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Managing Unsteady Multiphase Flow from Horizontal Wells with ESP Systems

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Abstract

The production phase in the unconventional wells of the Powder River basin is very dynamic and changes based on the total volume of fluids produced and the gas-to-liquid ratio. These dramatic changes in production that occur within a few weeks or months make it impractical to use a single artificial lift method effectively throughout the life of a well. Samson Resources sought to maximize early production on their horizontal wells in the Powder River basin by installing ESP systems shortly after the completion of the well rather than flowing the wells naturally until they loaded up and then installing artificial lift. The result has been improved cash flow for the company.

All ESP systems include downhole pressure sensors that measure pump intake pressure and other parameters. Samson uses the pressure data to manage the drawdown and accelerate production early in the lives of the wells. Wide ranges of operating conditions exist while drawing down the reservoir from above to below the bubble point. Below the bubble point events of 100% gas flow frequently occur, resulting in challenging pumping conditions. Based on the development of the field so far, toe-up wells have more gas influx problems than toe-down wells have.

A special configuration of ESP systems with redundant gas separation and gas handling devices, including a multiphase axial pump, was used. This configuration has been proven to effectively manage the drawdown by reducing the pump intake pressure (PIP) from 4,000 psi to between 200 to 400 psi, followed by an extended period of sustained production at a target of 100 to 200 psi PIP. The ESP is kept in operation until the production declines to between 150 to 250 BFPD, at which point the well is put on rod pump for the remainder of the life of the well. The first ESP systems were pulled in operable condition after 7 months of operation. Upon retrieval from the well, the downhole components of the ESP systems were inspected, tested, and repaired, if necessary, at the manufacturer's assembly, repair, and testing (ART) Center for reuse in the next wells.

The gas handling technology installed allowed the operator to optimize production early in the well life cycle. The timely artificial lift conversion from ESP to rod pump reduced CAPEX and OPEX by transferring the ESP system to another new well and replacing it with a rod pump, leading to more efficient well operations at the lower rate during the rest of the remaining well life cycle.

Production Development of the Shannon Formation

The focus of this study is a Shannon sandstone field developed by Samson Resources in the Powder River basin, located in the northeastern Wyoming. Field development was accomplished by drilling multiple-well pads containing 2 to 4 horizontal wells per pad with lateral lengths ranging from approximately 1 to 2 miles. Wellbore construction included 7-in. intermediate casing with 4 1/2-in. liners incorporating openhole swell packers and frac sleeves. For the eight wells in this study, the 4 ½-in. liner tops were set at an average depth of 9414 ft measured depth (MD) [9371 ft true vertical depth (TVD)] and an average inclination of 10°. Shannon formation TVD averages 10,007 ft. Half of the wells were drilled toe-up and the other half toe-down based on the wells' spacing units and pad locations.

Of the eight wells in this study, two had 1-mile laterals (640s) and six had 2-mile laterals (1280s) and were located on four pads roughly spaced 0.5 mile from each other. The 640s had 8 to 10 frac stages and the 1280s had 16 to 18 frac stages each. All wells were fractured down 4 ½-in. tieback casing strings using a cross-linked guar-borate system with an average of 1,800 barrels of fluid containing 28,000 lb. 40/70 and 100,000 lb. 20/40 white sand or ceramic proppant per stage. Dissolvable frac balls were incorporated to aid fracture flowback and to eliminate coiled or stick tubing mill-outs. Wells on the same pad were fractured back-to-back and brought on to flowback after all fracture treatments on the pad were completed. Pads on production adjacent to offset pads being fractured were shut in to minimize well-to-well fracture communication.

Transitional Artificial Lift: A Good Well Becomes a Better Well with an ESP

Suitability for running ESPs was determined by monitoring the initial flow rates and pressures up the 4 1/2-in. tieback casing. Wells that flowed without loading up were selected for ESPs whereas wells that loaded quickly or did not flow had rod pumps installed. The decision was made to accelerate the running of ESPs during the flow period instead of allowing the wells to flow until they loaded up to maximize cash flow from increased production. The wells produced via natural flow for 2 to 3.5 months before the ESP was run. To prevent having to kill a flowing well to pull the tieback casing and install the ESP, packers with pump-out plugs and screens were run on wireline into the liners under pressure. Once the packer was set with the plug in place, downhole well control was established enabling the tiebacks to be pulled and the tubing and ESP equipment to be run safely in the hole under static conditions. After the tubing was landed, pressure was applied to the 2 7/8-in. × 7-in. annulus, which sheered the pins holding the pump-out plug and allowed communication with the formation. The ESP was then started up with no additional down time and without killing the well.

ESP systems were used as transitional artificial lift to increase the early production of the well and to improve the cash flow from operations using a controlled drawdown approach. The production at the end of the natural flow phase was on average 348 BOPD and was boosted to 597 BOPD at the start of the ESP phase, which represents a 72% average production increase for the eight wells in this study. The average production at the transition between the natural flow phase to ESP phase is illustrated in **Fig. 1.**

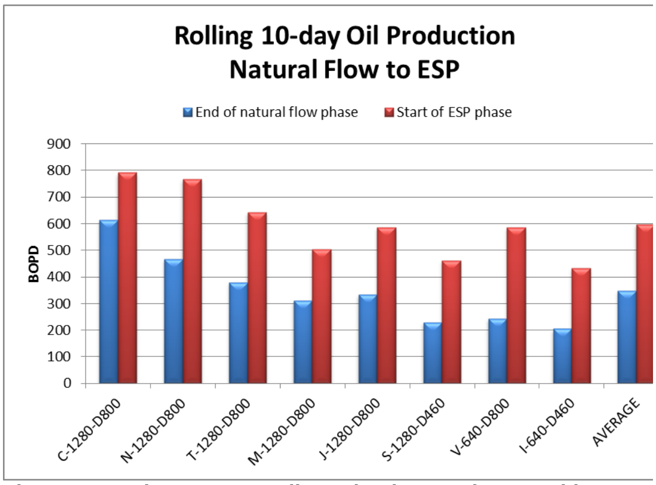


Fig. 1.—Ten-day average oil production at the transition from natural flow phase to ESP phase.

ESP System Design and Operation

As with any unconventional application, the production behavior of the wells is not consistent and there existed a level of uncertainty on what would be the initial production at the ESP phase. Based on preliminary analysis of the production decline it was determined that the initial ESP production could be as high as 700 BFPD and was expected to drop to as low as 250 BFPD. Based on two previous wells in the field, the ESP phase was initially expected to last approximately three months.

Because the wells were built with a 7-in. intermediate casing and with a 4 ½-in. liner, the designs were done for a pump setting right above the top of the liner. **Fig. B-1** illustrates a typical ESP setting and configuration.

The reservoir and fluid properties are listed in **Table A-1**. The oil produced has an API gravity ranging from 37° to 40°API and water cut between 5% and 20%. The initial gas-liquid ratio (GLR) averaged 300 scf/STB but was expected to increase with time after conditions dropped below the bubble point pressure, estimated to be 1,900 psi.

The first ESP system was installed in well S-1280-D460, which was producing 230 BFPD at the end of the 56 days of natural flow. The D460N pump was selected to handle the low flow rates of this application. D800N pumps were used for the higher rate Shannon wells. As illustrated in **Fig. 2** and **3,** these pumps have a wide recommended operating range (ROR) that covers rates down to 200 BFPD and 250 BFPD, respectively, at 60 Hz. Both these pumps have radial flow stages.

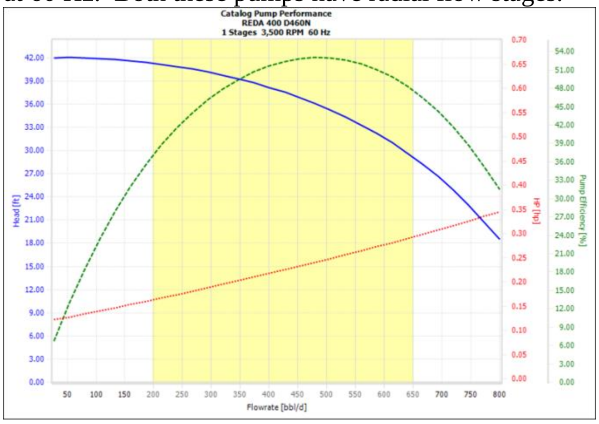


Fig. 2— D460N pump performance curves

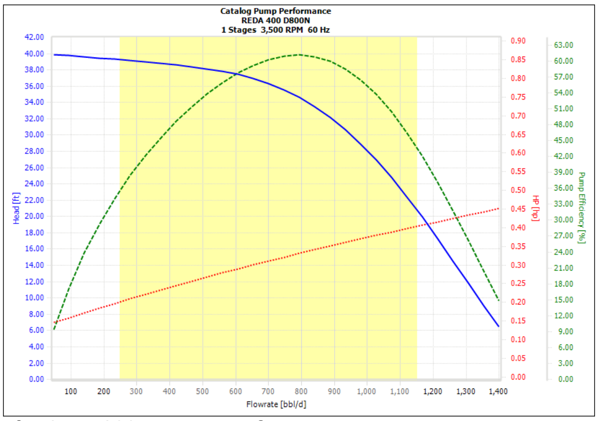


Fig. 3— D800N pump performance curves.

Radial-type stages can handle up to 10% free gas before gas locking (Kallas 1995, Castro 1998, Villamizar 1993) or suffering severe degradation as illustrated in **Fig. 4.**

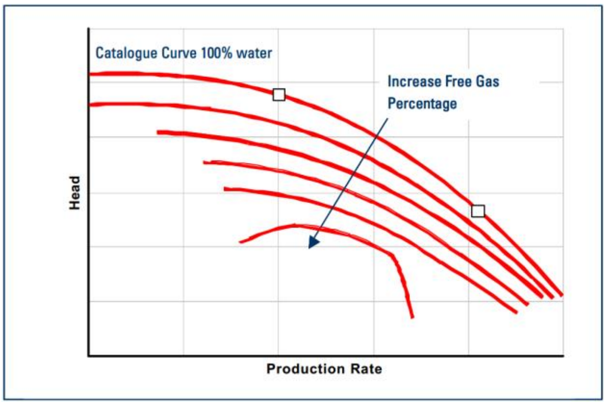


Fig 4—Pump degradation and gas lock (Villamizar 1993)

Unconventional applications are very challenging due to the unsteady flow and extreme variations of the multiphase mixtures. These mixtures can vary from a negligible gas volume factor (GVF) at start-up to episodic slugs of up to 100% GVF (Ferguson 2013).

A Vortex VGSA D20-60 gas separator was installed on each system. In spite of the typical high separation efficiency of the separator, it was expected that, especially during the slugging events, the free gas after separation would be too high for the pump to handle without severe degradation and the pump would eventually gas lock. To prevent this, a gas-handling device is required to process the multiphase fluid before entering the first stage of the pump.

The advanced gas handler (AGH) device used is a highly modified multistage, high-specific-speed centrifugal pump that was designed to improve the gas handling capabilities of the low-flow 400 series pumps typically used in 4 1/2-in. to 5 ½-in. casing (Kallas 1995). The AGH brings a unique benefit to this type of application where the GVF increases with time because it works more like a pump and thus actually contributes head to the system in the early stage of the operation. This functionality allows the ESP to meet the head requirement to lift the fluid column while operating at lower speed. As the GVF increases, the gas handling device does not contribute head but works as a processor of the multiphase mixture delivering a more homogeneous mixture that the pump can handle without gas locking.

For applications dealing with more than 45% GVF the AGH is not effective and a more advanced gas handling device is recommended. The Poseidon is a multiphase gas handling device that uses axial stages and is rated for up to 75% free gas (Ferguson 2013, Villamizar 1993). There are applications where this multiphase axial gas handler can operate with up to 80% GVF (Camilleri 2011).

To maximize the flexibility of the ESP system to handle the widest range of multiphase flow, especially considering that the goal was to draw down the wells to approximately 200 psi pump intake pressure, it was decided to install the centrifugal gas handler and the axial multiphase axial pump in tandem to feed the centrifugal pump on top.

All pumps and gas handling devices are built in compression-type construction. Thus the impeller stack works as a single body maintaining spacing with the diffusers even with the large volume differences that can occur throughout the stages when pumping high GVF applications and with gas slugging events. Additionally, since all the pump downthrust is handled by a protector thrust bearing, the pump operating range can be extended below the catalog minimum operating range as long as the protector bearing has enough capacity to do so.

The pumps and the AGH for these applications were built in abrasion resistant (ARZ) configuration. The multiphase gas handling device with axial stages is a full bearing housing (FBH) configuration with silicon carbide (SICG) bearing design on each stage to maximize its reliability in the very poor lubricating conditions encountered when pumping high GVF mixtures.

The system uses factory-filled and factory-shimmed protectors with multiple positive isolation chambers and redundancy on shaft sealing layers stages to keep the motor oil isolated even during the wide thermal cycles that can occur during the operation of unconventional wells.

The motors are factory-filled variable rating motors that provide flexibility to adjust the performance to match the load requirements from the application.

All ESP systems were equipped with a Type-1 downhole multisensor device for monitoring real-time

ESP operating parameters including pump intake pressure, discharge pressure, intake temperature, motor temperature, vibration, and current leakage.

A typical ESP system setting depth and configuration is illustrated in **Fig. 5.**

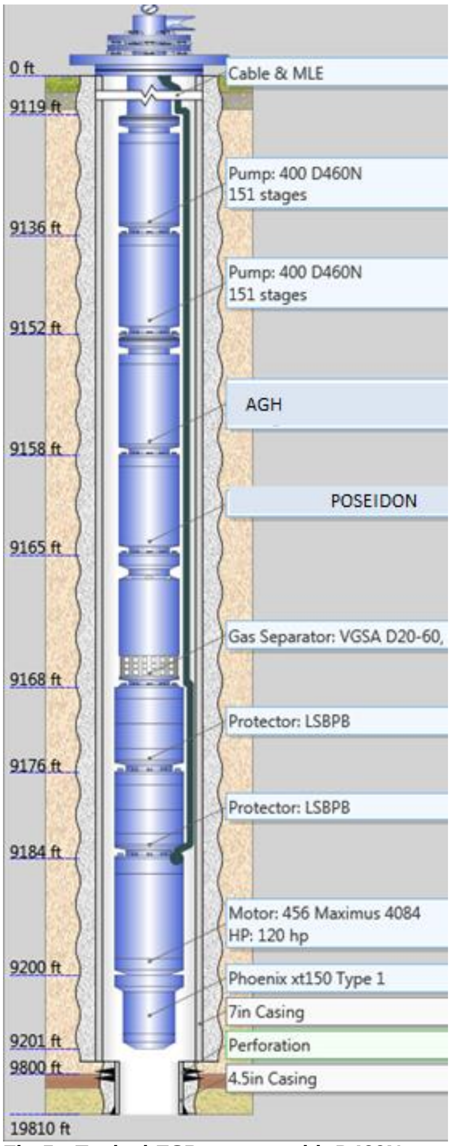


Fig 5—Typical ESP system with D460N pumps used in two of the Shannon wells.

A sine wave variable speed drive (SWD) was used to feed clean filtered electrical power to the ESP, to minimize stress in the ESP motor and power cable and to provide additional operational flexibility and control of the drawdown.

One of the characteristics of unconventional wells is that the well behavior varies substantially from well to well and even in the same well as it progresses through the production phase. The motor controller is typically set to operate in target speed mode originally; later, depending on the performance, it is switched to motor current or pump intake pressure feedback control mode to optimize the well production and drawdown. In addition to the preset operating modes, manual adjustments are sometimes required under special operating circumstances which are carried out by the Artificial Lift Surveillance Center (ALSC) engineers. These new routines are being documented and validated for future implementation in the motor controller.

Every well was connected to the LiftWatcher remote monitoring and control system that delivers real-time ESP data directly to the desktops of the operator, application engineers, the ALSC and the technical support team on a 24 hour basis. The surveillance engineers are in direct contact with the ESP field service technicians and with Samson's engineers and field personnel to coordinate surface adjustments that cannot be done remotely, such as adjusting surface chokes or manual restarting of equipment.

The ESP phase lasted 195 days on average, and as the wells were drawn down the effects of the unsteady flow into the pump became more severe and slugging events occurred more frequently. There is not a universal operation mode that works in every well, but rather the method is selected for each well at a given time based on the trends and operating conditions. **Fig. 6** is a snapshot of well S-1280-D460 operating in pump intake pressure feedback control with an original target of 200 psi, which was later decreased to 180 psi. As noted in **Fig. 6** the motor controller adjusts the operating frequency within the range to chase the target intake pressure, which also results in large swings of the motor amperage.

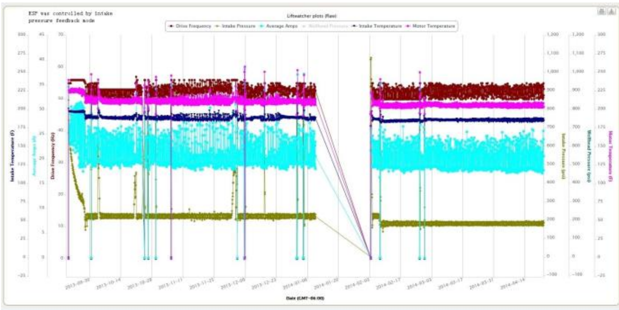


Fig. 6—Operation trends for well S-1280-D460.

Some wells reached a relatively stable operating condition when running in motor current feedback control mode, at least for some time. One example of this is the well C-1280-D800, which was running with pump intake pressure as low as 100 psi during the last weeks of operation before being pulled proactively to convert to rod pump due to logistics and rig availability in February 2015. A snapshot of the operating parameters of this well is shown in **Fig. 7.**

Fig. 7—Operational trends for well C-1280-D800.

The rate of drawdown at the start of the ESP phase was between 40 to 50 psi/day. As shown in the **Fig. 7**, the pump intake at the start of the ESP phase was 3,900 psi and it was brought down to 500 psi during the first 2 months of operation. The PIP was then lowered further and the ESP operated with pump intake pressure of 100 to 200 psi during most of the ESP phase.

ESP Diagnostics

The performance of the ESP system was modeled for several conditions including a basic design assuming a steady inflow condition at the beginning of the ESP phase. This model resembles a typical design for conventional, vertical well applications. According to this model, considering both natural separation and the mechanical separation efficiency of the VGSA D20-60 Vortex gas separator, most of the gas should be vented to the annulus which would minimize the gas interference or gas locking of the pumps. Additional sensitivity analyses to model the productivity decline and increasing GLR were performed during the design phase.

Later during operation, due to the nature of the unconventional wells, the ESP system is exposed to drastic changes in fluid properties, from single phase liquid to multiphase mixtures. During gas slugging the pump has to deal with severe gas interference events that last from a few minutes to more than 2 hours. **Fig. 8.** illustrates an example of such events.

Fig. 8—Snapshot of operation, unsteady flow and gas interference.

We used the diagnostic module of DesignPro, the ESP sizing program, for analysis and matching the actual operating conditions of the ESP system. Although the daily production of oil, water and gas can be used to run an average performance model that would be representative when the flow is relatively steady, it does not show the large swings in rate and composition of the multiphase fluid in these unconventional wells.

A comprehensive model can be created using OLGA, the dynamic multiphase flow simulator, but we did a very simplified model by taking snapshots in time of the operating parameters and entering them into the diagnostic module of the ESP design software to model the ESP performance during the transient states. We used the real-time data from the downhole sensor and surface meters including pump intake and discharge pressure, motor operating current, temperature, tubing and casing pressure, and, if available, data from spot flow rates. **Figs. 9 and 10** illustrate the operating point (black dot) at downhole conditions 1 and 2, as illustrated in the snapshot in **Fig. 8.**

The ESP system was operating in motor current feedback control mode at that time. Condition 1 in **Fig. 8** illustrates a relatively stable operation at 55 Hz prior to the severe gas interference event. The snapshot model was made for the measured operating parameters including 355 psi pump intake pressure, 3,410 psi pump discharge pressure, and average motor current of 24A. Although a match of this condition cannot be achieved using exactly the production rate as reported in the daily production report, a match was achieved for 450 BFPD at surface, as illustrated in the diagnostic plot in **Fig. 9**. This is typical behavior of unsteady and cyclic production with higher and lower production rates, or even zero production, as the severe gas interference events occur during the day.

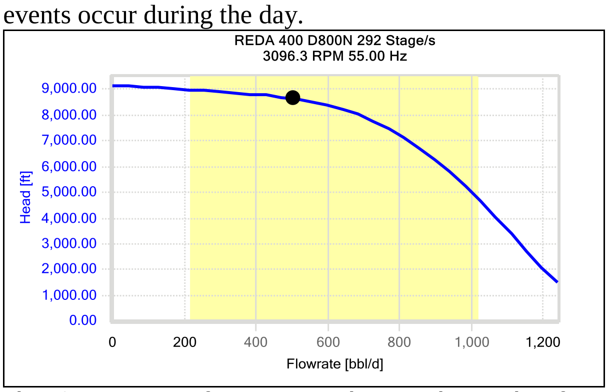


Fig. 9—Pump performance and operation point from diagnostic report on condition 1.

Condition 2 represents a typical severe gas interference event where even after the frequency had increased to 60Hz, the average motor current dropped to 14.5A, accompanied by a decrease in discharge pressure and tubing head pressure, and an increase of motor temperature.

The operating point for condition 2 is considerably below the pump head curve as shown in **Fig. 10** when maintaining the same inputs for fluid properties. One could manually apply a degradation factor to the pump head curve throughout the pumps; in this case, a 25% degradation would bring the pump performance curve down to match the operating point at 120 BFPD surface rate.

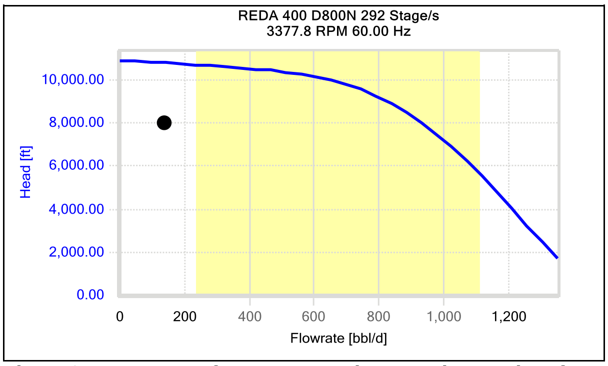


Fig. 10—Pump performance and operation point from diagnostic report on condition 2.

The actual flow dynamics during these events are transient in nature and for this reason the ESP system is subjected to drastic changes in very short periods of time. We attribute the ability to ride through these events to the conditioning of the fluid done by the axial and centrifugal gas handling devices before transferring the mixture to the pump.

Since no spot gas measurements were available, several sensitivities were used to model the transients by setting instantaneous liquid rate and GVF to simulate gas interference during the transient. The ESP design software does stage-by-stage calculations. The program has the actual performance degradation curves for the different stages and gas handling devices built into it. **Fig. 11** shows a snapshot from the match of the 120 BFPD (condition 2) case after running the diagnostic analysis with increased GVF. Instead of manually entering a degradation factor to the head of all stages of the pump, the degradation is determined internally in the program for each of the stages. As illustrated in **Fig. 12,** the pump head degradation is over 70% at the lowermost stage, but then the degradation is reduced as the fluid passed throughout the stages.

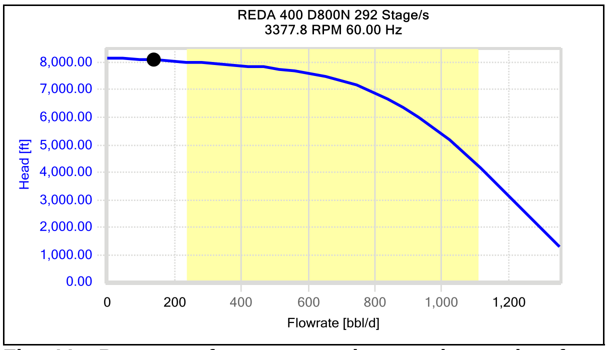


Fig 11. Pump performance and operation point from diagnostic report on condition 2 after increasing GVF

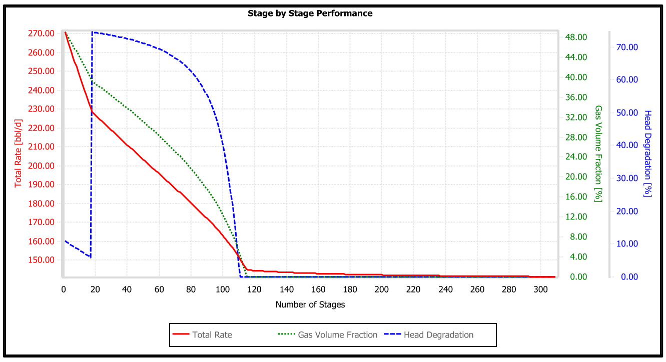


Fig. 12. Stage-by-stage performance from diagnostic report on condition 2 after increasing the GVF

ESP Gas Interference in Toe-up vs Toe-down Wells

Although the sample size of eight wells is not large, there does appear to be evidence that wells drilled toe-up have worse gas interference than wells drilled toe-down. This observation was independently validated by Samson using OLGA transient multiphase modeling.

While all wells exhibited some degree of gas interference once the bottom hole pressure fell below the bubble point, the wells drilled toe-up experienced operational problems earlier in the ESP phase, and the problems were more severe. These wells had greater day-to-day production fluctuations and the pumps shut down on high motor temperature more frequently than the toe-down wells. An example of a toe-up well with these issues is the T-1280-D800 (see Table A-2.). The C-1280-D800 well is a direct offset, was drilled toe-down, and exhibited more consistent production and pressure drawdown (see chart in Appendix 3). C-1280-D800 was also able to be produced at a lower pump intake pressure, between 100 to 200 psi, compared to 400 psi in the T-1280-D800. We propose that toe-up wells have more gas slugging due to gas being trapped at higher elevations along the lateral until the pressure becomes low enough for it to enter the pump. Toe-down wells may have a more constant gas inflow and fewer traps along the lateral in which to form slugs.

Real-Time Surveillance and Control

Samson Resources initiated a one-week 24 hour surveillance test program in which the ESP company's Artificial Lift Surveillance Center (ALSC) engineers remotely monitored and controlled the operation of the ESPs. The goals of the test program were to prevent downhole shutdowns due to gas slugs, to achieve more consistent run time, and to increase production. The premise was that by actively monitoring the ESPs, gas slugs could be detected early and operating parameters could be adjusted thus avoiding a shutdown. The workflows, requirements of reports on operation, and communication protocols between the surveillance engineers, pumpers, application engineer, and production engineers from Samson were defined in advance.

Among the key roles of the surveillance engineer is to monitor the trends of operating parameters and gather field operation reports from the operator, including production tests, chemical treatment, surface facilities maintenance, etc. By combining the real-time data with the field operation reports the engineer analyzes the trends and performance of the ESP system and makes adjustments to the alarms and trip points for the key variables.

Samson Resources' policy was that a pumper must be physically present at the wellsite when the ESP was restarted, regardless of the reason for shutdown. As the wells were drawn down the number of trips became more frequent as the ESP was tripping typically on high motor temperature or low pump intake pressure. Unfortunately it often took several hours, or sometimes until the next day, until the pumper was available to come to the wellsite to restart the pump. In an effort to maximize the uptime, the workflows of the surveillance center were modified during this one-week trial to increase the autonomy of the ALSC engineers to make adjustments remotely to all the operating parameters as needed to optimize the performance of the ESP. The surveillance engineers had direct communication with the field service technician and the pumper, and coordinated the effort when field support was required to diagnose and optimize the performance or to correct issues with surface facilities.

The surveillance engineers remotely made adjustments to the operating mode or switched between operating modes as needed. **Fig. 13** shows a summary of the weekly uptime report right before the 1-week trial for well N-1280-D800.

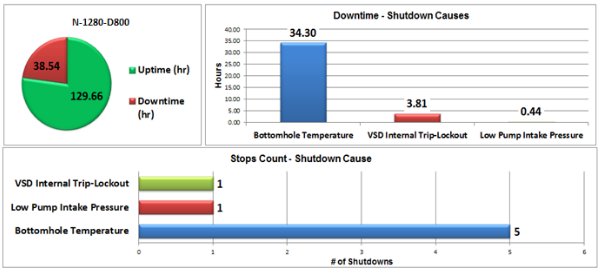


Fig. 13. Snapshot of the uptime report before extended scope service

The implementation of the expanded scope of action of the ALSC resulted in improved uptime and increased production, especially in the wells with the most challenging gas influx problems such as the N-1280-D800. **Fig. 14** shows how the operating parameters were much more stable during the one-week 24 hour surveillance test and resulted in a 12% production increase compared to the previous weeks, with zero trips.

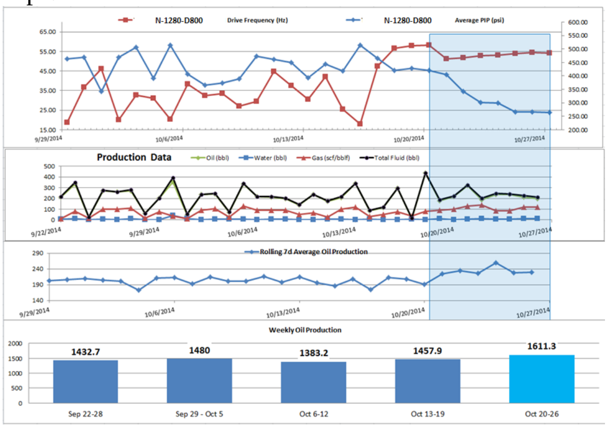


Fig14. Increased scope of service of the ALSC

The one-week 24 hour surveillance test validated our assumption that the pumps could be run more consistently and without shut downs by having the ALSC engineers optimizing their operation. This resulted in increased production and less time on location for the pumpers. Samson recognized the value in this surveillance service and would have continued it had the ESP program in this field not been nearing its completion.

Transition from ESP to Rod Pump Phase

To maximize the runlife of the rod pump systems the designs were made to set the pump approximately at the same depth as the ESP system, in a region of low inclination and low dog leg severity above the liner top.

The criteria for the timing of the transition to rod pumps were based on one or more of the following factors: condition of the ESP system, flow rate, readiness for deployment of rod pump system, and availability of a workover rig.

The majority of the ESPs in the study were exposed to fracture treatments of nearby wells. Although the wells on ESP were shut in for several days prior to and after the fracs, the pumps were affected by the incremental influx of fluid and proppant. On three occasions the ESP systems were able to successfully deal with the influx and resume operating conditions after being hit, but on the other three occasions the ESPs failed shortly after the offset frac. The three wells that were negatively affected by the offset fracs had to have the ESPs pulled earlier than anticipated. The systems were in good operating condition prior to being shut in for the offset fracs. Samson did not achieve the expected runtime for those systems. **Table A-2** illustrates the summary of runtime and fracturing activity in the eight wells.

Although Samson's development plan was designed to minimize the impact of fracturing infill wells on producing wells, it was necessary to shut in our producing wells when other operators in the area were fracturing their wells. As mentioned previously three ESPs were damaged due to offset operator's fracturing and had to be pulled prematurely.

Fig. 15 illustrates the production profile and drawdown of the well C-1280-D800. The well was shut in after 6 months in the ESP phase to prevent damage to the ESP while a nearby well was fractured. Although the ESP was not running, the downhole sensor was powered on so we could monitor the effect of the nearby fracturing on the well. This information eventually could be used for optimization of well spacing. An example of the interference of a frac job near well C-1280-D800 can be seen in **Fig 15**.

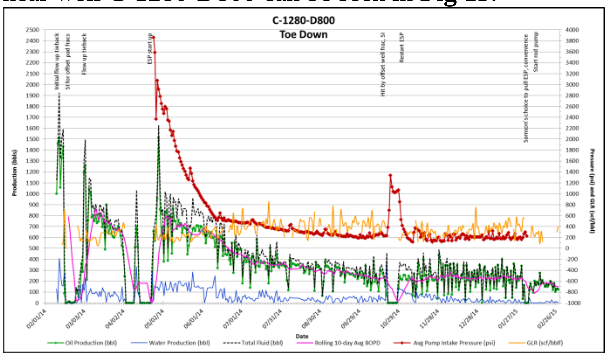


Fig. 15. Well C-1280-D800 Production profile and Pump Intake Pressure

The pump intake pressure increased rapidly by 1,000 psi shortly after the offset frac at the end of October 2014. The ESP was restarted 8 days later and resumed stable operation for 3 additional months at a pump intake pressure of approximately 200 psi when it was manually shut down on Feb 4, 2015. Towards the end of the ESP phase, the pump started to trip frequently on low pump intake pressure (PIP) which was set at 100 psi and high motor temperature. Although the system could have been restarted remotely or set up for auto-restart following a low PIP trip, this was not implemented due to Samson Resources' operating policy. Thus it was required for the pumper to restart the pump manually, often the next morning. This caused the production to be quite erratic from day to day. The daily production prior to pulling the ESP averaged 205 BOPD with swings from 37 to 358 BOPD.

Even though the ESP was in operable condition after 287 days, it was pulled proactively due to rig availability in the well pad. The well started its rod pump phase on Feb 6, 2015.

From the production standpoint, the plan was to transition to rod pumps after the production with ESP decreased to 250 BFPD or below, which was deemed achievable with the rod pump and pumping unit selected. While the compression type technology mitigates the downthrust in the pump stages when producing below the minimum ROR, the pump efficiency decreases as the flowrate decreases as noted in **Fig 4**. The 10-day average rate of the well C-1280-D800 was 205 BOPD at the end of the ESP phase, which is considerably below the D800N pump's Best Efficiency Point (BEP).

The 10-day average production at the start of the rod pump was 177 BOPD and the swings were from 95 to 273 BOPD which is a much tighter spread than what was experienced at the end of the ESP phase. After implementation of the rod pumping systems we noticed that although the daily production was often more consistent, the average production at the start of the rod pump phase was lower than the average daily production at the end of the ESP phase in all wells except V-640-D800. On average, the production with rod pumps was 17% lower than the rate at the end of the ESP phase. **Table A-2** shows the ten-day average production before and after the transition of production phases and the uplift for the eight wells in the study and the average. **Fig. 16** illustrates the rolling 10-day average production during the transition from ESP to rod pumps for the eight wells in the study.

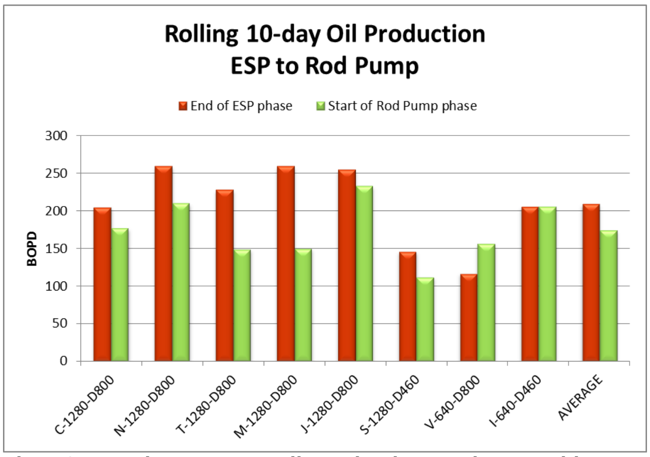


Fig. 16. Ten-day average oil production at the transition from ESP to rod pump phase.

The performance of rod pumps in horizontal wells also has its own challenges. Samson is in a continuous improvement process to define the best combination of pump size, gas handling, stroke length and strokes per minute. We are trying different combinations of equipment and are monitoring production and pump life to determine which is most effective. We are leaning towards slow pumping with long stroke lengths using variable slippage pumps which tend to handle the gas better. This set-up provides more consistent daily production, but does not necessarily provide the volumes equal to what was achieved at the end of the ESP phase. Our anticipation is that pump life will be longer and fewer pump changes will be required, which should result in less downtime and lower operating costs.

Upon completion of the ESP Phase on each well, the surface equipment is transferred to the next well and the downhole equipment and power cable are sent to the ESP service center for inspection, testing, and repairs so it can be used in future wells.

Results

Samson Resources successfully implemented the ESP transitional artificial lift system to optimize production and drawdown in the early stage of the well life cycle. The peak production achieved in the ESP phase was as high as 85% of the 1-day initial production of natural flow and on average it was 63% for the eight wells as illustrated in **Fig. 17.**

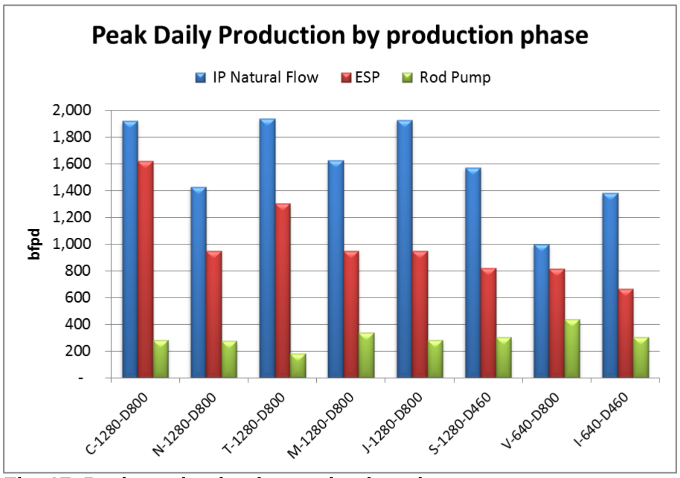


Fig. 17. Peak production by production phase

The incremental production achieved during the ESP transitional phase was significant. As an example, the cumulative production of well C-1280-D800 at the end of the 287 days of the ESP phase was estimated to be 65% higher compared to the scenario in which a rod pump would have been installed instead.

Based on the equipment available, the rod pump would have been limited in its ability to pump down the well and the production would have been limited as well. **Fig. 18** illustrates the cumulative production actual compared to the rod pump scenario.

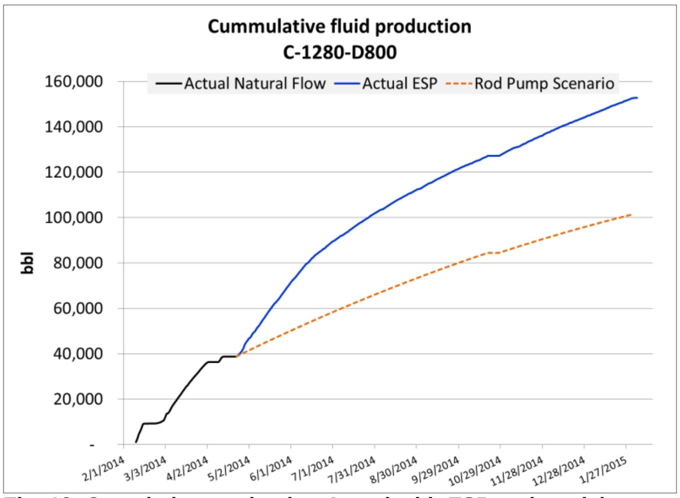


Fig. 18. Cumulative production Actual with ESP and model for Rod Pump scenario for well C-1280-D800

The rod pump design was modeled as if we had chosen to install the same rod pump system (C912-427-192 pumping unit, downhole pump, rods, stroke length and volumetric efficiency) instead of running the ESP in this well. **Fig B-2** shows the design report for 252 BFPD. It was assumed the same rate throughout the 287 days and 100% uptime for the rod pump, except for the 8 days well shut-in in October for the offset frac.

Conclusions

- ESP systems proved to be an efficient transitional artificial lift method as they allowed accelerating production and improving cash flow from operations during this stage. The incremental production was approximately 65% compared to the rod pump limited scenario.
- Oil production at the start of the ESP phase was on average 70% higher than the average production at the end of the natural flow phase.
- Oil production at the start of the rod pump phase was on average 17% lower than the average production at the end of the transitional ESP phase.
- Although Samson Resources planned its ESP deployments with regard to their own offset drilling and fracturing operations, offset operators' development posed challenges which in some cases resulted in damaged downhole equipment. Pressure data from the downhole sensor was useful in understanding interference from fracs on offset wells.
- The only certain way to prevent damage to an ESP system when an offset well was being fractured was to pull it.
- For the group of wells considered in this paper, wells drilled toe-up had worse gas interference than wells drilled toe-down.
- The gas handling technology combined with operational procedures was instrumental in maintaining uptime and operations, even with radial pump stages maintaining pump intake pressure of less than 200 psi.
- Real-time surveillance and remote control proved to be a service that increased production and protected the downhole equipment.
- Open communication and close collaboration between the operator and the ESP service provider are critical for the successful operation of ESP systems in unconventional plays. Working together resulted in a successful program.

Appendix A: Tables

BASIN	Powder River, Wyoming	
FORMATION	Shannon Sandstone	
# OF WELLS	10 on ESP, 8 in study	24 Total on AL
	From	To
AVG. BFPD	700 initial	240 final
SIBHP, PSI	5900 virgin	3600 some depletion
BUBBLE POINT, PSI	~1900	
PUMP INTAKE PSI	3260 avg. initial	190 avg. final
GLR, SCF/STKBBL	325 avg. initial	460 avg. final
API, SP.GR.	37° low	40° high
BHT, F	210°	
TBG, O.D.(IN) & WT.	2-7/8" 6.5 #/ft	
CSG, O.D.(IN) & WT.	7" 26 & 29 #/ft	4.5" 11.6 #/ft
TVD, FEET	10,000' avg.	
SETTING TVD, FEET	9190' avg.	
SETTING INCLINATION, °	8° avg.	
MD, FEET	14,600' avg. 640s (2 wells)	19,800' avg. 1280s (6 wells)
SCALE (LIGHT, ETC)	Very light	
SAND	Frac and formation fines	
H2S	None	
CO2	None	
EMULSION (yes or no)	Emulsion no, foam yes	
ONSHORE/OFFSHORE	Onshore	

Table A-1—Samson Resources application data and fluid properties of the Shannon sandstone in the Powder River basin.

	End of flow phase	Start of ESP phase	Uplift: Natural Flow to ESP phase		Peak daily prod on ESP	End of ESP phase	Duration ESP phase	Offset Frac	REASON FOR PULLING ESP
Well	(bopd)	(bopd)	(bopd)	(%)	(bfpd)	(bopd)	(days)		
C-1280-D800	614	792	178	29%	1,624	205	286	Y	Proactive pull, rig availability
N-1280-D800	467	768	301	64%	949	259	210	N	Broken shaft. Sand.
T-1280-D800	379	643	264	70%	1,304	228	205	N	Pump wear, sand
M-1280-D800	311	504	193	62%	949	259	181	Y (2)	Pump failures, sand. Shortly after 2nd offset frac
J-1280-D800	334	587	253	76%	947	255	179	Y (2)	Abrasives, pump and tubing plugged shortly after 2nd offset frac
S-1280-D460	230	462	232	101%	820	146	157	Y	Proactive pull, offset frac
V-640-D800	244	587	343	141%	813	117	161	N	Broken shaft. Sand.
I-640-D460	205	434	229	112%	664	206	181	Y	Abrasives, pump plugged. Shortly after offset frac
AVERAGE	**348**	**597**	**249**	**72%**	**1,009**	**209**	**195**		

Table A-2. Ten-day average production and ESP phase summary

Appendix B: ESP and Rod Pump Data

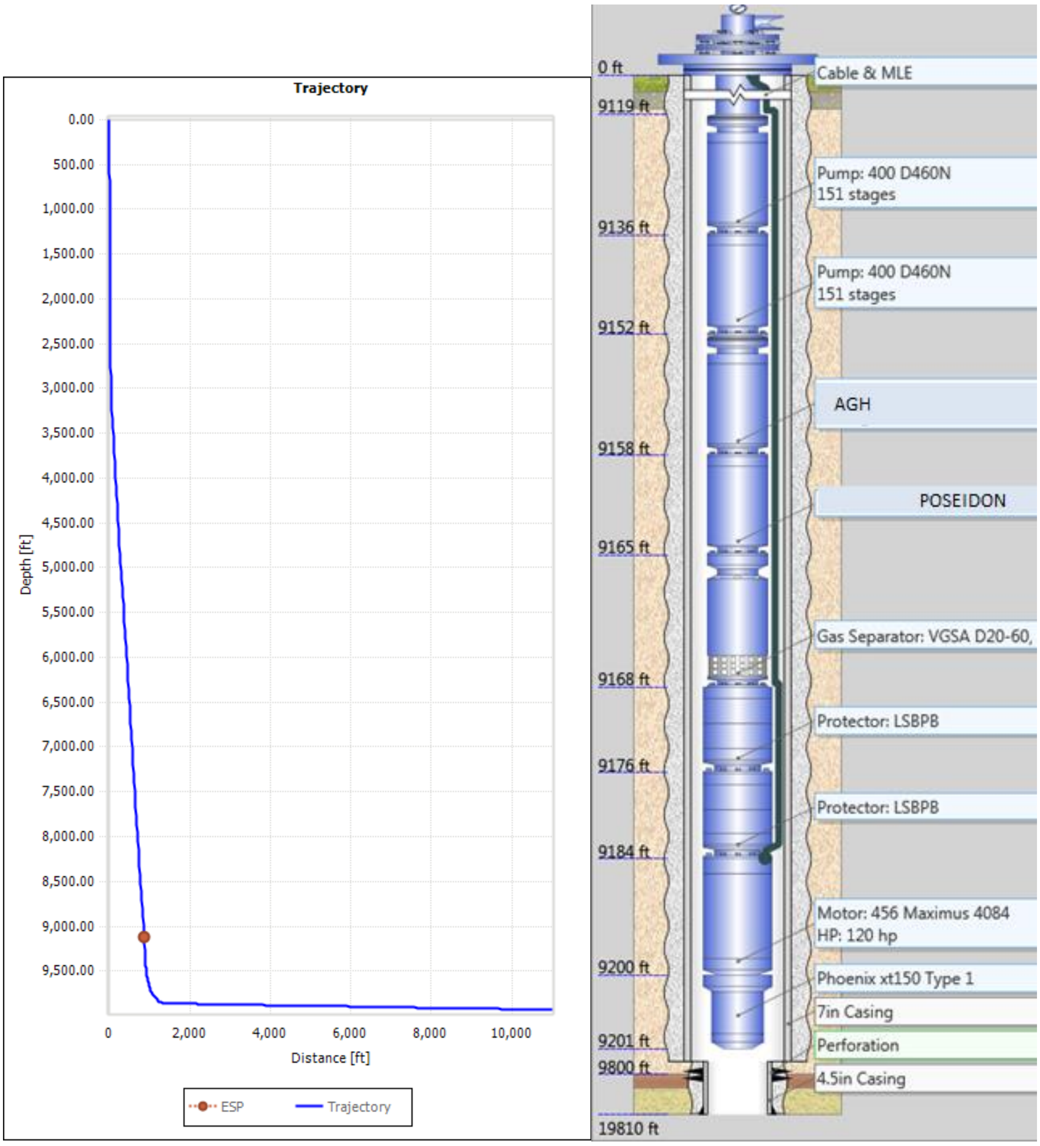


Fig. B-1—Typical ESP setting depth and configuration.

INPUT DATA				CALCULATED RESULTS (TOTAL SCORE: 85% GRADE: B+)			
Strokes per minute:	5.5	Fluid level		Production rate (bfpd):	252	Peak pol. pod load (lbs):	32613
Run time (hrs/day):	24.0	(ft from surface):	5000	Oil production (BOPD):	232	Min. pol. rod load (lbs):	12760
Tubing pres. (psi):	100	(ft over pump):	4170	Strokes per minute:	5.5	MPRL/PPRL:	0.391
Casing pres. (psi):	40	Stuf.box fr. (lbs):	100	System eff. (Motor->Pump):	22%	Unit struct. loading:	76%
		Pol. rod. diam. 1.5"		Permissible load HP:	73	PRHP / PLHP:	0.38
				Fluid load on pump (lbs):	4633	Buoyant rod weight (lbs):	19613
				Fluid level tvd (ft from surface):	4992	N/No: .214 , Fo/SKr: .144	
				Polished rod HP:	27.4		

Fluid Properties

Water cut:	8%
Water sp. gravity:	1.03
Oil API gravity:	38.0
Fluid sp. gravity:	0.8504

Motor & Power Meter

Power meter	Detent
Elect. cost:	$.06/KWH
Type:	NEMA D

Required prime mover size (speed var. not included)	BALANCED (Min Torq)
NEMA D motor:	50 HP
Single/double cyl. engine:	40 HP
Multicylinder Engine:	50 HP

Pumping Unit:Weatherford Maximizer II

API Size: C-912-427-192 (Unit ID: EWM2)	
Crank hole number:	# 1 (out of 3)
Calculated stroke length (in):	192.1
Crank rotation with well to right:	CW
Max. cb moment (M in-lbs):	Unknown
Structural unbalance (lbs):	-825
Crank offset angle (degrees):	-14.0

Torque analysis and electricity consumption	BALANCED (Min Torq)
Peak g'box torq.(M in-lbs):	856
Gearbox loading:	93.9%
Cyclic load factor:	1.277
Max. cb moment (M in-lbs):	2247.97
Counterbalance effect(lbs):	25752
Daily electr.use (Kwh/Day):	654
Monthly electric bill:	$1198
Electr.cost per bbl fluid:	$0.156
Electr.cost per bbl oil:	$0.169

Tubing And Pump Information

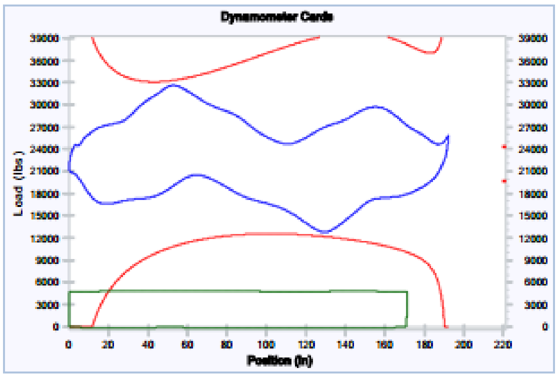
Tubing O.D. (in):	2.875	Upstr. rod-fl. damp. coeff.:	0.100
Tubing I.D. (in):	2.441	Dnstr. rod-fl. damp. coeff.:	0.100
Pump depth (ft):	9170	Tub.anch.depth (ft):	9102
Pump conditions:	Full		
Pump type:	Insert	Pump vol. efficiency:	75%
Plunger size (in):	1.75	Pump friction (lbs):	200.0

Tubing, Pump And Plunger Calculations

Tubing stretch (in):	.1
Prod. loss due to tubing stretch (bfpd):	0.1
Gross pump stroke (in):	171.1
Pump spacing (in. from bottom):	27.5
Minimum pump length (ft):	26.0
Recommended plunger length (ft):	6.0

Rod string design					Rod string stress analysis (service factor: 0.9)				
Diameter (inches)	Rod Grade	Length (ft)	Min. Tensile Strength (psi)	Fric. Coeff	Stress Load %	Top Maximum Stress (psi)	Top Minimum Stress (psi)	Bot. Minimum Stress (psi)	# Guides/Rod
+ 1	WFT S88	2795	140000	0.3	73.3%	41397	16374	10194	4
0.875	WFT S88	375	140000	0.22	62.9%	35759	12798	12339	4
0.875	WFT S88	575	140000	0.2	58.1%	33295	11596	11000	0
0.875	WFT S88	200	140000	0.22	53.1%	30458	10134	10562	4
0.875	WFT S88	2850	140000	0.2	51.0%	29348	9654	3922	0
0.75	WFT S88	2125	140000	0.2	45.2%	23313	4219	137	0
@ 1.5	Flexbar C	250	90000	0.2	36.6%	6565	-1030	-113	0

+requires slimhole couplings. @ stress calculations based on elevator neck of 7/8 (for 1.25 sinker bars) or 1 (for other sinker bars).
NOTE: Displayed bottom minimum stress calculations do not include buoyancy effects (top minimum and maximum stresses always include buoyancy).



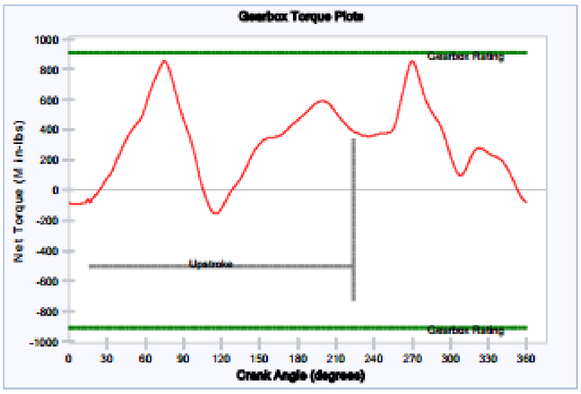


Fig. B-2—Example of rod pump design report.

Appendix C: Production Results

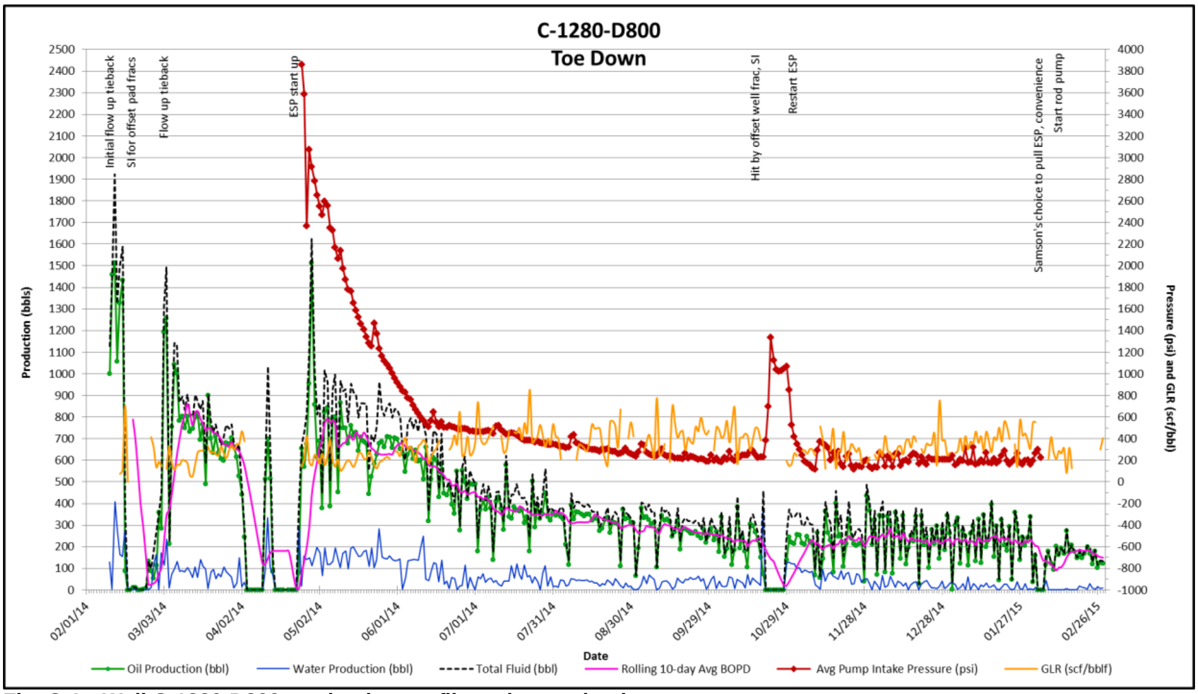


Fig. C-1—Well C-1280-D800 production profile and pump intake pressure.

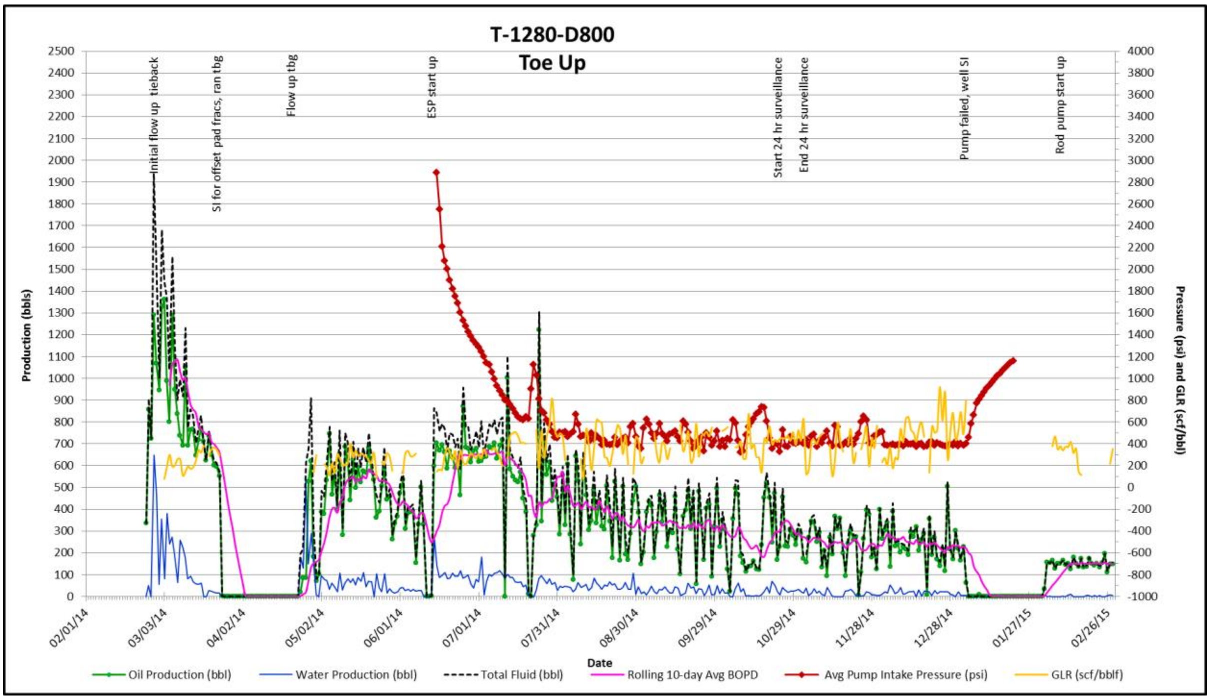


Fig. C-2—Production curve, well T-1280-D800.

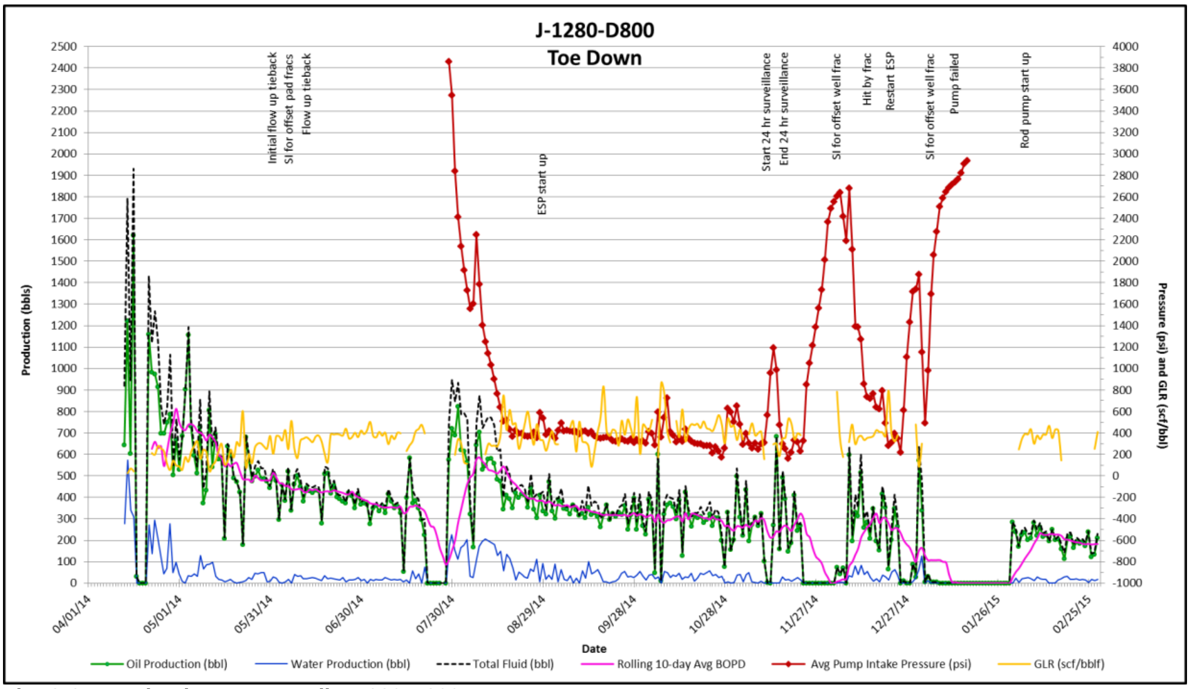


Fig. C-3—Production curve, well J-1280-D800.

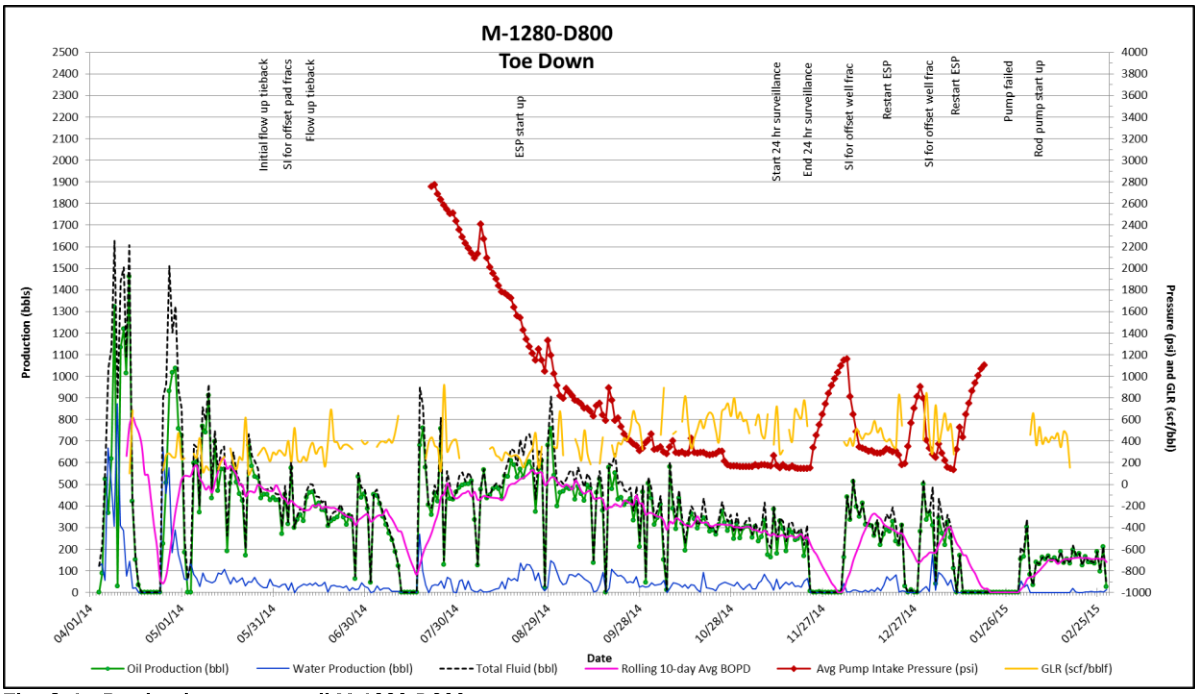


Fig. C-4—Production curve, well M-1280-D800.

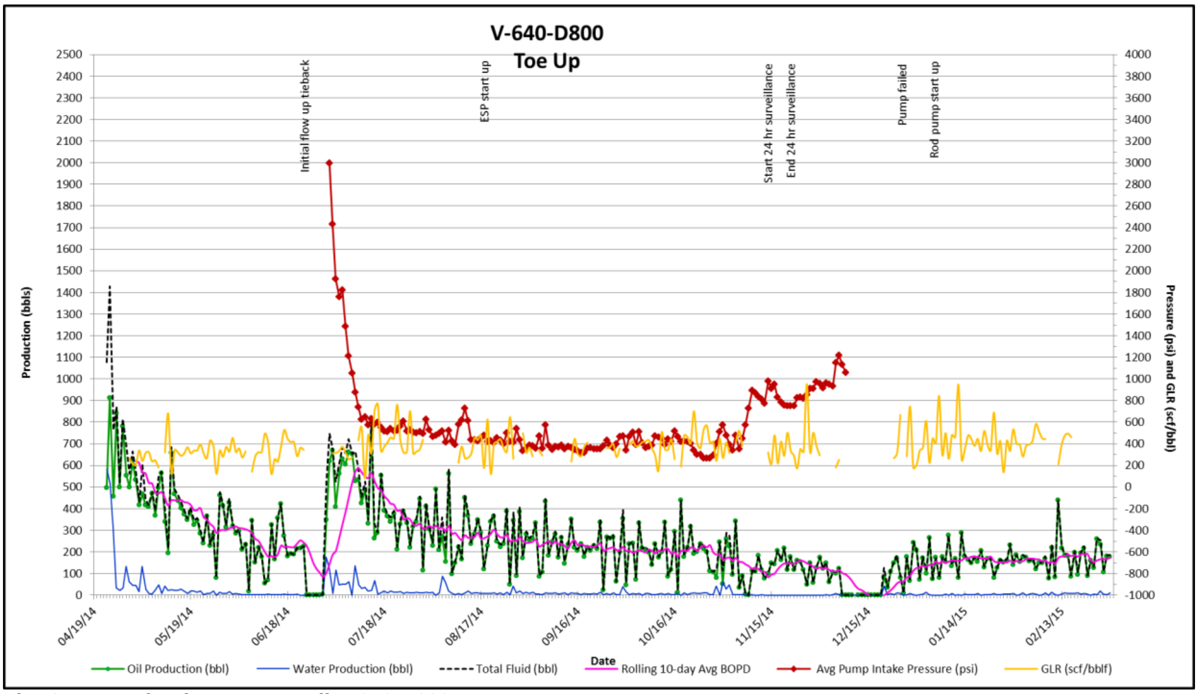


Fig. C-5—Production curve, well V-640-D800.

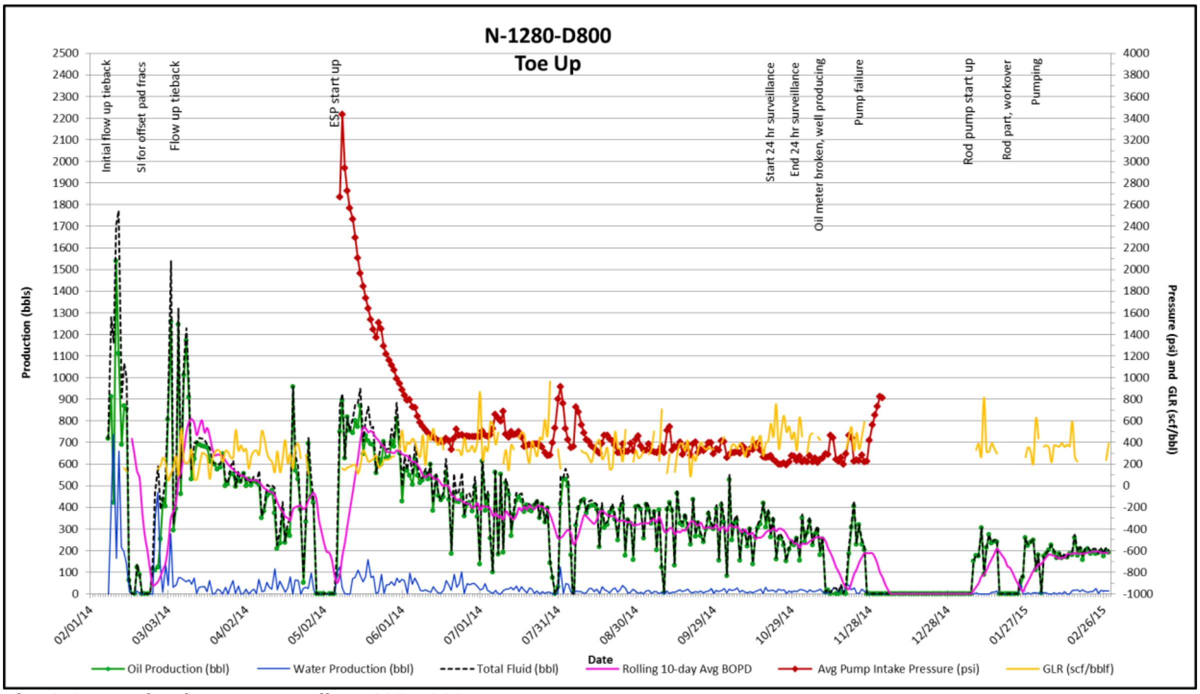


Fig. C-6—Production curve, well N-1280-D800.

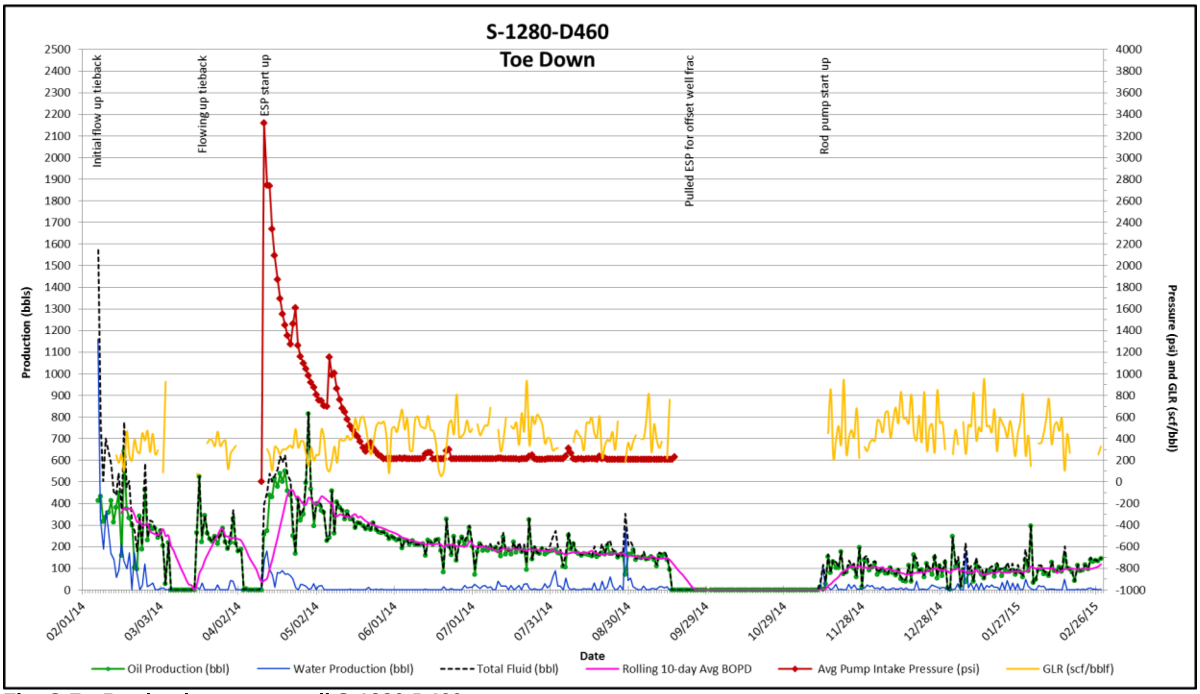


Fig. C-7—Production curve, well S-1280-D460.

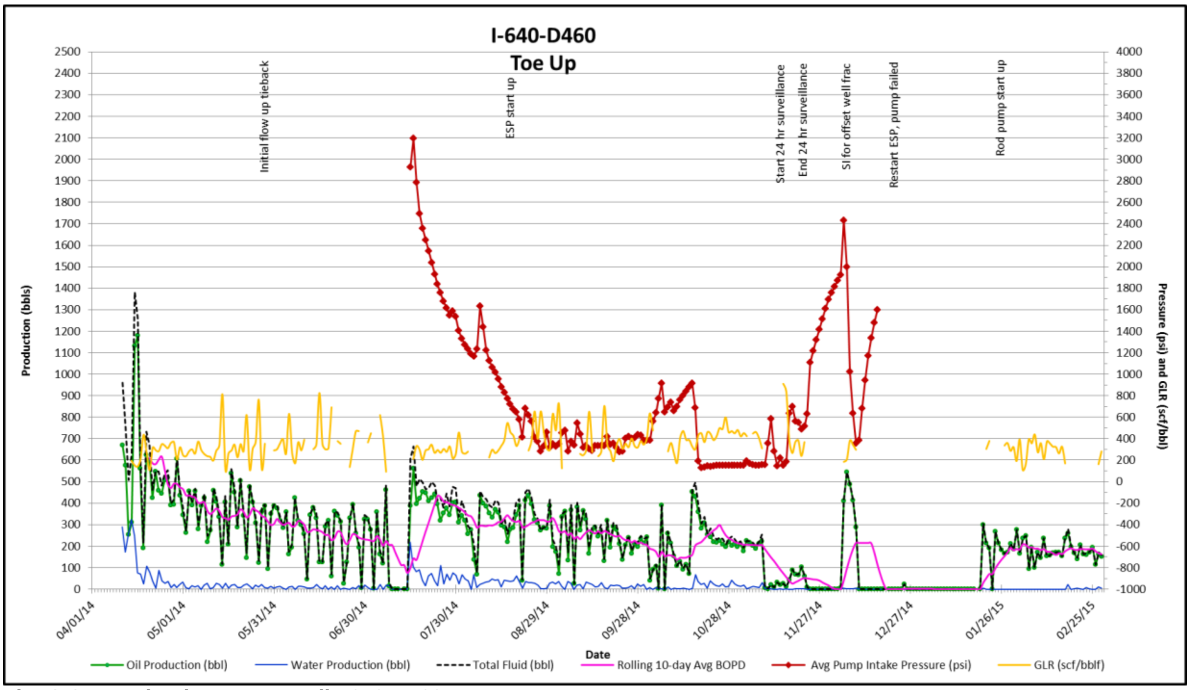


Fig. C-8—Production curve, well I-640-D460.

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