ACQUISITION OF SCHEDULED FLUID LEVEL, DYNAMOMETER, POWER DATA TO MONITOR CHALLENGING SUCKER ROD LIFTED WELLS

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ABSTRACT

At the well or through the cloud from any location in the world an operator can troubleshoot and analyze the performance of any well. Fluid level and dynamometer test can be acquired and used to analyze challenging operation in sucker rod lifted wells without requiring the operator to be present at the wellsite. The operator can automatically acquire precisely time stamped high frequency data using an acquisition schedule created/modified remotely to acquire data for an extended time period and/or acquire individual test on demand. This paper will present examples of using this data to:

1) analyze/monitor an unconventional horizontal sucker rod well as the wells flows while pumping, flumps up casing approximately every 10 hour and as the well flows up the tubing as the VSD changes speed to maintain pump fillage,
2) show conventional tubing anchors can trap gas below the tubing anchor in horizontal unconventional wells that flumping up the casing,
3) determine bottom hole pressures versus time from a pressure buildup or fall-off test created using an acoustic liquid level instrument with acquisition controlled according to a predefined schedule,
4) perform Walker fluid level depression test to determine the annular gradient below the liquid level and determine the producing pump intake pressure,
5) Setup a timer to control run-time for a marginal electrically driven sucker rod pumped well using acoustically derived drawdown and build-up data.

In the past an operator using a portable system and laptop was required to be at the wellsite to perform these tests. Now the operator can schedule unattended fluid level, dynamometer, pressure, and power acquisitions test. Using internet or cell phone access a well anywhere in the world to monitor in detail with high speed and high-resolution wireless sensor data. Scheduled acquisition time, frequency and sampling speed may be changed to monitor a well for an extended time. Schedule can be changed and data can be remotely retrieved without requiring the operator to make a trip to the wellsite to retrieve and view the acquired well data.

Introduction

This paper will discuss many sets of data acquired from different wells remotely. In most cases the data was transmitted over long distances through the cloud. At the well or through the cloud from any location in the world the operator can troubleshoot and analyze the performance of any well. Fluid level and dynamometer test can be acquired and used to analyze challenging sucker rod lifted wells without requiring the operator to be present at the wellsite. The operator can automatically acquire precisely time stamped high frequency data using an acquisition schedule created/modified remotely to acquire data for an extended time period and/or acquire individual test on demand. This paper will present examples of using this data to: 1) analyze/monitor an unconventional horizontal sucker rod well as it flumps up casing approximately every 10 hour and as it flows up the tubing as the VSD changes speed to maintain pump fillage, 2) show conventional tubing anchors trap gas below the tubing anchor in horizontal unconventional wells that flumping up the casing, 3) determine bottom hole pressures versus time from a pressure buildup or fall-off test created using an acoustic liquid level instrument with acquisition controlled according to a predefined schedule, 4) perform Walker fluid level depression test to determine the annular gradient below the liquid level and determine the producing pump intake pressure, 5) Setup a timer to control run-time for a marginal electrically driven sucker rod pumped well using acoustically derived drawdown and build-up data.

Monitoring a flumping unconventional Eagle Ford Sucker Rod Lifted Well using 66 hours of Dynamic Fluid Level, Dynamometer, Power Data acquired on a horizontal toe up Eagle Ford Sucker Rod Lifted Well sampling every 20 minutes. 200 fluid level shots synchronized with 3 minutes of simultaneous acquisition of dynamometer, tubing pressure, and power referenced to the same clock time. The well flows liquid to the surface up the casing annulus at an approximate 10-hour time intervals. Casing pressure and casing pressure build up rate were very much related to the increase in the annular liquid level and the flow of liquid up the casing. The VSD slowed the SPM down to approximately 3.6 SPM due to incomplete pump filllage and would increase pumping speed up to 8 SPM when pump was full. Fluid level, casing pressure pump card loads, tubing pressure, and fillage constantly changed throughout the 66-hour time period.

The combination of the tubing anchor along with annular gas flow has been shown to cause gas to accumulate below the tubing anchor in wells appearing to be pumped off. Gas trapped below the tubing anchor is shown to also be an unexpected problem for flumping unconventional horizontal sucker rod lifted well.

Pressure buildup testing involves a major commitment of time and manpower in addition to a temporary loss of oil/gas production while the well is shut-in. This data is created using an acoustic liquid level instrument to determine the annular or tubular fluid distribution while measuring the wellhead pressure. The progress of the test is controlled according to a predefined schedule. Acquisition and processing of the data is automatic and presentation of the information to the operator is available at any time during the test. The system has the overwhelming advantage over wireline-conveyed measurements that it does not require entering the well bore but is totally based on surface measurements. Through the cloud the operator now can remotely decide if sufficient data has been acquired to ensure that the test will yield accurate and complete data. Preliminary analysis of the data can be done via the cloud, then followed up with detailed transient analysis by exporting the BHP data vs. time to other analysis software.

Marginal wells can be operated by using a timer to control the on and off time of electrically driven sucker rod pumped systems. Timers are normally used on wells where the pump capacity exceeds the liquid producing capacity of the well. An acoustically derived drawdown and build-up curve will be used to determine the optimum down-time and corresponding runtime for use in setting an electrical manually-set on/off timer to control the pumping unit motor cycle.

In the past an operator using a portable system and laptop was required to be at the wellsite to perform tests. Now the operator can schedule unattended fluid level, dynamometer, pressure, and power acquisitions test. Using internet or cell phone access a well anywhere in the world to monitor in detail with high speed and high-resolution wireless sensor data. Schedule time, frequency and sampling speed to monitor a well for an extended time. Schedule can be changed and data can be remotely retrieved without requiring the operator to make a trip to the wellsite to retrieve and view the acquired well data.

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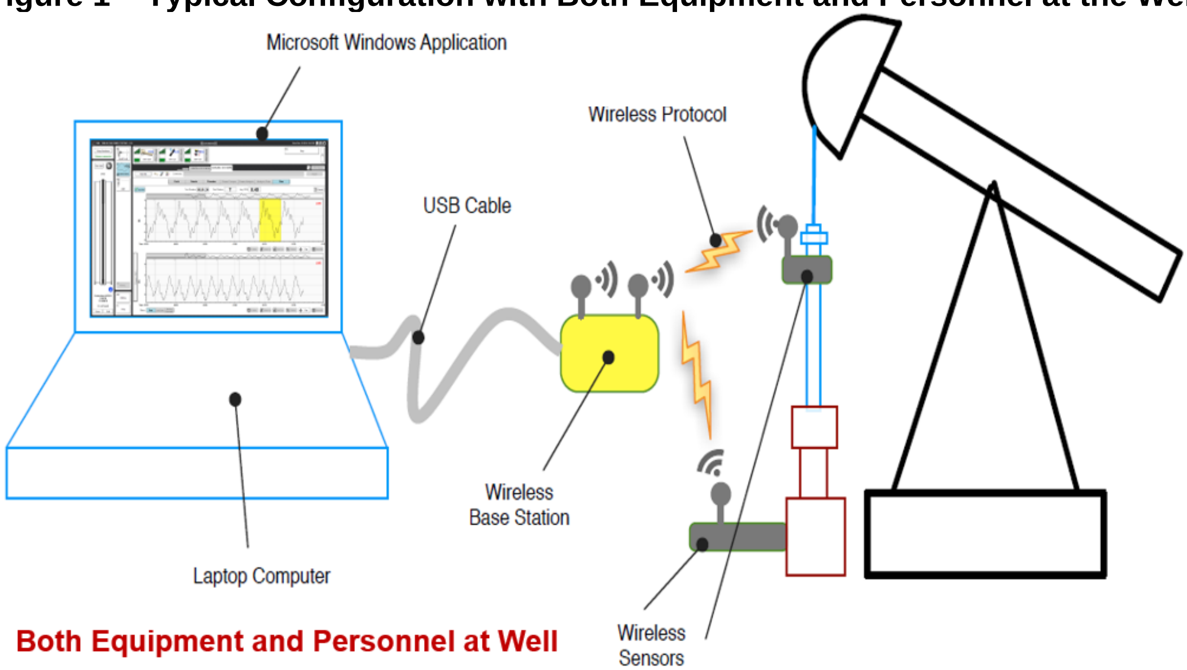
Remote Asset Monitoring

The goal to increase oil production and reduce operating costs for a well is achievable through the integrated analysis[1] of the pumping system including the performance and interaction of all the elements: the surface equipment, the down hole equipment, the well bore and the reservoir. The well's analysis is to be based on data acquired at the surface without entering the well bore and proper analysis yields an accurate representation of conditions that exist at the surface, within the well bore, at the sand face and within the reservoir.

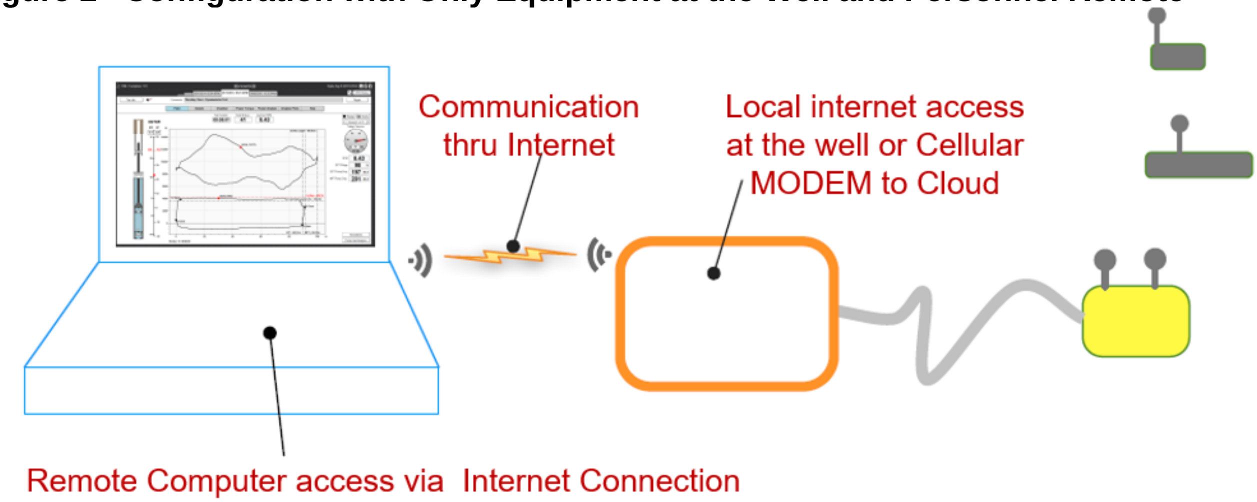
A typical configuration of this system is shown in **Fig. 1** where both the personnel and the equipment are present at the well during data acquisition. The system consists of a portable computer with software connected by USB to data acquisition system connected to appropriate sensors.

Figure 1 – Typical Configuration with Both Equipment and Personnel at the Well



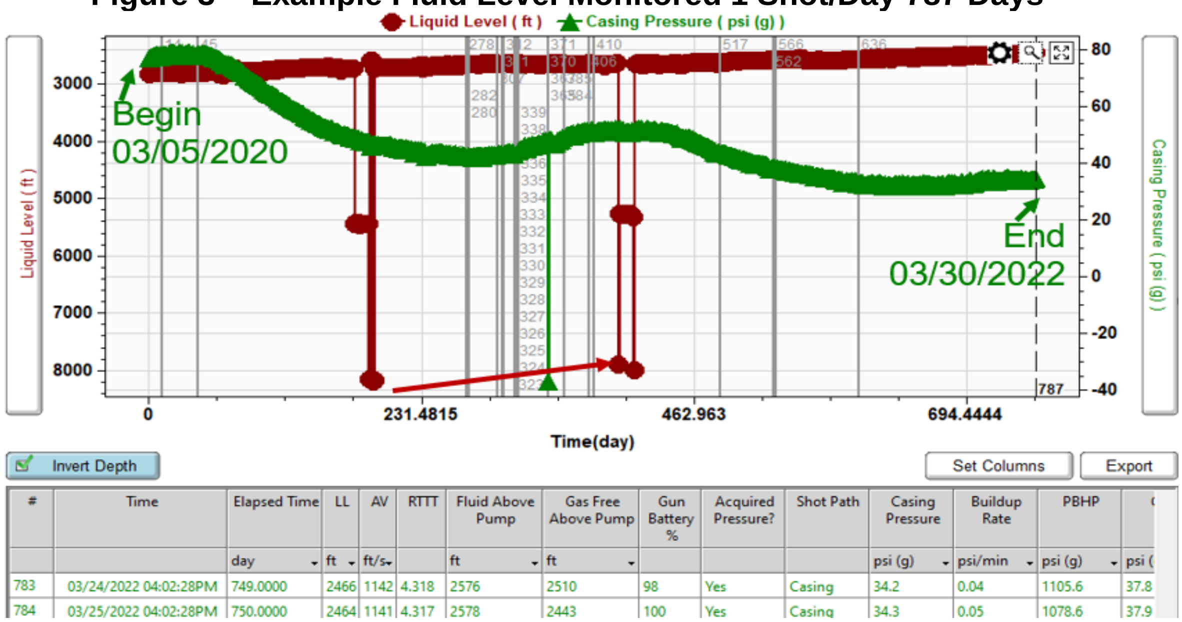
Access to the internet at remote location is available at the wellsite for most locations in North America and many other locations throughout the world. A typical configuration of this system is shown in **Fig. 2** where the equipment is present at the well during data acquisition and personnel access to the data acquisition system at the wellsite is via a computer connected to the internet, where the acquired well data is communicated through the cloud over the internet using local internet access or cellular Modem access at the wellsite.

Figure 2 –Configuration with Only Equipment at the Well and Personnel Remote



Unattended remote acquisition provides the benefit of being able to acquire the exact same quality and type of data as in the past when as operator was at the wellsite and performed data acquisition tests with the Wireless Well Analyzer System and laptop computer. Now using internet or cell phone modem for access, any well that is anywhere in the world can be monitored remotely in detail with high speed and high-resolution wireless sensor data. The operator can schedule unattended fluid level, dynamometer, pressure, and power acquisitions test remotely, setting the scheduled acquisition time, frequency and sampling speed. Too monitor a well for an extended time the schedule can be changed and data can be remotely retrieved without requiring the operator to make a trip to the wellsite to retrieve and view the acquired well data.

Figure 3 – Example Fluid Level Monitored 1 Shot/Day 787 Days



#	Time	Elapsed Time	LL	AV	RTTT	Fluid Above Pump	Gas Free Above Pump	Gun Battery %	Acquired Pressure?	Shot Path	Casing Pressure	Buildup Rate	PBHP	(
		day	ft	ft/s		ft	ft				psi (g)	psi/min	psi (g)	psi (
783	03/24/2022 04:02:28PM	749.0000	2466	1142	4.318	2576	2510	98	Yes	Casing	34.2	0.04	1105.6	37.8
784	03/25/2022 04:02:28PM	750.0000	2464	1141	4.317	2578	2443	100	Yes	Casing	34.3	0.05	1078.6	37.9

Fig. 3 displays the remote fluid levels and surface pressures acquired at a frequency on 1 shot per day for 787 shots beginning in 03/05/2020 and ending the monitoring on

03/30/3023. 1 solar panel provided sufficient energy to maintain the charge in the external 12V battery that was used to power the electronics, wireless gas gun and wireless internet connection for the entire time of the test. During the 2+ year test the nitrogen gas in two (2) large nitrogen cylinder was consumed by recharging the volume chamber in order to be able to fire the gas gun, each cylinder contains a volume of 142 cubic feet of N2 when pressurized to 2200 psi. The pressure regulator was set at @ 500 psi to charge gas gun. The well surface casing pressure average 58 psi through shot 321. The pressure difference between the charge and discharge pressure in the gas gun was approximately 442 psi. The gas gun volume chamber is 12.5 cubic inches. 361 shots were calculated to be approximately available from a full cylinder, but cylinder pressure became too low and shots 321-339 were not acquired. Beginning with shot 340 the second N2 cylinder was setup at the well allowing the gas gun to have sufficient charge pressure to fire a shot. Observations from the test: 1) the wireless remote fire gas gun is dependable and weather resistant (recommendations are to service the wireless remote gas gun at time period of 6 months, replace O-rings and lubricate all moving parts with a light film of grease), 2) wireless remote communication through the cloud is reliable, 3) leaving this unattended equipment at the well for over 2 years was reasonably problem free, 3) casing pressure appears to gradually change over a 1 year time period, 4) the liquid level increased gradually during the test form 2818 to 2442 feet from the surface.

Similar types of monitoring can be undertaken on sucker rod lifted, electrical submersible pumped, progressive cavity pumped, plunger lift, gas lift, flowing and other types of wells.

1) Flumping Unconventional Horizontal Sucker Rod Well w/ VSD

Fluid Level, Dynamometer, Tubing Pressure and Power Data test were acquired for a time period of 66 hours on this flumping unconventional Eagle Ford Sucker Rod Lifted Well. General information about the well: Plunger Dia: 2.0”, Pump Depth: 5977 ft., VSD: 3 – 8 SPM, Production: 158 BOPD - 56 BWPD, Pump Displacement: 539 BPD. The acquisition schedule was setup to acquire a fluid level shot and acquire synchronized 3 minutes of simultaneous dynamometer, tubing pressure, and power data. During the 66-hour time period the acquired test consisted of 199 liquid level shots and 201 dynamometer acquisitions. A total of 3359 strokes were acquired with the VSD varying the pumping speed from a minimum of 3.29 SPM to a maximum of 8.04 SPM. In general, the VSD operated near the maximum SPM during the time when the well was flowing liquid up the casing to the surface or when liquid was surging up the casing toward the surface. The VSD operated nearest to the slowest SPM when the liquid level had fallen back and the liquid level was the lowest in the casing annulus. The number of strokes acquired during each 3-minute interval varied between 9 when the liquid level was the lowest and 20-24 strokes when the well was flumping. Approximately every 9 hours for a time period of 120 minutes liquid is lifted up the casing annulus to the surface as high-pressure gas is discharged from the lateral (Casing ID: 5.5” /OD: 4.778” w/ approximately 1236 cubic ft. volume gas storage in the lateral). Free gas is stored in the lateral because of the toe up drilled lateral (Kick Off: 8184.9’ TVD \ 8557.0’ MD, Toe: 7960.2’ TVD \ 18487.0’ MD).

Table 1 summarizes the 199 fluid level shot listing the 56 shots where the well was either Flowing(cyan), Surging(orange), or the liquid level was the Lowest(pink). The behavior of the casing liquid level is periodic, where the liquid level at the highest casing pressure buildup rate, dP/dT, flows to the surface for approximately 120 minutes, then at the lowest dP/dT the liquid level falls back to the lowest level, and the liquid level surges toward the surface when dP/dT is less than 10 and greater than 1 psi/min. This flumping well is shown to be very dynamic where the annular gas rate (dP/dT) determines if the well is flowing liquid to the surface or recharging gas into the 2-mile-long toe up horizontal section of the wellbore.

The relation of the pumping speed, SPM, to the liquid level in the annulus is shown in **Fig. 4** the VSD operates near the fastest SPM when the well is flowing up the casing and the liquid level is at the deepest depth. When the liquid level is Surging toward the surface the pumping SPM is generally the slowest SPM.

Figure 4 – Key Dyno and LL @ 20 min. During 66-hour Monitoring Test

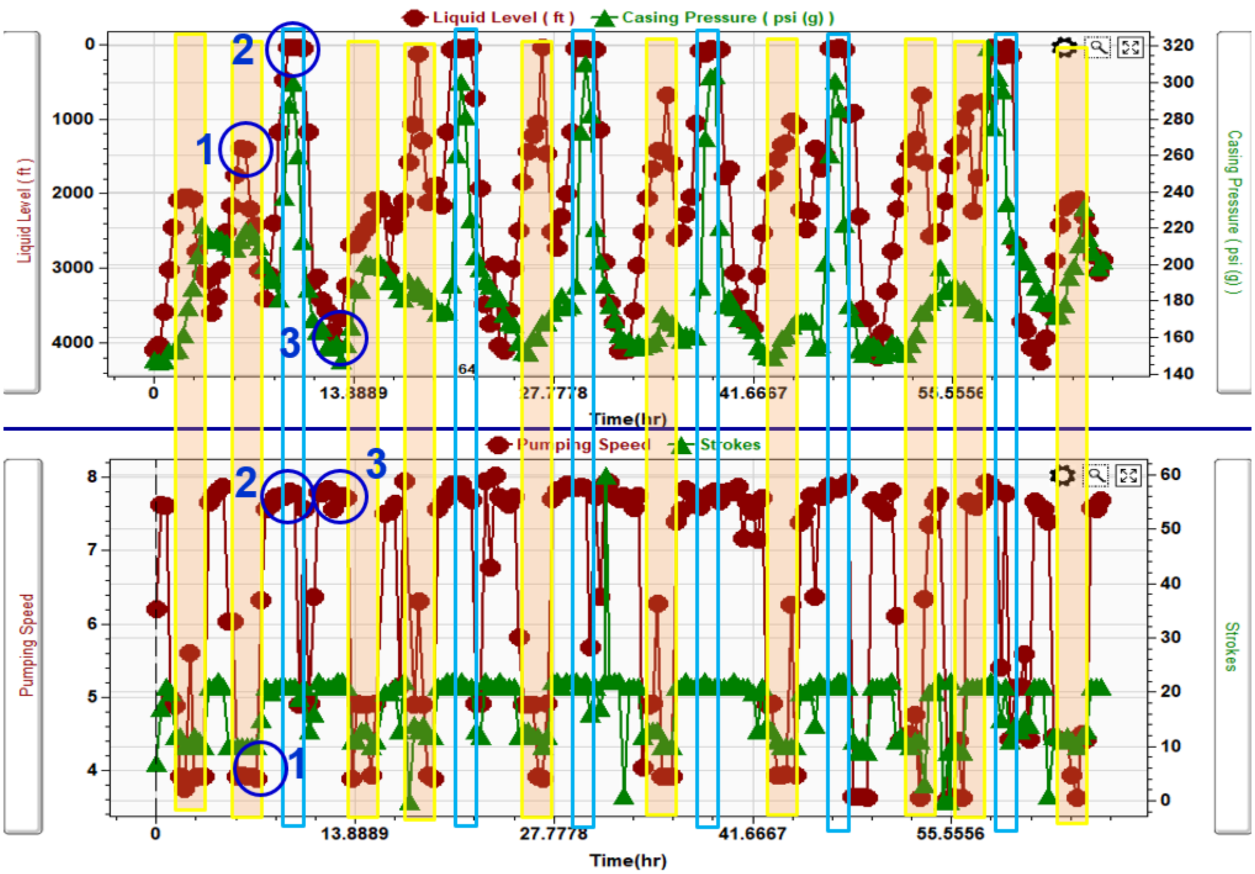


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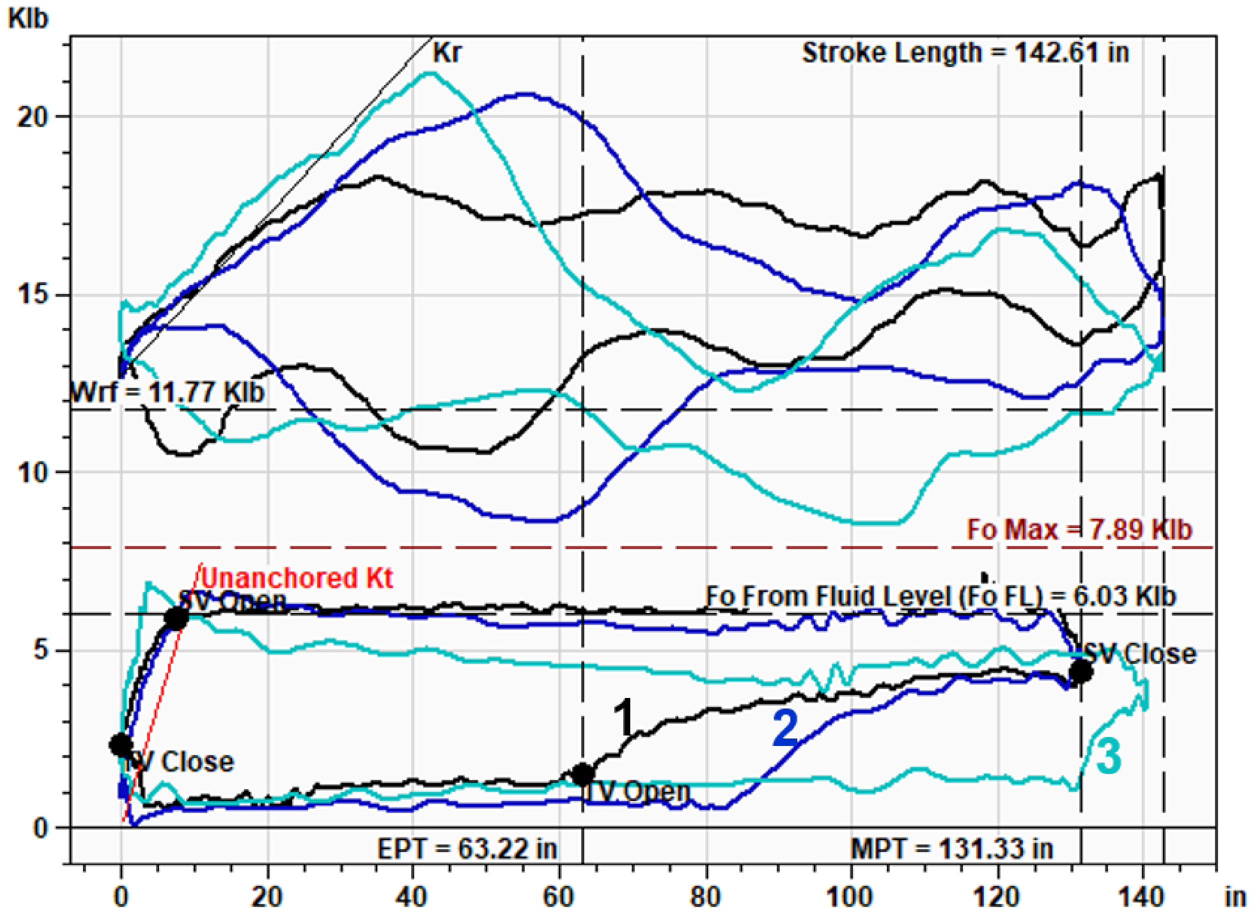
Fig. 5 overlays the surface and pump dynamometer cards for (1) when the liquid level is Surging toward the surface, (2) where the well is Flowing with the liquid level at the surface and (3) where the pump is filled with liquid and the liquid level has fallen back to the Lowest level in the casing annulus. The VSD is operating near the fastest speed at 7.74 SPM when the pump is full (3) the liquid level is the Lowest at 4053 ft from the surface; primarily liquid is being produced up the tubing as the tubing backpressure varies from 250 to 400 psi. The VSD is operating near the slowest speed at 3.91 SPM when the pump is less than 50% (1) the liquid level is the Surging toward the surface at 1391 feet from the surface. Significant amount of gas flowing up the tubing resulting in the measured sucker rods weight in tubing fluid to be the heaviest with gas in the tubing creating the lightest gradient. When the liquid level is at the surface and Flowing up the casing annulus the VSD is operating near the fastest speed at 7.81 SPM with pump fillage greater than 50% at 65%. Rod loading appears to be normal range whit liquid and gas pumped up the tubing.

Figure 5 – Dynamometer Overlays for LL (1) Surging, (2) Flowing, (3) Lowest



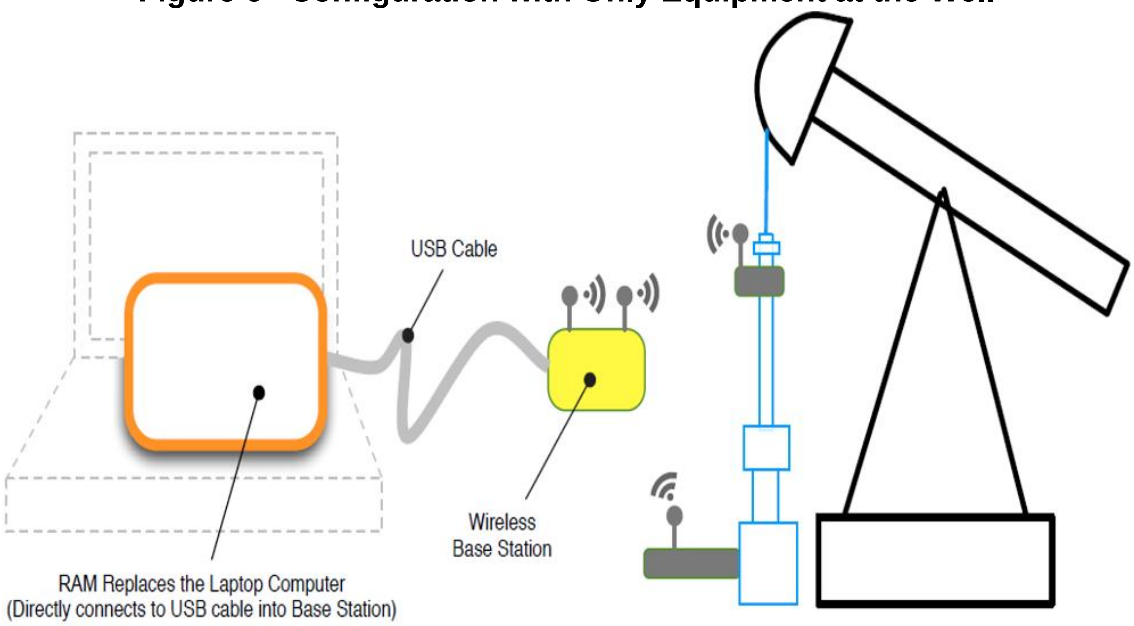
The behavior of this flumping well can be described by using the synchronized simultaneous fluid levels, dynamometer and tubing pressure data acquired at the surface of the well (no downhole sensors were used). Common knowledge is horizontal toe up Eagle Ford Sucker Rod Lifted Wells may flow up the casing annulus. The behavior of this well during the 66-hour test where liquid flowed up the casing annulus for time periods of 120 minute at a frequency of every 9 hours may or may not be representative of horizontal wells (additional test should be conducted). Pump fillage, tubing fluid gradient, and flow up the casing appear to be related to the annular gas flow rate up the casing annulus. Annular gas flow rate is related to the toe up configuration of the horizontal section of the wellbore and the bottom hole pressure which causes significant compressed gas volume to be stored as energy to provide lift for each cycle

The time step between acquisition tests can be short (few minutes between acquisitions) or long (less frequent that 1 test per day). To monitor a dynamic condition may be successful when acquiring test at a 20-minute time step, but a 5-minute or 10-

minute acquisition frequency will likely improve resolution when monitoring a surging flumping well. When conducting a test for 66 hours the disadvantage of acquiring 800 shots at 5-minute interval versus 200 shots may result the need for additional N2 cylinders to provide gas gun charge pressure 66-hour time period of the test. Plotting key values over the entire test time period, allows the operator identify unusual events or abnormal data that may occur during a long-term test.

At the well prior to the beginning of the 66-hour test the acquisition schedule was defined and the system was setup where the equipment is left unattended at the well during data acquisition, as shown in **Fig. 4**. Access to the acquired data during the test is only at the wellsite via a laptop computer connected the local area network generated by the system. At this wellsite access to the cloud is not available through local internet access or by cellular Modem.

Figure 6 –Configuration with Only Equipment at the Well



The well flows liquid to the surface up the casing annulus at an approximate 9 or 10-hour time intervals. Casing pressure and casing pressure build up rate were very much related to the increase in the annular liquid level and the flow of liquid up the casing. The VSD slowed the SPM down to approximately 3.6 SPM due to incomplete pump filllage and would increase pumping speed up to 8 SPM when pump was full. Fluid level, casing pressure pump card loads, tubing pressure, and fillage constantly changed throughout the 66-hour time period.

2) Gas Trapped Below Tubing Anchor

At the well prior to the beginning of the 442-minute liquid level depression test the acquisition schedule was defined to shoot a liquid level every 15 minutes; to begin the test with the 1st shot the casing valve was closed to trap produced gas in the casing annulus and push the liquid level down. Casing surface pressure built from 213-625 psi(g) during the test pushing the liquid level down to the pump intake while the sucker rod pumping continued throughout the entire test. The system was setup where the equipment is left unattended at the well during data acquisition, as shown in **Fig. 4.** Previously a field study[2] was conducted using fluid level and dynamometer tests to determine why low pump liquid fillage existed in wells with high fluid levels. When a high fluid level exists in a pumping well, a tubing anchor set some distance above the perforations can cause free gas to collect below the tubing anchor and restrict production from the formation and liquid entrance to the pump. The operator may think that a gaseous liquid column exists from the top of the fluid level down to the pump, when actually, the gaseous liquid column exists from the top of the fluid level down to the tubing anchor, and primarily free gas exists from the tubing anchor down to the pump. In this horizontal toe up Eagle Ford Sucker Rod Lifted Well the tubbing anchor 5777.1 ft is set above the end of tubing 6231 feet. **Table 2** lists liquid level shot 50 and 60 where the liquid level from shot 59 was at 5961 due to free gas trapped below the tubing anchor the liquid level from shot 60 dropped 335 feet.

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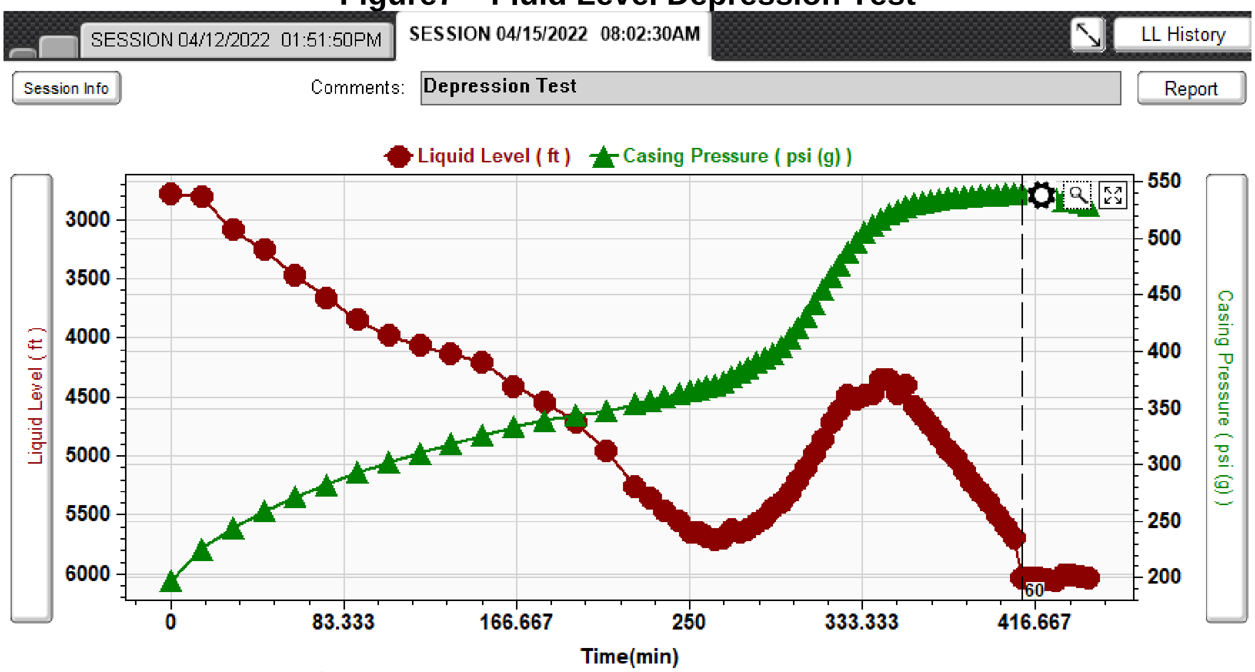
Figure7 – Fluid Level Depression Test



The wells in the study[2] had incomplete pump fillage occur after approximately 8 strokes from startup and inflow of liquid into the well bore was significant less than pump capacity even though a high gassy fluid level existed above the pump. This flumping unconventional Eagle Ford sucker rod lifted well's producing conditions are significantly different from the wells in the study[2]. Two similarities between the wells in study[2] and this well is the presence of a tubing anchor set above the producing zone and annular gas rate in excess of the downhole pump displacement volume at the pressure of the pump intake. Due to these two similarities gas flow was likely restricted an the tubing anchor with the appearance of gas trapped below the tubing anchor. Gas trapped below the tubing anchor appears to be a wider problem than is currently known by industry.

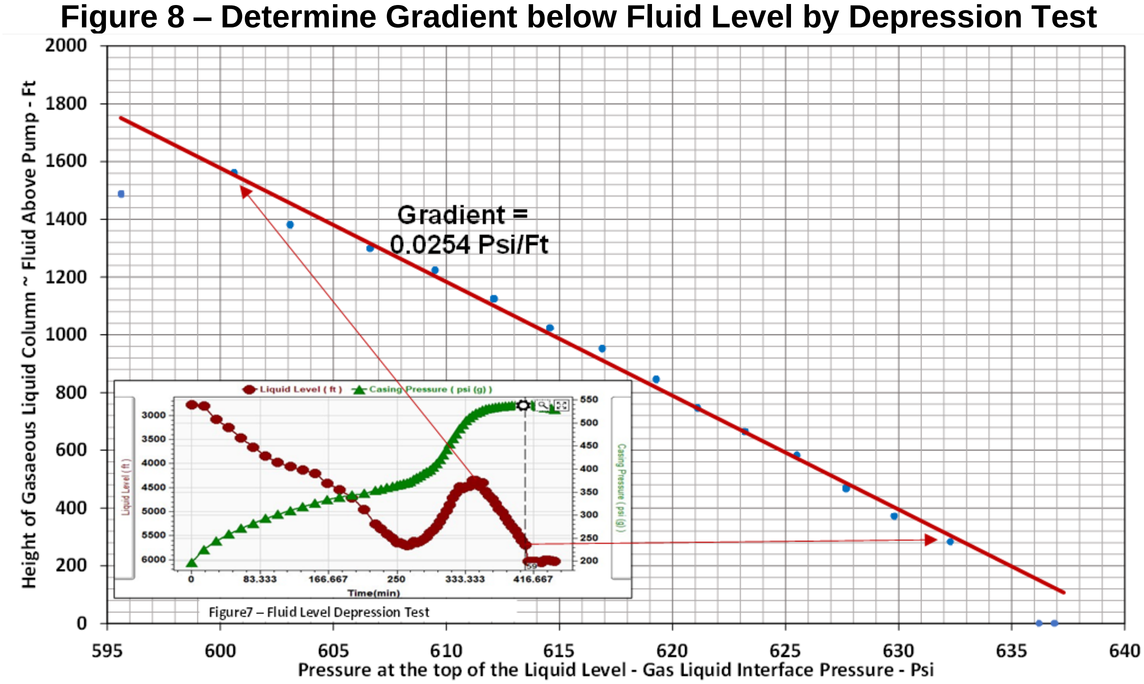
3) Scheduled Multi-shot Pressure Transient Test

Pressure transient[3,4,5] tests are used to determine bottom hole pressures versus time from a pressure buildup or fall-off test. The data the created using an acoustic liquid level instrument with acquisition controlled according to a predefined schedule. Analysis of the data collected provides formation pressure, permeability and well bore skin factor for a zone or formation. Pressure buildup testing involves a major commitment of time. This testing also results in loss of revenue due to a temporary loss of oil/gas production while the well is shut-in. Acquisition and processing of the data is automatic and presentation of the information to the operator is available at any time during the test. The system has the overwhelming advantage over wireline-conveyed measurements that it does not require entering the well bore but is totally based on surface measurements. Through the cloud the operator now can remotely decide if sufficient data has been acquired to ensure that the test will yield accurate and complete data. Preliminary analysis of the data can be done via the cloud, then followed up with detailed transient analysis by exporting the BHP data vs. time to other analysis software. Access to the internet at the well's location can reduce manpower commitment because a round trip drive to the well is not required to check the progress of the test and check the status of power, gas supply and function of the equipment. The preferred configuration of this system for pressure transient testing is shown in **Fig. 2** where the equipment is present at the well during data acquisition and personnel access via the cloud to the data acquisition system at the wellsite. When the equipment is left unattended at the well during data acquisition, as shown in **Fig. 4**. Access to the acquired data during the test is only at the wellsite and manpower commitment increase because round trip drives to the well are required to periodically check on the status of the test.

4) Depress Liquid Level to Determine Gradient Below the Liquid Level

Upon inspection of **Fig. 7 Fluid Level Depression Test** a straight line is seen for shots 40 – 59. A straight-line plot of liquid level depression versus time often indicates a likely constant gradient exist below the liquid level. Using the modified Walker method the gradient of 0.0254 psi/ft is calculated by performing a least square linear curve fit (red line) through the linear portion (points 40-59) of a plot of height of the gaseous liquid column versus the pressure at the top of the gas/liquid interface **Fig. 8**.

Figure 8 – Determine Gradient below Fluid Level by Depression Test

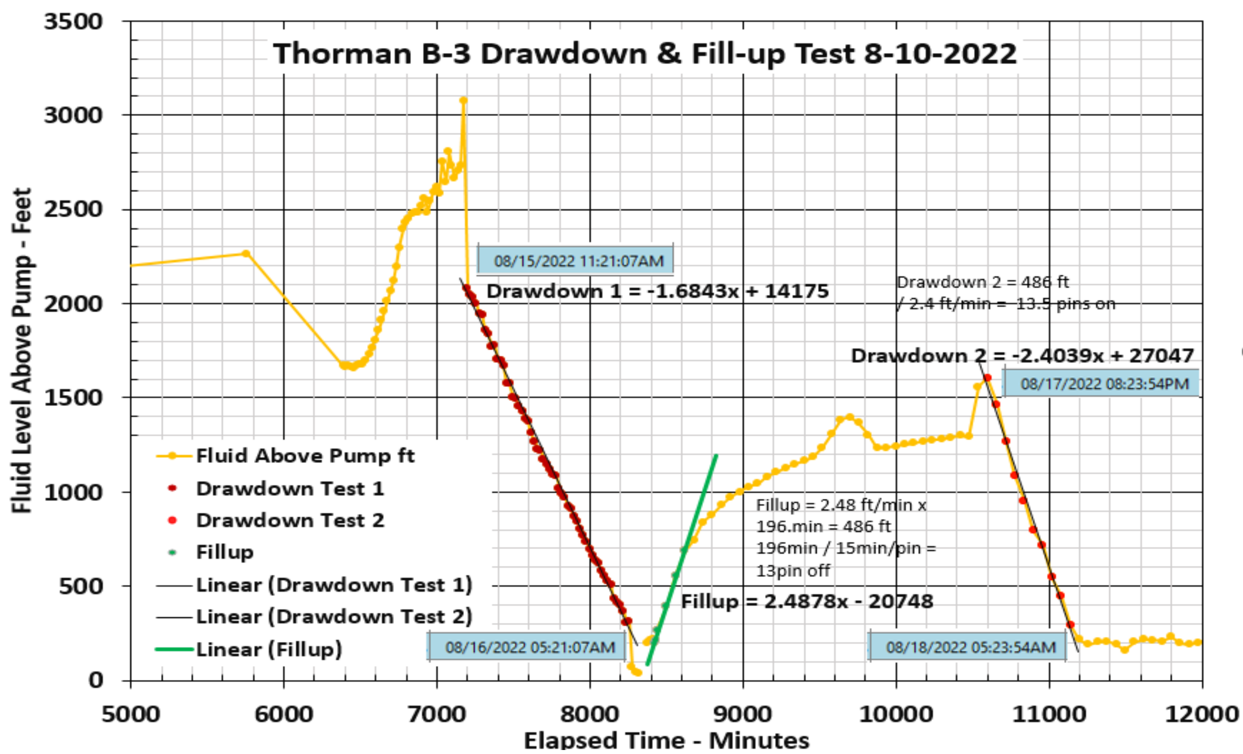


C.P. Walker[6,7] developed a process for determining the producing bottomhole pressure in wells which have gaseous liquid columns. The procedure consisted of determining the pressure at the gas/liquid interface at normal operating conditions. Then, the casing pressure was increased by use of a back-pressure valve and stabilized. When the liquid level was stable, the gas/liquid interface pressure was determined at the lower depth. The liquid level depths were plotted against the gas/liquid interface pressures. The pressures at the gas/liquid interfaces were extrapolated to the producing formation depth or pump depth. Walker's studies and other studies[8] indicated that gaseous liquid columns have a constant gradient throughout the entire column. The Walker method was modified[9] to not stabilize the casing pressure with a back pressure valve. In most cases this modified method delivers reasonably accurate downhole pressures and gradients of the gaseous liquid column (should plot as a straight line); but when displacing the liquid out of the gaseous liquid column should not increase the producing bottom hole pressure. In many cases extrapolating the pressures at the top of gaseous liquid columns which have been depressed using the annular gas flow to increase the casing pressure is a good method for obtaining downhole pressures and gradients.

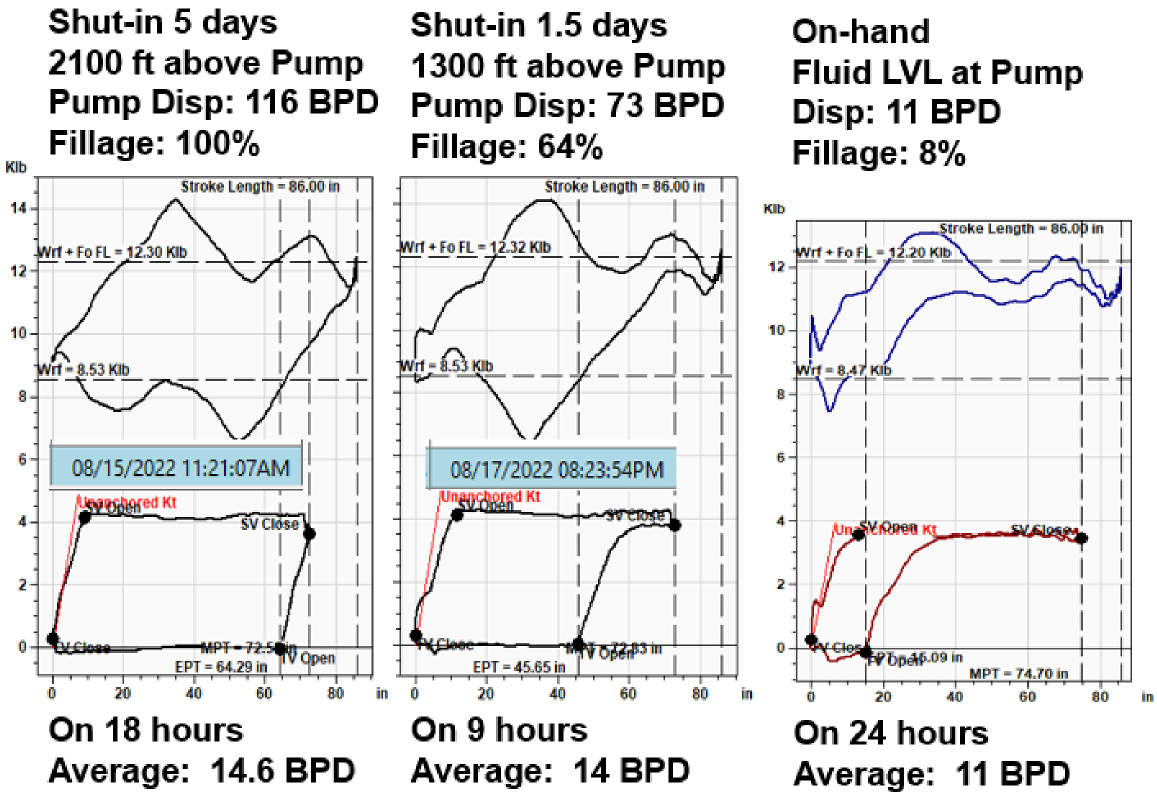
5) Control Run Time

To monitor the drawdown and fill-up test the system setup is shown in **Fig. 2** where the equipment is present at the well during data acquisition and personnel access to the data at the wellsite is via a computer connected to the internet, where the acquired well data is sent through the cloud. Experience[10] with the wells is this marginal field have shown using a 15-minute percentage timer often results in a pump that is not filled with liquid during the on-time portion of the cycle. Two shut-in drawdown tests were remotely monitored during an 8-day time period.

Figure 9 – Drawdown and Fill-up Tests



. **Figure 10 – Compare 2 Drawdown and Fill-up Tests versus On-hand**



The first off-on cycle monitored consisted of fill-up where the well was shut-in for 5 days accumulating 2100 feet of liquid above the pump, then turned on to drawdown the fluid level at -1.68 feet/minute rate for 18 hours. On 08/16/2022 at 05:21:07 AM the producing fluid level had been lowered to the pump and the well was shut for the next off-on cycle. The second off-on cycle consisted of fill-up where well was shut-in for 1.5 days accumulating 1300 feet of liquid above the pump, then turned on to drawdown the fluid level at -2.48 feet/minute rate for 9 hours. On 08/18/2022 at 05:23:54 AM the producing fluid level had been lowered to near the pump identifying the end of this cycle. On-hand produced approximately 11 BPD with a pump fillage of 8%. Off for 1.5 days and on for 9 hours resulted in an average production of 14 BPD, during the 9 hours of on time the pump displacement was 73 BPB with 64% pump fillage. Off for 5 days and on for 18 hours resulted in an average production of 14.6 BPD, during the 18 hours of on time the pump displacement was 116 BPB with 100% pump fillage. Highest average production rate was achieved with the longest shut-in time period. The pump was filled with liquid the entire 18 hours run time, which should result in the most efficient operations. Recommendation would be to setup an additional test cycle that would be easy for the operator to control like off for 6 days and on for 1 day. The production measured for the off 6 days and on 1 day may justify adjusting the on-hand continuous run cycle.

Conclusion

Acquisition of data remotely can increase productivity and permit detailed long-term monitoring of complicated problems. Observations from the test: 1) the wireless remote fire gas gun is dependable and weather resistant 2) wireless remote communication through the cloud is reliable, 3) leaving this unattended equipment at the well for over 2 years was reasonably problem free, 4) acquisition of 787 unattended fluid levels at a frequency of 1 shot /day indicates high hardware, firmware and software reliability. Setting proper charge pressure for gas gun can be important in providing quality acoustic fluid level shots. Long term fluid level test with frequent number of shots, it is important to determine the number of shots possible from a cylinder and the operator should plan to bring a new N2 Cylinder to the Well prior to pressure dropping too low to fire the gas gun. An acquisition frequency of 1 acquisition every 5 minutes can result in huge quantities and withdrawal of large amounts of N2 gas from the cylinder. Powering system via solar panel can provide sufficient power for long term unattended fluid level, dynamometer, pressure, and power acquisitions test. Internet or cell phone access is available at all/most well sites allowing an operator to remotely monitor a well in detail with high speed and high-resolution wireless sensor data.

Acknowledgements

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Table 1 – Fluid Level Shot Summary: Flowing, Surging, or Lowest

#	Time	Elapsed Time min	Liquid Level ft	Fluid Above Pump ft	Casing Pressure psi (g)	Buildup Rate psi/min	Gas Liq Interface Pressure	CODE
1	04/12/2022 01:52:05PM	0	4100	1857	147.8	0.73	166.8	L
6	04/12/2022 03:32:05PM	100	2086	3864	153.2	1.03	163.7	S
13	04/12/2022 05:52:05PM	240	3596	2356	213.4	0.79	236.6	L
19	04/12/2022 07:52:05PM	360	1391	4559	213.3	1.78	222.2	S
24	04/12/2022 09:32:05PM	460	3413	2538	199.4	0.75	219.5	L
29	04/12/2022 11:12:05PM	560	40	5910	287.6	27.35	288.1	F
30	04/12/2022 11:32:05PM	580	39	5910	299.8	31.26	300.2	F
31	04/12/2022 11:52:05PM	600	32	5917	259.7	23.43	260	F
32	04/13/2022 12:12:05AM	620	55	5894	212.6	16.02	213	F
39	04/13/2022 02:32:05AM	760	4053	1904	157	1.00	177.2	L
47	04/13/2022 05:12:05AM	920	2095	3855	199.3	1.03	212	S
51	04/13/2022 06:32:05AM	1000	2443	3507	190.7	1.67	204.4	L
56	04/13/2022 08:12:05AM	1100	118	5831	189	7.02	189.8	F
58	04/13/2022 08:52:05AM	1140	2121	3829	182.5	1.37	194.1	L
63	04/13/2022 10:32:05AM	1240	69	5880	188.8	10.43	189.3	F
64	04/13/2022 10:52:05AM	1260	40	5909	260.5	17.87	260.9	F
65	04/13/2022 11:12:05AM	1280	69	5880	300.3	26.61	301.1	F
66	04/13/2022 11:32:05AM	1300	57	5892	281.6	23.08	282.2	F
67	04/13/2022 11:52:05AM	1320	45	5904	224.9	15.83	225.3	F
74	04/13/2022 02:12:05PM	1460	4105	1853	173	0.87	195.3	L
82	04/13/2022 04:52:05PM	1620	31	5918	167.9	3.10	168.1	F
85	04/13/2022 05:52:05PM	1680	2730	3221	176.2	0.97	190.7	L
89	04/13/2022 07:12:05PM	1760	46	5903	188.3	8.39	188.6	F
90	04/13/2022 07:32:05PM	1780	55	5894	272.9	21.18	273.5	F
91	04/13/2022 07:52:05PM	1800	47	5902	310.5	28.70	311	F
92	04/13/2022 08:12:05PM	1820	71	5878	282.7	22.83	283.4	F
93	04/13/2022 08:32:05PM	1840	70	5879	219.6	14.64	220.2	F
98	04/13/2022 10:12:05PM	1940	4112	1846	161.5	0.93	181.9	L
106	04/14/2022 12:52:05AM	2100	1424	4525	159.4	0.82	166.6	S
110	04/14/2022 02:12:05AM	2180	2594	3356	165.1	2.34	178	L
115	04/14/2022 03:52:05AM	2280	78	5871	187.9	8.01	188.5	F
116	04/14/2022 04:12:05AM	2300	126	5823	269.4	18.05	270.7	F
117	04/14/2022 04:32:05AM	2320	51	5898	303.6	27.67	304.2	F
118	04/14/2022 04:52:05AM	2340	67	5882	303.7	16.13	304.5	F
119	04/14/2022 05:12:05AM	2360	72	5877	220.3	10.30	220.9	F

Table 1 (continued) – Fluid Level Shot Summary: Flowing, Surging, or Lowest

#	Time	Elapsed Time min	Liquid Level ft	Fluid Above Pump ft	Casing Pressure psi (g)	Buildup Rate psi/min	Gas Liq Interface Pressure	CODE
126	04/14/2022 07:32:05AM	2500	3799	2155	163.7	1.30	183.1	L
134	04/14/2022 10:12:05AM	2660	1021	4928	166	2.82	171	S
137	04/14/2022 11:12:05AM	2720	2478	3472	169	1.17	181.2	L
142	04/14/2022 12:52:05PM	2820	51	5898	260.5	20.32	261	F
143	04/14/2022 01:12:05PM	2840	65	5884	301	27.13	301.8	F
144	04/14/2022 01:32:05PM	2860	44	5905	285.7	19.16	286.2	F
145	04/14/2022 01:52:05PM	2880	62	5887	222.1	13.22	222.6	F
152	04/14/2022 04:12:05PM	3020	4198	1760	154.3	0.82	174.5	L
161	04/14/2022 07:12:05PM	3200	675	5274	173.2	7.26	177.7	S
163	04/14/2022 07:52:05PM	3240	2562	3388	179.7	1.99	193.7	L
171	04/14/2022 10:32:05PM	3400	779	5170	183.2	2.38	188.6	S
172	04/14/2022 10:52:05PM	3420	2227	3723	175.1	1.73	186.7	L
176	04/15/2022 12:12:05AM	3500	37	5912	275.5	17.25	275.9	F
177	04/15/2022 12:32:05AM	3520	120	5829	302.5	24.48	303.9	F
178	04/15/2022 12:52:05AM	3540	160	5789	295.3	16.96	297.1	F
179	04/15/2022 01:12:05AM	3560	40	5909	233.7	11.95	234.1	F
180	04/15/2022 01:32:05AM	3580	141	5808	215.8	7.17	216.9	F
184	04/15/2022 02:52:05AM	3660	4071	1886	194.9	0.71	219.4	L
193	04/15/2022 05:52:05AM	3840	2082	3867	199.1	0.56	211.8	S
198	04/15/2022 07:32:05AM	3940	3069	2881	198.4	1.19	216.1	L
199	04/15/2022 07:52:05AM	3960	2890	3060	201.9	2.28	219.1	

F - FLOWING
S - SURGE
L - Lowest Liquid Level

Table 2 – Shots 59 & 60 where LL Drops 335 feet Due to Gas Trapped Below TAC

#	Time	Elapsed Time	LL	Casing Pressure	GLIP
		min	ft	psi (g)	psi (g)
59	04/15/2022 02:48:37PM	406.117	5691	540.2	632.3
60	04/15/2022 02:52:37PM	410.117	6026	539.7	636.9