

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

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Title: System and Method for Treatment Optimization

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

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I. INTRODUCTION

1. This declaration supplements my opinions from my previous declaration. I have reviewed the Declaration of Dr. Robert A. Durham (EX-2013) and the documents and exhibits cited in his declaration. In this supplemental declaration I respond to assertions made in the Durham Declaration.

2. In addition to the Durham Declaration and exhibits cited therein, in preparation of this supplemental declaration I have reviewed the following documents:

Exhibit No.	Description
1001	U.S. Patent No. 11,373,058
1002	File History of U.S. Patent No. 11,373,058
1004	Curriculum Vitae of Dr. Michael Nikolaou
1005	U.S. Patent App. Pub. No. 2018/0230782 to Pankaj et al.
1006	U.S. Patent App. Pub. No. 2016/0258267 to Payne et al.
1007	S. Dalvi, Fundamentals of Oil & Gas Industry for Beginners (Notion Press 2015) (excerpts)
1008	U.S. Patent App. Pub. No. 2013/0306322 to Sanborn et al.
1009	U.S. Patent No. 9,410,410 to Broussard et al.
1010	U.S. Patent App. Pub. No. 2012/0255734 to Coli et al.
1011	U.S. Patent No. 10,020,711 to Oehring et al.
1012	U.S. Patent App. Pub. No. 2008/0236818 to Dykstra et al.
1013	U.S. Patent App. Pub. No. 2006/0015310 to Husen et al.
1014	U.S. Patent App. Pub. No. 2016/0061003 to Gottumukkala et al.
1015	U.S. Patent No. 10,280,722 to Bello et al.
1016	Print-Out from the Internet Archive at: https://web.archive.org/web/20180728025208/https://www.mayoclinic.org/tests-procedures/allergy-tests/about/pac-20392895
1017	U.S. Patent No. 5,809,428 to Garahi et al.
1018	U.S. Patent App. Pub. No. 2006/0015310 to Rashid et al.

Exhibit No.	Description
1019	U.S. Patent No. 8,352,227 to Klumpen et al.
1020	U.S. Patent No. 7,953,585 to Gurpinar et al.
1021	U.K. Patent App. GB 244051 to Varadarajan et al.
1022	RESERVED
1023	PCT International Pub. No. WO 2018/084871 to Madasu et al.
1024	U.S. Patent No. 10,378,333 to Dawson et al.
1025	RESERVED
1026	RESERVED
1027	U.S. Patent No. 10,087,722 to Lecerf et al.
1028	T. Jacobs, <i>These Five Companies are Reinventing the U.S. Frac Fleet</i> , <i>Journal of Petroleum Technology</i> (July 31, 2019)
1029	Website Printout, Internet Archive (U.S. Well Services) at: https://web.archive.org/web/20151121102607/http://uswellservices.com/
1030	Excerpt from <i>Petrophysics Theory and Practice of Measuring Reservoir Rock and Fluid Transport Properties</i> , Gulf Professional Publishing, 2015.
1032 New	A. Shchipanov <i>et al.</i> , <i>Step Rate Test as a Way to Understand Well Performance in Fractured Carbonates</i> , SPE-185795-MS (June 2017)
1033 New	United States Environmental Protection Agency, Region VIII, <i>Step Rate Test Procedure</i> (Jan. 12, 1999)
1034 New	European Patent EP 1 393 136, <i>Method for Monitoring and Detecting Sensor Failure in Oil and Gas Production System</i> , published Feb. 18, 2009
1035 New	PCT WO 2011/041794 A1, <i>Method and Apparatus for Differential Pressure Measurement</i> , published April 7, 2011
1036 New	U.S. Patent Application Publication No. US 2015/0377716 A1, <i>Pipeline Constriction Detection</i> , published Dec. 31, 2015
1037 New	PCT WO 2016/025672 A1, <i>Method of Treating an Underground Formation Featuring Single-Point Stimulation</i> , published Feb. 18, 2016
1038 New	U.S. Patent Application Publication No. US 2015/0075778A1, <i>Controlling an Injection Treatment of a Subterranean Region Based on Stride Test Data</i> , published March 19, 2015

Exhibit No.	Description
1039 New	PCT WO 2015/057242 A1, <i>Managing a Wellsite Operation With a Proxy Model</i> , published April 23, 2015
1040 New	PCT WO 2014/039036 A1, <i>Wellbore Completion and Hydraulic Fracturing Optimization Methods and Associated Systems</i> , published March 13, 2014
1041 New	U.S. Patent App. Pub. No. US 2014/0262232, <i>Controlling Net Treating Pressure in a Subterranean Region</i> , published Sept. 18, 2014
1042 New	U.S. Patent No. 7,806,182, <i>Stimulation Method</i> , issued Oct. 5, 2010
1043 New	U.S. Patent No. 7,788,037, <i>Method and System for Determining Formation Properties Based on Fracture Treatment</i> , issued Aug. 31, 2010
1044 New	U.S. Patent No. 7,516,793, <i>Methods and Systems for Fracturing Subterranean Wells</i> , issued April 14, 2009
1045 New	U.S. Patent App. Pub. No. US 2017/0175484, <i>Hydraulic Fracturing with Strong, Lightweight, Low Profile Diverters</i> , published June 22, 2017
1046 New	M. Van Domelen, <i>A Practical Guide to Modern Diversion Technology</i> , SPE-185120-MS (March 2017)
1047 New	<i>Reservoir Modeling</i> , Wikipedia Website (Internet Archive dated April 1, 2019)
1048 New	Nexus® User Guide, Halliburton Landmark Software & Services (Dec. 2009)
1049 New	May 2, 2024 Deposition of Robert A. Durham

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

II. GROUNDS OF INVALIDITY

A. **GROUND 5: The Claimed Features of the 058 Patent were conventional features of the prior art.**

4. As I explained in my original declaration (¶¶191-193), the claim 1 steps were all known and standard in the industry before the 058 patent—that is, September 2019. Because of this, a POSITA would have understood that the only advancement over the prior art is the fact that claim 1 is “computer-implemented.” This is consistent with the specification which explains (incorrectly) that “typically” frac pump settings were “performed manually based on manually appraised information.... [A] technician may review sensor data and ... adjust various settings... In some cases, a representative system model may be used for determining pump settings based on sensor information; however, the ... model is typically manually selected by a technician.” EX-1001 [1:14-22].

5. I understand that Dr. Durham has asserted that “the claimed techniques were not well understood, routine, or conventional.” EX-2013, ¶85. For the reasons expressed in my original declaration, and as explained further below in response to the arguments raised by Dr. Durham, I disagree with his assessment. In my opinion, all the claimed steps of the 058 patent were known and standard in the industry well before the critical date of the 058 patent—that is, September 2019.

1. **Claim 1: “Generating a sequence of stimuli” along with “receiving formation response data” was a conventional feature of the prior art.**

6. I understand that Patent Owner and Dr. Durham have taken the position that the following claim limitations represent an improvement over the prior art:

“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; [and] receiving a formation response data comprising data from one or more downhole sensors or surface sensors.”

Dr. Durham claims that these were “unconventional steps” that “amount to more than well-understood, routine, and conventional activity previously known in the hydraulic fracturing industry.” EX-2013, ¶¶140-144. I do not agree, as these steps were instead well known and standard in the industry prior to the filing date of the 058 patent (September 2019) for the reasons I discuss below and for the reasons I explained in my previous declaration.

7. As I noted above, claim 1 requires that the generated “sequence of stimuli” comprises “one or more of particulate concentrations, chemical concentrations, or a pump rate control.” A POSITA would have understood “pump rate control” to mean controlling the rate at which, e.g., a fracturing fluid is delivered from a pump. This is consistent with what the 058 patent teaches. EX-

1001 [3:34-43] (“Electric pumps can be controlled to generate specific subsurface conditions (e.g., via fluid rate, etc.) as particulates and/or chemicals enter a formation through perforation clusters. In some examples, flow rates can be controlled dynamically to achieve a particular downhole target pressure, dynamic downhole pressure, and/or a rate profile in coordination with particulate and/or chemical concentrations in a pumped treatment fluid...”); *see* EX-1012, [0025] (“Pump drive signal 350 drives the pumping system to the rate that fracturing fluid ... is required to be delivered down hole.”). I understand that Dr. Durham agrees with this. EX-2013, ¶142 (stating that a pump rate control “would have been understood by a POSITA to mean controlling the rate that the pump is operating.”); EX-1049 at 36:6-17; 38:13-20; 39:10-16. The pump rate is frequently expressed in terms of liters or gallons per second or minute. *See* Payne, EX-1006 [0006] (“Fracturing equipment operates over a range of ... injection rates, and can reach ... 265 litres per second (9.4 cu ft/s) (100 barrels per minute)”); Sanborn, EX-1008 [0005] (“Fracturing equipment needs to be designed to operate over a wide range of ... injection rates, and can operate at about ... 265 L/s (100 barrels per minute), or higher.”).

8. For decades before 2019, the industry tested well response by altering pump rates, and/or other stimuli such as amount of proppant or injection chemicals and determined a well’s response with each rate adjustment. One such test was

known as a “step rate” test. A research paper for the Society of Petroleum engineers demonstrates how “step-rate” tests were ubiquitous in the industry. EX-1032.001 (“Step Rate Test (SRT) is commonly used to estimate formation parting (or fracture opening) pressure for stimulated wells. SRTs may also focus on changes of well performance at different rates/pressures.... Installation of permanent downhole gauges (PDG) and running SRTs on injection wells ... gave a chance to improve the understanding of reservoir and well performance.”); *id.*, (explaining SRTs were traditionally used as described by sources dated in the years 1987, 1992, and 1995); *Id.*, .002 (“SRTs may be used for evaluating any changes in well and reservoir parameters with changing pressure and rate.”).

9. SRTs were so well-known and standard in the industry that the Environmental Protection Agency in January 1999 issued a “step-rate test procedure” for injection wells. EX-1033 (“The purpose of this document is to provide a guideline for the acquisition of a Step Rate Test (SRT).... These procedures are consistent with acceptable oilfield practices.”). When performing SRTs, a “series of successively higher injection rates should be determined” and the “elapsed time and pressure values” are read and recorded “for each rate and time step.” EX-1033.001. The pressure values in the well should be “measure[d] and record[ed] for “each time step and corresponding pressure.” *Id.*, .002. The SRT helps determine the “minimum pressure required to hold open a fracture in this

formation at this well.” *Id.* This is known as the “instantaneous shut-in pressure” or ISIP. *Id.* I understand that Dr. Durham is also familiar with ISIP and agrees with that definition. EX-1049 at 29:3:18.

10. The EPA document provides an example of a SRT test procedure below:

Well: Anywell #1 Date: April 15, 2000 Operator: Lotza Oil

STEP #1 Test Rate (5% of maximum rate) .2 (bbl/min)

Time (min)	: 0	5	10	15	20	25	30
Pressure (psi):	0	90	95	98	99	100	100

STEP #2 Test Rate (10% of maximum rate) .4 (bbl/min)

Time (min)	: 0	5	10	15	20	25	30
Pressure (psi):	80	170	185	195	199	201	202

STEP #3 Test Rate (20% of maximum rate) .8 (bbl/min)

Time (min)	: 0	5	10	15	20	25	30
Pressure (psi):	190	320	385	392	398	403	404

STEP #4 Test Rate (40% of maximum rate) 1.6 (bbl/min)

Time (min)	: 0	5	10	15	20	25	30
Pressure (psi):	380	700	790	792	798	803	805

STEP #5 Test Rate (60% of maximum rate) 2.4 (bbl/min)

Time (min)	: 0	5	10	15	20	25	30
Pressure (psi):	751	990	1032	1093	1155	1188	1202

STEP #6 Test Rate (80% of maximum rate) 3.2 (bbl/min)

Time (min)	: 0	5	10	15	20	25	30
Pressure (psi):	1133	1250	1326	1370	1397	1399	1403

STEP #7 Test Rate (100% of maximum rate) 4.0 (bbl/min)

Time (min)	: 0	5	10	15	20	25	30
Pressure (psi):	1350	1448	1503	1530	1571	1590	1600

ISIP : 1000 (psi)

EX-1033.005. As shown above, at step one, the pump rate is 0.2 “bbl/min”, which is known in the industry as “barrel per minute.”¹ The downhole pressure response is measured at seven points over a 30-minute period. At step two, the pump rate is increased to 0.4 bbl/min, and the pressure response is again measured at seven points over a 30-minute period. This process proceeds until the maximum pump rate of 4.0 bbl/min is reached. *See also* EX-1033.001 (“A series of successively higher injection rates should be determined using guidelines below” and the “elapsed time and pressure values for each time and rate-step” are read and recorded.); .002 (“Measure pressures with a down hole pressure bomb.... Measure and record injection pressures with a gauge or recorder (for immediate test results. Record each time step and corresponding pressure.”).² As I previously noted, the

¹ See

<https://www.petrobasics.com/24028/bblmin#:~:text=Definition%3A,bbl%2Fmin%2C%20Dimension%3A%20Flowrate>. Dr. Durham testified he was also familiar with the term “barrels per minute” as used in the industry. EX-1049 at 38:13-39:5.

² A pressure “bomb” is known in the industry as a container that holds pressure measuring devices for measuring and recording pressure in a wellbore. *See* http://oilglossary.com/bottomhole_pressure_bomb.html.

SRT is used for determining, among other things, the “instantaneous shut-in pressure or ISIP.” *Id.*

11. A POSITA would have understood SRTs are an example of the “sequence of stimuli” claimed in the 058 patent, and more particularly that adjustments to the pump rates made during SRTs satisfy the claimed “*sequence of stimuli*” as applied to a well where the sequence of stimuli comprises “*one or more of ... a pump rate control*” as claimed. The patent discloses that successively increasing the pump rate is a “sequence of stimuli.” See EX-1001 [2:30-33] (A “sequence can include a particular stimulus (e.g., injection rate) being stepped through a sequence of various amplitudes (e.g., high, medium, low, etc.).”) That is exactly what SRTs do. EX-1033.001 (“A series of successively higher injection rates should be determined” and the “elapsed time and pressure values for each time and rate-step” are read and recorded.).³ This is the case even under PO’s and Dr. Durham’s interpretation of this limitation, in which they require that the sequence of stimuli be predetermined before application to the well. SRTs meet this because the pump rate increases are set forth in advance. EX-1033.001 (disclosing that the “suggested injection rates” should be predetermined

³ Dr. Durham agreed that there is a relationship between the injection rate and pump rate. EX-1049 at 36:20-37:21; 39:10-16.

percentages of the “anticipated maximum injection rate,” increasing over time); *see also* ¶18 herein (identifying other prior art teaching this).

12. Further, as described above, a SRT test also measures the pressure response at the well as the test proceeds. This is also exactly as described in the 058 patent. *See* EX-1001 [2:33-36] (“[R]esponse variables (e.g., responsive sensor data values such as pressure or flow distribution or microseismic events or strain events) can be measured over time to generate a record of a dynamic formation response.”).

13. This evidence—the SPE article (EX-1032) and the EPA step-rate test document (EX-1033)—are representative of the knowledge in the art and show that SRTs were in regular use many years before the 058 patent’s September 2019 filing date. Other prior art confirms that such SRTs were commonly used well before that filing date. *See* EX-1037 [0041] (“the treatment designs may further include diagnostic tests to improve analysis of formation characteristics. Examples of such diagnostic tests are injectivity tests performed above and below fracturing pressure, ... step-up rate test, step down tests...”); [0057] (“[D]ata acquired by drilling, completing, and measuring data from a first well, may be used to enable a further optimization of a fracturing process.”). I understand that Dr. Durham agreed that step-rate tests were “certainly” known in the industry before 2019. EX-1049 at 39:17-40:11.

14. Another conventional test—that is, “mini-frac” testing—was also commonly known and used in the industry years before 2019. Like SRTs, mini-frac tests were “used to determine formation properties and residual fracture properties before a regular or full fracture treatment.” EX-1043 [3:5-9] (dated 2010). The mini-frac test involves controlling the pumps/valves during the treatment test and measuring the response. *Id.* [5:37-42]; [9:30-38] (noting that the system may “modify pump times, [and] pump pressures”);⁴ [10:67-11:8] (“[D]ata is collected from the mini fracture treatment. The data may comprise pressure, rate and time data as well as other data...”); EX-1013, [0024] (“Fracturing jobs often start with a ‘mini-frac’ test. To do this, the pump speed is suddenly reduced (e.g., from 15 to 10 barrels/minute). The result is a sinusoidal pressure transient from which fluid efficiency, near well damage, and minimum in situ stress can be calculated.”). “Mini-frac” testing is therefore another example of a well-known test that adjusts pump rates over time (i.e., “*sequence of stimuli*”) as applied to a well where the sequence of stimuli comprises “*one or more of ... a pump rate control*” and measuring a response to such adjustments. Again, I understand that

⁴ Controlling pumps in this manner is generating a “*sequence of stimuli*” as claimed.

Dr. Durham had knowledge of mini-frac tests and agreed that they were known in the industry before 2019. EX-1049 at 40:12-41:3.

15. Both SRTs and mini-frac tests also confirm that “receiving formation response data” received from “downhole” or “surface sensors” as recited in claim 1 was conventional in the industry. For example, EX-1032 describes using “permanent downhole gauges” for this purpose. EX-1032.001. EX-1033, in another example, notes that both a “surface gauge” and a “down hole pressure bomb” may be used, EX-1033.002, which as I described above in ¶10 a POSITA would understand to include pressure gauges/sensors.

16. A POSITA would have understood that “gauges”— such as the ones described in EX-1032 and EX-1033—are a type of pressure sensor in that they provide pressure values by measuring pressure at the well. The terms “pressure sensor” and “pressure gauge” are often used interchangeably in the industry. EX-1034.004 (referencing the “down-hole pressure measured by a downhole pressure sensor (gauge)”); EX-1035.003 (identifying a “differential pressure sensor/gauge”); EX-1036 [0041] (identifying “pressure measurement device[s] (e.g., a pressure sensor, gauge, transmitter, etc.)”). A POSITA would have thus recognized that the “permanent downhole gauge” in EX-1032 and “surface gauge” or pressure bomb in EX-1033 satisfy the claimed “downhole” or “surface” sensors, respectively.

17. Other references confirm that sensors were conventional well before September 2019. A Halliburton patent (EX-1043) explains that, as of August 2010, “surface and down-hole sensors” were used to collect data from the mini-frac test. *Id.* [3:57-60] [10:67-11:8]. Another Halliburton patent, EX-1044 (published in 2009), explains that a “‘mini-fracture’ test is usually conducted in which a relatively small amount of proppant-free fracturing fluid is pumped into the formation to determine and/or confirm at least some of the properties of the formation....” *Id.* [2:8-12]. The patent further explains that “data from the mini-fracture test then is usually used ... to confirm or modify the original desired target profile of the fracture and the process used to achieve the fracture.” *Id.* [2:24-27]. Halliburton’s own patents thus confirm that the claimed sensors (as well as mini-frac testing) were well-known and ubiquitous in the industry as of at least 2010.

18. Another published Halliburton patent application, EX-1038, confirms that what Dr. Durham describes as the supposed improvements of the 058 patent over the prior art were conventional and well-known years before. Below are some excerpts from this Halliburton publication describing both step-rate tests and mini-fracture tests as “conventional injection tests.” These excerpts confirm that a POSITA would have recognized that the claimed requirements of a “sequence of

stimuli” and “receiving formation data” from the sequence of stimuli⁵ were well-known, standard, and conventional in the industry (all emphasis added).

- “Injection tests are sometimes performed before a fracture treatment. *Conventional* injection tests include *step-rate tests*, *mini-fracture tests*, and diagnostic fracture injection tests (DFIT).” EX-1038, [0002].
- “*Data from the injection test* can provide information about the subterranean region, and the information can be used, for example, to modify or otherwise *design an ongoing or future injection treatment*.” [0010].
- “The injection system 108 can be used to *perform an injection test*, *whereby fluid is injected* into the subterranean region 104 through the wellbore 102....” [0017].

⁵ Specifically, the “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;” and “receiving a formation response data comprising data from one or more downhole sensors or surface sensors” limitations.

- “[A]n injection test includes a *controlled injection sequence* that is *calibrated to induce a measurable response* from the subterranean region 104.” [0018]; *see also* [0030] (“The injection control subsystem 111 may receive, generate, or modify an injection test design or an injection treatment design (e.g., an *injection test sequence*, a pumping stage sequence, etc.) that specifies parameters (e.g., *injection rate and material*) of an injection test or an injection treatment to be applied to the subterranean region 104”).
- “The injection test can employ *various injection rates and injection materials to test and measure the response* of the subterranean region 104 to the varied materials.” [0037].
- “[T]he *injection rate 420 is increased over time across different injection periods* and maintained constant within each individual injection period.... Moreover, the injection rate can vary (increase or decrease) during an individual injection period.” [0066].
- “[A] *measurement system can acquire pressure data* from the wellbore 102 during the injection test, and the pressure data can be analyzed to determine ... properties of the subterranean region 104 about the wellbore 102.” [0017].

- “[T]he injection test can be *calibrated to induce a pressure response* from the subterranean region 104 *that can be measured*, for example, by *pressure sensors* in the wellbore 102, and analyzed to gain information about the subterranean region 104.” [0019].
- “The injection system 108 may also include *surface and down-hole sensors* 136 to measure pressure, rate, fluid density, temperature or other parameters of treatment or production.” [0027].
- “*Sensors* (e.g., the sensors 136) or other detecting equipment in the well system 100a can detect and monitor the subterranean response (e.g., pressure, temperature, etc.), collect and transmit the response data, for example, to the computing subsystem 110.” [0037].
- Fig. 6 of this Halliburton patent application shows a relevant embodiment with the 058 patent steps one and two highlighted in green and orange, respectively:

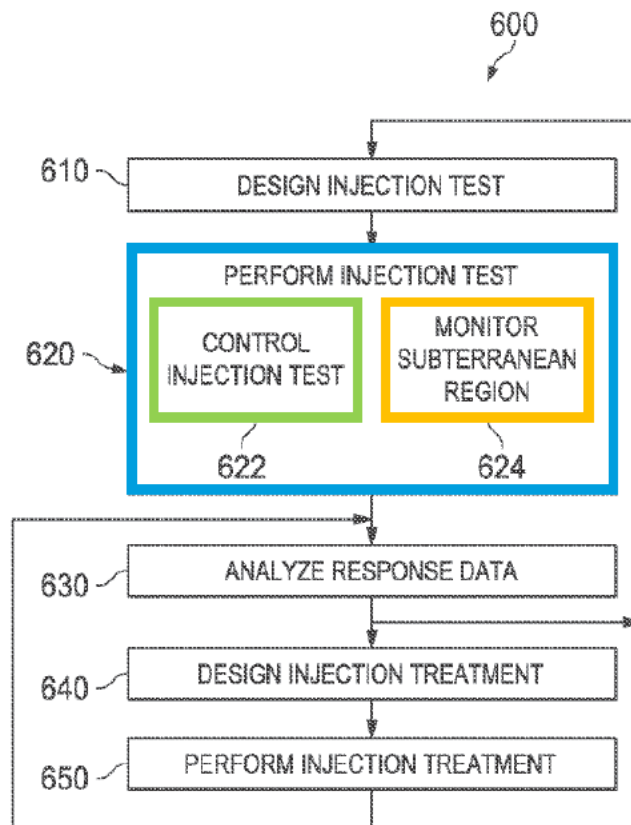


FIG. 6

EX-1038, Fig. 6 (annotated)

As the above demonstrates, the evidence I have cited, including Halliburton's own patent application filed in 2013 and published in 2015 (EX-1038), disproves Dr. Durham's opinion. Instead, a POSITA would have recognized that both claimed features—that is, the claimed steps of generating a sequence of stimuli and obtaining formation response data therefrom—were well-understood, routine, and conventional in the industry many years before September 2019.

2. Claim 1: “selecting a representative model” was another well-known and conventional feature of the prior art.

19. I understand that Patent Owner and Dr. Durham have also taken the position that another claim limitation represents an improvement over the prior art and was not known and conventional, specifically:

“selecting a representative model based on the received
formation response data and sequence of stimuli.”

However, like the other claim limitations, this step was also known, standard, and conventional in the industry prior to the September 2019 filing date of the 058 patent for the reasons I discuss below and for the reasons I explained in my previous declaration.

20. The 058 patent describes that the aim of this step is to select a “representative system model for stage and/or well treatment schedules (e.g., treatment sequences, compositions, etc.).” EX-1001 [2:38-41]; *see* [7:58-61]. Based on this description, POSITA would have understood that the representative models are selected based on the formation response data received in response to

the sequence of stimuli and used to design or control injection treatment for a well.⁶

21. Returning to SRTs, the system model would be selected based on what the results of the SRT showed with respect to the well. Using the EPA example in EX-1033, the results of the SRT showed that the ISIP (instantaneous shut-in pressure) was 1,000 psi. EX-1033.004-006. A POSITA would have understood to select a treatment plan (system model) for such a well that would include pump rates sufficient to maintain the maximum injection pressure at the ISIP. EX-1033.004 (“Because the injection formation will part at 1000 psi, the maximum injection pressure will be held to the ISIP.”). Selecting a model that would not pump at a rate sufficient to reach the ISIP would be disfavored as it would mean that the well formation could close, and conversely selecting a model that pumps at a significantly higher rate would at a minimum be wasteful in terms of the fracturing fluid used.

⁶ Dr. Durham agreed that the “formation response data is the data that you receive in response to the sequence of stimuli that was applied.” EX-1049 at 42:10-14. He also agreed that one type of formation response data is a pressure value. *Id.* at 42:15-43:12.

22. Modeling of the type described in the 058 patent was a standard technique used in the industry for years before the 058 patent filing date. For example, Wikipedia stated that in the “oil and gas industry, reservoir modeling involves the construction of a computer model of a petroleum reservoir, for the purposes of improving estimation of reserves and making decisions regarding the development of the field, predicting future production, placing additional wells, and evaluating alternative reservoir management scenarios.” EX-1047. I understand that Dr. Durham testified that he had done reservoir modeling before April 1, 2019, and further he was aware of models used for well treatment schedules before the 058 patent. EX-1049 at 25:17-26:18; 22:6-19.

23. The Wikipedia page explains that multiple models may exist that approximate the conditions of a particular well, and the production history of the well is therefore taken into consideration: “flow simulation continues the integration process by bringing in the production history.... If the properties in the model are realistic, simulated well bottom hole pressure behavior should match historical (measured) well bottom hole pressure. Production flow rates and other engineering data should also match.” EX-1047.003. Following this comparison, “some models are eliminated. After the initial history match process, dynamic well parameters are adjusted as needed for each of the remaining models to improve the match. The final model represents the best match to original field measurements

and production data and is then used in drilling decisions and production planning.” *Id.* This describes the 058 patent embodiment wherein a set of system models are used and the best or most accurate model is selected based on, for example, measured well pressure. That selected or “final” model is then used for both drilling decisions and production planning, which a POSITA would understand to include well treatment schedules.

24. Well modeling was and is performed using computer software packages. This has been the case for many years in the industry. For example, Pankaj identifies several software packages for well modeling that were commercially available as of his August 2016 filing date. *See* EX-1005 [0031]. But commercially available modeling software was in use many years before that.⁷ For example, Halliburton provided a product called “Nexus” that was described as a “next-generation reservoir simulation package” that delivered “significant speed increase over older simulators while enabling true integrated asset management by providing the ability to model subsurface reservoir systems simultaneously with surface facilities in a tightly coupled solution environment.” EX-1048.009. Nexus

⁷ Dr. Durham agreed that well modeling software was in use in the oil and gas industry before the 058 patent filing date. EX-1049:12-20.

was available by at least December 2019—approximately a decade before the 058 patent filing date. EX-1048.001.

25. Halliburton’s own prior art (EX-1038) discloses that representative models were known to be selected and used in the same way described in 058 patent—years before it was filed. EX-1038 [0010] (stating that analysis of the injection test data “can be used to ***design or control an ongoing injection treatment***, for example, in real time during the injection treatment”); [0031] (“[T]he injection control subsystem 111 may process the [injection test] data or otherwise use the data ***to select or modify ... treatment to be applied to the subterranean region*** 104”); [0043] (“The memory 250 ... includes data 254 and applications 258.... The applications 258 can include a ***fracture design model***, a reservoir simulation tool, a ***fracture simulation model***, or any other appropriate applications.”); [0055] (“The analysis and design systems 320, 330 can include various tools (e.g., injection test or treatment design tools), ***models*** (e.g., fracture models, reservoir models, leak off models, wellbore models, etc.) ... for analyzing the subterranean data and designing injection tests and treatments.”); [0091] (“[A]n injection treatment is generated, modified, or otherwise designed.... [T]he injection treatment can be designed ***based on the analysis of the response data of the subterranean region to the injection test***.”); EX-1038 [0045] (“[T]he data 254 include injection test data relating to an injection test.... [T]he injection test data

can include pressure data, flow data, seismic data, ... and other types of response data acquired during an injection test.”). Based on the above disclosures, Halliburton’s own prior art patent application confirms that “*selecting a representative model based on the received formation response data and sequence of stimuli*” was not unconventional or unknown but was instead disclosed in the prior art and in common use.

26. Another published Halliburton patent application (EX-1039) (published in 2013) also confirms that this claim limitation was well-known and conventional. Specifically, and as shown below, EX-1039 discloses both (1) selecting a well fracturing model based on well response data and (2) selecting the model based on received sensor data.

27. EX-1039 teaches selecting a well fracturing model based on received well response data. *See id.* [0029] (“The present disclosure describes techniques for managing a wellsite operation, such as a hydraulic fracture operation, by ***using one or more proxy models to determine setpoint controls for operational equipment***.... Selected proxy models ... may be optimized ... and used to determine the operational setpoints and/or setpoint trajectories (e.g., rates of change of setpoints or otherwise”); [0070] (“[A] model selection algorithm 608 ***chooses a particular proxy model*** 610. From there, the selected model 610 is

simulated in a model simulator 612 in order to generate estimates 618 of a wellsite operation condition, such as a predicted fracture condition.”).

28. EX-1039 also describes selecting the model based on sensor data. *Id.* [0046] (“The illustrated system 200 also includes sensors 202 that gather measured or observed data (measurements) 204.... In some instances, the sensors 202 record and/or measure micro-seismic activity, pressure, and temperature, among other quantities.”); [0047] (“The system 200 also includes a Proxy Model Generator (PMG) 206 that receives, as inputs, *the measured properties 204 from the sensors 202*. The PMG 206 includes *one or more proxy models that can be updated based on the measure properties 204*. For example, the PMG 206 may use the measured properties 204 to update parameters within the one or more proxy models of the PMG 206.”) (emphasis added). Figs. 2, 3, 6A, 6B show the selection of proxy models based on sensor measurements, with Fig. 3 reproduced below:

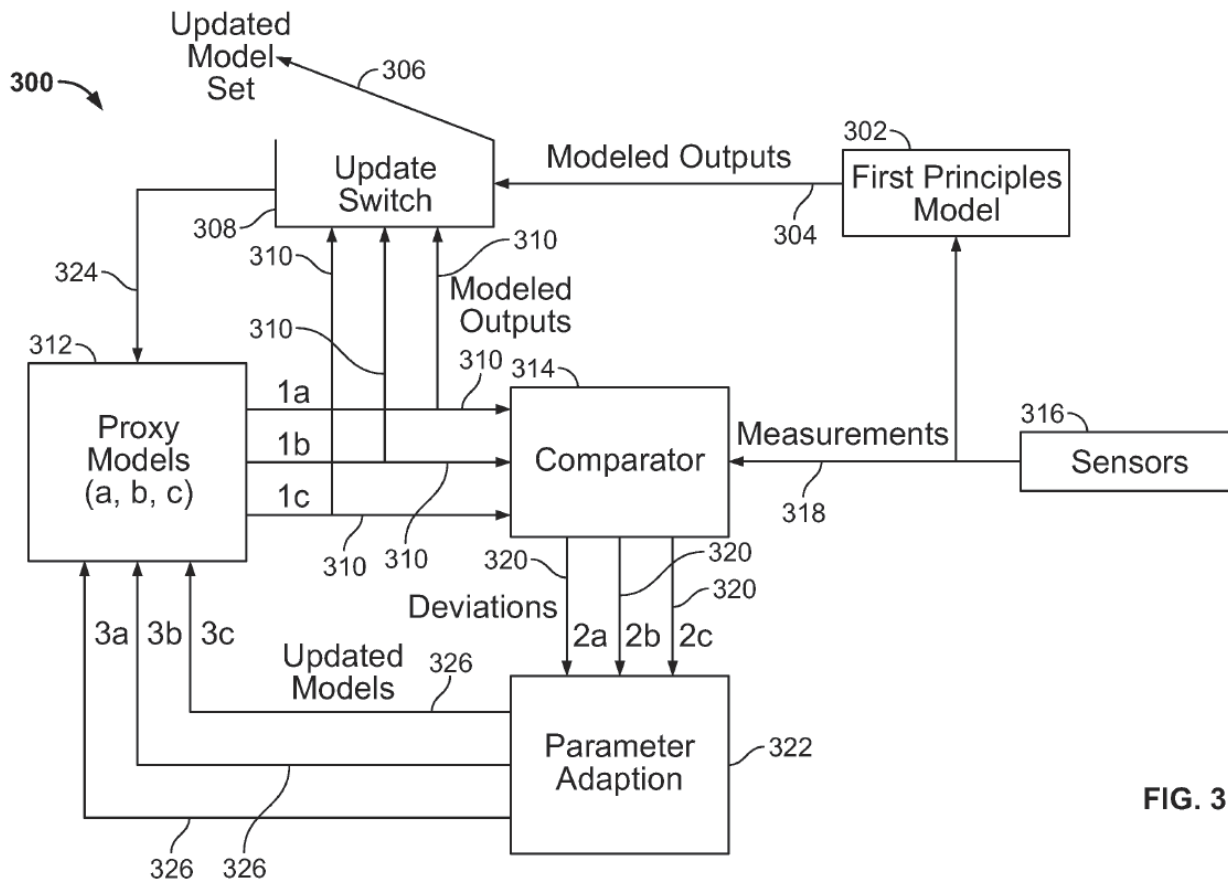


FIG. 3

EX-1039, Fig. 3

Based on the above disclosures, Halliburton's published patent application (EX-1039) is additional evidence confirming that selecting a well fracturing model based on well response data and sensor data was well-known in the prior art.

29. EX-1039 teaches that such well models were well-known and commercially available by at least 2013 (the publication's filing date). *Id.* [0030]

(identifying commercially available reservoir and well models).⁸ This is consistent with still other prior art. EX-1042 is a patent filed in 2008 disclosing that “fracture simulation models” were well-known and a “commercial fracture simulation model that is widely used by several service companies is known as FracCADE™.” *Id.* [14:20-28]. The patent also teaches that an output of the FracCADE program is a model used to generate “a pumping schedule that is used to pump the fracture stimulation fluids into the wellbore.” *Id.* [14:30-35]. That is what the 058 patent disclosed and claimed over a decade later.

30. Other prior art similarly discloses selecting a well model based on received sensor data. EX-1040 was filed in September 2012 and shows this in Figs. 3 and 4:

⁸ While EX-1039 was also filed by Halliburton and discloses commercially-available modeling software as of 2013, Halliburton did not include a similar identification of available modeling software in the 058 patent.

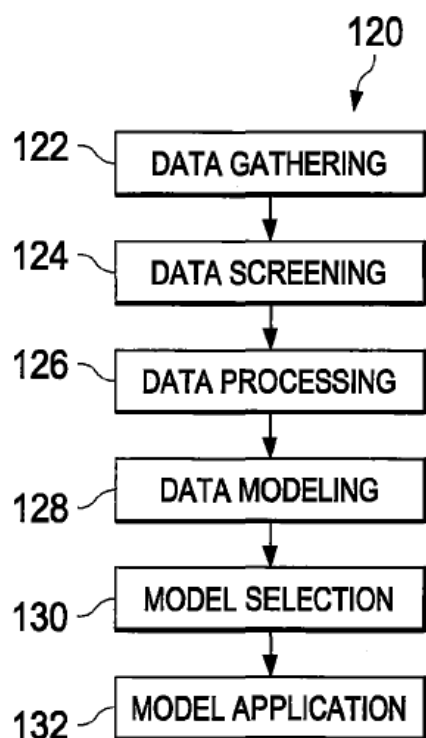


Fig. 3

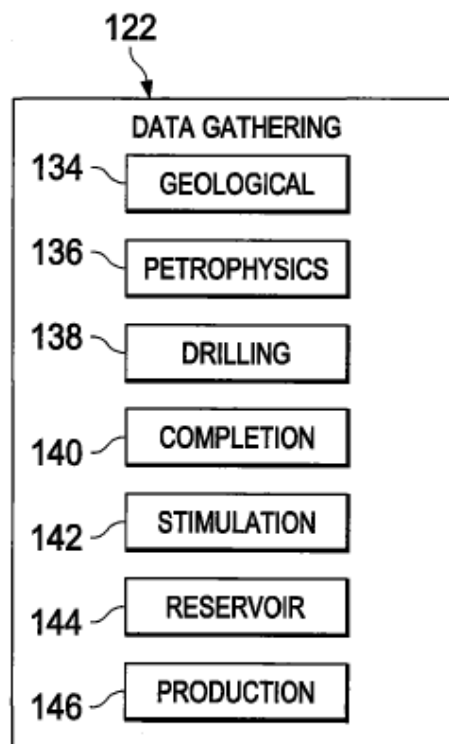


Fig. 4

EX-1040, Figs. 3 and 4

EX-1040 explains that the above data gathering step 122 includes determining, among other things, well pressure values which are used “in a predictive model to estimate the effects of various stimulation options (e.g., hydraulic fracturing parameters) on well production.” EX-1040.0012-13. As shown in Fig. 3, the method includes “*model selection* at step 130 and then *model application* at step 132.” (emphasis added); *Id.*, .0023; *see* .0026 (“[I]t is understood that the methods and systems of the present disclosure can utilize generally any type of model selection to *select a best or final model from a plurality of available models.*”) (emphasis added). *See also* EX-1018, Fig. 6 (showing “well models 626” stored in

“mass storage 610”). Thus, EX-1040 and the other exhibits cited herein confirm that it was well understood, routine, and conventional to select a well model based on received sensor data, including when that sensor data is based on a sequence of stimuli (such as a step-rate test).

3. Claim 1: “controlling a fracturing pump based on the representative model” was another conventional and well-known feature of the prior art.

31. I understand that Patent Owner has taken the position that a third claim limitation was not known and conventional and instead represents an improvement over the prior art:

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

As with the other claimed features, this feature was also well-known, conventional, and in use in the industry prior to the filing date of the 058 patent for the reasons I discuss below and for the reasons I explained in my previous declaration.

32. Using models to control fracturing pumps was common in the industry years before the 058 patent. That is exactly what EX-1042, filed in 2008, discloses:

The procedural techniques for pumping fluids down a well-bore to treat a subterranean formation can be facilitated by many useful tools to help design and implement treatments, one of which is a computer

program commonly referred to as a fracture simulation model (also known as fracture models, fracture simulators, and fracture placement models). One commercial fracture simulation model that is widely used by several surface companies is known as FracCADE™.... All of the various fracture simulation models use information available to the treatment designer concerning the formation to be treated and the various treatment fluids (and additives) in the calculations, and the *program output is a pumping schedule that is used to pump the fracturing stimulation fluids into the wellbore.*”

EX-1041 [14:20-35] (emphasis added).

33. Halliburton’s published patent application (EX-1038) (published in 2015) also discloses this claimed step: “The injection system 108 may include *pump controls* or other types of controls for *starting, stopping, increasing, decreasing or otherwise controlling pumping* as well as controls for selecting or otherwise controlling fluids pumped during the injection treatment.” EX-1038 [0027]. The Halliburton published patent application explains that the pumps can be computer-controlled. *Id.* (“The injection control subsystem 111 may communicate with such equipment to monitor and control the injection treatment.”); [0060] (“[T]he injection treatment can be modified, adjusted, or

otherwise controlled automatically by an injection control system, manually by a well operator or field engineer, or in a hybrid manner during the treatment.”).⁹

34. Another published Halliburton patent application (EX-1039) (filed in 2013) confirms that using models to control fracturing pumps was commonplace in the industry. EX-1039 teaches automated control of well operations, including pumps, based on selected well models. *Id.* [0027] (“[A] control system ... may automate a wellsite operation (e.g., a hydraulic fracturing process).... [C]ontrol optimization may be performed in real-time (or near real time) through one or more proxy models.”); [0029] (“The present disclosure describes techniques for managing a wellsite operation, such as a hydraulic fracture operation, by *using one or more proxy models to determine setpoint controls for operational equipment*. The operational equipment ... can include ... *pumps*, mixers, and other equipment for a hydraulic fracturing operation (or other operation) The selected proxy models may be optimized (as described below) and used to determine the operational setpoints and/or setpoint trajectories (e.g., rates of change of setpoints or otherwise).”); [0041] (“[T]he computing environment 250 may control valves

⁹ Further, the “injection treatment can be updated or modified in real time or dynamically, for example, *based on response data from an injection test* during the injection treatment.” EX-1038 [0094].

190 that modulate a flow 10 of the liquid source 217 and/or the gel source 195, as well as *control one or more pumps....*”); [0044]; claim 11 (“The *computer-implemented* method ... further comprising *controlling the hydraulic fracturing operation equipment* based on the control output to hydraulically fracture a subterranean zone...”).

35. Another Halliburton patent (EX-1041) (published in 2014) shows an automated system for analyzing well data, selecting well models, and controlling pumps to optimize well performance:

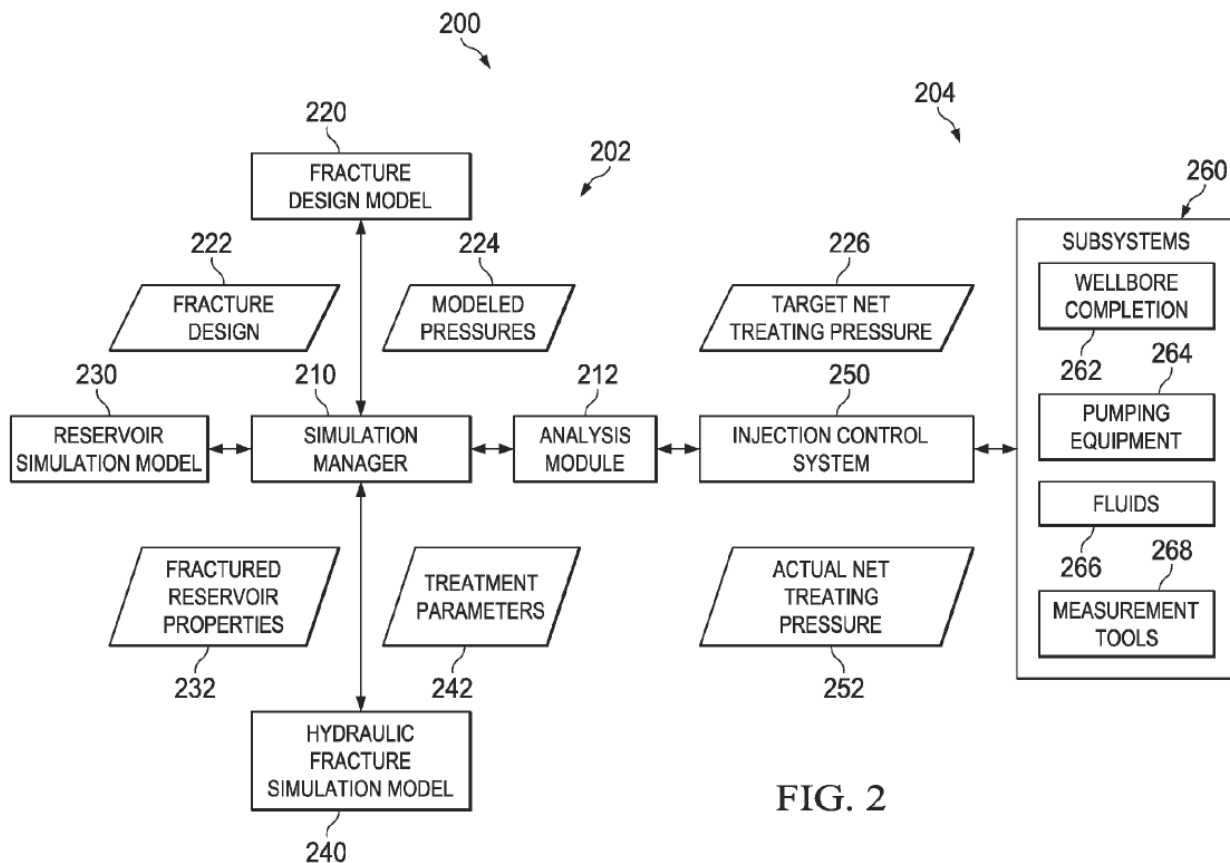


FIG. 2

EX-1041, FIG. 2

36. EX-1041 states that a computing subsystem “can calculate, select, or optimize fracture treatment parameters for initialization, propagation, or opening fractures in the subterranean region 104. The injection treatment control subsystem [] may receive, generate or modify an injection treatment plan (e.g., a **pumping schedule**) that specifies properties of an injection treatment to be applied to the subterranean region 104.” *Id.* [0030]; *see also* [0031] (stating that the “treatment control subsystem [] may initiate control signals that configure the injection system 108 or other equipment (e.g., **pump trucks**, etc.) to execute aspects of the injection treatment plan. The injection treatment control subsystem [] may receive data collected from the subterranean region 104 ... by sensing equipment, and ... may ... **use the data to select or modify properties of an injection treatment** to be applied to the subterranean region 104.”); [0032] (disclosing that the control system may “control and change the net treating pressure of an injection treatment to improve or maximize fracture volume or connected fracture surface area. Controlling the net treating pressure may include modifying pumping pressures, **modifying pumping rates**, modifying pumping volumes, modifying proppant concentrations, modifying fluid properties....”); [0046] (disclosing that the control system selects well models as part of the process); [0053], [0054]; [0027] (explaining that the control system uses communication links to communicate with the pumps and with sensors or other data collection devices in the well); [0028]

(teaching that the system includes “***pump controls*** ... for starting, stopping, increasing, decreasing or otherwise controlling pumping as well as controls for selecting or otherwise controlling fluids pumped during the injection treatment. The [control system] may ***communicate with such equipment to monitor and control the injection treatment.***”); [0068] (explaining that the control system may include “computer-implemented algorithms that can ***automatically*** control the subsystems” that include the pumps, or may be controlled by an operator); [0073] (same); claims 14-22 (all emphasis added).

37. EX-1012 similarly teaches that a computer control system can “simultaneously cause the delivery of the proppant and chemical components comprising a well treatment fluid with the desired property at the desired rate to the blending unit where it can be immediately pumped to the desired well location.” *Id.* [0021]; [0028] (“[T]he pump drive signal 350 can control the pumping pressure or pumping rate of the pumps driving the well treatment fluid into a well.”).

38. These exhibits cited herein show that this claimed step of “controlling an electrical fracturing pump based on the representative system model” was well-understood, routine, and conventional in the industry well before the 058 patent filing date.

4. Claims 2, 10, and 17 recite a conventional and well-known limitation.

39. I understand that Patent Owner and Dr. Durham have taken the position that another claim limitation appearing in certain dependent claims was not well-known and conventional but instead represents an improvement over the prior art:

“wherein the representative system model is retrieved
from a data store based the received formation response
data.”

I disagree. The above limitation was also well-known and standard in the industry prior to the filing date of the 058 patent for the reasons I discuss below and for the reasons I explained in my previous declaration.

40. These claims add that the system model is retrieved “from a data store” based on the response data. The 058 patent confirms that a “data store” may be merely computer memory. EX-1001 [7:19-21]. The references discussed above confirm that retrieving models from memory “based on” sensor data was well-known and conventional.

41. Indeed, a POSITA would immediately understand that in computer-controlled systems like those described in the prior art, the system models would be stored in computer memory. *See* EX-1038 [0010] (stating that analysis of the

injection test data “can be used to *design or control an ongoing injection treatment*, for example, in real time during the injection treatment”); [0031] (“[T]he injection control subsystem 111 may process the [injection test] data or *otherwise use the data to select or modify ... treatment to be applied to the subterranean region* 104”); [0043] (“The *memory* 250 ... includes data 254 and applications 258.... The applications 258 can include a *fracture design model*, a reservoir simulation tool, a *fracture simulation model*, or any other appropriate applications.”); EX-1039 [0046]; [0047] (“The system 200 also includes a Proxy Model Generator (PMG) 206 that receives, as inputs, *the measured properties 204 from the sensors* 202. The PMG 206 includes *one or more proxy models that can be updated based on the measure properties 204*. For example, the PMG 206 may use the measured properties 204 to update parameters within the one or more proxy models of the PMG 206.”) (all emphasis added); EX-1040, Figs. 3 and 4:

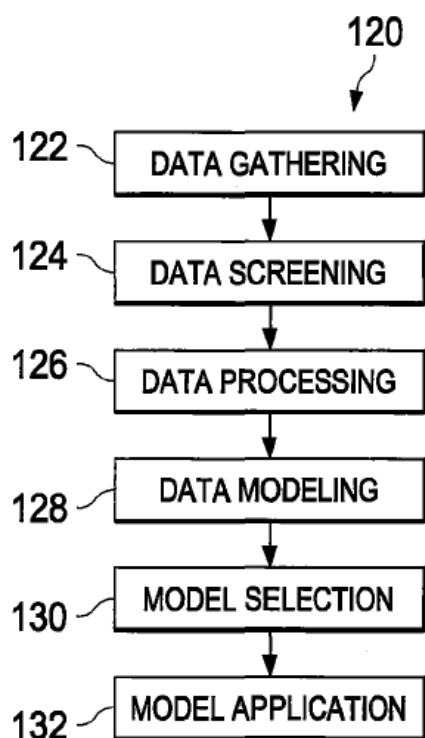


Fig. 3

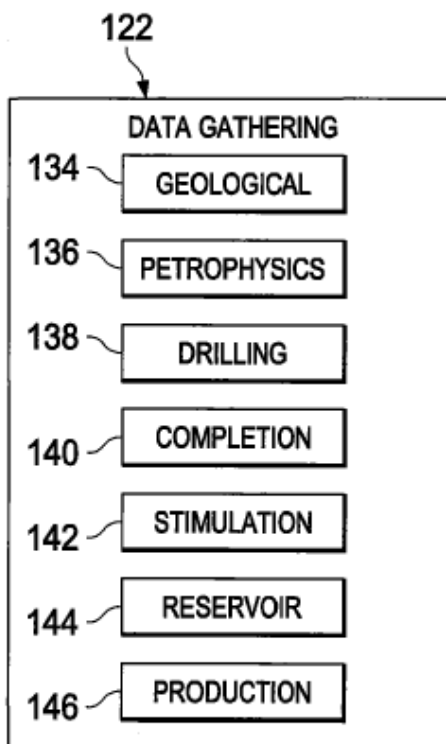


Fig. 4

42. EX-1040 explains that the above data gathering step 122 includes determining, *inter alia*, well pressure values which are used “in a predictive model to estimate the effects of various stimulation options (e.g., hydraulic fracturing parameters) on well production.” EX-1040.0012-13. As shown in Fig. 3, the method includes “model selection at step 130 and then model application at step 132.” *Id.*, .0023; *see* .0026 (“[I]t is understood that the methods and systems of the present disclosure can utilize generally any type of model selection to select a best or final model from a plurality of available models.”).

43. A POSITA would understand that such models are stored in computer memory. Thus, this exhibit and the others cited above confirm that it was well

understood, routine, and conventional to select a well model based on sensor response data where the model is selected from a “data store” (e.g., computer memory).¹⁰

5. Claims 4, 12, and 19 recite conventional and well-known limitations.

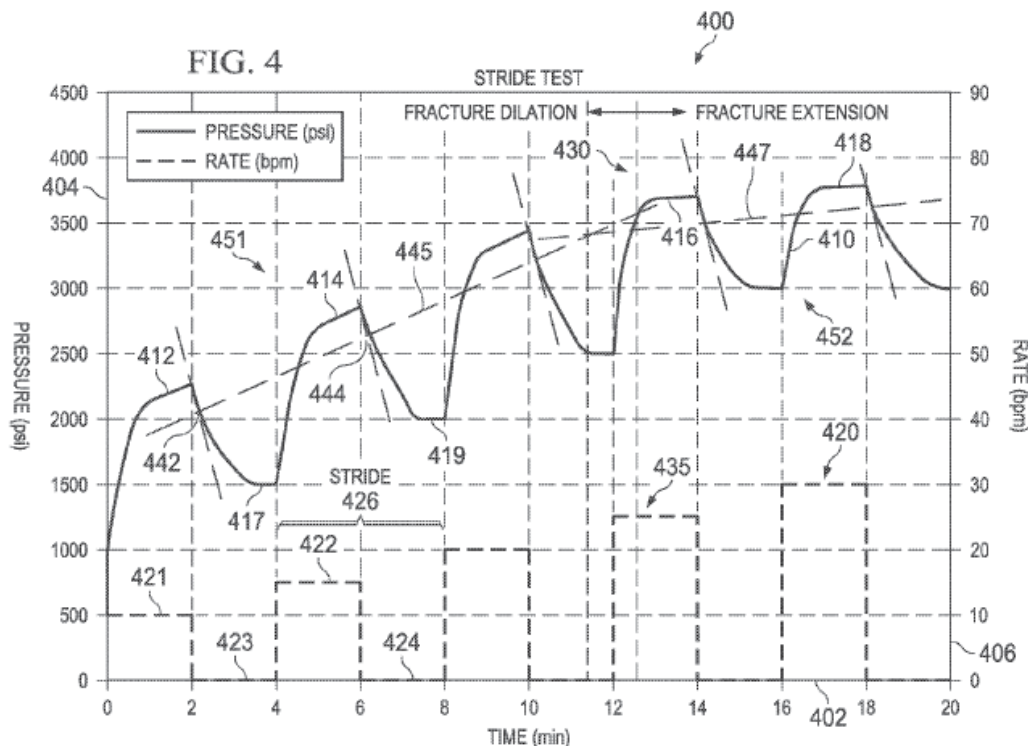
44. I understand that Patent Owner and Dr. Durham have taken the position that another claim limitation appearing in certain dependent claims represents an unconventional feature and improvement over the prior art:

“wherein selecting the representative system model
further comprises:
determining one of a linear or a non-linear relationship
between the sequence of stimuli and received formation
response data; and
updating the one of the linear or the non-linear
relationship based on multiple iterations of the generated
sequence of stimuli.”

¹⁰ Dr. Durham confirmed that the claimed “data store” may include computer memory or computer storage, such as a computer hard drive or a server. EX-1049 at 44:8-45:19.

However, the above feature was also known and standard in the industry prior to the filing date of the 058 patent for the reasons I discuss below and for the reasons I explained in my previous declaration.

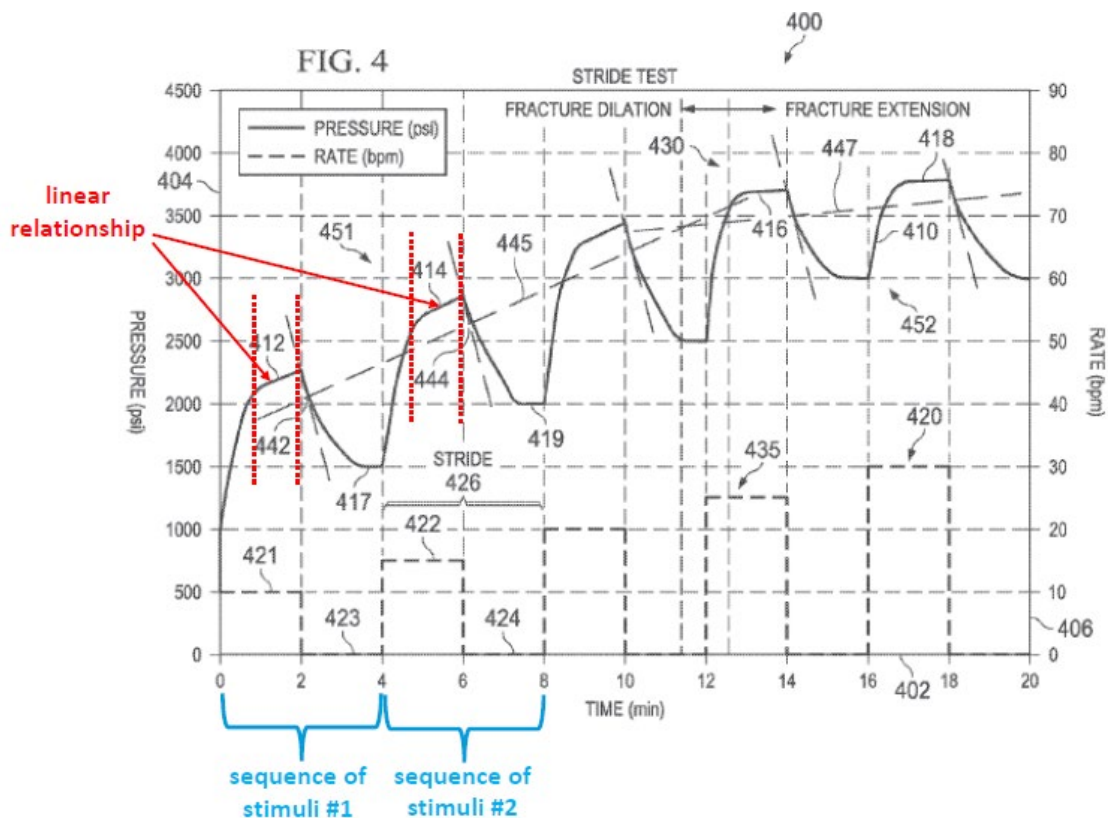
45. A POSITA would have understood that SRTs and mini-frac tests both (1) determine a linear or non-linear relationship between the sequence of stimuli and response data and (2) update the linear or non-linear relationship based on multiple iterations of the sequence of stimuli. EX-1038 confirms that such injection tests plot the relationship between, e.g., the pump rate(s) and the measured pressure, and repeatedly update the relationship based on multiple changes (“iterations”) of the pump rate. *Id.* [Abstract] (“response data from an injection test of a subterranean region are received.... [T]he response data are acquired during a *series* of injection periods and shut-in intervals of the injection test.”); [0053] (“[T]he control subsystem 312 can interact with the monitoring subsystem 314 to control the injection test based on the formation response obtained from the monitoring subsystem 314”); [0055] (“The analysis and design systems 320, 330 can include various tools ... for analyzing the subterranean data and designing injection tests....”); [0056]; [0063] (“FIG. 4 is a plot illustrating the injection rate 420 and a pressure response 410 of an example injection test.”):



EX-1038, Fig. 4

46. EX-1038 explains that the injection test “includes a *succession* of injection periods (e.g., injection periods 421 and 422) and shut-in intervals (e.g., shut-in intervals 423 and 424)... [The] injection test can be referred to as a stride test where a single ‘stride’ 426 includes the combination of one injection period 422 and one shut-in interval 424.” *Id.* [0064] (emphasis added); *see* [0065]; [0066] (“the injection rate 420 is increased over time across different injection periods”); [0067] (“[E]ach injection period may last at least to a point where the pressure curve 410 *reaches a steady slope* such as the constant slope at 412 and 414”) (emphasis added); [0071]; [0073] (“The shape, the decline rate, or other information of the pressure curve 410 can be analyzed to derive formation

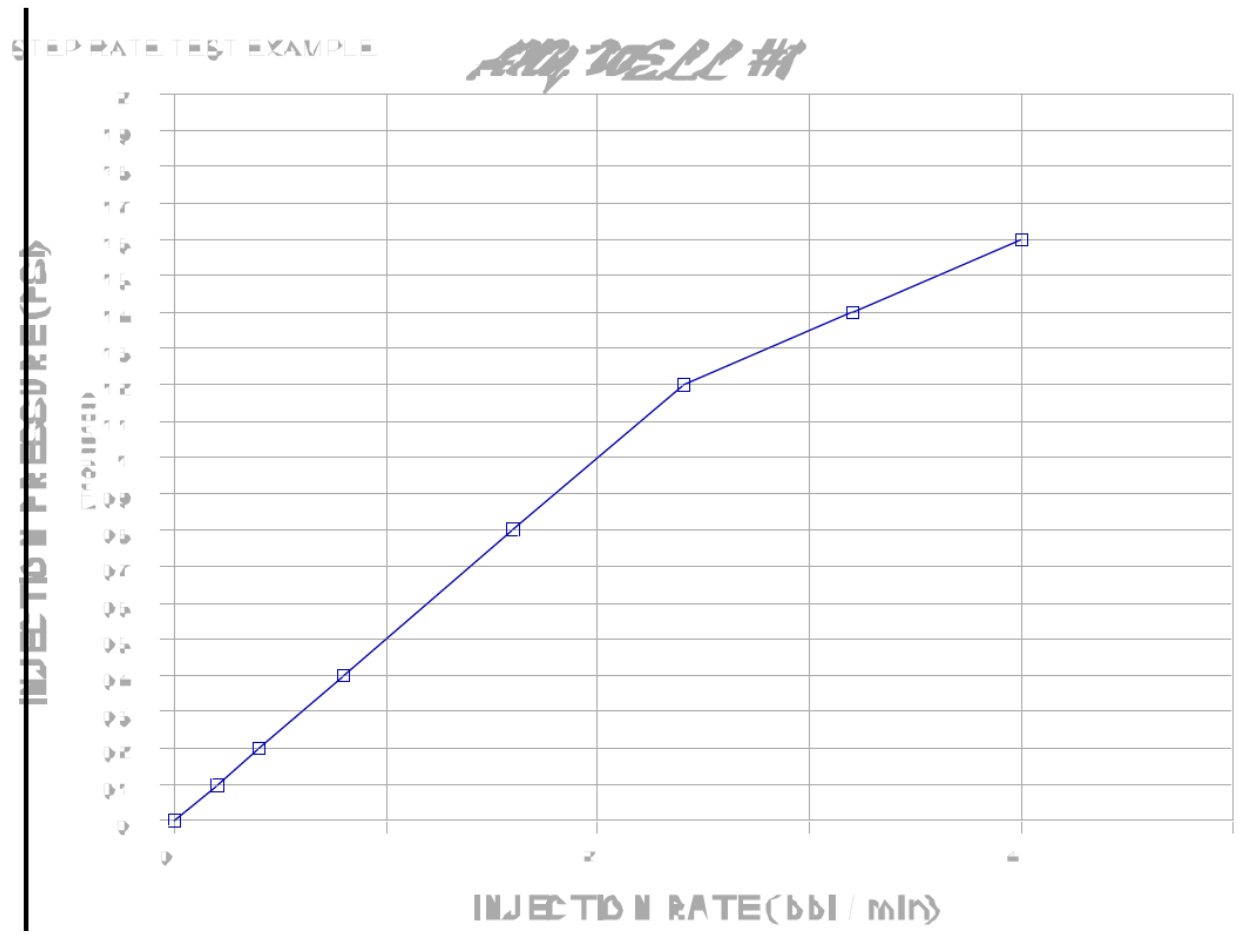
properties”); [0075]; [0077]; [0080]; [0088] (“[T]he injection rate and the duration of each injection period *can be controlled such that the pressure reaches a stabilized slope* such as the constant slopes 412 and 414”) (emphasis added); [0089]-[0090]. EX-1038 therefore shows and describes claims 4, 12, 19, disclosing that the SRT may be “controlled” so that the pressure reaches a “stabilized slope,” for example a linear slope:



EX-1037, Fig. 4 (annotated)

47. EX-1033 also shows that this was industry standard for years, shown below:

Plot the injection rates and the corresponding stabilized pressure values. These are graphically represented as a constant slope straight line to a point at which the formation fracture, or breakdown pressure is exceeded. The slope of this subsequent straight line should be less than that of the before-fracture straight line (see example).



EX-1033.002, .006.

48. Other prior art teaches this as well. *See* EX-1043, [9:39-54, Figure 4A] (showing and describing a non-linear relationship between pressure and pump rate across an injection tests); *see* ¶14 (discussing EX-1043). Thus, these claims are also directed to well-understood, routine, and conventional technology.

6. **Claims 5 and 13 recite a conventional feature.**

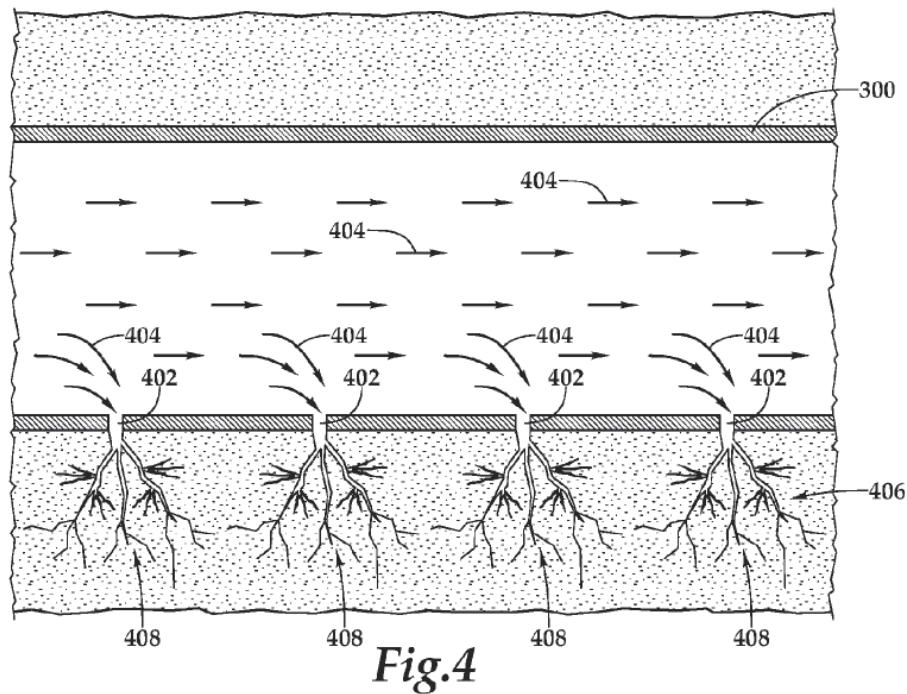
49. I understand that Patent Owner and Dr. Durham have taken the position that another limitation in certain dependent claims represents an unconventional improvement over the prior art:

“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.”

The above feature was also known and standard in the industry prior to the filing date of the 058 patent for the reasons I discuss below and for the reasons I explained in my previous declaration.

50. First, using diverters to change flow distribution is using diverters in their conventional manner. EX-1024, [1:31-33] (explaining that diverters will “divert the flow of well treatment fluids (e.g., injection fluids) from perforations taking more fluid to perforations taking less fluid”); EX-1046.001 (“The diversion process is used to help ensure that stimulation fluids are distributed across the entire interval to be treated.... To accomplish complete coverage, some placement aid may be used to divert the treating fluid from one zone to another.”); *see* EX-

1046.002;¹¹ EX-1045, [0013] (“[D]iverters are introduced into the frac fluid entering the wellbore.... to obstruct and temporarily seal [the perforations], thereby causing frac fluid to flow toward the remaining ones of the plurality of perforations not being obstructed....”). Figs. 4-6 show this:



¹¹ Diverters have been used “to enhance stimulation treatments for over 80 years.” EX-1046.002.

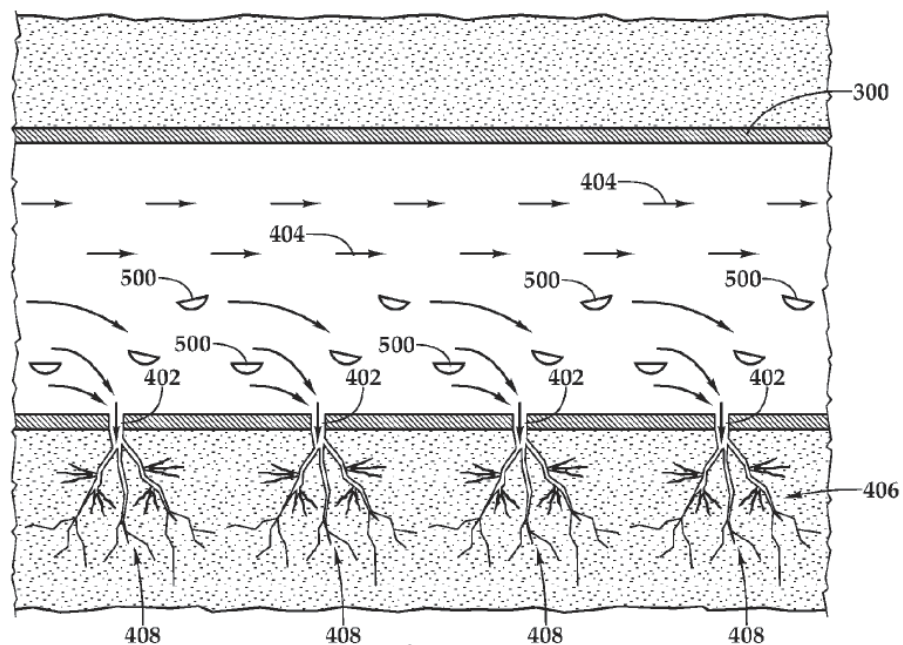


Fig.5

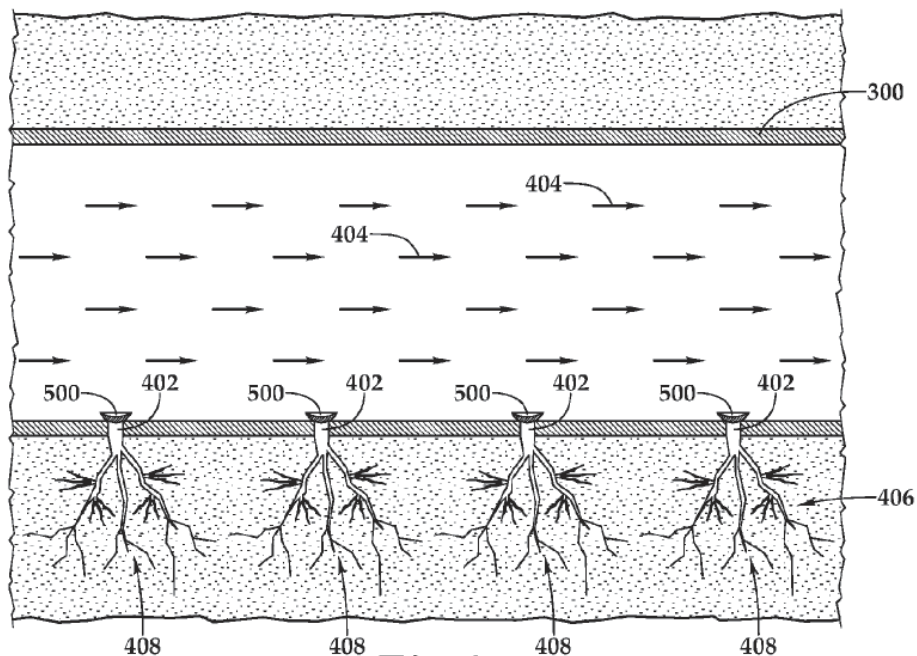


Fig.6

EX-1045, Figs. 4-6

51. As shown above, “FIG. 4 shows multiple perforations 402.... The flow of frac fluid is indicated by flow lines 404. All the perforations are not sealed

and therefore open. The pressurized frac fluid flows into the perforations ... as shown by directional lines 404.” EX-1045, [0041]. “In FIG. 5 ... diverters 500 ... are shown entrained in the flow of frac fluid and being moved toward perforations 402 by the flow of the frac fluid....” *Id.*, [0042]. “In FIG. 6, the ... diverters are shown seated on the openings of the perforations ... thus temporarily sealing the perforations against substantial frac fluid flow.... The high pressure of the frac fluid within the well bore pushes against the seated diverters with sufficient force to keep them in place *while the frac fluid flows past them*, as indicated by the frac fluid flow lines 404 in the figure.” *Id.* Dr. Durham agrees that diverters are typically used to divert the flow of fluid from perforations taking more fluid to ones taking less fluid, and that diverters have been used in the industry for some time. EX-1049 at 45:20-46:21.

52. It was also common knowledge and conventional to use sensors to measure the well response to diverters. EX-1046.016 (“[M]onitoring of the treatment is critical for real-time optimization of the diversion process.... [T]he ... most common way to monitor diversion effectiveness is to evaluate the pressure responses during pumping and changes in fracture gradients throughout the stimulation treatment.”); *id.*, .017 (showing in Fig. 15 pressure response to diverters entering the perforations at flags 67-70; see Fig. 16 (same) (explaining that a “method used to estimate diverter effectiveness is to look for instantaneous

pressure increases as the diverter enters the formation”); *id.*, 018 (showing in Fig. 17 estimating diverter effectiveness by looking for an “increase in net pressure from the beginning to the end of the stimulation treatment.”).

53. Finally, it was also conventional to use diverters as part of injection tests, and, as explained earlier, use the measured response from the injection tests (including with diverters) as part of selecting a system model. *See* ¶¶20-30; EX-1038 [0067] (“During each injection period, ... diverters can be used to test and determine the subterranean response....”); [0054]-[0056]; [0077]; [0082]-[0083]; [0086]; [0088]-[0089]; [0091]; Fig. 6.

B. GROUND 1: Pankaj (EX-1005)

54. During my deposition, I misspoke about whether step 1182 in Pankaj Fig. 11 teaches “controlling a fracturing pump.” After reviewing my original declaration and Pankaj (EX-1005), I incorrectly answered questions about this issue as I explain below.

55. During my deposition, I answered the following questions incorrectly:

Q. Dr. Nikolaou, I believe you testified earlier that step 1182 of Figure 11 of Pankaj related to production operations as opposed to controlling a fracturing pump, is that right?

A. That is correct, yes.

EX2014, 56:17-22; 54:16-55:22.

Q. Earlier today counsel asked you whether step 1182 of Figure 11 of Pankaj related to the production operations as opposed to controlling a fracturing pump, is that right?

And you responded: That is correct.

Is that consistent with your declaration?

A. Yes.

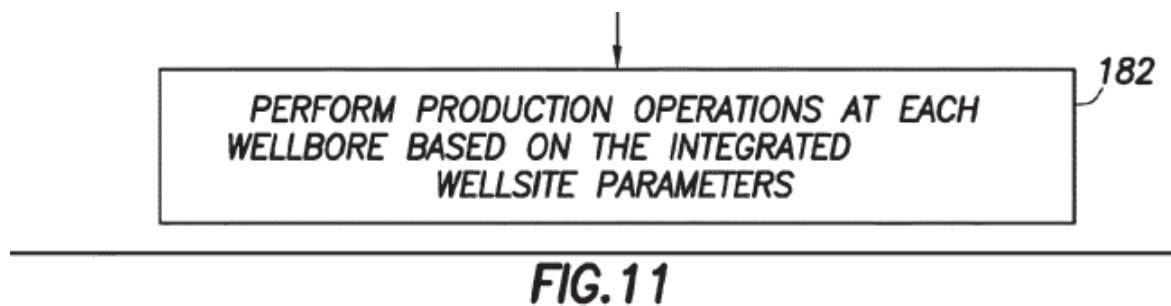
* * *

Q. During step 1182, are there changes to how a fracturing pump is controlled?

A. Oh, in step 1182, the fracturing pump is no longer at play because fracturing as already been completed. It has already been performed. And 1182 refers to performing production operations.

EX-2014, 82:21-84:24.

56. In answering the questions above, I focused on the textual description in Figure 11 alone, which mentions only production operations, shown below (there is a typographical error in the labeling as “182” should be “1182”):



As shown above, the textual description for this step does not mention anything about fracturing operations. This led me to answer the questions that the above step, as shown in Fig. 11, does not involve fracturing operations, which is incorrect based on the description of this step in Pankaj.

57. Pankaj discloses that step 1182, shown above, describes both fracture operations and/or production operations:

[0141] The method performing 1182 may involve performing fracture and/or production operations at one or more of the wellbores of the wellsite based on the integrated wellsite parameters. For example, production operations may be performed based on the validated fracture geometry. With the knowledge of the geomechanical parameters, such as microseismic locations, the fractures may be predicted and used to define operational decisions accounting for such locations. The fracturing treatment parameters may be optimized to achieve the desired stimulation objectives to maximize well production.

EX-1005 [0141]. The “fracture operations” above include the control of a fracturing pump. *Id.* For example, the above paragraph explains that “fracturing treatment parameters may be optimized,” include the parameters that control the fracturing pump. *Id.* Based on this paragraph, Pankaj discloses that step 1182 teaches “controlling a fracturing pump.”

58. This correction is consistent with what I said in my original declaration. In paragraph 97 of that declaration, I both cite and quote the above paragraph in providing the same explanation:

97. Pankaj explains that step 1182 (shown above) includes optimizing “fracturing treatment parameters” “to achieve the desired stimulation objectives to maximize well production.” *Id.*, [0141]. Pankaj discloses that fracture treatment parameters—that is, parameters for “*controlling an . . . fracturing pump*—are updated based on the resulting model. *Id.*, [0126] (“The method continues with

EX-1003, ¶ 97

As shown above, my original declaration explained how Pankaj's optimization of fracture treatment parameters controls a fracturing pump.

59. For the above reasons, I supplement my previous declaration to correct my deposition answers in that Pankaj's step 1182 does, in fact, teach "controlling a fracturing pump."

60. There are other portions of Pankaj that confirm that the fracturing pumps are under computerized control. Paragraph [0055] explains that fracturing "is performed by pumping fluid into the formation using a pump system 329." *See also* Fig. 3.1 (showing the "fracturing operations" at a wellsite, including pump system 329); *see* [0015]. The pump system 329 pumps the fracturing fluid into the well. EX-1005 [0056]. Pankaj teaches that a "computerized control system may be employed to direct the entire pump system 329 during the fracturing operation," [0058], which a POSITA would have understood to mean encompasses using the computer system to control the pumps, e.g. without human intervention. Dr. Durham agreed that this was a fair understanding of what Pankaj disclosed to a POSITA. EX-1049 at 64:7-65:9.

61. I have also considered Patent Owner's and Dr. Durham's arguments that Pankaj does not disclose the claimed step of 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.” For the reasons explained in my first declaration, I disagree. I understand the Patent Owner and Dr. Durham have interpreted this limitation to mean a “series of events that are generated in advance of the actual stimulation and then applied to a well environment.” EX-2013, ¶64. I disagree that the 058 patent requires such a narrow interpretation. Regardless, Pankaj also discloses the sequence of stimuli limitation under that narrower reading.

62. For example, Pankaj teaches that as the “fracturing fluid pumping treatment continues for some duration (e.g. around a couple of hours) ... the fluid and proppant flow in the fractures is determined from simulation on the collected wellsite information. The *sequence of increasing the proppant concentration* on the surface is also a parameter that may be recorded while pumping. The proppant concentration increment causes increase in the hydraulic fracture conductivity as proppants fill up the fractured volume.” EX-1005 [0104] (emphasis added). Table 1 also shows a “pumping schedule” for one stage as input for the simulator:

TABLE I

Pump rate (bbl/min)/ (kL/min)	Fluid name	Fluid volume (gal)/(kL)	Proppant	Proppant concentration (PPA)
90/(14.3)	Fracturing fluid	20000 (75.7)	None	0
90/(14.3)	Fracturing fluid	15000 (56.8)	Proppant type 1	0.5
90/(14.3)	Fracturing fluid	15000 (56.8)	Proppant type 1	1
90/(14.3)	Fracturing fluid	15000 (56.8)	Proppant type 2	1.5
90/(14.3)	Fracturing fluid	15000 (56.8)	Proppant type 3	2
90/(14.3)	Fracturing fluid	15000 (56.8)	Proppant type 4	2.5
90/(14.3)	Fracturing fluid	10000 (37.9)	Proppant type 5	3
90/(14.3)	Fracturing fluid	10000 (37.9)	Proppant type 6	3.5
90/(14.3)	Fracturing fluid	5000 (18.9)	Proppant type 7	4

Pankaj, EX-1005 Table I

A POSITA would have understood that Table 1 shows a “predetermined” pumping schedule that meets claim 1’s “sequence of stimuli” limitation even if Patent Owner’s and Dr. Durham’s construction of the limitation (a predetermined schedule determined in advance of application to the well environment) were accepted. The proppant concentration, which reads on a sequence of stimuli

comprising a “particulate concentration,” is varied over time in the Table I schedule.¹²

63. Table I refers to an “input for the simulator,” but a POSITA would have understood that Table I would also be used to apply to the well environment. As explained above, step-rate tests and mini-frac tests were commonplace in the industry and were applied to wells, and a POSITA would understand that Table I is an example of such a test. Therefore, in my opinion Pankaj also discloses the sequence of stimuli limitation under Patent Owner’s and Dr. Durham’s interpretation of the limitation.

III. JURAT

64. I declare that all statements made herein of my own knowledge are true and that all statements made on information and belief are believed to be true; and further that these statements were made with the knowledge that willful false statements and the like so made are punishable by fine or imprisonment, or both, under Section 1001 of Title 18 of United States Code.

¹² I understand that Dr. Durham agreed that proppant is a stimulus within the meaning of the claim limitation. EX-1049 at 34:20-35:13.

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

Executed this 10th day of May 2024 in Houston, Texas.

A handwritten signature in black ink, appearing to read "Michael Nikolaou", written over a horizontal line.

Michael Nikolaou, Ph.D.