

UNITED STATES PATENT AND TRADEMARK OFFICE

BEFORE THE PATENT TRIAL AND APPEAL BOARD

PROFRAC HOLDING CORPORATION
and
U.S. WELL SERVICES, LLC,
Petitioners,

v.

HALLIBURTON ENERGY SERVICES, INC.,
Patent Owner

PGR2023-00023

PETITION FOR POST-GRANT REVIEW

OF

U.S. PATENT NO. 11,373,058 B2

TABLE OF CONTENTS

I. MANDATORY NOTICES	1
A. Real Party-in-Interest	1
B. Related Matters.....	1
C. Lead and Back-up Counsel and Service Information.....	1
II. GROUNDS FOR STANDING.....	2
III. INTRODUCTION	2
IV. BACKGROUND OF THE TECHNOLOGY	5
A. Oil and Gas Extraction From Wells	5
B. Hydraulic Fracturing	8
C. Control Systems for Hydraulic Fracturing Operations	16
V. THE '058 PATENT AND FILE HISTORY.....	19
A. The '058 Patent	19
B. The Prosecution History	22
C. The Challenged Claims	22
VI. LEVEL OF ORDINARY SKILL IN THE ART	23
VII. STATUTORY GROUNDS FOR THE CHALLENGES	24
VIII. CLAIM CONSTRUCTION.....	25
IX. IDENTIFICATION OF HOW THE CLAIMS ARE UNPATENTABLE.....	25
A. GROUND 1: Claims 1–4, 6–7, 9–12, 14, 16–19 are Obvious Over Pankaj in View of Payne.....	25
1. Pankaj Introduction	25
2. Payne Introduction	30
3. A POSITA Would Have Been Motivated to Combine Pankaj and Payne	31
4. Pankaj and Payne Render Obvious Claim 1	38
5. Pankaj and Payne Render Obvious Independent Claims 9 and 16	51

6. Pankaj and Payne Render Obvious Dependent Claims 2-4, 6–7, 10-12, 14, 17-9	53
B. GROUND 2: Claims 5, 6, and 13 of the '058 Patent Are Obvious Over Pankaj and Payne In Further View of Dawson	63
1. Dawson Introduction	63
2. Pankaj, Payne, and Dawson Render Obvious Claims 5 and 13	64
3. Pankaj, Payne, and Dawson Render Obvious Claim 6	68
C. GROUND 3: Claims 8, 15, and 20 of the '058 Patent Are Obvious Over Pankaj and Payne, In Further View of Lecerf.....	69
1. Lecerf Introduction.....	69
2. Pankaj, Payne, and Lecerf Render Obvious Claims 8, 15, and 20.....	70
D. GROUND 4: Claims 3, 11, and 18 of the '058 Patent Are Obvious Based on Pankaj in View of Payne, in Further View of Klumpen	77
1. Klumpen Introduction	77
2. Pankaj, Payne, and Klumpen Render Obvious Claims 3, 11, and 18	78
E. GROUND 5: Claims 1-20 of the '058 Patent are Invalid Under 35 U.S.C. § 101.....	83
1. Legal Standards	84
2. Claims 1, 9, 16: <i>Alice</i> Step One	86
3. Claims 1, 9, 16: <i>Alice</i> Step Two.....	93
4. The Dependent Claims Are Directed to the Same Abstract Idea and Add Only Conventional Elements	98
X. DISCRETIONARY DENIAL IS NOT APPROPRIATE	106
XI. CONCLUSION	107

PETITIONERS' EXHIBIT LIST

Exhibit No.	Description
1001	U.S. Patent No. 11,373,058
1002	File History of U.S. Patent No. 11,373,058
1003	Declaration of Dr. Michael Nikolaou
1004	Curriculum Vitae of Dr. Michael Nikolaou
1005	U.S. Patent App. Pub. No. 2018/0230782 to Pankaj <i>et al.</i>
1006	U.S. Patent App. Pub. No. 2016/0258267 to Payne <i>et al.</i>
1007	S. Dalvi, <i>Fundamentals of Oil & Gas Industry for Beginners</i> (Notion Press 2015) (excerpts)
1008	U.S. Patent App. Pub. No. 2013/0306322 to Sanborn <i>et al.</i>
1009	U.S. Patent No. 9,410,410 to Broussard <i>et al.</i>
1010	U.S. Patent App. Pub. No. 2012/0255734 to Coli <i>et al.</i>
1011	U.S. Patent No. 10,020,711 to Oehring <i>et al.</i>
1012	U.S. Patent App. Pub. No. 2008/0236818 to Dykstra <i>et al.</i>
1013	U.S. Patent App. Pub. No. 2006/0015310 to Husen <i>et al.</i>
1014	U.S. Patent App. Pub. No. 2016/0061003 to Gottumukkala <i>et al.</i>
1015	U.S. Patent No. 10,280,722 to Bello <i>et al.</i>

Exhibit No.	Description
1016	Website Printout from the Internet Archive concerning the Mayo Clinic allergy test procedures, accessed 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 <i>et al.</i>
1018	U.S. Patent App. Pub. No. 2016/0153266 to Rashid <i>et al.</i>
1019	U.S. Patent No. 8,352,227 to Klumpen <i>et al.</i>
1020	U.S. Patent No. 7,953,585 to Gurpinar <i>et al.</i>
1021	U.K. Patent App. GB 2443051 to Varadarajan <i>et al.</i>
1022	Federal Court Management Statistics for the Western District of Texas (Dec. 31, 2022)
1023	PCT International Pub. No. WO 2018/084871 to Madasu <i>et al.</i>
1024	U.S. Patent No. 10,378,333 to Dawson <i>et al.</i>
1025	Website Printout from Amazon.com (Dalvi Book), accessed at: https://www.amazon.com/Fundamentals-Oil-Gas-Industry-Beginners/dp/9352064194/ref=sr_1_1?crid=2OJL05AXX8XSF&keywords=Dalvi+oil+gas+industry&qid=1679761993&srefix=dalvi+oil+gas+industry%2Caps%2C182&sr=8-1

Exhibit No.	Description
1026	Website Printout from the Internet Archive (Dalvi Book), accessed at: https://web.archive.org/web/20161108121245/https://notionpress.com/store/categories/technology-engineering
1027	U.S. Patent No. 10,087,722 to Lecerf <i>et al.</i>
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 from the Internet Archive (U.S. Well Services) accessed at: https://web.archive.org/web/20151121102607/http://uswellservices.com/
1030	Website Printout from Amazon.com – D. Tiab, <i>Petrophysics: Theory and Practice of Measuring Reservoir Rock and Fluid Transport Properties</i> , 4 th Ed. (Gulf Professional Pub. 2015), accessed at: https://www.amazon.com/dp/0128031883?psc=1&smid=AZOLNCI5GS0EX&ref_=chk_typ_imgToDp

I. MANDATORY NOTICES

A. Real Party-in-Interest

The real parties-in interest are ProFrac Holding Corporation and U.S. Well Services, LLC (“Petitioners”).

B. Related Matters

U.S. Patent No. 11,373,058 (“the ’058 patent”), along with several other patents, has been asserted by Halliburton Energy Services, Inc. (“Halliburton” or “PO”), Halliburton US Technologies, Inc., and Halliburton Group Technologies, Inc. in the case *Halliburton Energy Services, Inc. v. U.S. Well Services, LCC and ProFrac Holding Corp.*, Case No. 6:22-cv-00906-ADA (W.D. Tex.) filed September 1, 2022.

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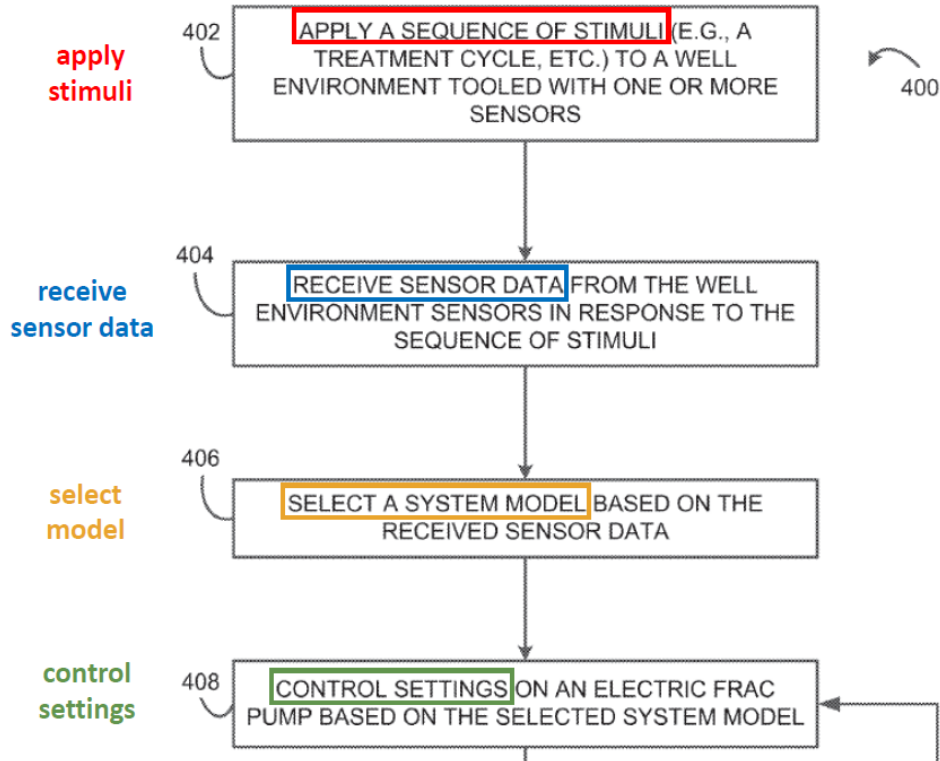
II. GROUNDS FOR STANDING

Petitioners certify that the '058 patent is eligible for post-grant review because its claims issued from an application filed on September 17, 2019 with no earlier priority claim. Petitioners are not barred or estopped from requesting post-grant review challenging the claims on the identified grounds herein. Petitioners have not filed a civil action challenging the validity of any claim of the '058 patent. This Petition is being filed no later than the date that is nine months after the date the '058 patent issued (June 28, 2022). 37 C.F.R. § 42.202.

III. INTRODUCTION

The '058 patent relates to oil and gas well operation and is directed to methods and systems for “well treatment plan optimizations.” EX-1001 [1:6-7]. In general, “frac” pumps and associated equipment pump fluid into the well to fracture earth strata at the wellsite. *Id.* [4:66-5:2; 5:39-42; 5:52-6:5]. Sensors detect well operating conditions such as temperature, pressure, strain, vibration, or flow rate, and provide data in response to stimuli from the pumps. *Id.* [2:16-30; 5:46-48; 6:27-36]. In response to received sensor data, a “treatment optimization system” may select a “system model,” which is used for controlling the settings of pump.

Id. [7:47-61; 8:45-49]. The relevant portion of Fig. 4, annotated below, shows the disclosed and claimed invention:



'058 Patent, Fig. 4 (Portion) (annotated)

Claims 1-20 of the '058 patent are invalid for numerous reasons. First, the claimed methods and systems were already well-known and disclosed in the art. For example, U.S. Patent Publication No. 2018/0230782 ("Pankaj") (EX-1005) discloses the same system and method:

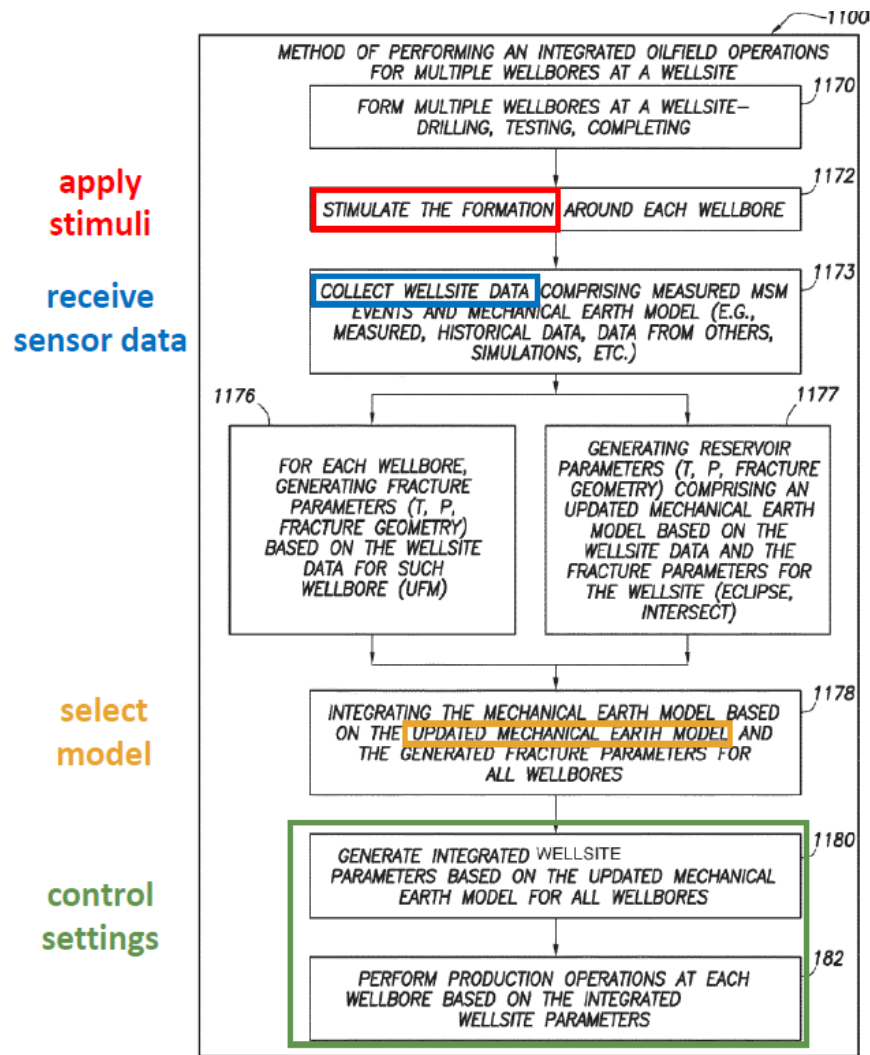


FIG.11

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

Pankaj and other prior art thus invalidate the challenged claims under 35 U.S.C. § 103.

Second, the challenged claims are invalid under 35 U.S.C. § 101 because they are drawn to non-statutory subject matter – an abstract idea. Indeed, it is admitted in the *Background* of the '058 specification that using a “representative system model ... for determining pump settings based on sensor information” was

known. EX-1001 [1:19-21]. The purported improvement disclosed in the 058 patent is that in the prior art “the representative system model is typically *manually selected* by a technician based on observed sensor data.” *Id.* [1:21-23].¹ The ’058 patent discloses using a computer do this instead. *See* claim 1 (requiring a “computer-implemented method” for performing the steps shown in Fig. 4). Such claims are precisely the kind courts have held invalid under § 101. *Alice v. CLS Bank*, 573 US 208, 223 (2014) (“Stating an abstract idea while adding the words ‘apply it with a computer’” is not enough.); *Data Engine Tech. v. Google*, 906 F.3d 999, 1013 (Fed. Cir. 2018) (“The mere automation of this [claimed] process does not negate its abstraction.”).

Petitioners therefore request that the Board find the challenged claims invalid and cancel them.

IV. BACKGROUND OF THE TECHNOLOGY

A. Oil and Gas Extraction From Wells

Methods for retrieving hydrocarbons such as oil and gas from the earth have existed for centuries. *See* S. Dalvi, *Fundamentals of Oil & Gas Industry for*

¹ All emphasis added herein unless otherwise stated.

Beginners (Notion Press 2015) (“Dalvi”) (EX-1007.013).^{2,3} The process involves searching for petroleum reservoirs, which are sub-surface hydrocarbon pools contained in porous rock formations. Oil and gas are contained in the porous rock (like water in a sponge). *Id.*, 029; EX-1003, ¶ 30.

When a reservoir is discovered, the rock formation is punctured by drilling a bore through it, and then tubing is inserted into the rock to extract the hydrocarbons. EX-1007.029, 056 (“An oil well can be described as a hole pierced through reservoir rock and pipes inserted to extract the hydrocarbon content of the reservoir.”). *See* EX-1003, ¶ 31.

Wells are typically drilled at an angle other than vertical (deviation drilling), to reach laterally remote parts of the formation. EX-1007.067. A well that has sections more than 80 degrees from vertical is called a horizontal well, which can extend for kilometers and thus achieve higher production. *Id.*:

² Pin cites herein are to the page number applied to exhibits in accordance with 37 C.F.R. § 42.63(d)(2)(ii). This number aligns with the PDF page number.

³ Dalvi was published October 2015 and was publicly accessible shortly thereafter. EX-1025, EX-1026; *see Vidstream LLC v. Twitter, Inc.*, 981 F.3d 1060, 1065-66 (Fed. Cir. 2020) (confirming public accessibility of reference based on, *inter alia*, Amazon.com and Internet Archive evidence).

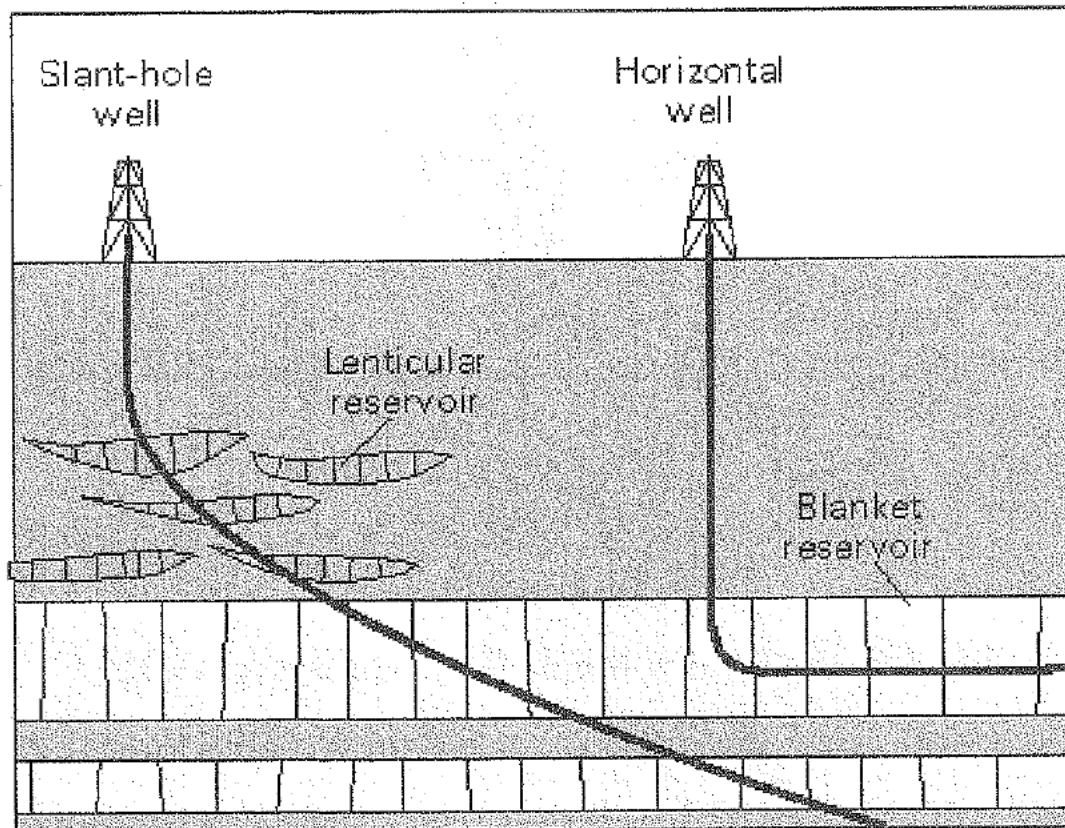


Fig.3.9: 37p Deviation Drilling for drilling at an angle

Dalvi, Fig. 3.9.37p (EX-1007.067)

See EX-1003, ¶ 32.

After drilling, the well is “cased,” which provides structural integrity to the well and acts as a barrier to debris. EX-1007.059. The underground formations have sufficient pressure to cause the hydrocarbons to come to the surface on their own. *Id.*, 074. The well opening at the surface is therefore closed by installing the “well head” and “production tree.” These devices control the formation pressure and flow. *Id.* The production tree is connected to pipes which carry the oil/gas to a

metering station, and from there to tanks for supplying to refineries. *Id.*, 075; EX-1003, ¶ 33.

Engineers measure well data to determine the maximum amount of hydrocarbons that the well can produce in a 24-hour period. EX-1007.074. From this, the “most efficient recovery rate” (“MER”) is determined. *Id.* The MER declines because the reservoir will lose pressure as the hydrocarbons are extracted. Calculations are thus made to determine when the well will need enhanced recovery methods. *Id.* This is known as providing “treatment” to the well. *Id.* The treatment includes injecting materials into the well to open the formation and allow the petroleum to more easily flow through the formation. *Id.*; EX-1003, ¶ 34.

B. Hydraulic Fracturing

Hydraulic fracturing, or “frac’ing,” increases the flow of hydrocarbons. U.S. Patent App. Pub. No. 2013/0306322 (“Sanborn”), [0003] (EX-1008). Hydraulic fracturing has been used for decades. U.S. Patent No. 9,410,410 [1:8-14] (“Broussard”) (EX-1009). Frac’ing involves pumping fluid at high pressures into a well to fracture the rock formation and form fissures therein. Sanborn, EX-1008, [0003]; Broussard, EX-1009 [1:14-21]. These openings create space for the hydrocarbons to move to the surface. Sanborn, EX-1008, [0003]. Sanborn states:

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]. Sand is a commonly-used proppant. *Id.*, [0026]; Broussard, EX-1009 [4:46-50]. *See* EX-1003, ¶ 35.

The proppant and fluid are mixed with other additives using a blender to form a “slurry” or “fracturing fluid” that is 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]; *see* U.S. Patent App. Pub. 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.... 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.”). EX-1003, ¶ 36.

Frac’ing requires large-scale equipment and massive amounts of fracturing fluid components on-site, such blenders, fracturing pumps, monitoring units, tanks for holding fracturing fluid materials, power units, and others. Sanborn, EX-1008, [0005]. This equipment is brought in and held by numerous tractor-trailer trucks. *Id.*; see [0025]-[0031] (describing the equipment and materials needed). Sanborn and Broussard graphically depict the trucks and equipment needed:

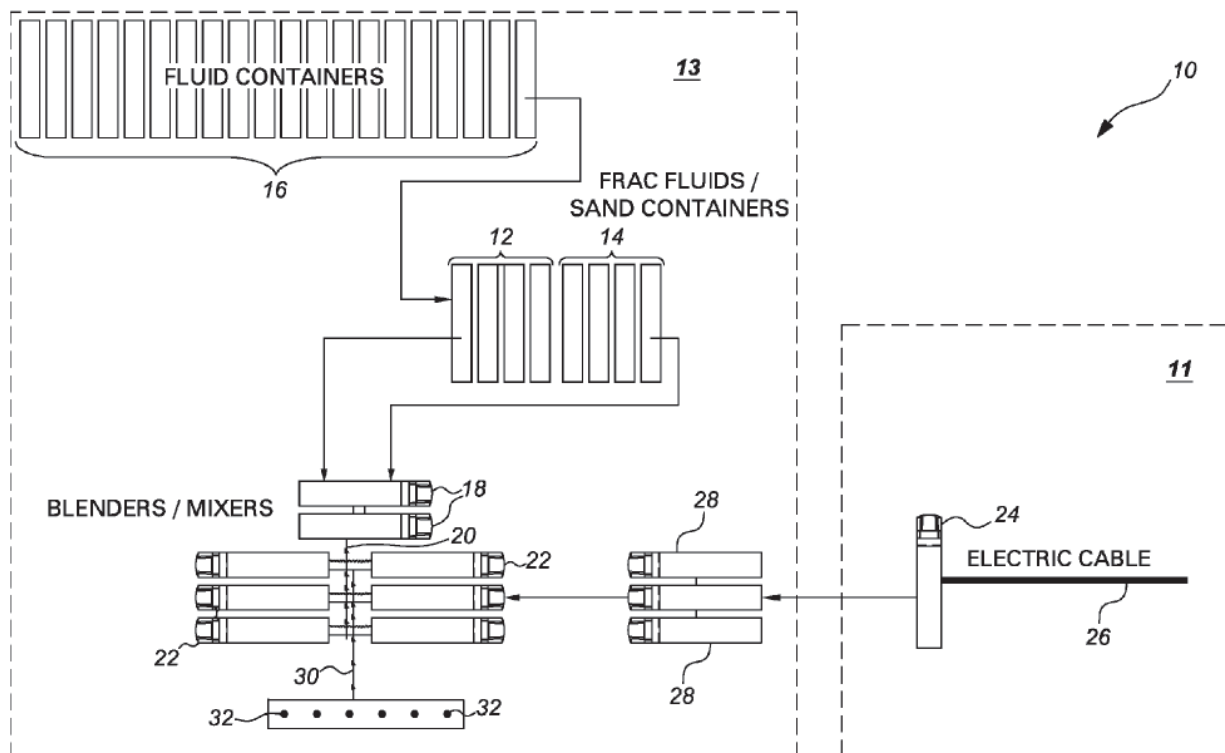


Fig. 1

Sanborn, Fig. 1 (EX-1008)

See EX-1003, ¶ 37. As shown above, the 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. EX-1008, [0034], [0036], [0038], [0040], [0043].

Broussard's Fig. 1 is similar:

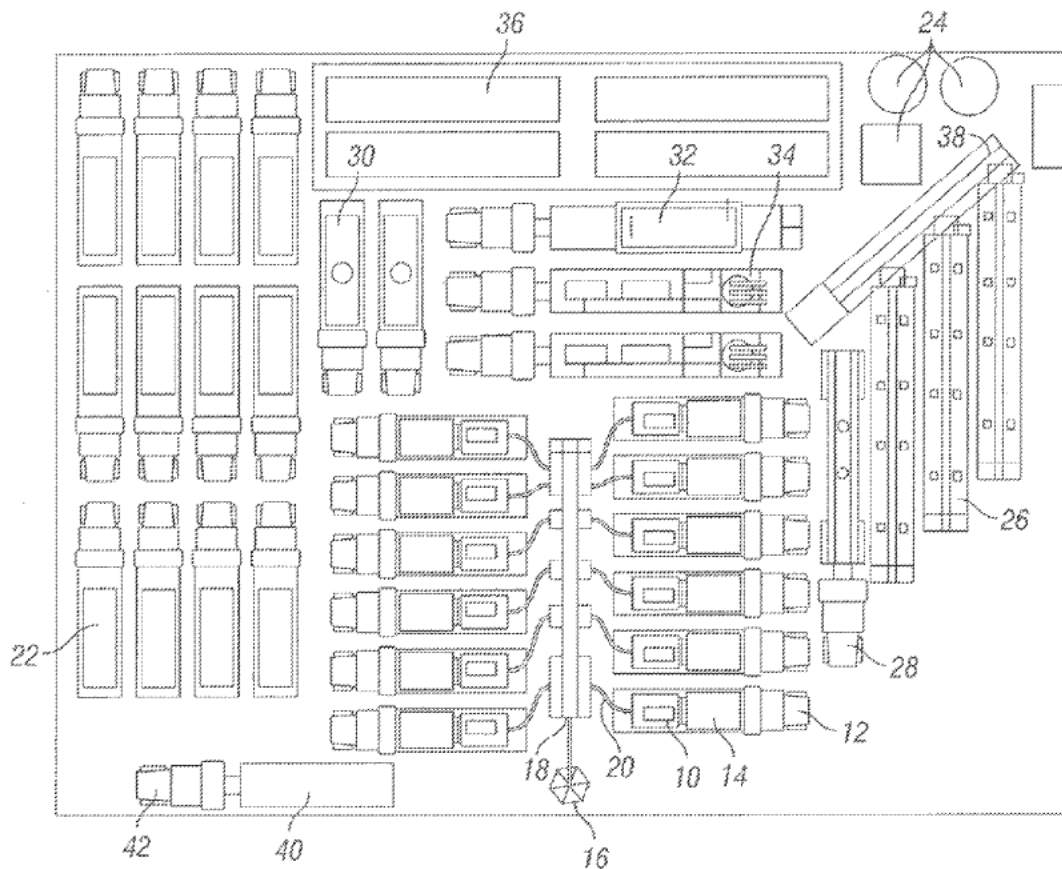


FIG. 1

Broussard, Fig. 1 (EX-1009)

Broussard states that “there 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]. Fig. 1 also 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 ... to supply the hydraulic fracturing fluid to the pumps 10.” *Id.* [4:60-67]. *See* EX-1003, ¶ 38.

Frac’ing requires multiple high-power pumps. Sanborn describes “16 tractor trailers [that] support 16 diesel-powered, 2000 hp fracturing pumps.... High-capacity, high-power hydraulic pumps (e.g., triplex or quintuplex types) are commercially available....” EX-1008, [0005]; *see* Coli, EX-1010, [0007] (describing “as many as fifty fluid pumps”). High-power pumps require commensurately high-power motors, or “prime movers,” to drive them. *Id.*, [0035] (describing using “multiple high pressure, plunger style pumps driven by diesel fueled prime movers”). Diesel-fueled motors were commonly used for this. *Id.*, [0005] (stating that “pumping systems are typically mobilized on skids or tractor-trailers and powered using diesel motors”); Sanborn, EX-1008, [0005] (“[T]ractor trailers are used to support individual sets of diesel engines and fracturing pumps....”). EX-1003, ¶ 39.

Diesel-powered systems had a “number of drawbacks.” Sanborn, EX-1008, [0006]. “[M]any 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 breakdowns.” *Id.* Further, these systems required “large amounts of diesel,” which led to “potential safety, noise, and environmental problems.” *Id.*, [0007]. The number of tractor-trailers required 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] (same); [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.”). *See* EX-1003, ¶ 40.

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

[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.

Id. [1:43-59]. *See* EX-1003, ¶ 41.

The industry thus considered ways to reduce reliance on diesel fuel. Coli proposed decreasing “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]. Another well-known solution was to substitute electric motors for diesel ones. Broussard, EX-1009 [1:8-11] (“[T]his technology relates to pumping fracturing fluid ... using pumps powered by electric motors.”);

Sanborn, EX-1008, Abstract (“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 ... to the generation and use of electrical power to deliver fracturing fluid to a wellbore.”). *See* EX-1003, ¶ 42.

Electrically-powered motors had several advantages. They 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” by “removing diesel prime movers”). This was because “diesel engines are very heavy, and so require ... a large amount of heavy equipment ... to transport the engines to and from” a wellsite. Oehring, EX-1011 [1:48-51]. Using electric motors means “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]. The electric motors may be powered with, for example, a natural gas-fueled turbine generator. *Id.*, Abstract. *See* EX-1003, ¶ 43.

Thus, years before the ’058 patent, it was known that fracturing operations could employ electric-powered pumps or traditional diesel ones. *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 “can be electric, gas, diesel, or natural gas powered”). *See* EX-1003, ¶ 44.

C. Control Systems for Hydraulic Fracturing Operations

Computerized control of fracturing operations was commonplace well before the '058 patent. Coli, EX-1010, [0065], [0072] (“Suitable controls and computer monitoring for the entire fracturing operation can take place at a single central location....”); Sanborn, EX-1008, [0030] (disclosing “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.”); [0050]; Dykstra, EX-1012, [0021] (disclosing an “electronic computer system” for monitoring and controlling the “operations of the chemical storage system, proppant storage system, blending unit, pumping grid, power unit, and manifolds”). *See* EX-1003, ¶ 45.

It was also well-known that control systems used well models to optimize performance. For example, U.S. Pat. Pub. No. 2006/0015310 (“Husen”) (EX-1013) teaches that 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....” [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 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]. *See* EX-1003, ¶ 46.

Husen discloses generating an optimized model that starts with a base model, inputs actual well performance data, and modifies the model to generate a performance prediction that “matches the actual performance for producing an optimized model.” EX-1013, [0035]. The model may be repeatedly optimized as actual performance data is collected. [0036]. Such models may be used “in monitoring or controlling the fracturing process or in performing subsequent fracturing jobs.” [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.”); [0023] (disclosing a “network model” used to determine “flow control valve settings”); [0025]. *See* EX-1003, ¶ 47.

U.S. Patent No. 10,280,722 (“Bello”) (EX-1015) discloses that a well 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.” [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.” [14:22-33]. See EX-1003, ¶ 48.

Accordingly, years before the '058 patent, optimized well operation and treatment models were known and available for well operations. For example, Bello shows in Figure 2 a “production data hub” that provides well operators (clients) with “software, data ... and modeling or prediction results.” EX-1015 [7:4-9]; see *id.* [6:48-7:9], [16-20-24]; see EX-1003, ¶ 49:

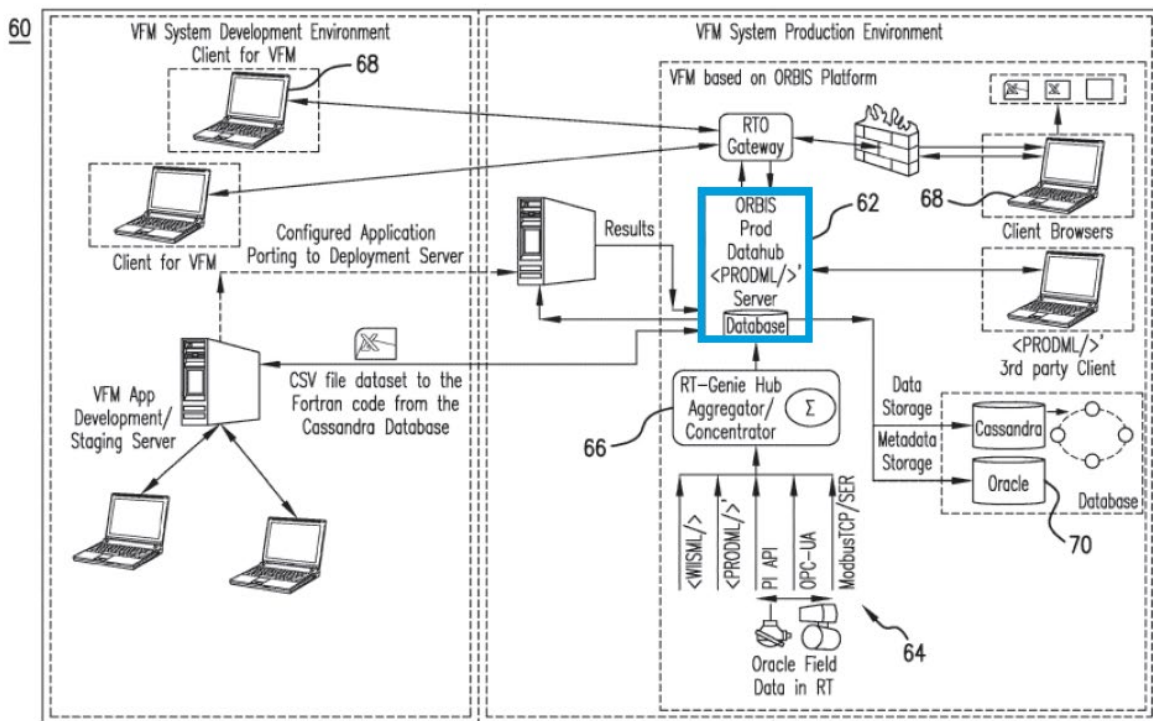


FIG.2

Bello, Fig. 2 (EX-1015) (annotated)

V. THE '058 PATENT AND FILE HISTORY

A. The '058 Patent

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

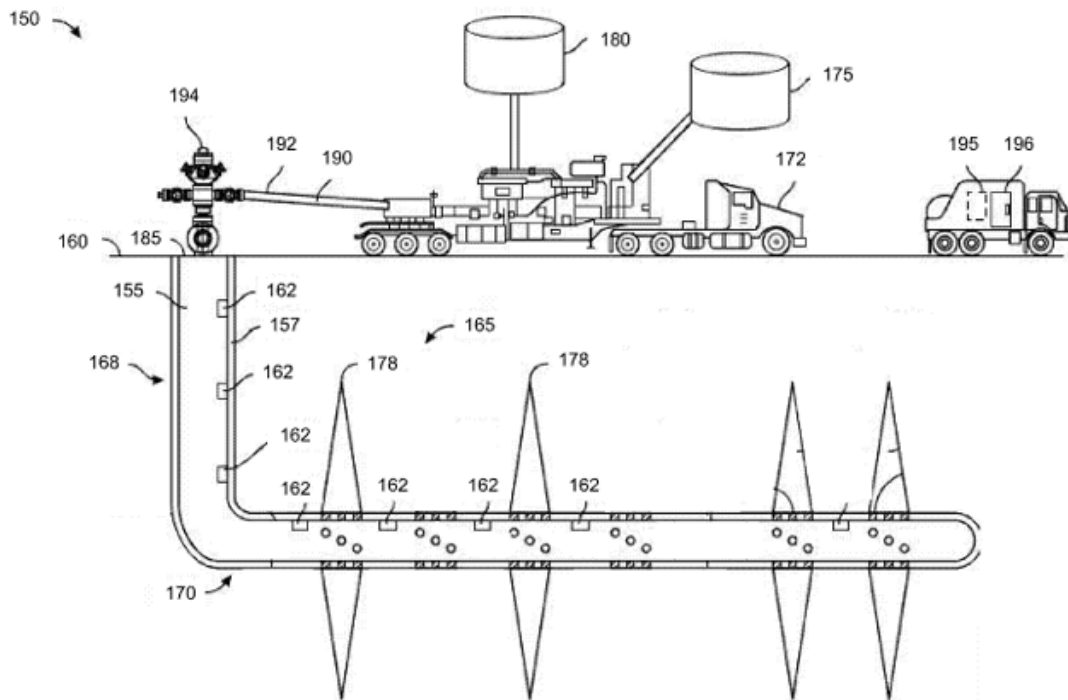


FIG. 1B

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

“Wellbore 155 extends from the surface 160 of the earth through the formation 165 formed by a drilling device from a previous drilling operation....”

Id. [5:39–42]. Sensors 162 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, such as pump rate and/or mixture of carrier fluid 175 and proppant 180 for treatment fluid 190, affects the measurements received from the sensors. [5:58–64].

The '058 patent acknowledges that “electric frac pumps are often controlled. . . to achieve certain downhole environment responses.” [1: 11–13]. According to the '058 patent, conventional systems relied on technicians manually adjusting the pump settings according to “appraised information retrieved from [sensors in] the downhole environment.” [1:13–15]; [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.”). The patent further admits that it was known to control the pumps by using system models—that is, models that technicians select to best represent a downhole environment measured by sensors—to determine pump settings. [1:19–26]. The '058 patent claims are directed at having a computer perform this manual process. *See* claims 1, 9, 16.

The purported '058 invention is depicted in Fig. 4, reproduced below:

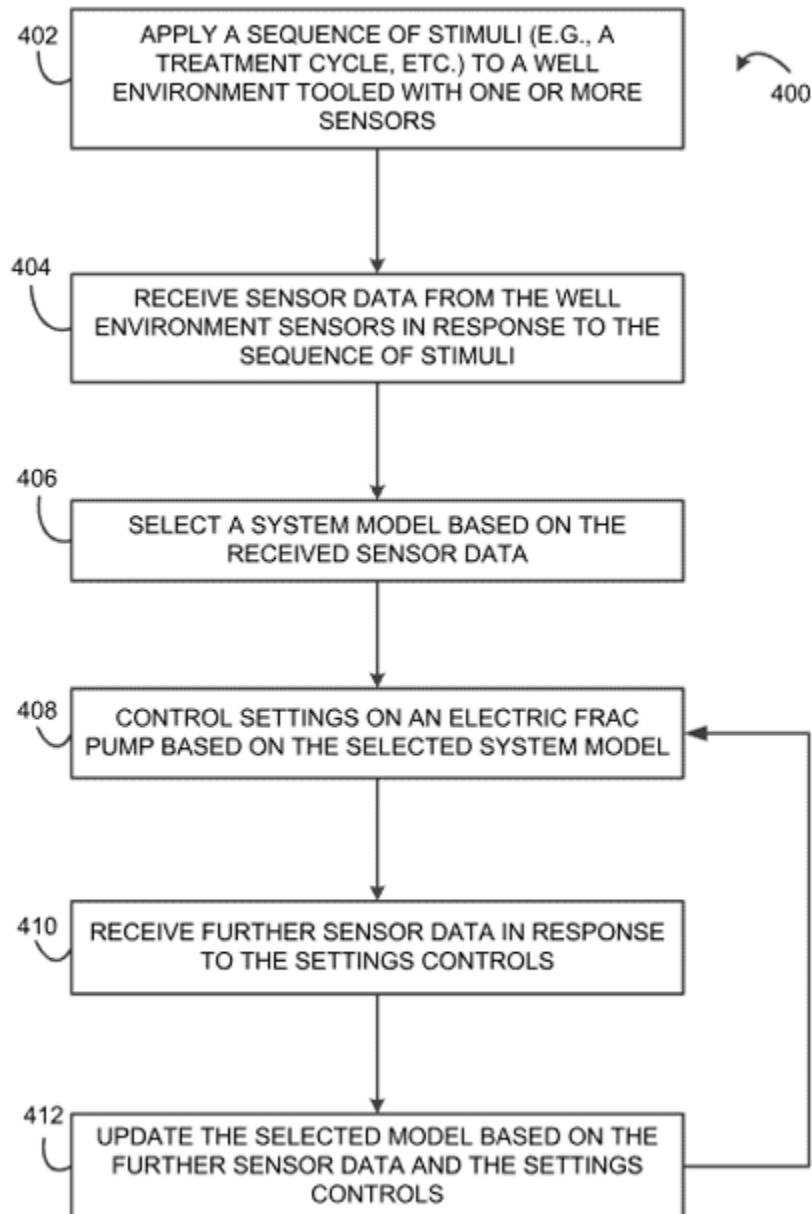


FIG. 4

058 Patent, Fig. 4 (EX-1001)

Figure 4 illustrates steps “for selecting and executing a representative system model.” *Id.* [8:22–23]. In step 402, “a sequence of stimuli is applied. . . to a well environment tooled with one or more sensors.” [8:26–28]. In steps 404 and 406,

sensor data is collected and used to select a representative system model. [8:19–44]. In step 408, “settings on an electric frac pump are controlled based on the selected representative system model.” [8:45–46]. Optionally, additional sensor data is measured and used to update the selected model and/or pump settings (steps 410, 412). [8:49–55]; see EX-1003, ¶¶ 51-54.

B. The Prosecution History

The '058 application was filed on September 17, 2019. EX-1002. The Examiner issued a first Office Action allowance, stating that “after a thorough search,” the claims were allowed. EX-1002.024. The Examiner, however, did not apply the prior art relied on herein, and also did not reject the claims under § 101.

C. The Challenged Claims

Claims 1-20 are challenged herein. Independent claims 1, 9, and 16 are materially identical. Each claim specifies the same four steps that are shown in blocks 402, 404, 406, 408 in Fig. 4. Claim 1 requires a “computer-implemented method,” claim 9 specifies a “system” with “one or more processors” and a “memory comprising instructions” for implementing the method, and claim 16 is directed to a “non-transitory computer readable medium storing instructions that, when executed by one or more processors, cause the processors” to implement the method. Claim 1 is thus representative:

Claim 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.

Dependent claims 2-8, 10-15, and 17-20 are directed to known and conventional elements of well operation and modeling.

VI. LEVEL OF ORDINARY SKILL IN THE ART

As of September 17, 2019, a person of ordinary skill in the art (“POSITA”) would have had a B.S. 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, a person with additional education but less professional experience, and vice-versa, may qualify. EX-1003, ¶ 4. Petitioners’ expert Dr. Michael Nikolaou is qualified to give testimony from the viewpoint of a POSITA. EX-1003, ¶¶ 5–16; EX-1004.

VII. STATUTORY GROUNDS FOR THE CHALLENGES

Ground 1	Obviousness under § 103 of Claims 1–4, 6–7, 9–12, 14, 16–19 based on U.S. Patent App. Pub. No. 2018/0230782 (“Pankaj”) (EX-1005) in View of U.S. Patent App. Pub. No. 2016/0258267 (“Payne”) (EX-1006)
Ground 2	Obviousness under § 103 of Claims 5, 6, and 13 based on Pankaj and Payne, in further view of U.S. Patent No. 10,378,333 (“Dawson”) (EX-1024)
Ground 3	Obviousness under § 103 of Claims 8, 15, and 20 based on Pankaj and Payne, in further view of U.S. Patent No. 10,087,722 (“Lecerf”) (EX-1027)
Ground 4	Obviousness under § 103 of Claims 3, 11, and 18 based on Pankaj and Payne, in further view of U.S. Patent No. 8,352,227 (“Klumpen”) (EX-1019)
Ground 5	Invalidity under § 101 of Claims 1–20 (Non-Statutory Subject Matter)

The above-identified references are prior art under 35 U.S.C. § 102(a) (post-AIA) as shown below:

Reference	Publication Date
Pankaj	08/16/2018
Payne	09/08/2016
Dawson	08/13/2019
Lecerf	10/02/2018
Klumpen	01/08/2013

VIII. CLAIM CONSTRUCTION

For this proceeding, Petitioners do not believe claim construction is required and apply the common and ordinary meaning of the claim terms. Petitioners reserve the right to challenge Patent Owner’s claim constructions in this or other proceedings, and to assert that certain terms are invalid under 35 U.S.C. § 112 in district court.

IX. IDENTIFICATION OF HOW THE CLAIMS ARE UNPATENTABLE

A. GROUND 1: Claims 1–4, 6–7, 9–12, 14, 16–19 are Obvious Over Pankaj in View of Payne

1. Pankaj Introduction

Pankaj discloses methods and systems for “performing wellsite operations.” EX-1005, [0001]. *See* Figure 3.1:

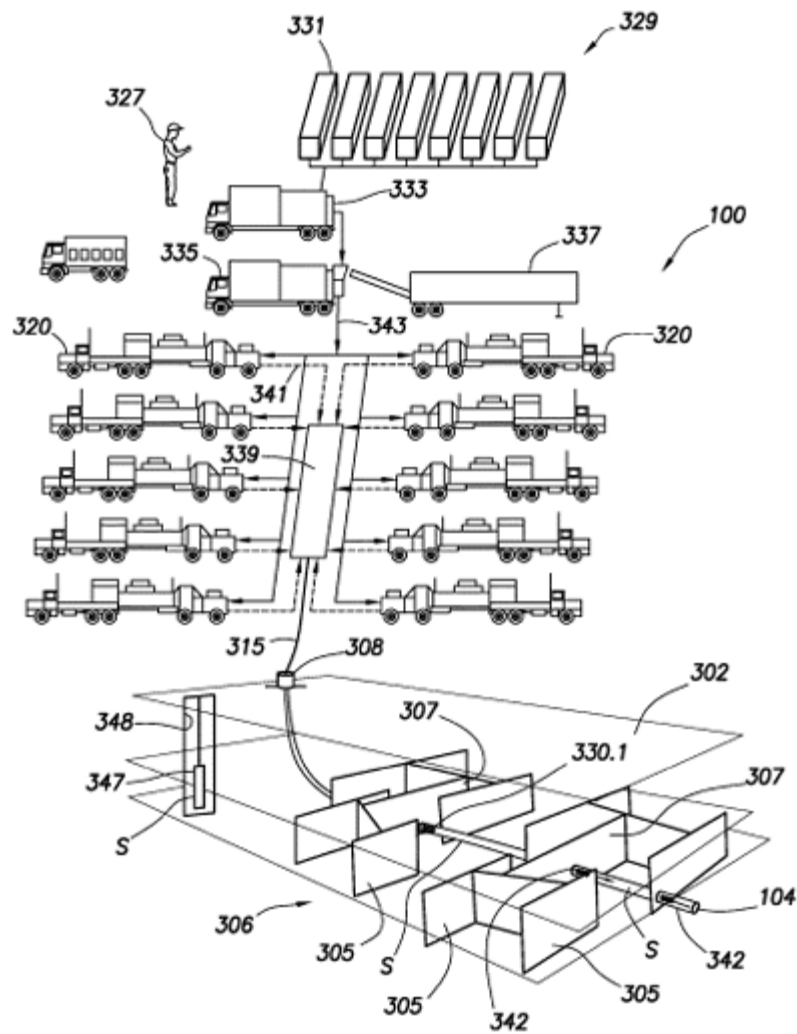


FIG.3.1

Pankaj, Fig. 3.1 (EX-1005)

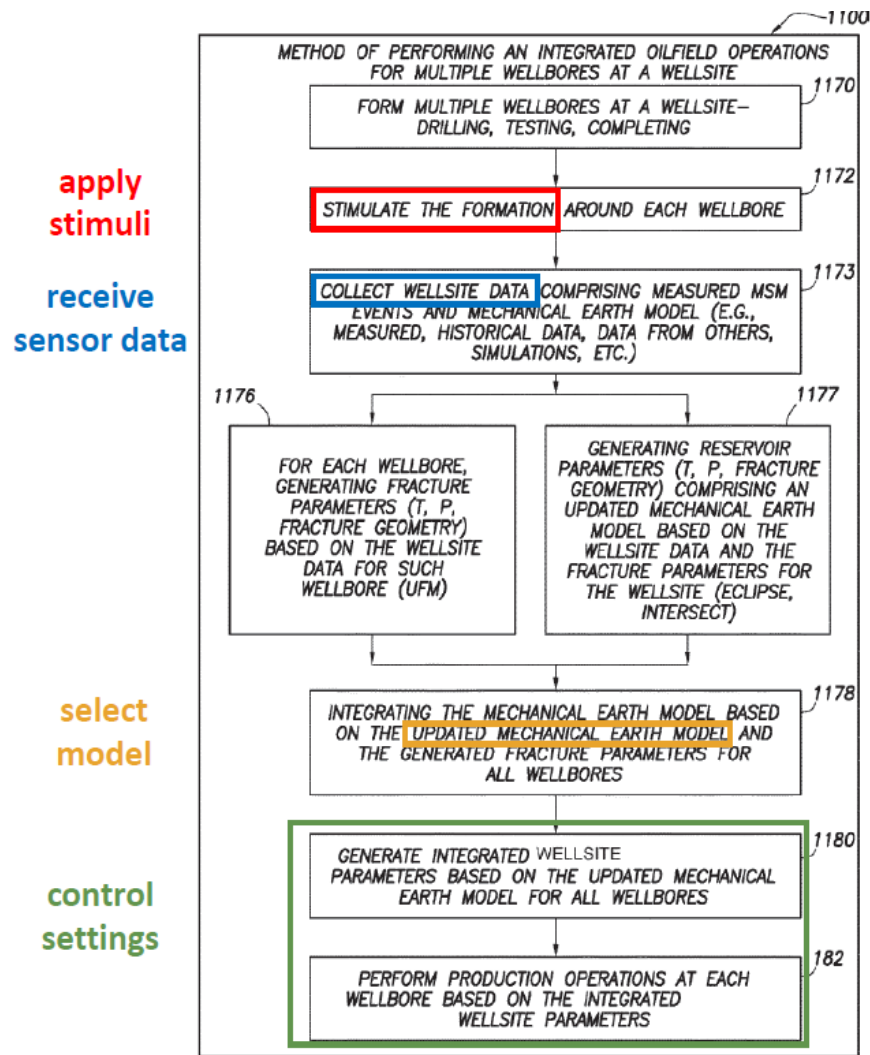
Id., [0054]. The “fracture operation at the wellsite 100 [involves] the injection of fluids into the wellbore ... to expand the fracture network 306 propagated therein.”

[0054]. Sensors (labeled “S”) are placed throughout the wellbore. [0062]. 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. Pankaj discloses that “fracturing treatment parameters may be optimized” based on sensor data. [0141].

To do so, Pankaj describes a method using mechanical earth models and sensor data that matches the '058 claimed method, as shown in annotated Figure 11:



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

Pankaj’s method includes steps for “performing integrated oilfield operations” using wellsite (sensor) data and models. [0097]. In steps 1172–1173, the method involves “stimulating the formation around each wellbore (e.g., perforating, injecting)” and “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. [0099] (“The

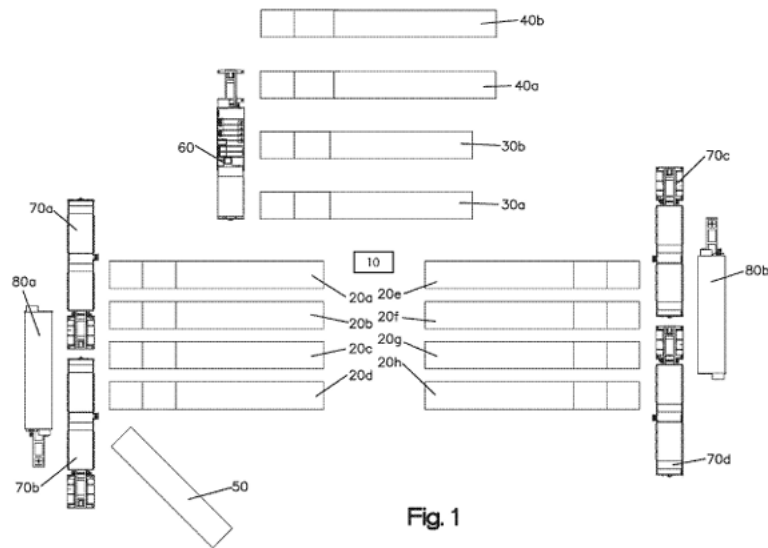
wellsite may also include a mechanical earth model (MEM).... In addition to property distribution (density, porosity) and fracture system, the model may incorporate wellsite parameters, such as pore pressures, state of stress, rock mechanical properties, etc.”); [0100] (“The 1176 fracture parameters may comprise ... pump rate, volume., fracture geometry..., concentration of proppant etc..., injection fluid parameters...”); [0103] (“Simulation techniques ... may be applied to these input parameters from the wellsite to predict the equivalent behavior of rock deformation causing the hydraulic fracture propagation.”). Using simulations, reservoir parameters are generated at step 1177 from both wellsite data and the generated fracture parameters. [0119]. At step 1178, Pankaj’s method uses generated fracture parameters to update the mechanical earth model. [0126]. Finally, new wellsite parameters are generated from the updated mechanical earth model (step 1180) and are used to perform fracture and/or production operations by, *e.g.*, controlling pump settings (step 1182). [0140]–[0141]; see EX-1003, ¶¶ 63-64.

For example, Pankaj discloses that the wellsite 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.*” [0042]. Further, “these adjustments *may be made automatically based on computer protocol*, and/or manually by an

operator.” *Id.*; [0064] (“Based on such simulations, adjustments may be made in the operations to generate optimal results...”); [0078] (“The fracture parameters for ... single well or multiple wells are then optimized. Examples of such fracture parameters may be volume of fracturing fluid, fracturing proppants, ... etc.”).

2. Payne Introduction

Payne discloses a fracturing system using electrical motors. EX-1006, [0042] (“FIG. 1 illustrates an example of a hydraulic fracturing fleet layout for a well fracturing system using electrical motors.”). *See* Figure 1:



Payne, Fig. 1 (EX-1006)

Payne’s system includes “electrical pump motors” and “electrical fracturing motors.” [0014]–[0015]. 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 diesel fuel. *Id.*, [0008]–[0009]; [0037]–[0040]; EX-1003, ¶ 66.

3. A POSITA Would Have Been Motivated to Combine Pankaj and Payne

It would have been obvious to a POSITA to combine the teaching in Payne extolling the use of electrical fracturing pumps with Pankaj’s teachings regarding methods for oilfield operations involving fracturing. Put another way, a POSITA would have readily understood that Pankaj’s systems and methods would benefit from Payne’s electrical fracturing pump teachings. EX-1003, ¶ 67.

Both Pankaj and Payne are analogous art to the ’058 patent. EX-1003, ¶ 68. Pankaj and Payne are both directed toward the same field of endeavor of the ’058 patent—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.”); EX-1003, ¶ 68. Pankaj and Payne are also 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] (“[O]perations may be selectively adjusted based on the data collected [from sensors]. Portions of the operation ... may be optimized based on the

information.... [W]ell plans may be adjusted to select optimum operating conditions, or to avoid problems.”), [0067], [0069], [0078], [0090], [0141]; EX-1006, [0010]–[0011]; Abstract (noting that the disclosed system includes “a system control unit [which] may control the operational parameters of the system”); EX-1003, ¶ 68.

Pankaj’s operations use fracturing equipment including pumps. EX-1003, ¶ 69. Figure 3.1 of Pankaj shows the fracturing equipment and pump system 329:

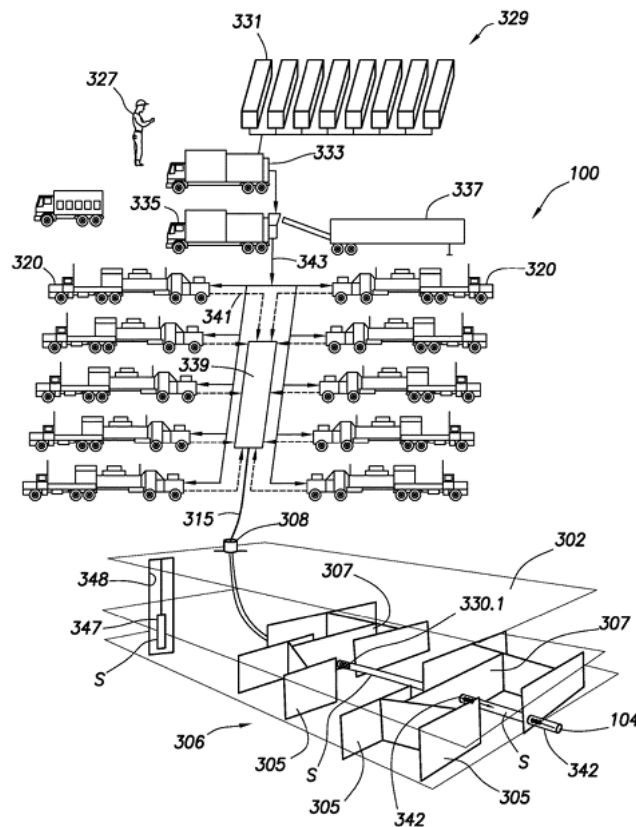


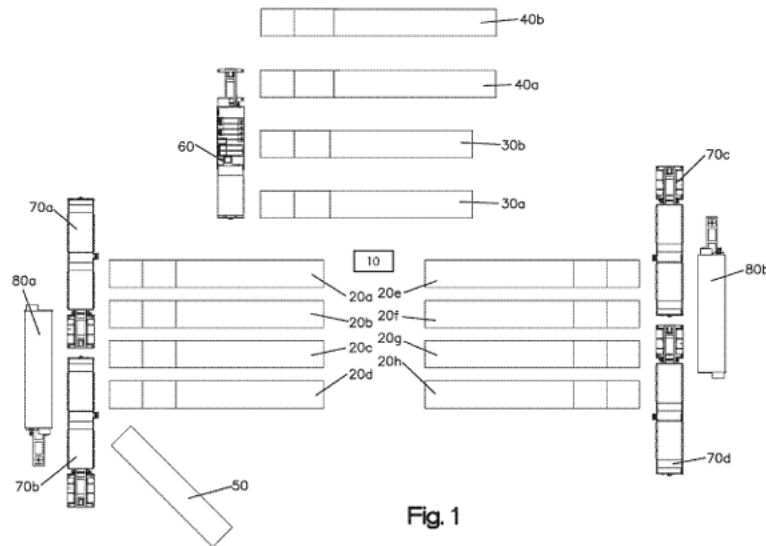
FIG. 3.1

Pankaj, Fig. 3 (EX-1005)

EX-1003, ¶ 69. Pankaj 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.” EX-1005, [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...”). Pankaj, however, does not specify or require any pump type. A POSITA would therefore understand that the pump choice was an implementation detail, and a POSITA would have naturally looked to known pump systems in the field for this choice. EX-1003, ¶ 69.

As explained above, *see* § IV.B, only a limited number of well-known choices for pumps used in fracturing operations existed as of the ’058 filing date. EX-1003, ¶ 70. 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 using electrical pumps was well-known in the industry as of the ’058 filing date. EX-1003, ¶ 70. A POSITA also would have recognized the advantages of electrical pumps over traditional diesel ones. EX-1003 ¶¶ 39–44. Payne is one reference teaching those advantages and disclosing the use of electrical pumps. EX-1003, ¶ 70.

Payne discloses a similar well fracturing system, using electrical motors to drive the pumps. EX-1003, ¶ 71; EX-1006, [0042] (“FIG. 1 illustrates an example of a hydraulic fracturing fleet layout for a well fracturing system using electrical motors.”). See Figure 1:



Payne, Fig. 1 (EX-1001)

This system may include “electrical pump motors” and “electrical fracturing motors.” EX-1006, [0014]–[0015]. Payne explains the benefits of using electrical motors for the pumps over traditional diesel ones. *Id.*, [0008] [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”); EX-1003, ¶ 71.

A POSITA would have been motivated to apply Payne’s teachings concerning the benefits of using “*electrical fracturing equipment*” and an “*electrical fracturing pump*” when considering Pankaj’s method and systems for numerous reasons. EX-1003, ¶ 72.

Payne provides four express reasons to modify Pankaj’s teachings to choose electrical motors and pumps (EX-1003, ¶ 73):

- “[e]lectrical motors are lighter, have fewer moving parts, and can more easily be transported” over conventional motors. EX-1006, [0009];
- “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.” [0037];
- “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.” [0009];
- electrical motors provide “the ability to independently control and operate ancillary sub-systems.” [0040].

For any of the above reasons, a POSITA would have been motivated to select Payne's "*electrical fracturing equipment*" and "*electrical fracturing pumps*" when reviewing Pankaj. EX-1003, ¶ 73.

Further, Pankaj is agnostic concerning the type of pumps used in the disclosed system, leaving that implementation detail to the POSITA. EX-1003, ¶ 74. 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. EX-1003, ¶ 74. Payne shows that electrical fracturing equipment and pumps were known years before the '058 filing date, making it a known technique. EX-1006, Cover; EX-1003, ¶ 74. Payne also discloses reasons why electrical fracturing equipment and pumps provide "advantages over traditional diesel-driven" equipment. EX-1006, [0037], [0009]; EX-1003, ¶ 74. Accordingly, a POSITA would have recognized that the system described in Pankaj would have benefitted from the improvements described in Payne. EX-1003, ¶ 74.

A POSITA would have also recognized that using Payne's electrical fracturing equipment and pump was a design choice. EX-1003, ¶ 75. There were only a limited number of identified predictable solutions for pumps used in fracturing operations. EX-1003, ¶ 75. A POSITA would have limited options,

including diesel-driven pumps and electric pumps. EX-1003, ¶ 75. For each option, a POSITA would have understood the trade-offs and advantages of each of these choices. EX-1003, ¶ 75. 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]; EX-1003, ¶ 75. This advantage 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 described in Pankaj that uses electrical motors—like the one in Payne—rather than the harder to transport diesel-driven solution. EX-1003, ¶ 75.

Finally, 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. EX-1003, ¶ 76. Using electrical equipment and pumps in the hydraulic fracturing industry was, by September 2019, commonly known. EX-1003, ¶ 76. Besides Payne, and as early as 2012, other references teaching the use of such equipment included Broussard (EX-1009), Sanborn (EX-1008), and Coli (EX-1010). EX-1003, ¶ 76. While Payne states that “the use and control of hydraulic fracturing operations using electrical motors has not been successfully implemented in practice,” (EX-1006, [0012]), that statement was made in an application filed years before the September 2019 ’058 filing date. EX-1003, ¶ 76. By then, operations using electric motors to drive pumps were

deployed, in public use, and commonly referred to as “e-fracturing.” EX-1003, ¶ 76; *see* EX-1029 (November 21, 2015 website 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 few years and as such would have had a reasonable expectation of success in combining Payne’s teachings of using electrical fracturing equipment and electric pumps with Pankaj’s teachings. EX-1003, ¶ 76.

4. Pankaj and Payne Render Obvious Claim 1

- i. A computer-implemented method for controlling electrical fracturing equipment for fracturing a well, the method comprising:*
[preamble]

If the preamble is limiting, Pankaj discloses it. EX-1003, ¶¶ 79–81. Pankaj discloses a method for “generating fracture parameters including a hydraulic fracture network of a fracture grid for each of [] multiple wellbores based on

wellsite data....” EX-1005, Abstract. Figure 11 shows a “method for performing an integrated oilfield” operation:

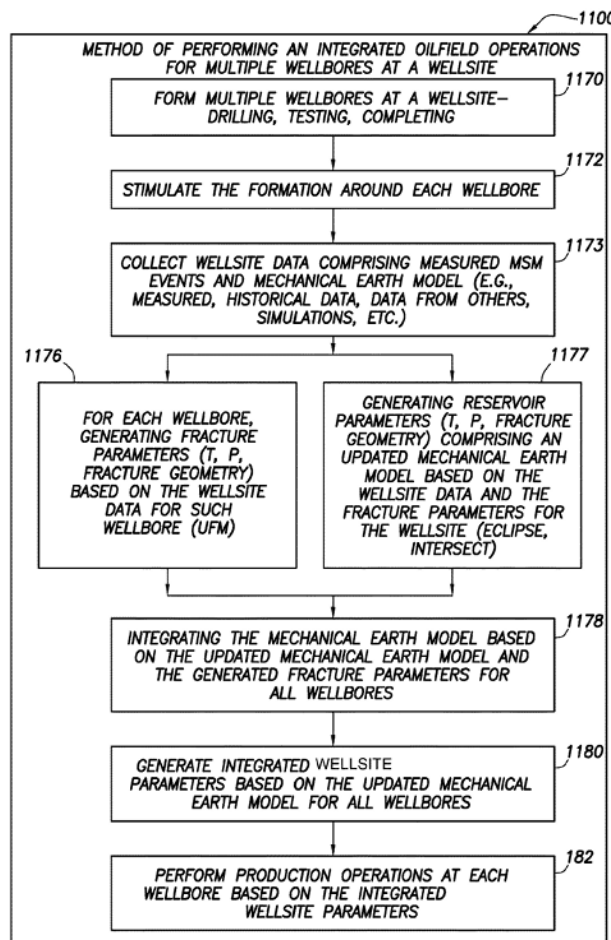


FIG. 11

Pankaj, Fig. 11 (EX-1005)

Pankaj discloses that the method may be computer-implemented. EX-1005, [0031], [0042], [0064]–[0066], [0113], [0099] (explaining that the “MEM may be built ... using conventional software”); EX-1003, ¶ 79.

Pankaj does not expressly disclose “*electrical fracturing equipment.*” As explained above, *see* § IX.A.3, combining Payne’s teachings concerning electrical

fracturing equipment and pumps with Pankaj’s teachings would have been obvious to a POSITA. EX-1003, ¶ 80. Thus, the combination of Pankaj and Payne discloses “[a] *computer-implemented method for controlling electrical fracturing equipment for fracturing a well.*” EX-1003, ¶ 80.

- ii. **“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;” [1A]**

Pankaj discloses or at a minimum renders this limitation obvious. EX-1003, ¶¶ 82–84. Pankaj discloses generating and monitoring a sequence of stimuli for application in a well environment, shown in annotated Figure 11:

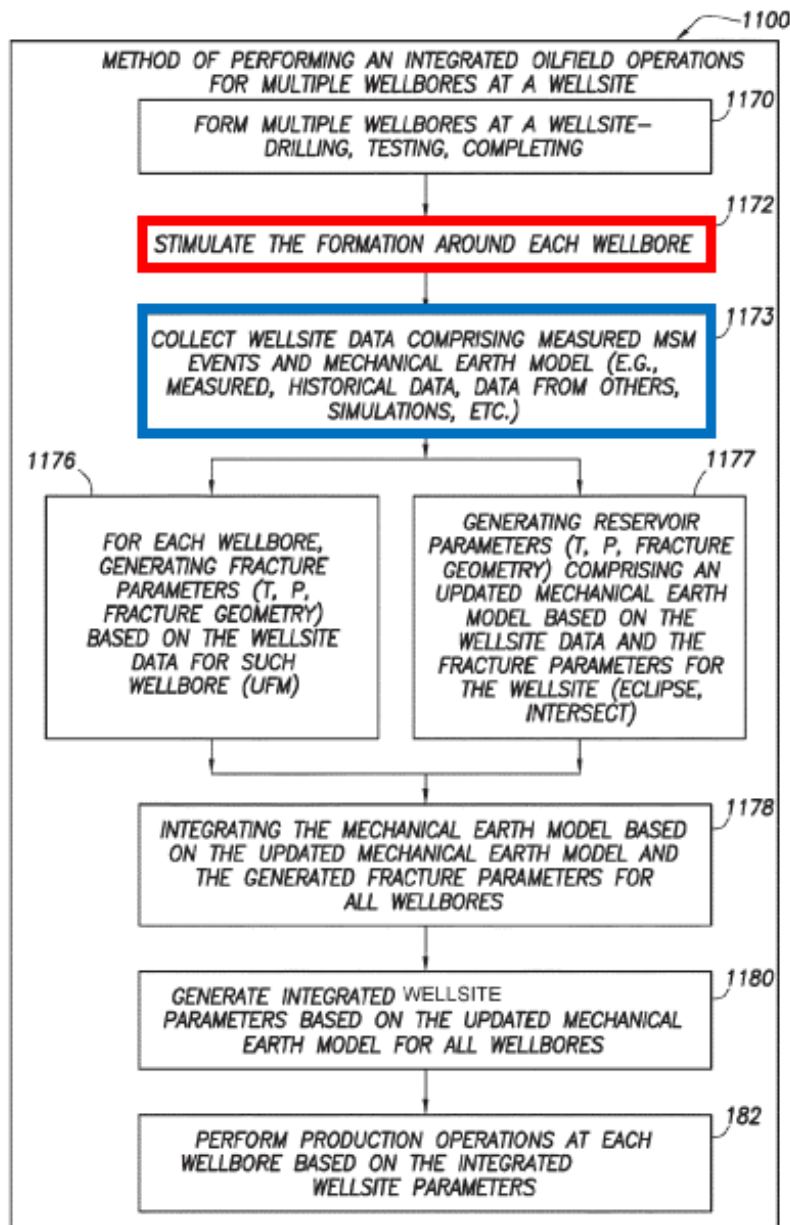


FIG.11

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

EX-1003, ¶ 82. Highlighted step 1172 discloses “*stimulating* the formation around each wellbore (e.g., *perforating, injecting*).” EX-1005, [0097]; EX-1003, ¶ 82.

A POSITA would understand “perforating” and “injecting” refer to fracturing treatment processes. EX-1003, ¶ 83; 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.)”).

A POSITA would understand 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”). EX-1003, ¶ 83. Thus, a POSITA would understand that Pankaj discloses (or renders obvious) “*generating a sequence of stimuli ... comprising one or more of particulate concentrations, chemical concentrations, or a pump rate control.*” EX-1003, ¶ 83.

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

Pankaj discloses this. EX-1003, ¶¶ 85–89. Figure 11 teaches generating both the “fracture parameters” 1176 and “reservoir parameters” 1177 using “wellsite data” 1173 from *wellbore sensors* (“formation response data”):

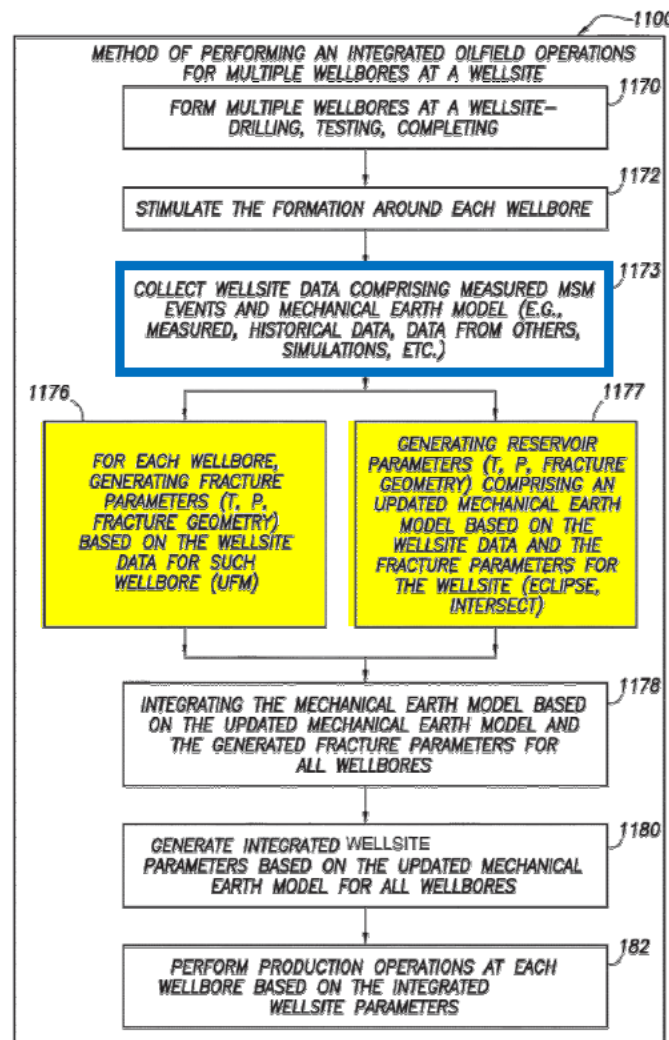


FIG. 11

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

EX-1003, ¶ 86; *see* EX-1005, [0100], [0119]. Pankaj further explains that, for each wellbore, fracture parameters in step 1176 are “based on wellsite data” collected from sensors. EX-1005, [0100]; EX-1003, ¶ 86.

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]; EX-1003, ¶ 87. Accordingly, a POSITA would have understood that this data includes “*formation response data*” measured using downhole sensors. *See* EX-1005, [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.”); EX-1003, ¶ 87.

Additionally, Pankaj discloses that sensors may “be located at various positions along the wellbore.” EX-1005, [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.”). Based on these disclosures, a POSITA

would understand that 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 EX-1005, [0062], [0102]; EX-1003, ¶ 87.

Moreover, Pankaj discloses that reservoir parameters in step 1177 are likewise “based on wellsite data,” EX-1005 [0119], that include, for example “borehole imaging logs, evaluating seismic measurements, ant tracking, sonic measurements, geological measurements, etc.” EX-1005, [0120]; *see* EX-1005, [0123]–[0124]; EX-1003, ¶ 88. A POSITA would have recognized that these wellsite data examples are from surface sensors. EX-1003, ¶ 88; EX-1005, [0121], [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.*”).

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

Pankaj discloses this. EX-1003, ¶¶ 90–94. Pankaj’s fracture parameters are modeled using wellsite data and the stimulation step. EX-1003, ¶ 91; *see* EX-1005, Fig. 11, [0102], [0105]. Step 1776 uses the received parameters for simulation (modeling) techniques, such as an Unconventional Fracture Model, that “help

predict the equivalent behavior of rock deformation causing the hydraulic fracture propagation.” EX-1005, [0103]; EX-1003, ¶ 91; *see* EX-1005, [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 that 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.

EX-1005, [0112] (emphasis added); EX-1003, ¶ 91; *see* EX-1005, [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.”). Selecting the appropriate model is based on both wellsite data (“*received formation response data*”), EX-1005, [0102], [0105] and fracture parameters and stimulation step (“*sequence of stimuli*”), EX-1005, [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.”); EX-1003, ¶ 91; *see* EX-1005, [0062] (explaining that wellsite data measured by sensors includes fracture parameters). 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.” EX-1003, ¶ 92. A POSITA would understand from Pankaj that the fracture parameters and reservoir parameters are generated in response to both the wellsite data and the stimulation step. *Id.*, ¶ 92; *see also* EX-1005, [0055], [0059], [0061], [0086], [0098], [0100], [0102]–[0103], [0112], [0116]–[0117].

Reservoir simulations likewise use models determined from generated fracture parameters (“*sequence of stimuli*”) and wellsite data (“*the received formation response data*”). EX-1005, [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.”); EX-1003, ¶ 93. Pankaj provides exemplary parameters used by a reservoir simulator:

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).

EX-1005, [0121]; EX-1003, ¶ 93.

The fracture parameters and reservoir parameters are then integrated into an updated mechanical earth model. EX-1005, 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.”); EX-1003, ¶ 93; *see* EX-1005, [0138]–[0139].

Accordingly, a POSITA would have understood that these disclosures teach 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*”). EX-1003, ¶ 93.

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

Pankaj discloses this limitation except for the fracturing pump being “electrical,” which is disclosed by Payne. EX-1003, ¶¶ 95–99.

Figure 11 of Pankaj discloses three steps addressing how a fracturing pump is controlled: (i) generating fracturing parameters based on the updated model 1180, (ii) using those updated parameters, generating integrated wellsite parameters, and (iii) operating a fracturing pump at a wellbore 1182, shown below:

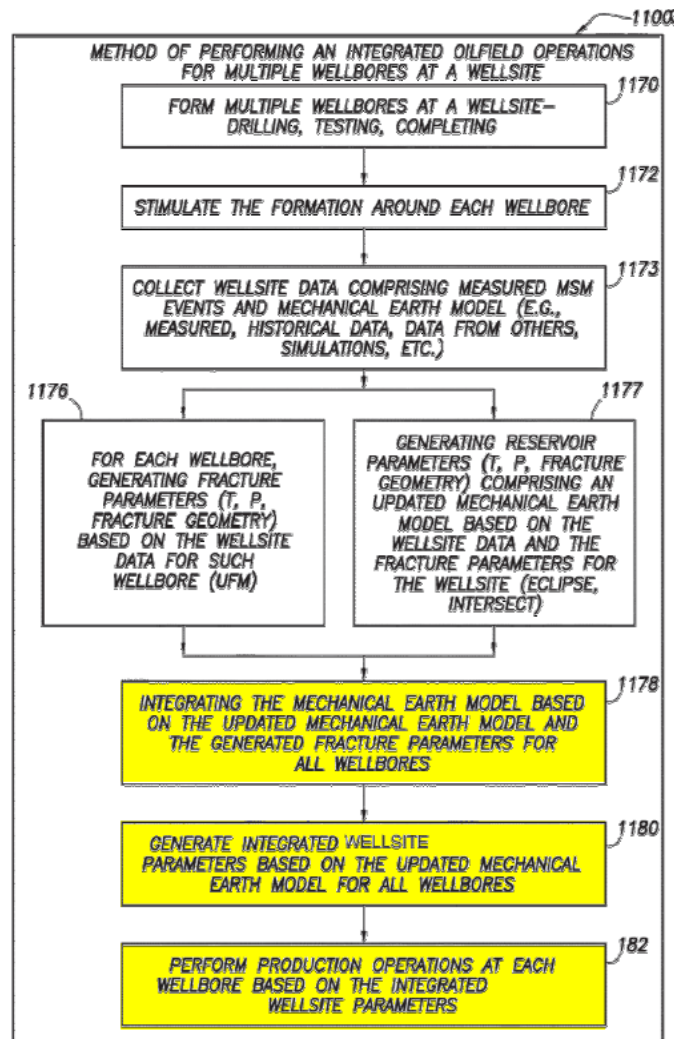


FIG. 11

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

EX-1003, ¶ 96; *see* EX-1005, [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. EX-1003, ¶ 96; EX-1005, [0105], [0140]

(“The integrated dynamic wellsite parameters may include, for example, production forecasts of production parameters (e.g., pressure, flow rate, permeability, etc.). . . .”). Wellsite parameters are generated from the updated mechanical earth model (shown in step 1180), and those same parameters are further used in step 1182 for “performing fracture and/or production operations at one or more of the wellbores of the wellsite.” EX-1005, [0141]; EX-1003, ¶ 96. Step 1182 includes optimizing “fracturing treatment parameters”—that is, parameters for “*controlling an . . . fracturing pump*”—“to maximize well production.” EX-1005, [0141], [0076], [0126]; EX-1003, ¶ 97.

Based on these disclosures, a POSITA would have recognized that a fracturing pump is controlled via these updated fracture parameters using the model. *See* EX-1005, [0140]–[0141]; EX-1003, ¶ 97.

Pankaj does not expressly disclose an “*electrical fracturing pump*,” but as explained above, *see* § IX.A.3, using Payne’s teachings regarding “*electrical fracturing pumps*” would have been obvious. EX-1003, ¶ 98. The combination of Pankaj and Payne thus renders obvious “*controlling an electrical fracturing pump based on the representative system model.*” EX-1003, ¶ 98.

5. Pankaj and Payne Render Obvious Independent Claims 9 and 16

Claim 9 recites “[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 recites “[a] non-transitory computer readable medium storing instructions that, when executed by one or more processors, cause the one or more processors to....”

To the extent these preambles are limiting, Pankaj discloses them. EX-1003, ¶¶ 126–128. As explained above, *see* § IX.A.4.i [1pre], Pankaj renders obvious “[a] computer-implemented method for controlling electrical fracturing equipment for fracturing a well.” EX-1003, ¶ 126. To implement this method, Pankaj discloses using a computer processor and memory to store instructions for that processor. EX-1003, ¶ 126; EX-1005, [0042]. Moreover, Pankaj explains that Figure 11’s illustrated method uses “modeling software and/or simulators”—all of which require a processor and memory with instructions for the processor to operate the software. EX-1005, [0031]; EX-1003, ¶ 127; *see* EX-1005, [0064]–[0066], [0113], [0099] (explaining that the “MEM may be built using geomechanical oilfield software . . . or other geomechanical techniques using conventional software”); [0037], [0098] (disclosing “computer facilities” and “computerized systems” respectively). EX-1003, ¶ 127.

The remaining limitations of claims 9 and 16 are materially identical to the four steps in claim 1, and therefore the above analysis (*see* §§ IX.A.4.ii-iv) applies to the remaining claims 9/16 limitations. EX-1003, ¶¶ 129–136.

6. Pankaj and Payne Render Obvious Dependent Claims 2-4, 6-7, 10-12, 14, 17-9

a. Claims 2, 10, 17

These claims are substantively identical. Ex. 1003, ¶¶ 137–138. Using claim 2 as representative, it depends from claim 1 and adds that the “*wherein the representative system model is retrieved from a data store based the received formation response data.*” The ’058 patent explains that one example of a data store is computer memory. EX-1001 [7:17-21]; Ex. 1003, ¶ 100.

A POSITA would have understood that Pankaj’s updated mechanical earth model is stored in and retrieved from memory and selected based on both the wellsite data and generated fracture parameters. EX-1003, ¶¶ 101-102. Pankaj explains that these mechanical earth models may be “a model that is provided, or may be calculated from the other wellsite data.” Ex-1005, [0099]; EX-1003, ¶ 102. A POSITA would have understood that Pankaj’s “provided” mechanical earth models are retrieved from computer memory (“a *data store*”). EX-1003, ¶ 102; *see* Ex. 1005, [0037] (explaining that the system includes “computer facilities for receiving, storing, processing, and/or analyzing data from the operation”); *id.* [0042], [0058], [0113].

Pankaj also discloses that the MEMs may be based on “built-in unconventional hydraulic fracture models like UFM™ (or other unconventional fracture models).” EX-1005, [0075]. A POSITA would have understood that the

UFMs were stored in a data store, e.g., computer memory, so that they can be used, if needed. EX-1003, ¶ 101. Accordingly, a POSITA would have also understood that Pankaj’s UFM’s are also “retrieved from a data store” as claimed. EX-1003, ¶¶ 101–102.

b. Claims 3, 11, 18

These claims are substantively identical. EX-1003, ¶¶ 139–140. Using claim 3 as representative, it depends from claim 1 and requires “*wherein the representative system model is generated based on data created through simulation with uncertainty parameters.*”

Pankaj discloses this limitation. EX-1003, ¶¶ 104–107. Pankaj explains that “fracture simulation software, such as MANGROVE, may be used to simulate fracture operations (or engineered stimulation design) alone or withing the software platform.” EX-1005, [0065]. Such simulation software includes workflows like that shown in Figure 4.2:

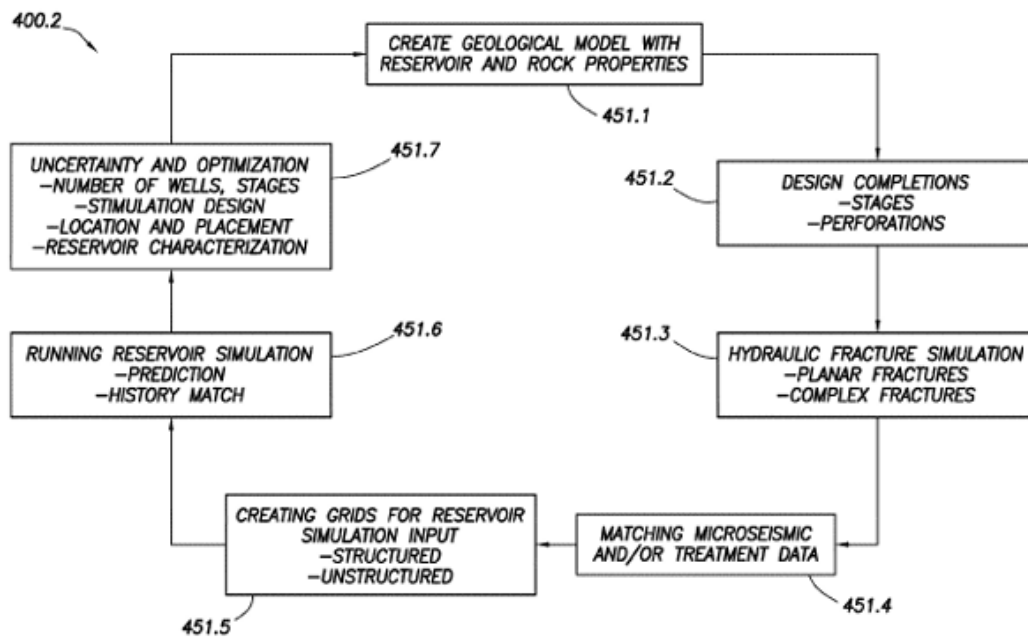


FIG.4.2

Pankaj, Fig. 4.2 (EX-1005)

EX-1003, ¶ 105; EX-1005, [0069] (“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 . . . 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).”). A POSITA would have understood that event 451.7 of the simulation software workflow performs uncertainty optimization. EX-1005, Fig. 4, [0069]; EX-1003, ¶ 105. 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.” EX-1003, ¶ 105; EX-1005, Fig. 4, [0069].

Further, a POSITA would have understood from Pankaj that the “*data created through simulation with uncertainty parameters*” is used to generate the “*system model*” as claimed. EX-1003, ¶ 106. Figure 4.2 discloses step “451.1 creating a geological model with reservoir and rock properties.” Ex-1005, [0069]. At step 451.7, uncertainty optimization (as discussed above) is performed on that model. [0069]. A POSITA would have understood that the optimized geological models are then used to generate the system model that ultimately is used for operations. [0067] (“After fracture design is completed, it may be coupled to the reservoir simulation in a seamless manner to allow operators to optimize the treatments for maximized productivity.”); [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.”). EX-1003, ¶ 106.

c. Claims 4, 12, 19

These claims are substantively identical. EX-1003, ¶¶ 141–142.

Representative claim 4 depends on claim 1 and recites two additional requirements: (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.*” Both requirements are disclosed by Pankaj. EX-1003, ¶¶ 108–115.

- 1) “*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*”

Pankaj’s UFM’s “simulate governing equations for cases involving smooth fractures.” EX-1005, [0112]. Pankaj also identifies equations used by these UFM’s, such as equations 1-5. See EX-1005, [0106]–[110] (describing multiple linear equations); EX-1003, ¶ 110. A POSITA would have understood that equations 1-5 are linear equations that represent a mathematical relationship between fracture parameters (“*sequence of stimuli*”) and modeled wellsite data (“*formation response data*”). EX-1003, ¶ 110. For example, 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: $(H_{fl}, \bar{w}(s, t), q_L, q(s, t), p(s, t), w(x, y, z), H(s, t))$.

EX-1003, ¶ 110. Accordingly, a POSITA would have understood equations 1–5 in Pankaj to represent “*a linear. . . relationship between the sequence of stimuli and received formation response data.*” EX-1003, ¶ 110.

Moreover, Pankaj explains that “nonlinear system of equations” may be used by “[c]ombining these equations and discretizing the fracture network into small elements.” EX-1005, [0111]; EX-1003, ¶ 111. 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.” EX-1003, ¶ 111. Pankaj therefore discloses “*determining. . . a non-linear relationship between the sequence of stimuli and received formation response data,*” as well. EX-1003, ¶ 111.

2) “*updating the one of the linear or the non-linear relationship based on multiple iterations of the generated sequence of stimuli*”

Pankaj discloses this limitation. EX-1003, ¶¶ 113–115. Using updated models, Pankaj discloses that “integrated dynamic wellsite parameters may then be generated 1180.” EX-1005, [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. EX-1003, ¶ 114; EX-1005, [0076]. Pankaj discloses that step 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.” EX-1005, [0141]. Accordingly, 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. EX-1003, ¶ 114; *see* EX-1005, [0141]; *see also* EX-1005, Fig. 4.2, [0076] (showing loop (“multiple iterations”) with matching exercise to change reservoir properties, fracture design parameters, and fluid properties).

d. Claim 6

Claim 6 depends from claim 1 and adds “*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.*”

Pankaj discloses this limitation. EX-1003, ¶¶ 116–120. Pankaj describes a wireline tool 106.3 that is “suspended by rig 128” “into the wellbore 136.” EX-1005, [0043]. *See* Figure 1.3:

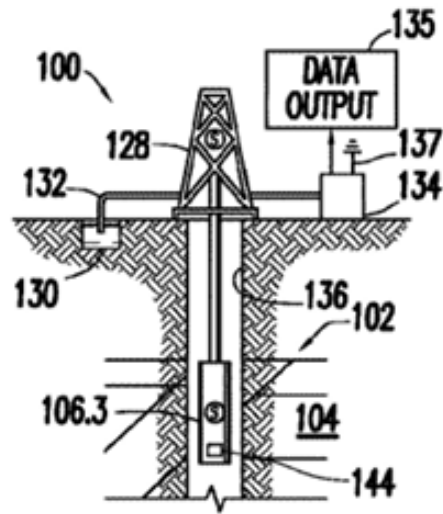


FIG. 1.3

Pankaj, Fig. 1.3 (EX-1005)

EX-1005, Fig. 3, [0043]; EX-1003, ¶ 117. 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. EX-1003, ¶ 117; EX-1005, [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* EX-1005, [0043]. Pankaj discloses that surface sensors may also be used. EX-1003, ¶ 117; EX-1005, [0049] (“Also, while certain data acquisition tools are depicted, it will be appreciated that various measurement tools ... 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.”). Based on these disclosures, a POSITA would have understood that these measurements 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. EX-1003, ¶ 117. Pankaj thus 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.*” EX-1003, ¶ 118.

To the extent one argues that Pankaj does not disclose this limitation, a POSITA would have been motivated to use, and thus found obvious, 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 pressure in a wellbore as taught in Pankaj. EX-1003, ¶ 119. A POSITA would have understood that each of these claimed sensors were routinely used during fracturing operations. *Id.*; 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 include the claimed sensor types. EX-1003, ¶ 119.

e. Claims 7 and 14

These claims are substantively identical. EX-1003, ¶¶ 143–144.

Representative claim 7 depends from claim 1 and recites “*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. EX-1003, ¶¶ 121–124. Pankaj discloses that wellsite data (“*formation response data*”) may be measured from different sensors. EX-1003, ¶ 122. Pankaj, in one example, explains that sensors may be positioned to measure “*pressures,*” “*temperature,*” and “*flow rates.*” EX-1005, [0047]; EX-1003, ¶ 122; *see* EX-1005, [0053] (disclosing that “measurements are taken of fluid properties, such as flow rates, pressures, composition, etc.... [T]he fracture and reservoir measurements may be analyzed and used to generate models of the subsurface formation to determine characteristics thereof.”).

Pankaj discloses that the wellsite also includes other sensors to measure wellsite data (“*formation response data*”). EX-1005, [0062] (“... the wellsite 100 may be provided with sensors (S) to measure wellsite parameters, such as ... pump rate, volume, ... pressure, temperature, viscosity, ... and/or other parameters as desired.”). EX-1003, ¶ 122.

Finally, with reference to Fig. 1.3 and “wireline tool 106.3,” Pankaj explains that this wireline tool may have electrical sources that “send[] and/or receive[] electrical signals to the surrounding subsurface formations 102 and fluids.” EX-1005, [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 as claimed. EX-1003, ¶ 123.

B. GROUND 2: Claims 5, 6, and 13 of the '058 Patent Are Obvious Over Pankaj and Payne In Further View of Dawson

1. Dawson Introduction

Dawson discloses “a system and method for using pressure signals to assess effectiveness of a diverter in a stimulation wellbore.” EX-1024, Abstract. Dawson explains that fracturing operations use diverters “to divert the flow of well treatment fluids (e.g., injection fluids) from perforations taking more fluid to perforations taking less fluid.” EX-1024, [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.” EX-1024, [1:38–45]. To determine whether a diverter is reliable, Dawson discloses that pressure measured “before and after the diverter are provided into the stimulation wellbore may be assessed to determine the effectiveness of the diverter.” EX-1024, Abstract.

2. Pankaj, Payne, and Dawson Render Obvious Claims 5 and 13

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 is substantively identical and depends from claim 9. Ex. 1003, ¶ 148.

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. EX-1003, ¶ 149; EX-1005, [0053]. In addition, Pankaj discloses that these fluid properties are used to match the resulting predicted values versus the observed data to confirm the model is correct. EX-1003, ¶ 149; EX-1005, [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.*” EX-1003, ¶ 149. Pankaj does not expressly disclose that these changes are “*in response to a diverter drop.*”

Dawson describes “a system and method for using pressure signals to assess effectiveness of a diverter in a stimulation wellbore.” EX-1024, Abstract. Dawson uses “pressure sensors in direct fluid communication with a second fluid in the second wellbore.” EX-1024, [2:11–14]. Dawson’s sensors measure pressure “before and after the diverter” to “determine the effectiveness of the diverters” (“*diverter drop*”). EX-1024, Abstract; *see* EX-1024, [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]. 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-1003, ¶ 151; 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.*” EX-1003, ¶ 151.

Dawson is analogous art to the '058 patent. EX-1003, ¶ 152. Dawson is directed toward the same field of endeavor of the '058 patent—fracturing operations. 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.”); EX-1003, ¶ 152. Dawson is also reasonably pertinent to a problem described by the '058 patent: optimizing conventional fracturing operations. *See* EX-1001, [1:11–26], [7:1–61]; EX-1018, [1:10–14], [5:21–29] (“[A] method has been developed for evaluating hydraulic fracture geometry and optimizing well spacing for a multi-well pad...”); EX-1003, ¶ 152. For these reasons, a POSITA would have understood that Dawson is analogous art. EX-1003, ¶ 152.

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. 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]; EX-1003, ¶ 154. A POSITA would have understood that fracturing operations, such as described in Pankaj, commonly use diverter drops. EX-1003, ¶ 154; *see* EX-1024, [1:16–50]. A POSITA 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]; EX-1003, ¶ 154.

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-1003, ¶ 155; 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-1003, ¶ 155; 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 well conditions. EX-1003, ¶ 155; 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.”). A POSITA would further recognize that Pankaj would improve fracturing operations by having a more accurate model of a well that uses a diverter. EX-1003, ¶ 155. This improvement would have motivated a POSITA to use Dawson’s diverter effectiveness technique in Pankaj’s fracturing operation (as modified by Payne). EX-1003, ¶ 155. A POSITA would have 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. EX-1003, ¶ 155. Thus, a POSITA would have had a reasonable expectation of success in combining the references' teachings. EX-1003, ¶ 155.

3. Pankaj, Payne, and Dawson Render Obvious Claim 6

To the extent that Patent Owner 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 renders this claim obvious.

As explained above, *see supra* § IX.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). EX-1003, ¶ 158. Using Dawson's diverter effectiveness technique would have included using the same “fiber [pressure] gauges” sensor. EX-1024, [5:58–60], [14:32–35]; EX-1003, ¶ 158. Consequently, 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. EX-1003, ¶ 158. Such a person would have been motivated to make this modification for the same reasons to modify the combination of Pankaj and Payne to incorporate Dawson's diverter effectiveness process. EX-1003, ¶ 158; *see supra* § § IX.B.2 (Dawson Ground - Claims 5 and 13).

Moreover, 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. EX-1003, ¶ 159. Only a limited number of pressure gauges are available. *See* EX-1024, [5:58–60]; EX-1003, ¶ 159. 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. EX-1003, ¶ 159.

C. GROUND 3: Claims 8, 15, and 20 of the '058 Patent Are Obvious Over Pankaj and Payne, In Further View of Lecerf

1. Lecerf Introduction

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:

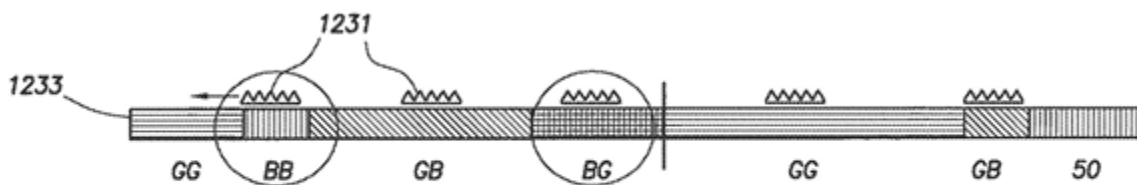


FIG.12

Lecerf, Fig. 12 (EX-1027)

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 to optimize fracturing operations. *See* EX-1027, [21:16–34], [22:20–23:14]; *see id.* Fig. 13, [19:22–40].

2. Pankaj, Payne, and Lecerf Render Obvious Claims 8, 15, and 20

Claims 8, 15, and 20 depend from claims 1, 9, and 16, respectively. Claims 8, 15, and 20 all recite “*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.*”

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.

Lecerf describes a fracture model (a “*representative system model*”) that is used to predict fracture geometry that can be calibrated and optimized. EX-1003, ¶ 166; 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* 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.”). Lecerf’s 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. EX-1003, ¶ 166; *see* EX-1027, [12:15–37]. Distances between fractures help define stages. EX-1003, ¶ 166; EX-1027, [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.”).

To optimize oilfield operations, Lecerf discloses that fracture stages each have stage classification results and composite quality indicators—each satisfying the claimed “*proxy values*.” EX-1003, ¶ 167. Figure 12 of Lecerf shows various perforation clusters are positioned “based on stage classification results 1231 and the composite quality indicator 1233”:

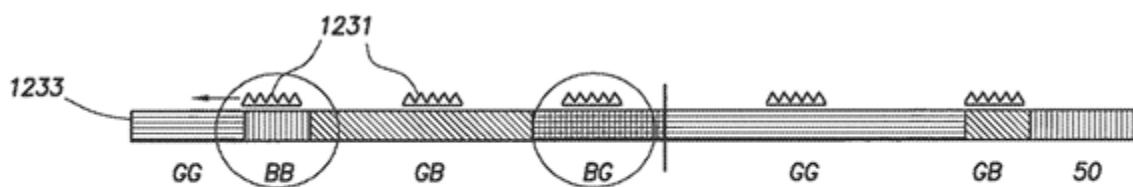


FIG.12

Lecerf, Fig. 12 (EX-1027)

EX-1003, ¶ 167. 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]; EX-1003, ¶ 167. A POSITA would have understood that each factor has a composite quality indicator satisfying both “*a complexity factor or a proximity index.*” EX-1003, ¶ 167; *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*.” EX-1003, ¶ 167; *see* EX-1027, Fig. 12, [18:67–19:10]; *see id.*, Fig. 13, [19:22–40] (describing Figure 13 and using the composite quality index). Accordingly, 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*.” EX-1003, ¶ 167.

Lecerf discloses that composite quality indicators (“*the predicted proxy value*”) may be used, in combination with stress log 903 to determine flow characteristics. EX-1003, ¶ 168. Lecerf explains that “composite quality indicator 901. . . . is combined (1348) with a stress log 903 segmented into stress blocks by 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:

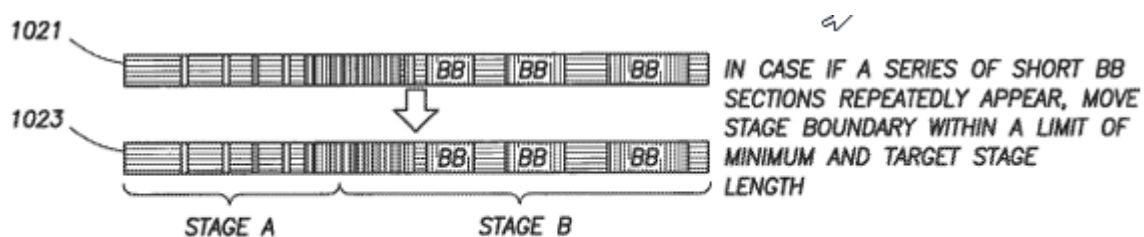


FIG.10

Lecerf, Fig. 10 (EX-1027)

EX-1003, ¶ 168. 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.” EX-1027, [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. EX-1003, ¶ 168; *see* EX-1027, 21:16–34, 22:20–23:14; *see also* EX-1001, [4:12–15]. Accordingly, 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.*”). EX-1003, ¶ 168.

Lecerf is analogous art to the ’058 patent for two reasons. First, Lecerf is directed toward the same field of endeavor of the ’058 patent—optimizing fracturing operations. 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.”); EX-1003, ¶ 169. Second, Lecerf is also reasonably pertinent to a problem described by the ’058 patent: optimizing conventional fracturing operations. *See* EX-1027, [19:15–18] (“The spacing and orientation of

multiple wells can be optimized to provide an entire formation with sufficient stimulation.”); EX-1003, ¶ 169.

A POSITA would have been motivated to incorporate Lacerf’s teaching regarding its composite quality technique for perforation clusters with the combined teachings of Pankaj and Payne for two reasons. First, a POSITA would have recognized that, by using Lacerf’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.”); EX-1003, ¶ 171. By considering the spacing and orientation across multiple well sites, 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]; EX-1003, ¶ 171. This would have motivated a POSITA to incorporate Lacerf’s teaching of a composite quality technique in the combined system of Pankaj and Payne, especially given that Pankaj also addresses optimization models across multiple wells. EX-1003, ¶ 171; *see* EX-1005, Fig. 5, [0033].

Further, a POSITA would have 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]; EX-1003, ¶ 172. Because

Pankaj's modeling technique seeks to accurately reflect the conditions inside a well 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]; EX-1003, ¶ 172. This improvement to Pankaj's model would have motivated a POSITA to incorporate Lecerf's teachings concerning composite quality technique with the teachings of Pankaj and Payne. EX-1003, ¶ 172.

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. EX-1003, ¶ 173; *see* EX-1005, Fig. 5, [0033]. Thus, a POSITA would have had a reasonable expectation of success in combining the references' teachings. EX-1003, ¶ 173.

Claims 8, 15, and 20 are therefore rendered obvious. Claim 20 additionally 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,*” which is obvious over Pankaj and Payne for the same reasons described above for claims 7 and 14. *See* § IV.A.6.e (Claim 7); EX-1003, ¶¶ 177–178.

D. GROUND 4: Claims 3, 11, and 18 of the '058 Patent Are Obvious Based on Pankaj in View of Payne, in Further View of Klumpen

1. Klumpen Introduction

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.” EX-1019, [3:59–63]. Figure 11 of Klumpen illustrates a method using several uncertainty parameters in its model to estimate performance of an oilfield operation:

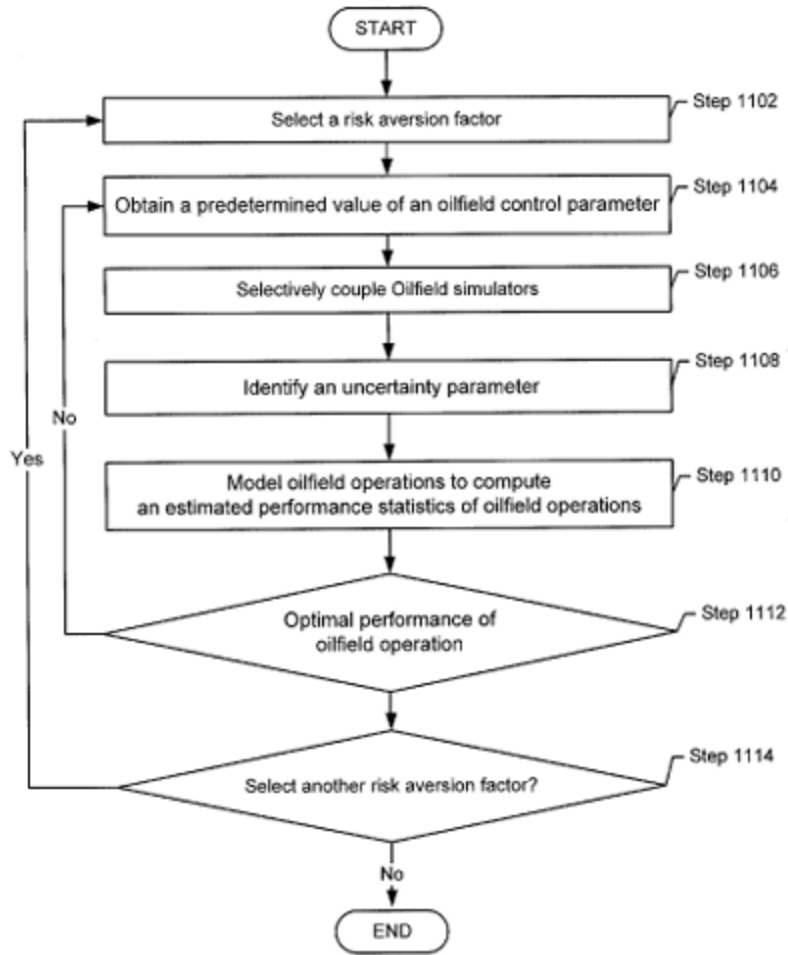


FIG. 11

Klumpen, Fig. 11 (EX-1019)

See id. [22:27–25:2]. Accounting for these uncertainty parameter in models helps “optimiz[e] oilfield operations.” EX-1019, [1:16–22].

2. Pankaj, Payne, and Klumpen Render Obvious Claims 3, 11, and 18

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

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* EX-1019, Abstract (“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;”). Klumpen explains that “[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]; EX-1003, ¶ 183. Klumpen further 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]. Accordingly, a POSITA would have recognized that Klumpen discloses a “*representative system model is generated based on data created through simulation with uncertainty parameters.*” EX-1003, ¶ 183.

Klumpen is analogous art to the ’058 patent, as it is directed toward the same field of endeavor of the ’058 patent—optimizing fracturing operations. EX-1019, [1:14–16] (“The present invention relates to techniques for optimizing oilfield operations relating to subterranean formations having reservoirs therein.”); EX-1003, ¶ 184. Klumpen is also analogous are because it is reasonably pertinent to a problem described by the ’058 patent: optimizing conventional oil field operations. EX-1019, [1:17–22] (“More particularly, the invention relates to techniques for

optimizing oilfield operations involving an analysis of reservoir operations...”); EX-1003, ¶ 184.

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. First, a POSITA would have been motivated to use Klumpen’s teachings regarding uncertainty parameters with Pankaj’s teachings regarding models for the express reasons described in Klumpen. EX-1003, ¶ 186. 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]; EX-1003, ¶ 186. 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.” EX-1019, [3:58–62]; EX-1003, ¶ 186. This express reason provided by Klumpen would have motivated a POSITA to use Klumpen’s uncertainty parameters in Pankaj’s modeling. *Id.*

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. EX-1003, ¶ 187. Because Pankaj’s modeling technique seeks

to best reflect 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. *Id.*; 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.”). Improving Pankaj's model by using Klumpen's uncertainty parameters would have likewise improved the accuracy of the Pankaj's model. EX-1003, ¶ 187.

Third, a POSITA would have been motivated to use Klumpen's uncertainty parameters in Pankaj's modeling because doing so would simply be the mere application of a known technique to improve the teachings of Pankaj. EX-1003, ¶ 188. 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]; EX-1003, ¶ 188. Consequently, a POSITA would have recognized that, by using parameter uncertainty techniques, Pankaj's representative models would represent observed data more accurately. EX-1001, [2:49–53]; EX-1003, ¶ 188.

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. EX-1003, ¶ 189; see EX-1005, Fig. 5, [0033]. Thus, a POSITA would have had a reasonable expectation of success in combining the references' teachings. EX-1003, ¶ 189.

E. GROUND 5: Claims 1-20 of the '058 Patent are Invalid Under 35 U.S.C. § 101

Claims 1-20 are unpatentable as being directed to an abstract idea with no inventive concept that transforms the abstract idea into a patent-eligible application. Instead, the claims merely automate a method that was – as the '058 patent itself confirms – previously performed manually.

Indeed, it is admitted in the '058 patent *Background* that the purported invention merely uses a computer to perform known steps that, according to the patent, were typically done by a person:

[T]ypically settings [on a fracturing pump] are *performed manually based on manually apprised information* retrieved from the downhole environment. For example, *a technician may review sensor data and, based on experience, adjust various settings....* In some cases, a representative system model may be used for determining pump settings based on sensor information; however, the representative system model is *typically manually selected* by a technician....

EX-1001, [1:11-26]. The claims are thus a textbook example of the type regularly invalidated under § 101. *Alice Corp. Pty. v. CLS Bank Int'l*, 573 US 208, 223 (2014) (“Stating an abstract idea while adding the words ‘apply it with a

computer” is not enough.); *Data Engine Tech. v. Google*, 906 F.3d 999, 1013 (Fed. Cir. 2018) (“The concept of manually tracking modifications across multiple sheets is an abstract idea. The mere automation of this process does not negate its abstraction.”); *Elec. Power Group, LLC v. Alstom S.A.*, 830 F.3d 1350, 1354 (Fed. Cir. 2016) (“The focus of the claims is not on an improvement in computers as tools, but on certain independently abstract ideas that use computers as tools.”).

1. Legal Standards

In defining patent-eligible subject matter, 35 U.S.C. § 101 contains “an important implicit exception: Laws of nature, natural phenomena, and abstract ideas are not patentable.” *Alice*, 573 U.S. at 216. Section 101 prohibits patenting claims “which merely require generic computer implementation” of an abstract idea. *Id.* at 221. The *Alice* two-step test is now well-known.

***Alice* Step One.** “[D]etermine whether the claims at issue are directed to one of those patent-ineligible concepts,” e.g., an abstract idea. *Id.* at 217. This step looks at “the ‘focus’ of the claims,” which may be informed by “looking to the specification to understand ‘the problem facing the inventor.’” *ChargePoint, Inc. v. SemaConnect, Inc.*, 920 F.3d 759, 765-66 (Fed. Cir. 2019) (quoting *Elec. Power*, 830 F.3d at 1353).

Where a claim recites “a desired function or outcome, without providing any limiting detail that confines the claim to a particular solution to an identified

problem,” the “functional nature of the claim confirms that it is directed to an abstract idea.” *Affinity Labs of Tex., LLC v. Amazon.com, Inc.*, 838 F.3d 1266, 1269 (Fed. Cir. 2016). The “essentially result-focused, functional character of claim language has been a frequent feature of claims held ineligible under § 101.” *Elec. Power*, 830 F.3d at 1356.

***Alice* Step Two.** If a claim is directed to ineligible subject matter, the second step is to “determine whether [any] additional elements transform the nature of the claim into a patent-eligible application” by reciting “an inventive concept—i.e., an element or combination of elements that is sufficient to ensure that the patent in practice amounts to significantly more than a patent upon the ineligible concept itself.” *Alice*, 573 U.S. at 217–18 (quotations omitted). Even if “the techniques claimed are groundbreaking, innovative, or even brilliant, [] that is not enough for eligibility” if “the advance lies entirely in the realm of abstract ideas.” *SAP Am., Inc. v. InvestPic, LLC*, 898 F.3d 1166, 1163 (Fed. Cir. 2018). “What is needed is an inventive concept in the non-abstract application realm.” *Id.* at 1168.

To the extent claims include non-abstract elements, they are still ineligible if they recite “well-understood, routine, conventional activities previously known to the industry.” *Alice*, 573 U.S. at 225 (quotation omitted). The “inquiry is not whether the claimed invention as a whole is unconventional or non-routine,” but

“whether the claim limitations other than the invention’s use of the ineligible concept to which it was directed were well-understood, routine and conventional.” *BSG Tech LLC v. Buyseasons, Inc.*, 899 F.3d 1281, 1290 (Fed. Cir. 2018).

PTO Guidance. The Office’s § 101 guidance (“*Guidance*”) appears in the Ninth Edition, Revision 10.2019 (revised June 2020) of the *Manual of Patent Examination Procedure* (“MPEP”), sections 2103 through 2106.07(c).⁴ The Federal Circuit has stated that the Guidance “cannot modify or supplant the Supreme Court’s law regarding patent eligibility, or [the Federal Circuit’s] interpretation and application thereof.” *In re Rudy*, 956 F.3d 1379, 1383 (Fed. Cir. 2020); *see* MPEP 2106(I). Accordingly, Petitioners herein apply the Supreme Court’s *Alice* two-part test and the Federal Circuit’s interpretation thereof, with reference to the *Guidance* only to demonstrate that the claims are invalid under the *Guidance* as well.

2. Claims 1, 9, 16: *Alice* Step One

The Board may consider a representative claim when other claims are “substantially similar and linked to the same abstract idea.” *Content Extraction & Transmission LLC v. Wells Fargo Bank, Nat. Ass’n*, 776 F.3d 1343, 1348 (Fed.

⁴ See <https://www.uspto.gov/patents/laws/examination-policy/subject-matter-eligibility>.

Cir. 2014). That is the case here. As explained in Section V.C, independent claims 1, 9, and 16 all contain the same four steps for performing the purported invention. Claim 1, directed to a “computer-implemented method” is representative of claims 9 and 16, which add nothing other than a generic “one or more processors” (both claims) and a “memory” (claim 9). Thus, it is appropriate to consider claim 1 as representative of claims 9 and 16.

Claim 1 of the ’058 patent covers a “computer-implemented method for controlling electrical fracturing equipment” requiring four steps: (1) generating a “sequence of stimuli for application to a well environment;” (2) receiving “response data ... from one or more downhole sensors or surface sensors;” (3) selecting a “representative system model based on” the sensor data and stimuli; and (4) controlling an electric fracturing pump “based on the representative system model.”

Claim 1 is thus directed to the abstract idea of *selecting a plan* (“representative system model”) *for a desired result* (“controlling” a pump) *based on information received* (“response data”) *in response to one or more inquiries* (“sequence of stimuli”). This type of abstract idea has been employed for years in multiple environments. For example, doctors routinely use this abstract idea to diagnose and treat a patient for allergies. *See* EX-1016 (disclosing “allergy skin tests” where the skin is exposed to different possible allergens (“sequence of

stimuli”), data (“response data”) is collected based on the skin’s reaction to the stimuli, and a doctor selects an “allergy treatment plan” (“representative system model”) to treat the patient (the desired result, or “controlling” the patient’s response to the allergens).

This abstract idea has also been used in technology. For example, a wireless messaging communication system (*see* EX-1017) sends a “probe” message (“sequence of stimuli”) to attempt to locate a mobile unit that has messages awaiting it in the network. Depending on the response to the probe message (“response data”), the communication system will select a plan (“representative system model”) for handling messages received for the mobile unit (the desired result, *e.g.*, “controlling” how the mobile unit receives messages). For example, the system may provide an alert to the mobile unit that messages are available; or it may automatically re-transmit the messages. *See id.*, *Abstract*.

Claims of this type have repeatedly been found abstract by the Federal Circuit. In *TDE Petroleum Data Solutions, Inc. v. AKN Enter.*, the claim was directed to an “automated method for determining the state of a well operation.” 657 F. App’x 991, 992 (Fed. Cir. 2016). The claim required “storing a plurality of states for a well operation,” “receiving mechanical and hydraulic data ... from a plurality of systems” (which the specification described as including “receiving data from sensors deployed on the oil well”), “determining that at least some of the

data is valid by comparing [it] ... to at least one limit,” and, if the data is valid, “based on the mechanical and hydraulic data, automatically selecting one of the states as the state of the well operation.” *Id.*

The *TDE Petroleum* claim is therefore in the same field as the ’058 patent claims and closely matches claim 1 thereof. The Federal Circuit, addressing *Alice* step one, noted that claims “generally reciting ‘collecting information, analyzing it, and displaying certain results of the collection and analysis’ are a ‘familiar class of claims ‘directed to’ a patent-ineligible concept.” *Id.* at 993 (citing *Elec. Power*, 830 F.3d at 1354). The Court thus held that the *TDE Petroleum* claim “is the sort of data gathering and processing claim that is directed to an abstract idea.” *Id.* at 993.

Similarly, in *FairWarning IP, LLC v. Iatric Sys.*, the claim was directed to a “method of detecting improper access of a patient’s protected health information ... in a computer environment.” 839 F.3d 1089, 1092 (Fed. Cir. 2016). The claim required, *inter alia*, “generating a rule for monitoring audit log data,” “applying the rule to audit log data to determine if an event has occurred, the event occurring if ... at least one criterion has been met,” “storing, in a memory, a hit if the event has occurred,” and “providing notification” that the event has occurred.” *Id.* The Court found that the claim was directed to an abstract idea, noting that the “realm of abstract ideas” includes “collecting information, including when limited to particular content.” *Id.* at 1093. Here, the ’058 patent claims are directed to

collecting information regarding a well and using that information to select a model for controlling a pump. That is not different conceptually from the *FairWarning* claim; the '058 “model” is akin to the *FairWarning* “rule,” the “sensor data” is akin to the audit log data, and controlling the pump is akin to providing a notification of misuse.

In addressing *Alice* step one, Patent Owner cannot argue that the '058 patent claims are directed to an improved computer system or interface. In *IBM v. Zillow Grp., Inc.*, 50 F.4th 1371 (Fed. Cir. 2022), the claims were directed to methods for coordinated geospatial and list-based mapping performed on computer systems. The Court noted that in cases “involving software innovations,” the step one inquiry “often turns on whether the claims focus on specific asserted improvements in computer capabilities or instead on a process or system that qualifies as an abstract idea for which computers are involved merely as a tool.” *Id.* at 1377.

That is the case with the '058 patent claims. The claims are not directed to any improvements in computers *per se*, but merely to using computers to automate a process that the '058 patent ***admits*** was typically performed manually by technicians. EX-1001 [1:11-26]. Thus, as in *IBM*, the 058 patent “merely contemplates automation using a computer.” 50 F.4th at 1377; *see id.* at 1378 (finding that the claims are “results-oriented, describing required functions

(*presenting, receiving, selecting...*), without explaining how to accomplish any of the tasks.”).

The ’058 patent claims also fail *Alice* step one because they are effectively directed to mental processes. *See FairWarning*, 839 F.3d at 1093 (stating that ‘mental processes’ fall “within the abstract-idea category.”). Here, the claims—by admission—may be performed by a human and thus are directed to an abstract mental process. It cannot be disputed that the claimed steps of selecting a system model based on the received sensor data and then controlling the settings on the pump can be and were done by humans. EX-1001 [1:9-26] (explaining that “typically” pump settings were performed “manually based on manually appraised information received from the downhole environment” and that the system model was “typically manually selected by a technician based on observed sensor data”).

The Federal Circuit has repeatedly held that “mental processes are abstract ideas under ... step one.” *In re Killian*, 45 F.4th 1373, 1379 (Fed. Cir. 2022);⁵ (citing *Affinity Labs of Texas, LLC v. DIRECTV, LLC*, 838 F.3d 1253, 1257 (Fed. Cir. 2016) and *Elec. Power*, 830 F.3d at 1353); *see In re Able*, 838 F. App’x 558,

⁵ In *Killian*, the claims were directed to the “mental process” of identifying people who may be eligible for SSDI benefits they are not receiving, performed on a computer. 45 F.4th at 1377-79.

559-570 (Fed. Cir. 2021) (affirming Board decision that claims requiring “physically generating” and “physically mailing” a mailer were abstract and unpatentable when those steps were properly characterized as “methods of organizing human activity” and “mental processes”).⁶

⁶ Here, the “focus of the claimed advance” is the automated selection of the system model and controlling the pump based on the system model, which unquestionably can be performed by humans. The claimed steps of applying a sequence of stimuli and receiving sensor data in response do not change this, because it cannot be disputed that these steps were conventional in the industry. *See* EX-1005, [0097] (disclosing “stimulating the formation around each wellbore (e.g., perforating, injecting)”); EX-1001 [1:9-26] (admitting that technicians “review sensor data” to adjust pump settings); *see Ex Parte Borselen*, 2018 Pat. App. LEXIS 2620, *8 (PTAB April 3, 2018) (“[T]he claims recite the abstract ideas ... at a very high level of generality with implementation on conventional sensors and processors without reciting any particular transformative features. That the claims recite generic processors, storage media, and sensors does not make the claims any less abstract for step one.”).

For all these reasons, the claims of the '058 patent are directed to an abstract idea under *Alice* step one.⁷

3. Claims 1, 9, 16: *Alice* Step Two

Alice step two asks “whether [any] additional elements transform the nature of the claim into a patent-eligible application” by reciting “an inventive concept—i.e., an element or combination of elements that is sufficient to ensure that the patent in practice amounts to significantly more than a patent upon the ineligible concept itself.” *Alice*, 573 U.S. at 217–18.

⁷ With respect to the *Guidance*, Step 1 asks whether the claimed subject matter falls within the four statutory categories of patentable subject matter: process; machine, manufacture, or composition of matter. MPEP 2106.03(II). Petitioners do not contest the challenged 058 patent claims fall within one or more of the four categories. Regarding *Guidance* Step 2A, Prong 1, for the reasons already explained, the claims recite a judicial exception, *i.e.* an abstract idea. MPEP 2106.04(II.1). The abstract idea qualifies as a “mental process” as set forth in MPEP 2106.04(a). And as to *Guidance* Step 2A, Prong 2, the 058 patent claims do not integrate the abstract idea into a practical application. For the reasons explained, the claims do not reflect an “improvement in the functioning of a computer” but merely use a computer as a tool. MPEP 2106.04(d)(I).

There is no inventive concept in the '058 patent claims. Any structural elements in the claim were known, conventional elements long in use in fracturing operations. Stimulating a well using “one or more of particulate concentrations, chemical concentrations, or pump rate control” (EX-1001, claim 1) was a well-known technique used to determine and simulate well performance. For example, Gottumukkala (EX-1014) teaches a “real time acquisition and control system/processor” that includes determining “pressure transient *responses* to continuous zonal rate *changes instigated by the actuation* of flow control valves.” [0029]. In other words, changes are made to flow control valves (“sequence of stimuli”) to measure pressure changes in the well. The pressure transient responses are provided by sensors in the well. *Id.*, [0031]; *see* Section IX.A.4.ii (explaining that Pankaj discloses sending sequence of stimuli); Ex. 1003, ¶¶ 192–193.

Further, using sensors to generate well data was ubiquitous, as the '058 patent concedes. EX-1001 [1:16-18] (stating that “a technician may review sensor data and, based on experience, adjust various settings...”). In addition to Pankaj, *see* EX-1005 and Section IX.A.4.iii *supra*, such sensors were disclosed in 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”); 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); Ex. 1003, ¶¶ 192–193. The Federal Circuit and Board have routinely found that claims specifying the use of sensors or sensed data fail *Alice* step two. *See TDE Petroleum*, 657 F. App’x at 993 (“TDE ... cannot argue that storing state values, receiving sensor data, validating sensor data, or determining a state based on sensor data is individually inventive.”); *Ex Parte Borselen*, 2018 Pat. App. LEXIS 2620 at *9-11 (finding that the “claimed sensors and processors are conventional.... The claims [] recite sensors and computers as generic tools used to implement an abstract idea without any technological advances in seismic imaging or computers.”).

The use of “system models” for controlling well site equipment was also known and in use well before the ’058 patent filing date, as confirmed by the patent itself. EX-1001 [1:18-21] (“In some cases, a representative system model may be used for determining pump settings based on sensor information....”). Pankaj listed several references disclosing “examples of fracture models.” EX-1005, [0005]; *see* Section IX.A.4.iv *supra*. Rashid discloses that “distributed control system incorporating a central controller coupled to individual well controllers.... The central controller may utilize a network ***simulation model*** as a proxy for the oilfield to generate an optimal allocation solution for the oilfield as a whole.” EX-1018, [0020]. Rashid shows in Fig. 6 (below) that a field optimization

program 624 “may be used to implement a field-wide, distributed real-time production optimization solution, e.g., based upon 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.” *Id.*, [0067]; Ex. 1003, ¶¶ 192–193.

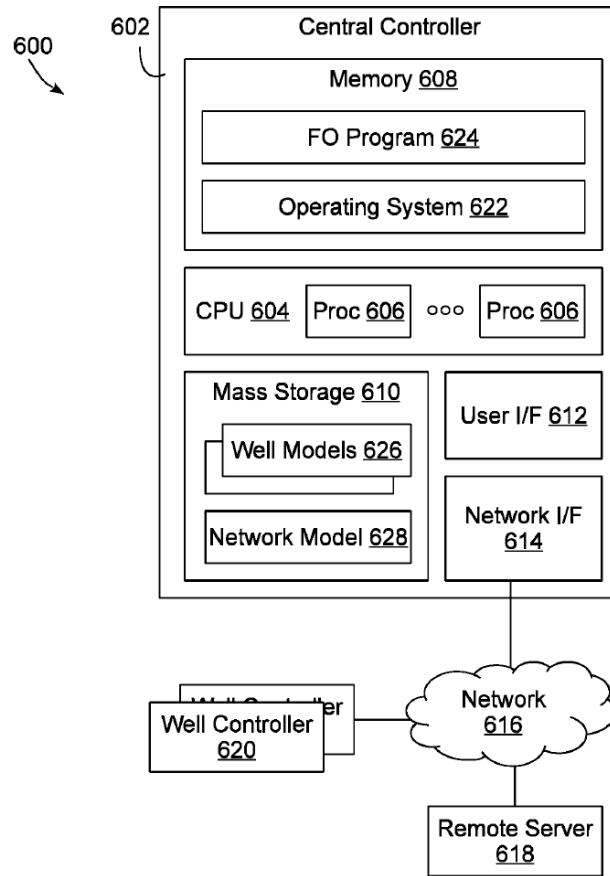


FIG. 6

Rashid, Fig. 6 (EX-1018)

Numerous other references disclose the use of such “system models,” proving their ubiquity in the industry before the ’058 filing date. *See* Lecerf, EX-1027, Fig. 14; Husen, EX-1013, [0032]; Ex. 1003, ¶¶ 192–193.

Finally, as explained in Sections IV.B and IX.A.3 *supra*, it cannot be disputed that using electric fracturing pumps was also well-known. The ’058 patent discloses using electric pumps in their conventional manner.

Accordingly, the claims “amount to nothing more than applying the ... abstract idea using techniques that are, whether considered individually or as an ordered combination, well-understood, routine, and conventional.” *cxLoyalty Inc. v. Maritz Holdings Inc.*, 986 F.3d 1367, 1377 (Fed. Cir. 2021). Indeed, much more detailed claims than those challenged here were struck down by the Federal Circuit in *Elec. Power*. The Court noted that “limiting the claims to the particular technological environment of power-grid monitoring is, without more, insufficient to transform them into patent-eligible applications of the abstract idea at their core.” 830 F.3d at 1354. So too here – that the 058 patent claims limit application of the abstract idea to use in a hydraulic fracturing environment does not transform the claims into patent-eligible subject matter. Just as in *Elec. Power*, the 058 claims “do not invoke any assertively inventive programming,” and do not require any “non-conventional and non-generic arrangement of known, conventional pieces,” but instead merely “call for performance” of the claimed functions “on a

set of generic computer components.” *Id.* at 1355; *see also Two-Way Media Ltd. v. Comcast Cable Communs., LLC*, 874 F.3d 1329, 1339 (Fed. Cir. 2017) (finding claims invalid under § 101 when the “claim uses a conventional ordering of steps – first processing the data, then routing it, controlling it, and monitoring its reception – with conventional technology to achieve its desired result”). Here, the claimed steps are performed in a conventional order – apply stimuli, receive data in response, select a model based on the data, and use the model to control the pump – using conventional technology, as explained above. *See TDE Petroleum*, 657 F. App’x at 993.

Accordingly, claims 1, 9, and 16 of the ’058 patent also fail *Alice* step two. As such, the independent claims are invalid under § 101.⁸

4. The Dependent Claims Are Directed to the Same Abstract Idea and Add Only Conventional Elements

The dependent claims do not provide “significantly more” to render them patent-eligible because they merely recite either “insignificant post-solution

⁸ *Guidance* Step 2B tracks *Alice* step two, and for the stated reasons “the claims at issue amount to ‘nothing significantly more’ than an instruction to apply the abstract idea.” *Alice*, 573 U.S. at 225-26.

activities” or features already well known, routine, and conventional in fracturing operations. *Apple Inc. v. Ameranth, Inc.*, 842 F.3d 1229, 1242 (Fed. Cir. 2016).

Claims 2, 10, 17. These claims require that the “system model is retrieved from a data store based [on] the received formation response data.” EX-1001, claims 2, 10, 17. The specification describes the “data store” as a “local memory, or a remote data store, such as networked memory or storage.” *Id.* [7:20-21]. Thus, the data store is conventional computer memory (whether local or remote), and cannot transform the claims into ones that are patent eligible. *Alice*, 573 U.S. at 226 (holding that a “data storage unit” is “purely functional and generic” and does not offer a “meaningful limitation beyond generally linking” the use of the method to “implementation via computers”). Moreover, data stores for storing well models were well-known in the art. *See* Rashid, EX-1018, Fig. 6; [0067]; Ex. 1003, ¶¶ 192–193.

Claims 3, 11, 18. These claims specify that the “system model is generated based on data created through simulation with uncertainty parameters.” EX-1001, claims 3, 11, 18.

The ’058 patent admits that this step generating was well-known in the art. EX-1001 [2:49-53] (stating that the “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”). There is

no disclosure in the '058 patent explaining **how** to use uncertainty parameters to generate a system model. Instead, consistent with the acknowledgement that doing so was “well known in the art,” the specification merely parrots the claim language. *See id.* [3:52-55; 4:4-7; 9:47-50; 10:30-33; 11:11-13]. Claiming well-known methods in the art confirms these claims are invalid. *In re TLI Communs. LLC Patent Litigation*, 823 F.3d 607, 613 (Fed. Cir. 2016) (holding that “mere recitation of concrete, tangible components is insufficient to confer patent eligibility to an otherwise abstract idea. Rather, the components must involve more than performance of well-understood, routine, conventional activit[ies] previously known to the industry”); Ex. 1003, ¶¶ 192–193.

Moreover, the '058 patent is correct in characterizing well modeling based on data created through simulation with uncertainty parameters as well-known. Klumpen (EX-1019) discloses exactly that, teaching 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.” *Id.*, Abstract. U.S. Patent No. 7,953,585 (“Gurpinar”) (EX-1020) similarly teaches a method 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. *Id.* [71:15-53]; Ex. 1003, ¶¶ 192–193.

Claims 4, 12, 19. These claims require that the step of selecting the system model includes: first, “determining one of a linear or non-linear relationship between the sequence of stimuli and received formation response data,” and second, “updating the one of the linear or the non-linear relationship based on multiple iterations of the generated sequence of stimuli.” EX-1001, claims 4, 12, 19.

Requiring that “*one* of a linear or non-linear relationship” be determined between the stimuli and response data is the epitome of abstractness because the relationship between two quantities can only be either linear or non-linear.⁹ Adding that the relationship is then updated based on multiple iterations is just as abstract, because a POSITA would understand that if the relationship is not regularly updated the data and model will quickly be outdated and unreliable. For that reason, modeling is routinely updated. *See* Husen, EX-1013, Abstract (“The

⁹ See <https://sciencing.com/non-linear-relationship-10003107.html> (“Any relationship between two quantities that doesn’t fit the definition of a linear relationship is a non-linear relationship.”)

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.... 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”); Ex. 1003, ¶¶ 192–193.

The 058 specification again provides no detail concerning *how* the additional steps of claims 4, 12, and 19 are performed. Instead, the language in the claims is merely repeated four times in the specification. *Id.* [3:56-58], [9:51-57], [10:34-40], [11:13-20]. Claims 4, 12, and 19 therefore effectively seek to improperly monopolize determining and updating *both of* a linear or non-linear relationship between the stimuli and response data. *See Elec. Power*, 830 F.3d at 1356 (noting that the claims before the Court “purport to monopolize every potential solution” to the problem).

Claims 5 and 13. These claims add that the data from the one or more sensors is “used to determine changes in flow distribution in response to a diverter drop, the changes in flow distribution used to determine” the system model. As explained in Section IX.B above, the use of diverters and sensors to determine a diverter drop was conventional and well-known, as was the use of flow distribution

to determine a system model. Pankaj discloses the “dynamic measurement of the fluid properties through the wellbore, which a POSITA would have understood represent the “changes in flow distribution” through the wellbore. EX-1005, [0053]. In addition, Pankaj discloses that these fluid properties are used to match the resulting predicted values versus the observed data to confirm the model is correct, e.g., to “determine the representative system model.” EX-1005, [0076]-[0077]; EX-1003, ¶¶ 192–193.

Dawson describes “a system and method for using pressure signals to assess effectiveness of a diverter in a stimulation wellbore.” EX-1024, Abstract. Dawson uses pressure sensors for this, which measure pressure “before and after the diverter” to “determine the effectiveness of the diverters” (“diverter drop”). EX-1024, Abstract; *see* [2:11-14], [7:50–55], [7:35–8:23]. 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 using sensors to measure the pressure changes. EX-1003, ¶¶ 192–193.

Claim 6. This claim provides a laundry list of sensors which are an example of “entirely conventional, generic technology”, *Elec. Power*, 830 F.3d at 1356, used in the oil and gas industry. *See TDE Petroleum*, 657 F. App’x at 993 (finding that “receiving sensor data, validating sensor data, [and] determining a state based on sensor data” was conventional in oil well operation). *See* U.K. Patent App. GB

2443051 (“Varadarajan”) (EX-1021), disclosing that “fiber optic sensors” were “used in wellbore measuring or sensing of parameters such as pressure, temperature, and seismic or chemical activity....” *Id.*, Abstract. *See iLife Techs., Inc. v. Nintendo of Am., Inc.*, 839 F. App’x 534, 538 (Fed. Cir. 2021) (“[T]he claim recites only generic computer components, including a **sensor**, a processor, and a communication device. The specification’s description of these elements confirms they are generic.”); EX-1003, ¶¶ 192–193.

Claims 7 and 14. These claims provide a laundry list of the the data that may be received from the sensors, including, *e.g.*, receiving pressure or temperature data from one or more sensors. EX-1001, claims 7, 14. That is what Varadarajan disclosed 15 years ago. *See* 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....”). This is another example of claims directed to “entirely conventional, generic technology” used in its normal and expected way. *Elec. Power*, 830 F.3d at 1356. *See* EX-1003, ¶¶ 192–193.

Claims 8 and 15. These claims state that the 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.” EX-1001, claims 8, 15. Once again, the specification does not even explain what these parameters are or *how* the system model does this prediction; only that it does. *See* EX-1001 [4:22-30; 10:7-13; 10:53-59; 11:27-33]. The only conclusion from this lack of explanation in the ’058 patent specification is that these claims are also directed to conventional, well-known technology.

The prior art bears this out. As explained in Section IX.C, Lecerf describes each of the elements in these claims. EX-1003, ¶¶ 192–193. Accordingly, 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.*” EX-1003, ¶¶ 192–193. Lecerf further discloses that composite quality indicators (“*the predicted proxy value*”) may be used, in combination with stress log 903 to determine flow characteristics. EX-1003, ¶¶ 192–193; EX-1027, [18:2–9], [18:30–35]; *see id.*, Fig. 13, [19:22–40]. Accordingly, 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.*”). EX-1003, ¶¶ 192–193.

Claim 20. This claim merely combines claims 7 and 8. For the same reasons as explained for those claims, claim 20 is not directed to patent-eligible subject matter.

X. DISCRETIONARY DENIAL IS NOT APPROPRIATE

Discretionarily denial under 35 U.S.C. § 314(a) is not warranted. The parallel litigation involving the '058 patent was filed on September 1, 2022 in the Western District of Texas, and this petition was filed less than seven months later. The median time to trial in the Western District is 29.5 months. *See* EX-1022 (court statistics); Director Memorandum, *Interim Procedure for Discretionary Denials in AIA Post-Grant Proceedings with Parallel District Court Litigation* (June 21, 2022) (stating that in applying the *Fintiv* factors the Board must consider “the median time from filing to disposition of the civil trial for the district in which the parallel litigation resides”).¹⁰ Thus, the Board here will issue a Final Written Decision approximately 10 months before any trial, which strongly counsels against discretionary denial. Further, as demonstrated herein, the merits presented in this Petition are compelling. *See* Director Memorandum at 2 (holding that the Board “will not rely on the *Fintiv* factors to discretionarily deny institution in view of parallel district court litigation where a petition presents compelling evidence of unpatentability.”).

¹⁰ *Apple Inc. v. Fintiv, Inc.*, IPR2020-00019, Paper 11 (PTAB Mar. 20, 2020) (precedential).

XI. CONCLUSION

Petitioners respectfully request that the Board institute trial and cancel all challenged claims as obvious and directed to non-statutory subject matter.

Date: March 28, 2023

Respectfully submitted,

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CERTIFICATE OF COMPLIANCE

The undersigned certifies that this petition complies with the word-count limitations of 37 C.F.R. § 42.24(a)(1)(ii). This petition contains 18,628 words as calculated by the Word Count feature of Microsoft Word, the word processing program used to create it.

The undersigned further certifies that this petition complies with the typeface requirements of 37 C.F.R. § 42.6(a)(2)(ii) and typestyle requirements of 37 C.F.R. § 42.6(a)(2)(iii). This petition has been prepared in a proportionally spaced typeface using Microsoft Word in Times New Roman 14-point font.

Dated: March 28, 2023

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CERTIFICATE OF SERVICE

Pursuant to 37 C.F.R. § 42.205 and § 42.6(e), the undersigned certifies that on March 28, 2023, a complete and entire copy of this Petition for Post-Grant Review and all supporting exhibits were sent via United States Postal Service Priority Mail Express to:

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