WELL PRODUCTION TESTING USING A ROD PUMP CONTROLLER

LeMoyne Boyer, Sam Gibbs, Ken Nolen, Andy Cordova and Alan Roberson
Lufkin Automation

ABSTRACT

Well tests are crucial to managing rod pumped wells and operators struggle to get tests as frequent as they desire. They are also essential to good reservoir management, especially in secondary and tertiary recovery projects. A production test method has been developed using the Down Hole Pump Card generated by a Rod Pump Controller that has proven to be accurate and reliable. The method will be explained and data will be presented of field tests showing actual well tests compared to the calculated well test from the Rod Pump Controller.

INTRODUCTION

Traditional Production Testing

Production testing has been an integral part of oil producing operations for many years. The gathering of this data is required for many reasons. Some reasons include governmental regulation, environmental conservation concerns, reserve estimates, reservoir management, business purposes, and well troubleshooting. Business purposes include the allocation of leaseholder royalties and costs.

Production specialists often use production tests as indicators that a well requires troubleshooting. A rapid decline in production between tests may indicate a mechanical problem such as a rod part, worn pump, tubing leak, or a bad flowline check valve that needs to be addressed. The change may also be due to a change in reservoir conditions related to secondary recovery operations.

Accepted methods and equipment for production testing are well documented[1]. Production test methods include manual and automatic tank gauging of oil, portable trailer mounted well testing equipment that measures oil, water, and gas, and permanent facility equipment such as lease automatic custody transfer systems (LACT). Various types of meters are in common use, for example turbine, positive displacement, orifice, ultrasonic, and coriolis meters.

A common method of metering with newer automated facility systems is that a well is redirected from a common flowline header from multiple wells and switched ‘on test’ periodically. The total flow of all wells is then metered for custody transfer purposes. This test period may be a few hours in duration. This ‘snapshot’ picture of that well’s production is then assumed to be a normal operating condition at all times while the well is ‘off test’.

There are several uncertainties in making a snapshot assumption. If the well has any downtime at all, for example due to a rod part, the actual production during a longer time period will be less than the reported test. Downtime is often neglected entirely in the reported test. Likewise, if a well was having problems during a test, for example an intermittent malfunctioning pump valve, the actual production may be more than the reported test if the problem was corrected in a timely manner. Meters require routine checks and maintenance and may have a problem that is not discovered for some time. Thus actual production can vary significantly from reported production tests, by as much as 10% or more. Also, metering errors will be reflected in many well tests, sometimes hundreds, until the meter is repaired and calibrated. The method described in this paper is ‘stand alone’, meaning that each well has its own independent test. Guidelines for testing include monthly testing, correction for recorded runtimes, periodic calibration of test separators and meters, and increasing the test period if possible for best results[2]. Good sampling procedures are important on high water cut wells.

Diagnostic Methods

A traditional production test may give an indication of a change in the condition of the well and/or its associated equipment, but it does not reveal any specific causes for the change. Diagnostic methods have been developed over the years to identify and rectify a problem. Trial and error methods are still used today, but superior results can be obtained with modern dynamometer analyses. A fluid level instrument by itself cannot typically determine the cause of an operational problem.

Modern diagnostic methods began in the 1960’s with the development of a method for determining the down hole pump card from surface dynamometer data by Dr. Gibbs[3, 4]. Although down hole dynamometer measurements have been performed since the late 1930’s[5], the expense and time made direct measurements impractical. As computers and solution methods evolved it became practical to determine pump cards from easily obtained surface dynamometer data. The ready availability of pump cards allowed for qualitative determination of numerous pump problems such as defective pump valves or barrels, gassy or pounding wells, unanchored tubing, and parted rods. The reliability of this method has been well established.

Quantitative information from pump cards reveals even more information about a given well. Fluid load, pump fillage, well friction, pump leakage, liquid and gas throughput (gross and net), pump efficiency, pump intake pressure, and oil shrinkage can be calculated using proper data inputs and correlations. Nolen and Gibbs[6] described calculation of pump leakage from dynamometer valve check measurements in 1990.

One can observe that all requisite information is available (from the dynamometer analysis) to utilize the down hole pump as an accurate metering device. The one limitation of the dynamometer analysis is that it is also a 'snapshot' picture and may not represent what occurs every stroke of the pumping unit. The next logical step to take is to implement diagnostic methods on a real-time basis at each well site using a Rod Pump Controller.

WELL PRODUCTION TEST VIA A ROD PUMP CONTROLLER

Rod Pump Controllers (RPCs) have advanced significantly in the last 30 years. Many are 'surface card controllers' which measure polished rod load and position and determine pump off by observing changes in the surface card shape. They have been used to approximate production by observing 'surface fillage,' see Figure 1a. With the addition of on-board well diagnostic capability they can accomplish many more functions real-time. The latest RPC Well Manager (WM) technology from Lufkin Automation[7] incorporates pump card technology to more accurately calculate production. This is discussed in more detail below.

SAM IP Method - k Factor

The current method in the SAM WM calculates the net stroke of the pump card, determines the stroke volume, and accumulates the incremental volume of each stroke during a 24 hour period; this is referred to as inferred production (IP). The incremental volume is calculated from

$$\Delta V_l = \frac{\pi}{4} d^2 \ S_n \qquad (1)$$

where d is the pump diameter, S_n is the net stroke. This is illustrated in Figure 1b. IP assumes that the pump is in good condition, leakage is minimal, the tubing is anchored at or near the pump, free gas in the pump is negligible at the time of traveling valve (TV) opening, and oil shrinkage effects are minimal. In reality not all of these assumptions are true, therefore this volume calculation will typically be greater than that reported from a well test. A gross adjustment, referred to as a k-factor, is applied to bring the IP into agreement with the production test and account for the error in the underlying assumptions. This approach is reasonable as long as conditions are steady. As such, k-factors should generally be less than 1; a common range is from 0.85 to 0.9. If a lower number is required, there may be excessive pump leakage or a tubing leak that should be addressed.

RPC's capable of pump IP calculation were installed on several wells in the Permian Basin (identities withheld to avoid RTS-Red Tape Syndrome). IP was configured and k-factors entered based on recent well tests. Figure 2 shows the comparison between the IP and the well test on 26 wells. In general the agreement is good; on wells S and U the k-factor could have been lowered to better agree with the well test; the k-factor could have been raised on well K for better agreement; wells G and X suggest that either the wrong pump diameter was entered, a bad well test, or some other problem exists because it would require a k-factor greater than 1 to have a good agreement between the test and the IP.

Data for these wells was tracked over a one year period. Two of these were selected for presentation. Figure 3 shows results for well I. Initially the calculated IP was high, as expected since the k-factor was at the 1.00 default. After setting the k-factor, the IP and Well Test are in good agreement with less than 15% difference for the remainder of the test period.

Figure 4 shows results for well R. Again the IP compares very well with the Well Test, within 10%. It is not certain if the k-factor was adjusted in March 2004, but it is apparent that the IP calculation was adjusted, since the agreement is within 5% after this date.

In Figure 5 the daily IP recorded for a one month period on a different Permian Basin well can be compared with 2 well tests during this period (from June 4 to July 3, 2004). The daily IP varies from about 68 to 80 BBL during this period with about 5 days of downtime; if each of the 30 daily IPs are added, a total monthly production of 1824 BBL is calculated. On the other hand, the two well tests average about 74 BBL; if it is assumed to be constant during the 30 day period, then the monthly report would be 2220 BBL, about 22% higher. This highlights the ability of IP to automatically and more appropriately account for runtime.

Table 1 presents results for three wells in the Lost Hills area near Bakersfield, California. These wells are tested through one test unit daily. The test unit is calibrated monthly. The metered production was reported on three different days. In each case, the total production from IP was within 2% of the test unit.

It is easy for one to say, 'Well, I'll just change the k-factor to exactly match the well test.' Indeed that is a good start, but as time goes on, some of the underlying assumptions may go awry, especially the one regarding pump leakage. As time goes on, the pump will wear, resulting in additional leakage. The pump still displaces what IP calculates, but now additional leakage means that less of the fluid that enters the pump arrives at the surface. Periodic adjustments may be acceptable, but require extra effort to maintain. If continuous IP is intended to be comparable to intermittent well tests, the limiting assumptions need to be addressed.

SAM Well Test

For reasons stated above, new technology is being developed to eliminate the underlying assumptions in the IP method. This new patent pending technology is referred to as SAM Well Test (SWT). It is anticipated that this method can be used to minimize or even replace traditional well tests and reduce facility testing infrastructure. At the minimum, it can be used for allocation purposes. Currently, SWT is in an initial phase of field trials; as such, this paper will introduce the method, but extensive field data is not yet available. A discussion of how the limiting assumptions in IP are eliminated follows. Figure 6 illustrates the relevant concepts from the pump card.

Pump Leakage

As mentioned previously, diagnostic methods are available for quantitatively determining the quantity of pump leakage from measured valve checks. Several techniques have been published elsewhere[6] and include the TV load-loss method from a valve check or from the critical velocity on a real-time pump card. SWT currently supports the TV load-loss method from a recorded valve check performed previously; the user can also manually enter a 'known' leakage. Both are based on a 24 hour run-time; SWT accounts for a stroke period and calculates the leakage for a single stroke. Figure 7 illustrate the TV load-loss method. S_{leak} in Figure 6 is the equivalent stroke length due to TV/plunger leakage.

Some training is required to properly perform this measurement; it is expected that pump leakage changes slowly with time, so monthly or quarterly valve checks should be sufficient and only take a few minutes to perform. Automated methods for determining pump leakage are being investigated, but not discussed here.

Tubing Movement

A simple static Hooke's Law model is employed to subtract the amount of pump stroke due to tubing movement for the unanchored portion of the tubing. It is assumed that the tubing anchor is holding, if installed. In Figure 6 S_t is the gross pump stroke length loss due to tubing movement. Net stroke is not affected by tubing movement.

Free Gas and Oil Shrinkage

Figure 6 shows a pump card with free gas in the pump at the time of TV opening. The volume of free gas after compression may not be small and is a function of the pressure of the gas as it enters the pump (pump intake pressure). $S_{gas@Pa}$ represents the corresponding stroke length. It is necessary to determine the pump intake pressure,

$$P_i = P_a - \frac{L_f}{A_p} \tag{2}$$

where P_i is the pump intake pressure, P_a is the pump discharge pressure due to hydrostatic head of oil-gas-water in the tubing and the tubing head pressure, L_f is the fluid load derived from the pump card, and A_p is the area of the plunger. SWT automatically determines L_f from the shape of the pump card. Figure 8 shows a representative downhole card where L_f has been calculated. The user can adjust L_f to account for additional well friction if necessary.

P_a is dependent on the amount of free gas and solution gas metered into the tubing each stroke, as well as the amount of water and oil. Data input includes water cut, and reservoir PVT properties. SWT includes an iterative solution algorithm, commonly referred to as PIP, to determine all outputs such that equation (2) is satisfied. PIP uses Nolen non-dimensional curves for solution gas and oil shrinkage as functions of pressure. Tubing GLR, P_i, P_a, and $S_{gas@Pa}$ are some of the outputs generated from the algorithm. A detailed description is beyond the scope of this paper.

SWT Discussion

All of the effects above are used to calculate oil, water, and tubing gas volume produced each stroke. Status information for SWT includes calculated production for fluid, oil, water, and tubing gas, pump volumetric efficiency, pump intake pressure, and pump fillage, see Figure 9. Cumulative production since gauge off is shown, as well as yesterday's production, the instantaneous rate, and a projected value based on current runtime. 60-day history plots and data are also available. Data entry for SWT is shown in Figure 10. By directly taking into account pump leakage, tubing movement, free gas and oil shrinkage, SWT has eliminated the need for the k-factor utilized in the IP method.

It should be understood that SWT is not without limitations. Certainly, if a tubing, flowline check valve, or flowline leak develops, the calculated production will be greater than what is received at the stock tank. Fluid flow up the casing (rare) is not considered. Recirculation of chemicals should be taken into account. Sudden changes in SWT and/or runtime from the historical trend may indicate that such problems have arisen. Proper water cut must be entered by the user and checked periodically. As discussed above, valve checks must be performed periodically to determine pump TV/plunger leakage.

SUMMARY

In summary, RPC's with advanced IP and SWT technology are capable of calculating production volumes by utilizing the pump as a flow meter. The IP method has been proven in the field with extensive testing to be comparable quantitatively with traditional production test equipment. The improvements incorporated in SWT eliminate the reliance on the underlying assumptions that exist in the IP method.

SWT provides much more detail than has been previously possible with respect to an individual well's production. It can definitely be used to more intelligently determine allocation. As industry acceptance is obtained, it may reduce or eliminate traditional production testing and related facilities. SWT may not replace custody transfer measurements at point of transfer to the customer, but it can be used as a cost-effective tool to find and reduce discrepancies. More field testing will need to be performed to substantiate the SWT concept, and industry participation is encouraged.

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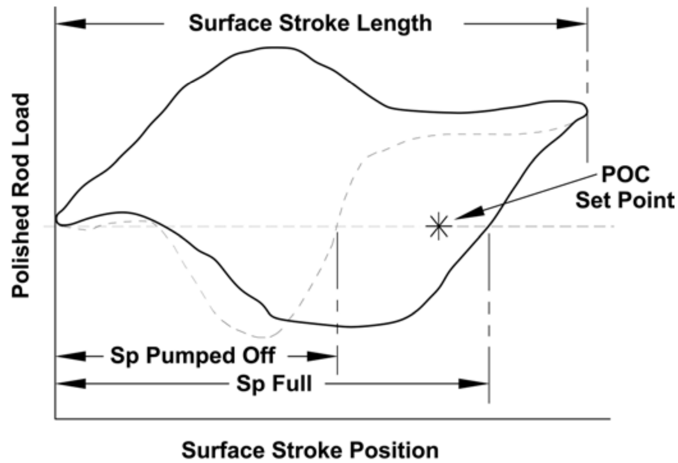
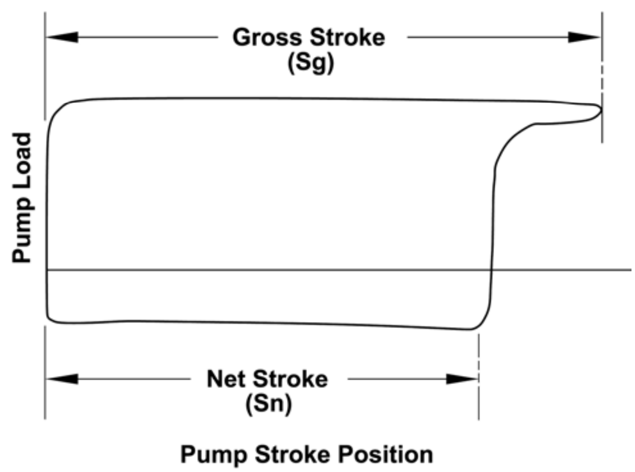
2. Joe D. Clegg, Sucker Rod (Beam) Pumping, 1st Ed., presented at SWPSC, April 1998, Lubbock, TX.
3. S G Gibbs, *Method of Determining Sucker Rod Performance*, US Patent 3,343,409, issued Sept 26, 1967.
4. Gibbs, S G and Neely, A B: "Computer Diagnosis of Down-Hole Conditions in Sucker Rod Pumping Wells," JPT, Jan 1966, pp 91-98.
5. Gilbert, G: "An Oil Well Pump Dynagraph," API Drilling and Production Practices, 1936, pp 84-115.
6. Nolen, Ken and Gibbs, S G: "Quantitative Determination of Rod-Pump Leakage with Dynamometer Techniques," SPE Production Engineering August 1990.
7. Dugan, L and Howard, L: "Beyond Pump-Off Control with Downhole Card Well Management", 49th SWPSC, April 2002, Lubbock, Texas, pp 55-62.

Table 1
IP Results on Three Lost Hills, California Wells

		11/4/2004	11/8/2004	11/11/2004
SAM IP	Well #1	378	358	346
SAM IP	Well #2	300	291	288
SAM IP	Well #3	518	568	537
SAM IP	Total	1196	1217	1171
Test Production		1207	1232	1192
% Difference		-0.9%	-1.2%	-1.8%



a)



b)

Figure 1 - Net Stroke Determination in RPC for a) The Surface Card, and b) The Pump Card (IP method)

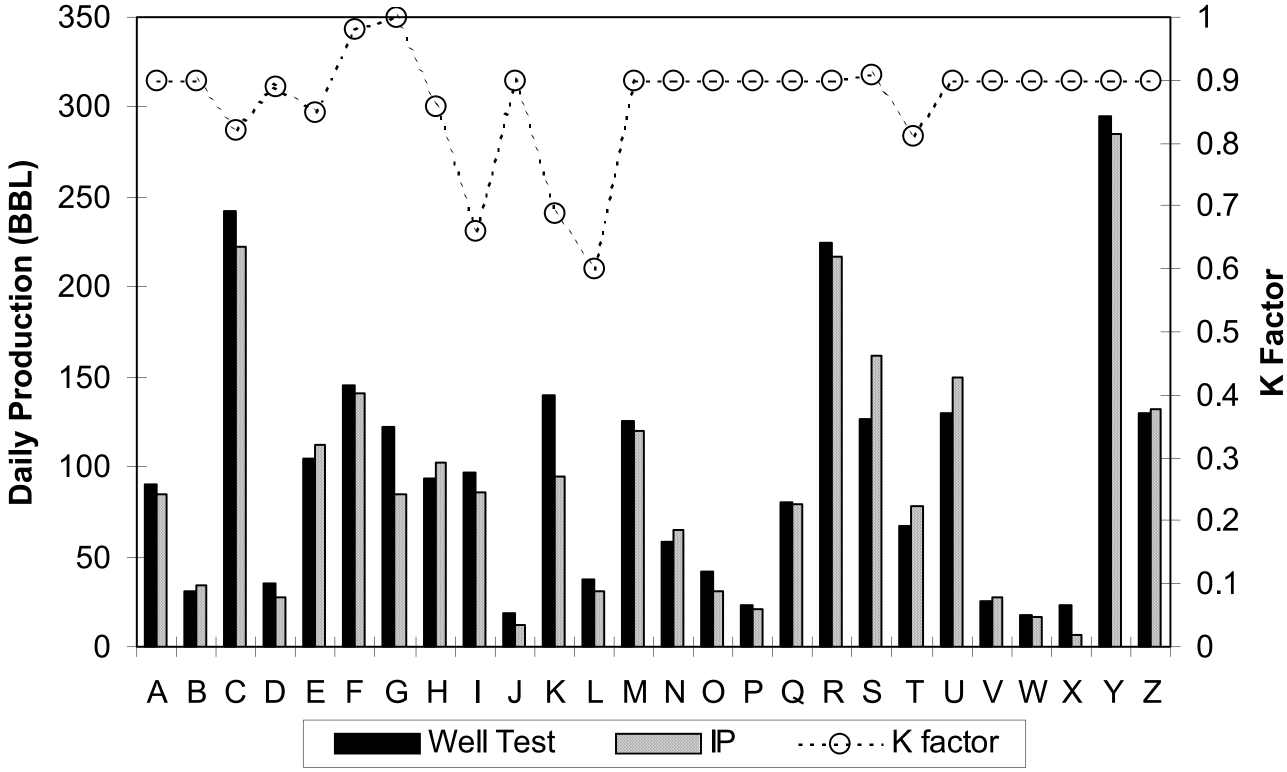


Figure 2 - Well Test Comparison to IP for 26 Permian Basin Wells

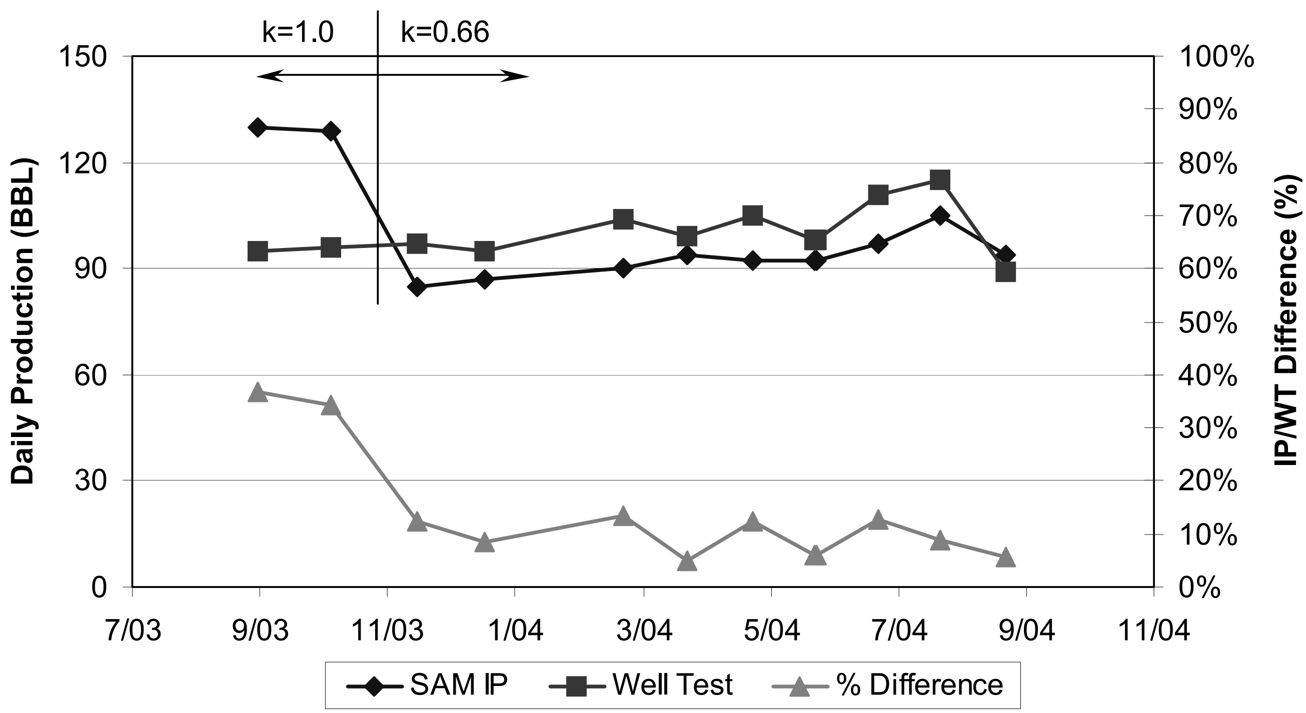


Figure 3 - IP and Well Test Tracking on Well I

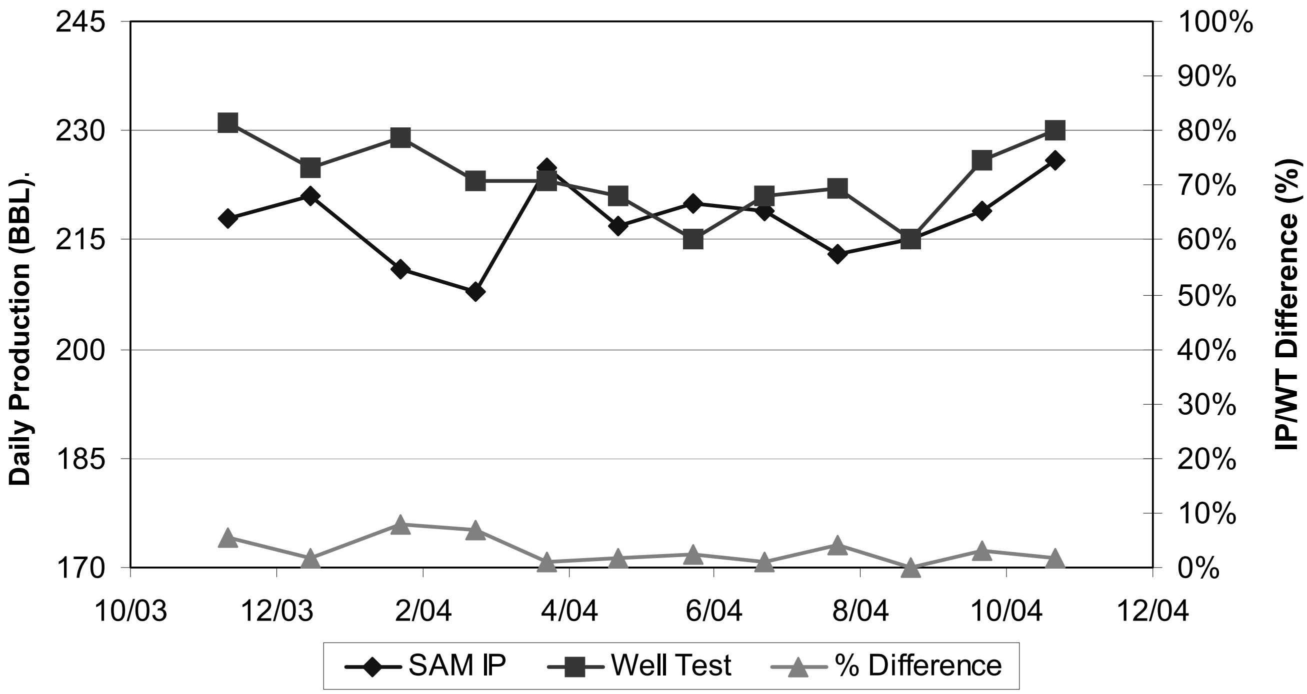


Figure 4 - IP and Well Test Tracking on Well R

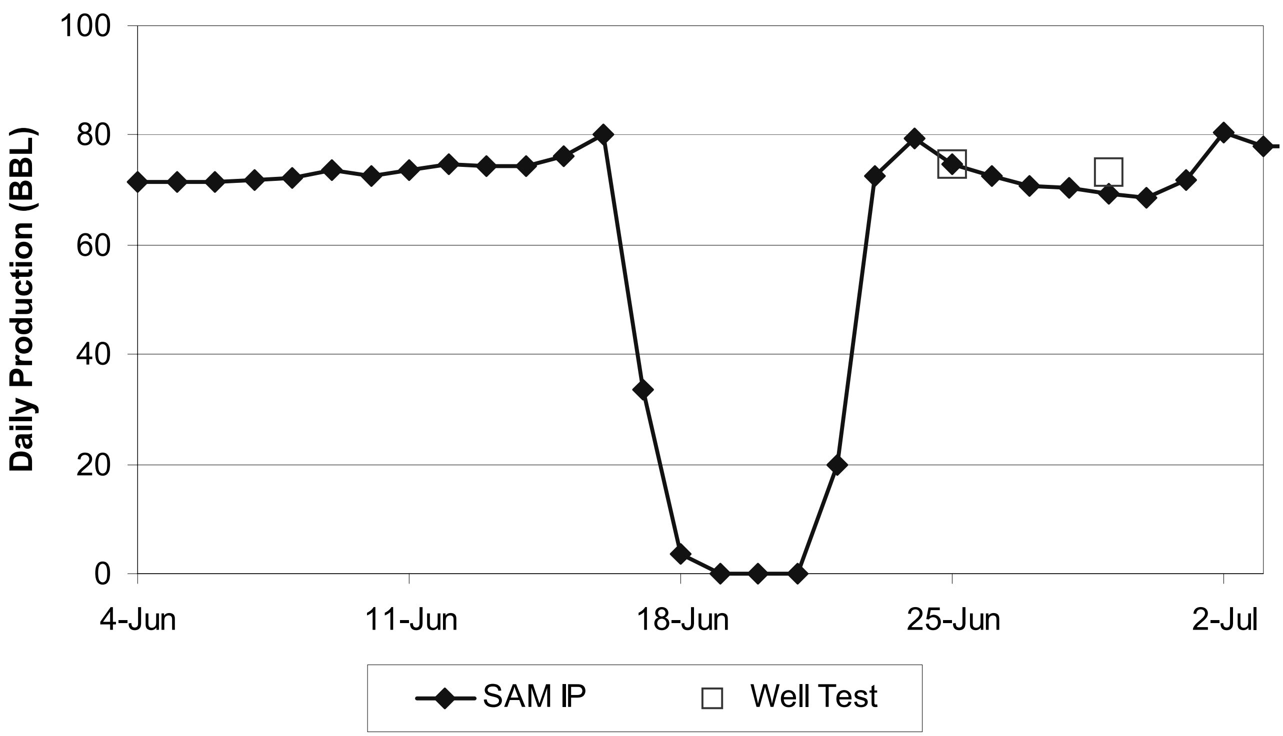


Figure 5 - Daily IP Over One Month Period Compared with Two Well Tests on a Permian Basin Well

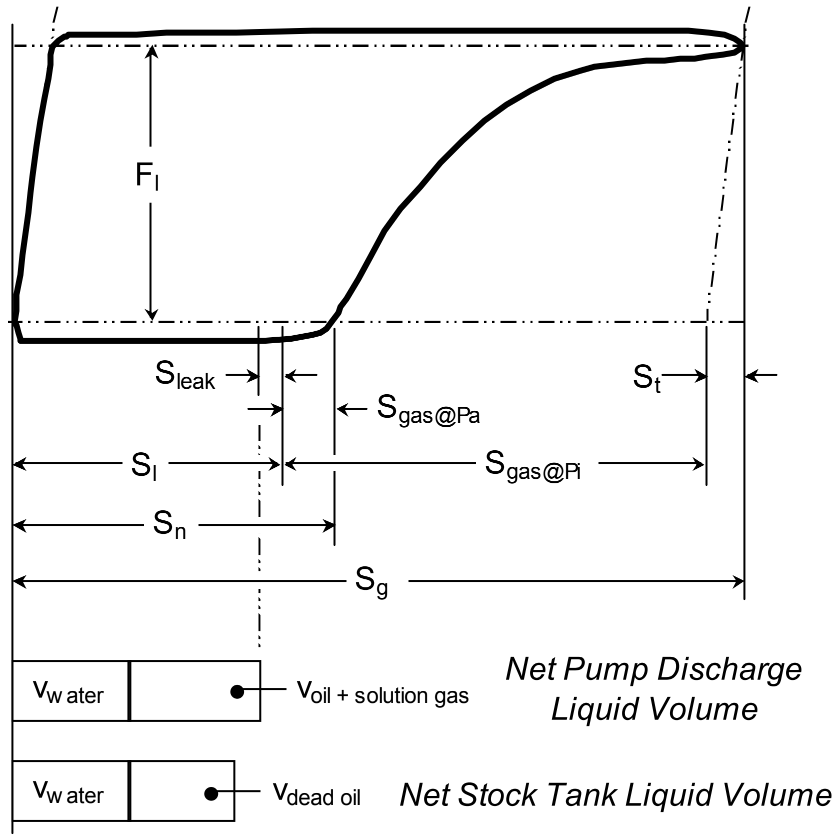


Figure 6 - Pump Card Illustrating SAM Well Test Concept

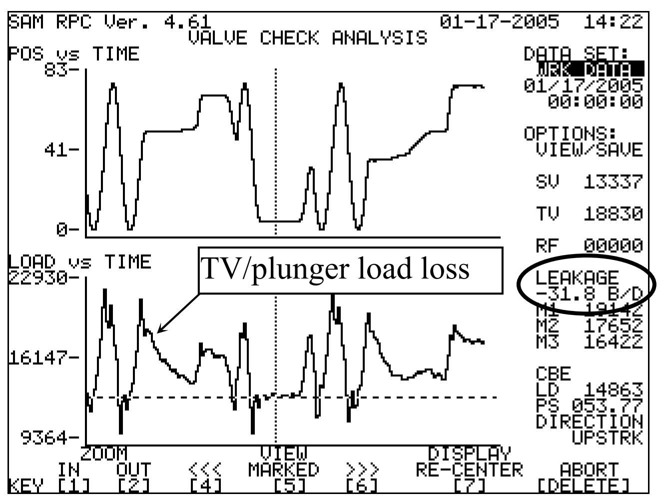


Figure 7 - Pump Leakage Calculation From On-Site Valve Checks (TV Load Loss Method)

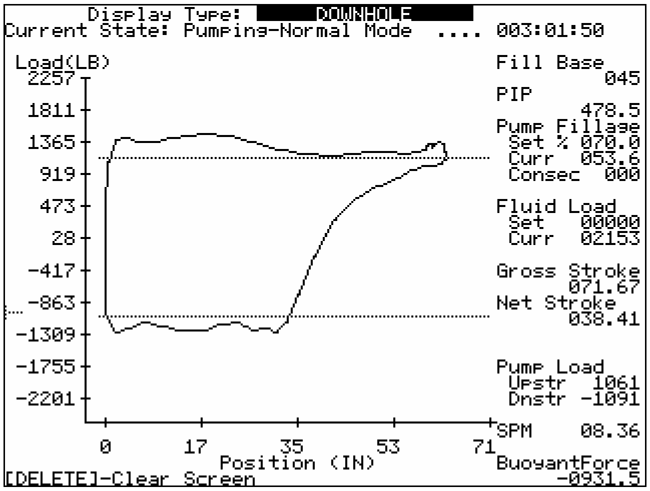


Figure 8 - SWT Pump Card Showing Fluid Load Lines

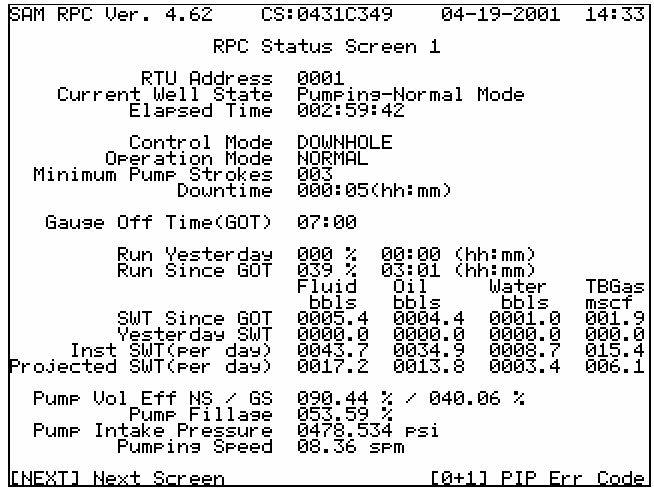


Figure 9 - SWT Status Screen

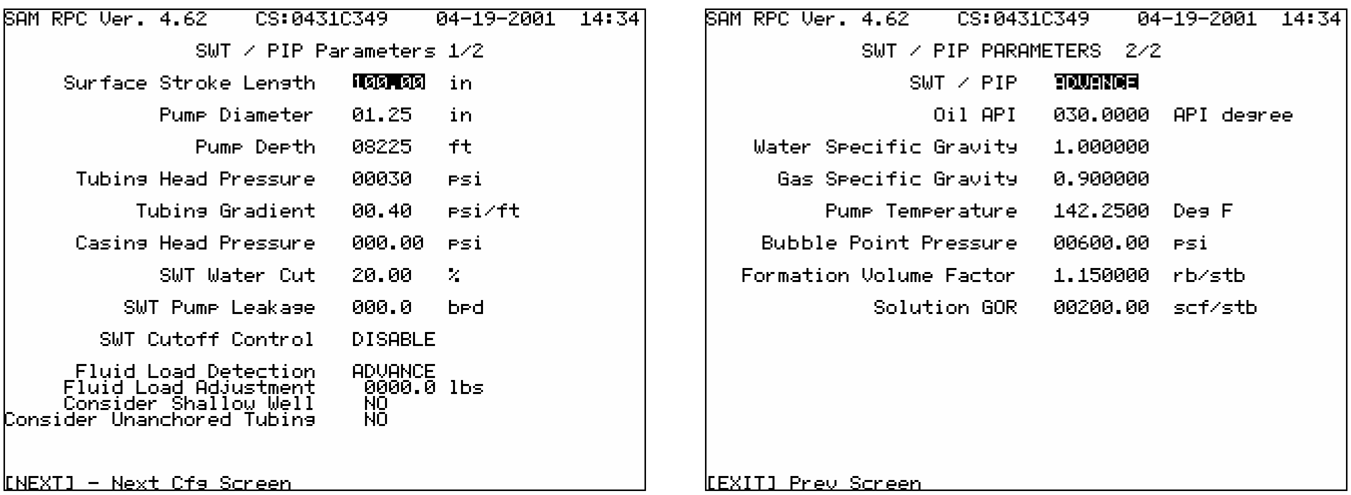


Figure 10 - SWT Configuration Screens