production parameters (e.g., pressure, flow rate, permeability, etc.) using the validated geomechanical parameters as inputs to a reservoir simulator (e.g., INTERSECT™ and/or ECLIPSE™).” *Id.* A POSITA would have recognized that these updated wellsite parameters are based on the updated representative model. *Id.*, [0076]. Pankaj discloses that the method 1182, using these updated parameters, performs “fracture and/or production operations at one or more of the wellbores of the wellsite based on the integrated wellsite parameters.” *Id.*, [0141]. A POSITA would have understood that this means the updated parameters are both (i) used for fracture and/or production operation and (ii) factored into the linear (or nonlinear) mathematical relationship mentioned above for future models. *See* Ex. 1005, [0141]; *see also id.*, Fig. 4.2, [0076] (showing loop with matching exercise to change reservoir properties, fracture design parameters, and fluid properties).

115. For these reasons, I believe a POSITA would have understood that Pankaj also discloses this limitation.

5. Dependent Claim 6

116. Claim 6 depends from claim 1. It further requires “wherein the one or more downhole sensors or surface sensors comprises one or more of a single-point electrical sensors, an optical sensor, or a fiber optic sensor.”

117. Pankaj discloses this limitation. Pankaj discloses a wireline tool 106.3 that is “suspended by rig 128” “into the wellbore 136.” *Id.*, [0043]. Figure 1.3 of Pankaj, shown below, illustrates this wireline tool 106.3:

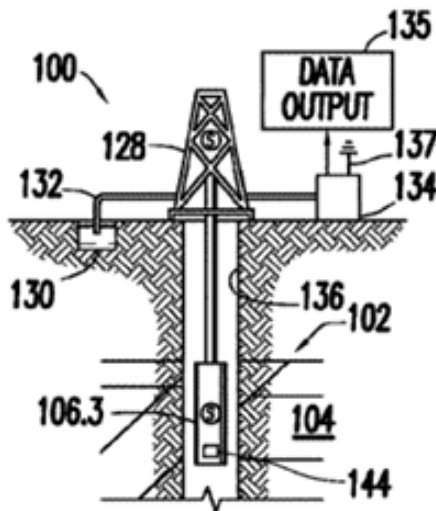


FIG. 1.3

Pankaj, Ex. 1005, Fig. 1.3,

see id. [0043] (“The wireline tool 106.3 may be adapted for deployment into a wellbore 136 for generating well logs, performing downhole tests and/or collecting

samples. The wireline tool 106.3 may be used to provide another method and apparatus for performing a seismic survey operation. The wireline tool 106.3 of FIG. 1.3 may, for example, have an explosive, radioactive, electrical, or acoustic energy source 144 that sends and/or receives electrical signals to the surrounding subsurface formations 102 and fluids therein.”). Wireline tool 106.3 includes sensors—such as single-point electrical sensors—for measuring downhole parameters, such as example porosity, permeability, fluid composition, and/or other parameters of the operation. *Id.*, [0045] (“As shown, the sensor (S) is positioned in the wireline tool 106.3 to measure downhole parameters which relate to, for example porosity, permeability, fluid composition and/or other parameters of the operation.”); *see id.*, [0043]. Pankaj discloses that surface sensors may also be used. *Id.*, [0049] (“Also, while certain data acquisition tools are depicted, it will be appreciated that various measurement tools (e.g., wireline, measurement while drilling (MWD), logging while drilling (LWD), core sample, etc.) capable of sensing parameters, such as seismic two-way travel time, density, resistivity, production rate, etc., of the subsurface formation and/or its geological formations may be used.”). A POSITA would have understood that the measurements described by Pankaj would include at least single-point electrical sensors for measuring resistivity and/or (fiber) optical sensors for measurements such as porosity, permeability, production rate, or density use.

118. Based on the above disclosures, a POSITA would have thus understood that Pankaj discloses “one or more downhole sensors or surface sensors comprises one or more of a single-point electrical sensors, an optical sensor, or a fiber optic sensor.”

119. Further, a POSITA would have been motivated to use any one of these claimed sensor types (i.e., “*single-point electrical sensors, an optical sensor,*” and “*a fiber optic sensor*”) as one of a finite number of identified predictable solutions to measure variables in a wellbore. A POSITA would have understood that each of these claimed sensors were routinely used during fracturing operations. *See* Ex–1021, Abstract. Design need, such as power concerns or sensitivity requirements, would have led a POSITA to pursue known options for these sensors within their technical grasp, which would included the claimed sensor types. Such a person would also be motivated to use these sensor types over other sensors based on a lack of commercial availability of other sensors.

120. For these reasons, in my opinion a POSITA would have understood that Pankaj discloses this claim.

6. Dependent Claim 7

121. Claim 7 depends from claim 1 and further recites that the “the formation response data comprises measurements of one or more of pressure,

temperature, flow, dynamic strain, static strain, acoustic intensity, resistivity, or electromagnetic signals or frequency, amplitude or phase of any of the electromagnetic signals.” Pankaj discloses this limitation.

122. Pankaj discloses that wellsite data (“*formation response data*”) may be measured from different sensors. For example, Pankaj explains that sensors may be positioned to measure fluid properties, such as “*pressures*,” “*temperature*,” and “*flow rates*.” *Id.*, [0047] (“As shown, the sensor (S) may be positioned in the production tool 106.4 or associated equipment, such as the Christmas tree 129, gathering network 146, surface facilities 142 and/or the production facility, to measure fluid parameters, such as fluid composition, ***flow rates, pressures, temperatures***, and/or other parameters of the production operation.”) (emphasis added); *see id.*, [0053] (“As the fluid flows through the wellbore, measurements are taken of fluid properties, such as flow rates, pressures, composition, etc. As described below, the fracture and reservoir measurements may be analyzed and used to generate models of the subsurface formation to determine characteristics thereof.”). Pankaj discloses that a wellsite may include other sensors to measure wellsite data (“*formation response data*”):

As also shown in FIG. 3.1 (as well as FIGS. 1.1-1.4), the wellsite 100 may be provided with sensors (S) to measure wellsite parameters, such as formation parameters (e.g., mechanical properties, petrophysical properties, geological structure, stresses, in situ stress distribution, permeability, porosity, natural fracture geometry, etc.),

fracture parameters (e.g., pump rate, volume (e.g., pad fluid and slurry), fracture geometry (e.g., propped fracture length), concentration of the proppant etc.), fluid parameters (e.g., viscosity, composition, proppant, temperature, density, etc.), reservoir parameters (e.g., pressure, temperature, viscosity), equipment parameters, and/or other parameters as desired. The sensors (S) may be gauges or other devices positioned about the oilfield to collect data relating to the various operations. Various sensors (S) may be located at various positions along the wellbore and/or the monitoring tools to collect and/or monitor the desired data. Other sources of data may also be provided from offsite locations.

Ex 1005, [0062].

123. Other sensors, and as explained above, may include wireline tool 106.3 that is “suspended by rig 128” “into the wellbore 136.” *Id.*, [0043], Fig. 1.3. Pankaj further explains that this wireline tool may have electrical sources that “send[] and/or receive[] electrical signals to the surrounding subsurface formations 102 and fluids.” *Id.*, [0043]. A POSITA would have recognized that, by sending and receiving electrical signals this way, such an electrical source would measure at least resistivity, electromagnetic signals or frequency, amplitude, or phase of any of the electromagnetic signals. Such a person would have further recognized that these measurements would have allowed the sensor to measure downhole parameters that relate to wellsite data (“*formation response data*”). *Id.*, [0044] (“The wireline tool 106.3 may be positioned at various depths in the wellbore 136 to provide a survey or other information relating to the subsurface formation.”);

Id., [0045] (“As shown, the sensor (S) is positioned in the wireline tool 106.3 to measure downhole parameters which relate to, for example porosity, permeability, fluid composition and/or other parameters of the operation.”). Pankaj thus discloses “*formation response data comprises measurements of one or more of pressure, temperature, flow, dynamic strain, static strain, acoustic intensity, resistivity, or electromagnetic signals or frequency, amplitude or phase of any of the electromagnetic signals.*”

124. For these reasons, in my opinion, a POSITA would have understood that Pankaj discloses this claim.

7. Independent Claims 9 and 16

a. Preambles of Claim 9 and 16

125. Claim 9 recites “[a] A system for controlling electrical fracturing equipment for fracturing a well, the system comprising: one or more processors; and a memory comprising instructions to.” Claim 16 likewise recites “A non-transitory computer readable medium storing instructions that, when executed by one or more processors, cause the one or more processors to.”

126. Pankaj discloses the preamble of both claims. As I explained above, *see* § VII.B.1.i [1pre], Pankaj renders obvious “[a] *computer-implemented method for controlling electrical fracturing equipment for fracturing a well.*” To implement this method, Pankaj discloses using a computer processor and memory

to store instructions for that processor. For example, Pankaj discloses that a controller and processor control the fracturing equipment:

The surface unit **134** may receive commands via the transceiver **137** or may itself execute commands to the controller. A processor may be provided to analyze the data (locally or remotely), make the decisions and/or actuate the controller. In this manner, operations may be selectively adjusted based on the data collected. Portions of the operation, such as controlling drilling, weight on bit, pump rates or other parameters, may be optimized based on the information. These adjustments may be made automatically based on computer protocol, and/or manually by an operator. In some cases, well plans may be adjusted to select optimum operating conditions, or to avoid problems.

Ex. 1005, [0042]. A skilled artisan would have understood that, to do so, such a controller and processor would require memory to store information, such as instructions for the processor to operate and data received from sensors.

127. In addition, Pankaj explains that Figure 11's illustrated method operates using "modeling software and/or simulators"—all of which require a processor and memory with instructions for the processor to operate the software. *Id.*, [0031]; *see Id.*, [0064]–[0066], [0113], [0099] (explaining that the "MEM may be built using geomechanical oilfield software . . . or other geomechanical techniques using conventional software as is understood by those of skill in the art"); [0037], [0098] (disclosing "computer facilities" and "computerized systems" respectively). Based on these disclosures, a POSITA would have understood that

Pankaj discloses both “*one or more processors and a memory comprising instructions,*” (Claim 9), and “[*a non-transitory computer readable medium storing instructions that, when executed by one or more processors, cause the one or more processors*” (Claim 16).

128. For these reasons, a POSITA would have understood that Pankaj discloses this claim.

b. Limitations [9A] and [16A]

129. Claims 9 and 16 both recite “generate a sequence of stimuli for application to a well environment, the sequence of stimuli comprising one or more of particulate concentrations, chemical concentrations, or a pump rate control.”

130. The combination of Pankaj and Payne renders this limitation obvious for the same reasons that I explain with respect to limitation 1A above. *See supra* Section § VII.B.1.ii [1A].

c. Limitations [9B] and [16B]

131. Claims 9 and 16 both recite “receive formation response data comprising data from one or more downhole sensors or surface sensors.”

132. The combination of Pankaj and Payne renders this limitation obvious for the same reasons that I explain with respect to limitation 1B above. *See supra* Section § VII.B.1.iii [1B].

d. Limitations [9C] and [16C]

133. Claims 9 and 16 both recite “select a representative system model based on the received formation response data and sequence of stimuli.”

134. The combination of Pankaj and Payne renders this limitation obvious for the same reasons that I explain with respect to limitation 1C above. *See supra* Section § VII.B.1.iv [1C].

e. Limitations [9D] and [16D]

135. Claims 9 and 16 both recite “control an electrical fracturing pump based on the representative system model.”

136. The combination of Pankaj and Payne renders this limitation obvious for the same reasons that I explain with respect to limitation 1D above. *See supra* Section § VII.B.1.v [1D].

8. Dependent Claims 10 and 17

137. Claims 10 and 17 depend from claims 9 and 16, respectively. Both claims 10 and 17 recite “wherein the representative system model is retrieved from a data store based the received formation response data.”

138. The combination of Pankaj and Payne renders this limitation obvious for the same reasons that I explain with respect to Claim 2 above. *See supra* Section § VII.B.2 [Claim 2].

9. Dependent Claims 11 and 18

139. Claims 11 and 18 depend from claims 9 and 16, respectively. Both claims 11 and 18 recite “wherein the representative system model is generated based on data created through simulation with uncertainty parameters.”

140. The combination of Pankaj and Payne renders this limitation obvious for the same reasons that I explain with respect to Claim 3 above. *See supra* Section § VII.B.3 [Claim 3].

10. Dependent Claims 12 and 19

141. Claims 12 and 19 depend from claims 9 and 16, respectively. Both claims 12 and 19 recite “selecting the representative system model further comprises: determining one of a linear or a non-linear relationship between the sequence of stimuli and received formation response data; and updating the one of the linear or the non-linear relationship based on multiple iterations of the generated sequence of stimuli.”

142. The combination of Pankaj and Payne renders this limitation obvious for the same reasons that I explain with respect to Claim 4 above. *See supra* Section § VII.B.4 [Claim 4].

11. Dependent Claims 14

143. Claim 14 depends from claim 9 and further recites “wherein the formation response data comprises measurements of one or more of pressure, temperature, flow, dynamic strain, static strain, acoustic intensity, resistivity, or

electromagnetic signals or frequency, amplitude or phase of any of the electromagnetic signals.”

144. The combination of Pankaj and Payne renders this limitation obvious for the same reasons that I explain with respect to Claim 7 above. *See supra* Section § VII.B.6 [Claim 7].

B. GROUND 2: Claims 5, 6 and 13 of the '058 Patent Are Obvious Based on Pankaj (EX-1005) in View of Payne (EX-1006), in Further View of Dawson (EX-1024)

145. Claims 5 and 13 depend from claims 1 and 9, respectively. As I explained above, independent claims 1 and 9 are rendered obvious by the combination of Pankaj and Payne. Claims 5 and 13 recite an additional limitation that, as I explain below, is rendered obvious by Pankaj in view of Payne, in further view of U.S. Patent No. 10,378,333 to Dawson et al. (“Dawson”) (EX-1024). To the extent one argues the combination of Pankaj and Payne does not render obvious claim 6, that claim is rendered obvious over the same combination in further view of Dawson. I briefly describe Dawson next, followed by a detailed explanation of how the combination of this reference with Pankaj and Payne renders obvious each limitation found in claims 8, 15, and 20.

1. Overview of Dawson

146. The application leading to Dawson was filed on June 24, 2016 and published on August 13, 2019. EX-1024, Cover.

147. Dawson discloses “a system and method for using pressure signals to assess effectiveness of a diverter in a stimulation wellbore.”, *Id.*, Abstract. In fracturing operations, Dawson explains that diverters are “used to divert the flow of well treatment fluids (e.g., injection fluids) from perforations taking more fluid to perforations taking less fluid.” *Id.*, [1:31–33]. “There are many types of commercial diverters. . . . Diverters, however, may be unreliable due to uncertainty in whether a diverter is going to work or not.” *Id.* [1:38–45]. To determine their reliability, Dawson discloses pressure measured “before and after the diverter are provided into the stimulation wellbore may be assessed to determine the effectiveness of the diverter.” *Id.*, Abstract.

2. Dependent Claims 5 and 13

148. Claim 5 depends from claim 1 and further recites “wherein the data from the one or more downhole sensors or surface sensors is used to determine changes in flow distribution in response to a diverter drop, the changes in flow distribution used to determine the representative system model.” Claim 13 depends from claim 9 and further recites the same limitation.

149. Pankaj discloses the “dynamic measurement of the fluid properties through the wellbore.” EX-1005, [0053]. A POSITA would have understood that these properties represent the “*changes in flow distribution*” through the wellbore. *Id.* Pankaj also discloses that these fluid properties are used to match the resulting

predicted values versus the observed data to confirm the model is correct. *Id.*, [0076]-[0077] (“The matching exercise may require changing the reservoir properties in the geological model and/or changing the fracture design parameters and fluid properties. Once a reasonable match of the predicted versus observed data is attained, the hydraulic fractures and the reservoirs may be gridded in structured or unstructured reservoir grids which serve as input for the reservoir simulation.”). Accordingly, Pankaj’s fluid properties are used to “*determine the representative system model.*”

150. Pankaj does not expressly disclose that these changes are “*in response to a diverter drop.*”

151. Dawson describes “a system and method for using pressure signals to assess effectiveness of a diverter in a stimulation wellbore.” EX-1024, Abstract. To do so, Dawson uses “pressure sensors in direct fluid communication with a second fluid in the second wellbore.” *Id.*, [2:11–14]. Dawson’s sensors measure pressure “before and after the diverter” to “determine the effectiveness of the diverters” (“*diverter drop*”). *Id.*, Abstract; *see id.*, [7:50-55] (“When the stage numbers in the monitoring wellbore and the adjacent wellbore do not correspond to each other, the stages being completed in the adjacent wellbore, while the pressure in the monitoring wellbore is monitored by the pressure gauge, typically include stages both before and after the observation stage.”); *see also id.*, [7:35–8:23]. Based on

these disclosures, a POSITA would have recognized that these pressure changes before and after a diverter represent “*changes in flow distribution*” based on the effectiveness of that diverter. EX-1024, Figs. 1 & 4, 11:60–2:2, [12:59–13:6] (explaining the effectiveness of diverters is determined by whether a flow distribution “stops, impedes, [has] no impact, or accelerates” based on measurements before and after the diverter drop). Such a person would have recognized that Dawson discloses that “*data from the one or more downhole sensors or surface sensors is used to determine changes in flow distribution in response to a diverter drop.*”

152. Dawson is analogous art to the ’058 patent for two alternative reasons. First, Dawson is directed toward the same field of endeavor of the ’058 patent—that is, fracturing operations. EX-1001, Abstract, [4:31–50]; EX-1024 [2:6–9] (“In certain embodiments, a method for assessing a diverter in a fracture wellbore used in treating a subsurface formation includes forming a first fracture emanating from a first interval in a first wellbore in the subsurface formation.”). Second, Dawson is reasonably pertinent to a problem described by the ’058 patent: optimizing conventional fracturing operations. See EX-1001, [1:11–26], [7:1–61]; EX-1024, [1:10–14], [5:21–29] (“According to an embodiment of the present invention, a method has been developed for evaluating hydraulic fracture geometry and optimizing well spacing for a multi-well pad by sequencing hydraulic fracturing

jobs for the multi-well pad and monitoring the pressure in said monitor well while hydraulic fractures are created in adjacent well(s), so that highly valuable data can be acquired for analyzing to evaluate hydraulic fracture geometry, proximity, and connectivity.”). For either reason, a POSITA would have understood that Dawson is analogous art.

153. A POSITA would have been motivated to use Dawson’s teaching of a diverter effectiveness technique with the combined system taught by Pankaj and Payne for two reasons.

154. First, a POSITA would have been motivated to use Dawson’s technique to allow for a “more effective assessment of the diverter,” which may be used to “improve the use of diverters.” EX-1024, [2:1–2]. A POSITA would have understood that fracturing operations, such as the one described in Pankaj, commonly use diverter drops. *See* EX-1024, [1:16–50]. Such a person would have been motivated to use Dawson’s technique to improve diverters in Pankaj for the express reason provided in Dawson—that is, Dawson’s technique allows for a “[m]ore effective assessment of the diverter [that] may be used to improve the use of diverters.” EX-1024, [2:1–2].

155. Second, a POSITA would have understood that using Dawson’s effectiveness technique in Pankaj’s fracturing operation would result in a more accurate representation of any well with a diverter. EX-1024, [1:66–2:1] (“Thus,

there is a need to be able to affectively assess if the diverter is effectively plugging existing perforations.”). Pankaj’s operation determines certain parameters based on a model representation of the well. EX-1005, Fig. 11, [0113], [0118], [0119], [0141]–[0142]. A POSITA would have recognized that, by monitoring the effectiveness of a diverter, Pankaj’s model would more accurately reflect conditions in a well. EX-1024, [12:42-45] (“Monitoring fracture growth rate and identifying when fractures slow or stop growth may be used to assess the effectiveness of a diverter placed in the stimulation wellbore.”). Such person would further recognize that Pankaj would improve fracturing operations by having a more accurate model of a well that uses a diverter. This improvement would have motivated a POSITA to use Dawson’s diverter effectiveness technique in Pankaj’s fracturing operation (as modified by Payne). Such a person would have further recognized no technical barriers to modifying the teachings of Pankaj to include Dawson’s diverter teachings, as diverters were well-known and commonly in use. Thus, a POSITA would have had a reasonable expectation of success in combining the references’ teachings.

156. For these reasons, I believe a POSITA would have understood that Pankaj in view of Payne, and in further view of Dawson, renders this limitation obvious.

3. Claim 6

157. To the extent that one argues that the combination of Pankaj and Payne does not disclose “wherein the one or more downhole sensors or surface sensors comprises one or more. . . an optical sensor, or a fiber optic sensor,” the combination of Pankaj, Payne, and Dawson would render this claim obvious.

158. As explained above, *see supra* Section VII.B.2 [Dawson Ground-Claims 5 and 13], it would have been obvious to a POSITA to use Dawson’s diverter effectiveness technique in Pankaj’s fracturing operation (as modified by Payne). Part of using Dawson’s diverter effectiveness technique would include using the same “fiber [pressure gauges] sensor. EX-1024, [5:58–60], [14:32–35]. In using Dawson’s diverter effectiveness process in the combined system of Pankaj and Payne, a POSITA would have used fiber gauge—both an “*optical*” and “*fiber optic*” pressure sensor. Such a person would have been motivated to make this modification for the reasons that I explained above. *See supra* Sections VII.B.2 [Dawson Ground-Claims 5 and 13].

159. In addition, a POSITA would have been motivated to use fiber gauges as one of a finite number of identified predictable solutions to measure pressure in a wellbore. For example, there are a limited number of pressure gauges available. *See* EX-1024, [5:58–60]. Design need, such as power concerns or sensitivity requirements, would lead a POSITA to pursue known options for pressure sensors

within their technical grasp, which would include fiber gauges. Such a person would also be motivated to use fiber gauges over other pressure sensors based on a lack of commercial availability of other sensors.

160. For the above reasons, the combination of Pankaj, Payne, and Dawson renders claim 6 obvious.

C. GROUND 3: Claims 8, 15, and 20 of the '058 Patent Are Obvious Based on Pankaj (EX-1005) in View of Payne (EX-1006), in Further View of Lecerf (EX-1027)

161. Claims 8, 15, and 20 depend from claims 1, 9, and 14, respectively. As I explained above, independent claims 1, 9, and 14 are rendered obvious by the combination of Pankaj and Payne. Claims 8, 15, and 20 recite an additional limitation that, as I explain below, is rendered obvious by Pankaj in view of Payne, in further view of U.S. Patent No. 10,087,722 to Lecerf et al. (“Lecerf”) (EX-1027). I briefly describe Lecerf next, followed by a detailed explanation of how the combination of this reference with Pankaj and Payne renders obvious each limitation found in claims 8, 15, and 20.

1. Overview of Lecerf

162. The application leading to Lecerf was filed on August 6, 2015 and published on October 2, 2018, which is about a year before the filing of the '058 patent. EX-1027, Cover.

163. Lecerf discloses a “system and method performing stimulation operations at a wellsite having a subterranean formation with of a reservoir therein is provided.” EX-1027, Abstract. Specifically, Lecerf’s method and system “generat[e] a plurality of quality indicators from a plurality of logs” for different sections of a fracturing perforation along a wellbore, shown as Bad (“B”), Good (“G”) sections below:

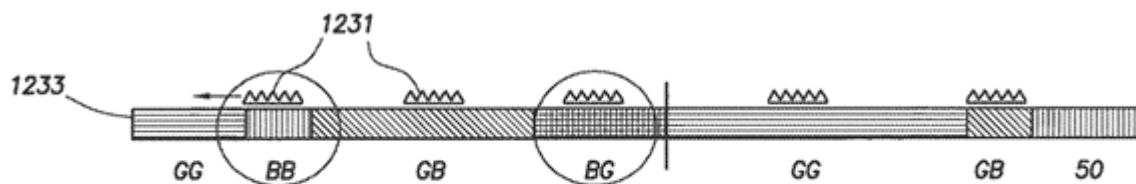


FIG.12

Lecerf, EX-1027, Fig. 12,

see id., Abstract. As shown above, “[t]he composite quality indicator may be combined with the merged stress blocks to form a combined stress and composite quality indicator” for a section off the wellbore.” EX-1027, Abstract. These composite quality indicators help with diverter design 1579 of the well to optimize fracturing operations. *See* EX-1027, [21:16–34], [22:20–23:14]; *see also id.* Fig. 13, [19:22–40] (describing Figure 13 and use of the composite quality index).

2. Dependent Claim 8

164. Claim 8 depends from claim 1 and further requires that the “wherein the representative system model predicts a proxy value comprising one or more of a cluster efficiency, a complexity factor, or a proximity index, and the predicted

proxy value is used to control one or more of a uniform flow across perforation clusters, a formation complexity, or interference in a neighboring well.”

165. Although Pankaj describes estimating “well-to-well interference during production,” EX-1005, [0033], Pankaj does not expressly disclose using a “*proxy value*” to do so.

166. Lecerf explains that a fracture model (a “*representative system model*”) is used to predict fracture geometry that can be calibrated and optimized. EX-1027, [12:4–9] (“Fracture modeling may be used to predict the fracture geometry that can be calibrated and the design optimized based on real time Microseismic mapping and evaluation.”); *see id.*, EX-1027, [11:59–64] (“workflows may integrate these predicted fracture models in a single 3D canvas where microseismic events are overlaid (see, e.g., FIG. 3.4). This information may be used in fracture design and/or calibrations.”). Part of this fracture modeling includes predicting values used in a fracture geometry, such as estimating fracture complexity (“*a proxy value comprising one or more of a complexity factor*”), and distances between orthogonal fractures. *See id.*, [12:15–37]. These distances help define stages. *Id.*, [15:56-63] (“Staging design may be performed (575) to define stages 574 along the wellbore. Finally, perforations 576 may be designed (577) along locations in the stages 574. A semi-automated method may be used to identify partitioning of a treatment interval into multiple sets of discrete intervals

(multi-stages) and to compute a configuration of perforation placements, based on these inputs.”).

167. To optimize oilfield operations, Lecerf discloses that fracture stages each have stage classification results and composite quality indicators—each satisfying the claimed “*proxy values*”. Figure 12 of Lecerf shows various perforation clusters are positioned “based on stage classification results 1231 and the composite quality indicator 1233”:

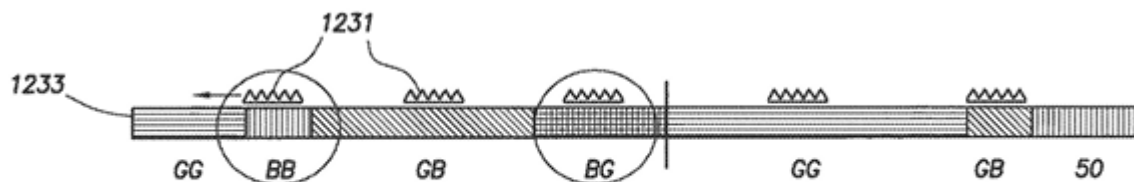


FIG.12

Lecerf, EX-1027, Fig. 12,

Lecerf describes composite quality indicators—like those in Figure 12 above—as indexes used to characterize a formation’s geophysical properties and its proximity to natural fractures:

“the underground formation may be divided into multiple sets of discrete volumes and each volume may be characterized based on information such as the formation's geophysical properties and its proximity to natural fractures. For each factor, an indicator such as “G” (Good), “B” (Bad), or “N” (Neutral) can be assigned to the volume. Multiple factors can then be synthesized together to form a composite indicator, such as “GG”, “GB”, “GN”, and so on.”

EX-1027, [18:67–19:10]. Based on these disclosures a POSITA would have understood that each factor has a composite quality indicator satisfying both “*a complexity factor or a proximity index.*” See Ex. 1030. Such a person would further have understood that, when factors are synthesized together to form a composite quality index for perforation clusters, as in Figure 12, that composite indicator represents a “*cluster efficiency.*” See EX-1027, Fig. 12, [18:67–19:10]; see *id.*, Fig. 13, [19:22–40] (describing Figure 13 and use of the composite quality index). Based on these disclosures, a POSITA would have understood that Lecerf discloses a “*a proxy value comprising one or more of a cluster efficiency, a complexity factor, or a proximity index.*”

168. Lecerf also discloses that composite quality indicators (“*the predicted proxy value*”) may be used, in combination with stress log 903 to determine flow characteristics. Lecerf explains that composite quality indicator 901. . . . is combined (1348) with a stress log 903 segmented into stress blocks by a stress gradient differences” resulting in “a combined stress & composite quality indicator 904.” See EX-1027, [18:2–9]. Figure 10 provides an example where a “BB” block is large enough 1021 to make flows uniform across multiple B sections:

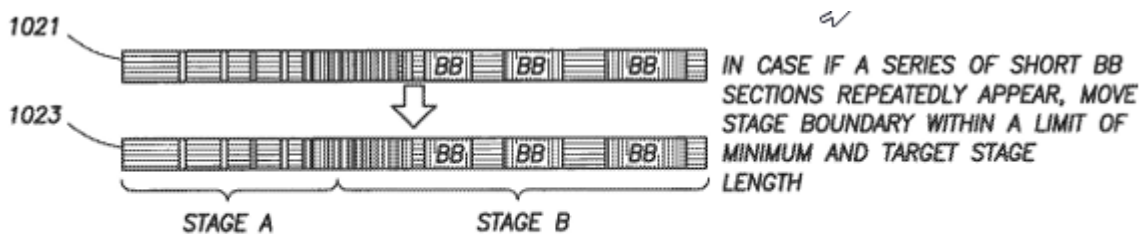


FIG.10

Lecerf, EX-1027, Fig. 10.

To do so, “the quality indicator may be shifted (1356) into its own stage as shown in the shifted quality indicator 1023. Additional constraints, such as hole deviation, natural and/or induced fracture presence, may be checked to make stage characteristics homogeneous.” *See id.*, [18:30–35]; *see id.*, Fig. 13, [19:22–40]. Figures 15.2 and 17–18 likewise show that Lecerf uses similar composite quality indicators to help with diverter design 1579. *See* EX-1027, [21:16–34], [22:20–23:14]; *see also* Ex. 1001, [4:12–15] (“For example, the representative system model may be used to achieve uniform flow across perforation clusters by adjusting pressure, flow rates, diverter composition. . . .”). Based on these disclosures, a POSITA would have understood that Lecerf’s composite quality indicators (“*the predicted proxy value*”) are used to ensure the that flow characteristics are homogenized over a larger stage (“*control one or more of a uniform flow across perforation clusters, a formation complexity, or interference in a neighboring well.*”). Lecerf thus discloses this limitation.

169. Lecerf is analogous art to the '058 patent for two alternative reasons. First, Lecerf is directed toward the same field of endeavor of the '058 patent—that is, fracturing operations. EX-1001, Abstract, [4:31–50]; EX-1027, [1:33–37] (“More particularly, the present disclosure relates to techniques for performing stimulation operations, such as perforating, injecting, and/or fracturing, a subterranean formation having at least one reservoir therein.”). Second, Lecerf is reasonably pertinent to a problem described by the '058 patent: optimizing conventional fracturing operations. *See* EX-1001, [1:11–26], [7:1–61]; EX-1027, [19:15–18] (“The spacing and orientation of multiple wells can be optimized to provide an entire formation with sufficient stimulation. The process may be repeated as desired.”). For either reason, a POSITA would have understood that Lecerf is analogous art.

170. A POSITA would have been motivated to incorporate Lecerf’s teachings regarding composite quality techniques for perforation clusters with the combined teachings of Pankaj and Payne for two reasons.

171. First, a POSITA would have recognized that, by using Lecerf’s optimization technique, the modified system of Pankaj and Payne would allow for better optimization of multiple wells. EX-1027, [19:15–18] (“The spacing and orientation of multiple wells can be optimized to provide an entire formation with sufficient stimulation. The process may be repeated as desired.”) By considering

the spacing and orientation across multiple wellsites, a POSITA would have been able to target fracturing operations at ideal areas (e.g., areas classified “G” for good). EX-1027, [17:48–58]. This would have motivated a POSITA to incorporate Lacerf’s composite quality technique in the combined system of Pankaj and Payne. This is particularly true given that Pankaj also addresses optimization models across multiple wells. *See* EX-1005, Fig. 5, [0033].

172. Second, a POSITA would have also recognized that, by using Lacerf’s composite quality indicators, the Pankaj model would have been improved by more accurately representing the multi-well field, *see* EX-1005, Fig. 5, especially by marking good and bad areas. EX-1027, [17:48–58]. Because Pankaj’s modeling technique selects the model that best reflects a well’s condition to generate parameters for fracturing operations, a POSITA would have recognized that the determined parameters will be improved by using a more accurate model. EX-1005, [0033] (“The methods and systems described herein may be used to solve the problem of addressing factors which can affect create errors in predictions used to design oilfield operations by providing features to incorporate the effects of interactions between actions taken on separate wellbores to the entire wellsite. With these additional features, fracture and production design may be provided which consider interactions of the wellsite and are tail[or]ed according to realistic predictions of the effects of fracturing at the multiple wellbores.”). This

improvement to Pankaj's model would have motivated a POSITA to incorporate Lecerf's teachings concerning composite quality techniques with the teachings of Pankaj and Payne.

173. A POSITA would have recognized no technical barriers to modifying the teachings of Pankaj to include Lecerf's optimization teachings for multi-well environments, especially as Pankaj also addresses optimization models across multiple wells. *see* EX-1005, Fig. 5, [0033]. Thus, such a person would have had a reasonable expectation of success in combining the references' teachings.

174. For these reasons, in my opinion, a POSITA would have understood that the combination of Pankaj, Payne, and Lecerf renders claim 8 obvious.

3. Dependent Claims 15

175. Claim 15 depends from claim 9 and further recites "wherein the representative system model predicts a proxy value comprising one or more of a cluster efficiency, a complexity factor, or a proximity index, and the predicted proxy value is used to control one or more of a uniform flow across perforation clusters, a formation complexity, or interference from a neighboring well."

176. The combination of Pankaj, Payne, and Lecerf renders this limitation obvious for the same reasons that I explain with respect to Claim 8 above. *See supra* Section VII.C.2 [Lecerf Ground-Claim 8].

3. Dependent Claims 20

177. Claim 20 depends from claim 16 and further recites “wherein the formation response data comprises measurements of one or more of pressure, temperature, flow, dynamic strain, static strain, acoustic intensity, resistivity, electromagnetic signals, or frequency, amplitude or phase of any of the signals, and the representative system model predicts a proxy value comprising one or more of a cluster efficiency, a complexity factor, or a proximity index, and the predicted proxy value is used to control one or more of a uniform flow across perforation clusters, a formation complexity, or interference from a neighboring well.” Thus, this claim combines the limitations of dependent claims 7 and 8.

178. The combination of Pankaj, Payne, and Lecerf renders this limitation obvious for the same reasons that I explain with respect to claims 7 (Ground 1) and 8 (Ground 3) above. *See supra* Sections VII.A.6 [Ground 1 – claim 7] and VII.C.2 [Lecerf Ground-Claim 8].

D. GROUND 4: Claims 3, 11, and 18 of the '058 Patent Are Obvious Based on Pankaj (EX-1005) in View of Payne (EX-1006), in Further View of Klumpen et al. (EX-1019)

179. As I explained above, claims 3, 11, and 18 are rendered obvious by the combination of Pankaj and Payne. To the extent that one argues claims 3, 11, and 18 are not rendered obvious by Pankaj and Payne, claims 3, 11, and 18 would be rendered obvious by Pankaj in view of Payne, in further view of U.S. Patent No.

8,352,227 to Klumpen et al. (“Klumpen”) (EX-1019). I briefly describe Klumpen next, followed by a detailed explanation of how the combination of this reference with Pankaj and Payne renders obvious each limitation found in claims 3, 11, and 18.

1. Overview of Klumpen

180. The application leading to Klumpen was filed on October 30, 2007 and published on January 8, 2013, which is years before the filing of the ’058 patent. EX-1019, Cover.

181. Klumpen discloses “a method for performing oilfield operations” that involves modeling “operations of the oilfield. . . [with] a predetermined value of the oilfield control parameter and at least one of the probable values of the uncertainty parameter.” EX-1019, Abstract. These uncertainty parameters improve the accuracy of conventional models by accounting for values that represent “reservoir uncertainty and/or financial uncertainty.” *Id.*, [3:59–63]. Figure 11 of Klumpen illustrates an exemplary method using several uncertainty parameters in its model used to estimate performance of an oilfield operation, shown 11 below:

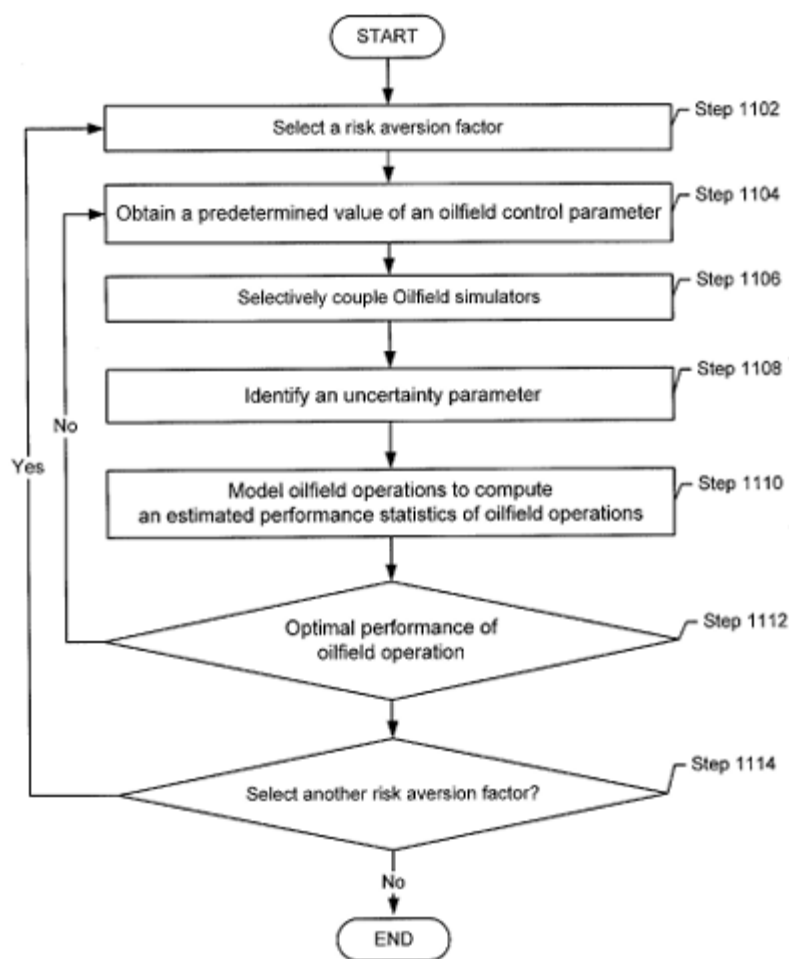


FIG. 11

Klumpen, EX-1019, Fig. 11,

see id., [22:27–25:2]. Accounting for these uncertainty parameters in models helps “optimiz[e] oilfield operations.” *Id.*, [1:16–22].

2. Dependent Claims 3, 11, and 18

182. Claims 3, 11, and 18 depend from claims 1, 9, and 14, respectively and further recite “wherein the representative system model is generated based on data created through simulation with uncertainty parameters.”

183. Klumpen discloses an “oil-field simulating modeling” method that “receives an oilfield control parameter” as an input, and identifies “an *uncertainty parameter* associated with probable values each corresponding to a weighted probability,” such that oilfield operations are “modeled with a predetermined value of the oilfield control parameter and at least one of the probable values of the uncertainty parameter.” EX-1019, [4:23–37]; *see also*, Abstract (“The method involves. . . modeling the operations of the oilfield to generate an estimated performance by selectively communicating between the oilfield simulators, the operations of the oilfield are modeled with a predetermined value of the oilfield control parameter and at least one of the probable values of the uncertainty parameter;”). As Klumpen explains, “[t]here is considerable uncertainty in a reservoir as to its geometry and geological parameters (e.g., porosity, rock permeabilities, etc.).” EX-1019, [3:34–36]; *see id.*, [3:58–62] (“It is desirable that such a complex analysis of oilfield parameters gathered throughout the oilfield and their impact on the oilfield operations be performed considering reservoir uncertainty and/or financial uncertainty.”). To account for these uncertainties, Klumpen uses uncertainty parameters in its representative system model. *See* EX-1019, Fig. 11, step 1108, [4:16–39], [23:20–24:2]. For example, Klumpen describes several uncertainty parameters that may be included in its model used to estimate performance of an oilfield operation:

The uncertainty parameter may be the reservoir uncertainty (e.g., the pore volume, the fault transmissibilities, the regional or field-wide permeability or porosity, or the production index of the aquifer supporting the water displacement for oil production, etc.) or the financial uncertainty (e.g., oil price or discount rate, etc.)

The uncertainty parameter may be modeled in many different ways to generate an estimated performance of the oilfield operation (Step 1110)

EX-1019, [23:41–49]; *see id.*, Fig. 11, [22:27–25:2]. Based on these disclosures, a POSITA would have recognized that Klumpen discloses a “*representative system model is generated based on data created through simulation with uncertainty parameters.*”

184. Klumpen is analogous art to the '058 patent for two reasons. First, Klumpen is directed toward the same field of endeavor of the '058 patent—that is, oil field operations. EX-1001, Abstract, [4:31–50]; EX-1019, [1:14–16] (“The present invention relates to techniques for optimizing oilfield operations relating to subterranean formations having reservoirs therein.”). Second, Klumpen is reasonably pertinent to a problem described by the '058 patent: optimizing conventional oil field operations. *See* EX-1001, [1:11–26], [7:1–61]; EX-1019, [1:17–22] (“More particularly, the invention relates to techniques for optimizing oilfield operations involving an analysis of reservoir operations, and their impact on such oilfield operations with deference to physical constraints present in any

part of the petroleum production and fluid injection systems and with deference to reservoir and financial uncertainty”). For either reason, a POSITA would have understood that Klumpen is analogous art.

185. A POSITA would have been motivated to incorporate Klumpen’s use of uncertainty parameters in the modeling of the combined system of Pankaj and Payne for three reasons.

186. First, a POSITA would have been motivated to use Klumpen’s teachings regarding uncertainty parameters with Pankaj’s teachings regarding models for a express reasons described in Klumpen. Klumpen explains that modeling oilfield operations, like that in Pankaj, has a “need to provide techniques capable of modeling and implementing operations based on a complex analysis of a wide variety of parameters affecting oilfield operations.” EX-1019, [3:54–58]. Based on this need, Klumpen explains, “[i]t is desirable that such a complex analysis of oilfield parameters gathered throughout the oilfield and their impact on the oilfield operations be performed considering reservoir uncertainty and/or financial uncertainty.” *Id.*, 3:58–62. This express reason from Klumpen would have motivated a POSITA to use Klumpen’s uncertainty parameters in Pankaj’s modeling.

187. Second, a POSITA would have recognized that models that use uncertainty parameters more accurately reflect a wellsite operation as opposed to

models that do not account for it. Because Pankaj's modeling technique selects the model that best reflects a well's condition to generate parameters for fracturing operations, a POSITA would have recognized that the determined parameters will be improved by using a more accurate model. *See* EX-1001, [2:49–53] (admitting it was well-known to use parameter uncertainty techniques to “help find models that represent the observed data more accurately.”). This improvement to Pankaj's model would have motivated a POSITA to incorporate Klumpen's teachings regarding uncertainty parameters with the teachings of Pankaj and Payne.

188. Third, a POSITA would have been motivated to use Klumpen's uncertainty parameters in Pankaj's modeling because it was simply the mere application of a known technique to improve the teachings of Pankaj. The '058 patent acknowledges that using parameter uncertainty techniques in representative models, like the one in Pankaj, was “well known.” EX-1001, [2:49–53] (“In other examples, a representative system model may be defined based on a multitude of models using parameter uncertainty techniques well known in the art to help find models that represent the observed data more accurately.”). Consequently, a POSITA would have recognized that, by using parameter uncertainty techniques, Pankaj's representative models would represent observed data more accurately.

189. A POSITA would have recognized no technical barriers to modifying the teachings of Pankaj to include Klumpen's uncertainty techniques, as such

techniques were well-known. *see* EX-1005, Fig. 5, [0033]. Thus, a POSITA would have had a reasonable expectation of success in combining the references' teachings.

190. For these reasons, in my opinion, a POSITA would have understood that the combination of Pankaj, Payne, and Klumpen renders claims 3, 11, and 18 obvious.

E. GROUND 5: Claims 1-20 of the '058 Patent Include Only Known, Generic Elements That Were Well-Known in Fracturing Operation

191. I have been asked by counsel to review whether the structural elements recited in the claims of the '058 patent were known, conventional elements that were previously used as part of fracturing operations as of September 17, 2019.

192. As shown in my analysis above, the prior art references (Exhibits 1005–1030) show that every element of claims 1–20 was a known, conventional element that was previously used in fracturing operations before September 17, 2019.

193. Other exhibits—including the '058 patent—that I have considered for this declaration confirm that each structural element was a known, conventional element that was previously used fracturing operations before September 17, 2019:

Structural Element	Exhibit Disclosing Element
a sequence of stimuli ... comprising one or more of particulate concentrations, chemical concentrations, or pump rate control (Claims 1, 9, and 16)	Gottumukkala (EX-1014), ¶ 0029, (teaching teaches a “real time acquisition and control system/processor” that includes determining “pressure transient <i>responses</i> to continuous zonal rate <i>changes instigated by the actuation</i> of flow control valves.”; <i>Id.</i>, ¶ 0031 (“As sensors 64 provide data, e.g. flow rate and pressure data while the flow areas of the flow control valve 66 are manipulated, the multi-rate data is deconvolved via module 78.... In this example, the data is deconvolved to estimate near well bore parameters, such as skin, permeability, productivity, and/or other desired parameters.”). <i>See also</i> Section ____ <i>supra</i> (discussing Pankaj, EX-1005 and its disclosure of stimulating a well).
one or more downhole sensors or surface sensors (Claims 1, 9, and 16)	Bello, EX-1015, Abstract (disclosing a method of “real-time estimation of production performance properties [that] includes receiving real-time field data taken by downhole sensors”);

Structural Element	Exhibit Disclosing Element
	Gottumukkala, EX-1014, ¶ 0027 (“The sensors 64 also may comprise a variety of other sensors 68, e.g. pressure sensors, temperature sensors, flow sensors, and/or other sensors, positioned at various locations” along the wellbore).
controlling an electrical fracturing pump based on the representative system model (Claims 1, 9, and 16)	Rashid, EX-1018 at Fig. 6 (showing “mass storage” that includes “well models”); ¶ 0067 (identifying a “set of well models 626 and network model 628 stored locally in mass storage 610 and/or accessible remotely from a remote server 618”).
A system model is retrieved from a data store based [on] the received formation response data (Claims 2, 10, 17)	Rashid, EX-1018 at Fig. 6 (showing “mass storage” that includes “well models”); ¶ 0067 (identifying a “set of well models 626 and network model 628 stored locally in mass storage 610 and/or accessible remotely from a remote server 618”).

Structural Element	Exhibit Disclosing Element
A system model is generated based on data created through simulation with uncertainty parameters (Claims 3, 11, 18)	Ex. 1001, [2:49-53] (admitting “a representative system model may be defined based on a multitude of models using parameter uncertainty techniques well known in the art to help find models that represent the observed data more accurately.”) U.S. Patent No. 7,953,585 (“Gurpinar”) (EX-1020), Abstract (teaches a method of managing a reservoir which “assimilates diverse data ... for iteratively producing a reservoir development plan that is used for optimizing an overall performance of a reservoir.”); <i>see id.</i>, 71:15-53 (explaining the method includes using a simulator and “history calibrated model” that is responsive to a “set of uncertainty parameters” for “generating a new history calibrated model” if the uncertainty parameters change.)

Structural Element	Exhibit Disclosing Element
determining one of a linear or non-linear relationship between the sequence of stimuli and received formation response data / updating the one of the linear or the non-linear relationship based on multiple iterations of the generated sequence of stimuli (Claims 4, 12, 19)	Husen, EX-1013, Abstract (“The method for generating the optimized performance data ... incorporates the steps of introducing known pressure transient data, well logging data and PVT data for the well into a base model and producing a performance prediction from the base model. These results are compared with actual performance data and the model is modified to generate a performance prediction that matches the actual performance for producing an optimized model.”); ¶ 0043 (disclosing that to “develop the optimized model, a reiterative loop [] is utilized”).
wherein the data from the one or more downhole sensors or surface sensors is used to determine changes in flow distribution in response to a	Dawson, EX-1024, Abstract (disclosing pressure measured “before and after the diverter are provided into the stimulation wellbore may be assessed to determine the effectiveness of the diverter”).

Structural Element	Exhibit Disclosing Element
diverter drop, the changes in flow distribution used to determine the representative system model (Claims 5 and 13)	
wherein the one or more downhole sensors or surface sensors comprises one or more of a single-point electrical sensors, an optical sensor, or a fiber optic sensor (Claim 6)	<i>See</i> U.K. Patent App. GB 2443051 (“Varadarajan”) Ex-1021, Abstract (disclosing that “fiber optic sensors” were “used in wellbore measuring or sensing of parameters such as pressure, temperature, and seismic or chemical activity....”); Dawson, EX-1024, [5:58–60], [14:32–35] (discloses using “fiber [pressure gauges” sensor.”)
the formation response data comprises measurements of one or more of pressure, temperature, flow, dynamic strain, static	<i>See</i> Varadarajan, EX-1021, Abstract (disclosing that “fiber optic sensors” were “used in wellbore measuring or sensing of parameters such as

Structural Element	Exhibit Disclosing Element
strain, acoustic intensity, resistivity, or electromagnetic signals or frequency, amplitude or phase of any of the electromagnetic signals (Claims 7, 14, and 20)	<i>pressure, temperature</i> , and seismic or chemical activity....”)
wherein the representative system model predicts a proxy value comprising one or more of a cluster efficiency, a complexity factor, or a proximity index, and the predicted proxy value is used to control one or more of a uniform flow across perforation clusters, a formation complexity, or interference in a neighboring well (Claims 8, 15, and 20)	See Lecerf, EX-1027, [18:2–9], [18:30–35]; see id., Fig. 13, [19:22–40].

VIII. JURAT

194. I declare that all statements made herein of 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 of Title 18 of United States Code.

I declare under penalty of perjury that the foregoing is true and correct.

Executed this 27th day of March 2023 in Athens, Greece.



Michael Nikolaou, Ph.D.