IADC/SPE 39400

Early Kick Detection Through Liquid Level Monitoring in the Wellbore

J.J. Schubert, SPE, Texas A&M University, and J.C. Wright, SPE, Conoco, Inc

Abstract

Through the years many tools have been developed to detect kicks in their early stages, when they can be handled more easily and safely. However, most of these tools are dependent upon the well being full of fluid with the liquid at the surface. When drilling wells where there are severe lost circulation problems (e.g., no returns to the surface) many of the major kick detection tools do not function properly since the liquid level may be hundreds or thousands of feet below the surface. During tripping operations, the major kick indicator is measurement of the volume of drilling fluid required to “fill” the hole to replace the volume of steel removed. If the annulus cannot be filled, again due severe losses to the open formation, measurement of the fluid pumped into the annulus does not give meaningful information as to formation fluid influx until the influx is great enough to begin to unload the annulus.

This paper proposes the use of an acoustic device installed on the casing valve to continuously monitor the liquid level in the annulus of wells experiencing complete loss of returns. A rise in liquid level can be interpreted as an early indication of a kick during drilling or tripping operations. The liquid level can also be used to determine the correct volume of fluid to pump into the well while tripping out of the hole.

This paper presents the results of tests run using common acoustic tools to monitor the liquid level in the wellbore of an Austin Chalk re-entry. Results of these tests show that the liquid level can be accurately monitored during complete lost returns so that kicks can be detected early during drilling or tripping operations.

Introduction

An unexpected influx of hydrocarbons into the wellbore while conducting drilling operations represents serious hazards. If these gas kicks are not handled properly, the very dangerous situation of a blowout becomes a definite possibility, resulting in the possible loss of hydrocarbons, environmental damage, loss of equipment and loss of life. Even when the kick is handled property, time and efficiency are inevitably lost.

Proper circulation of the gas kick from the wellbore is not the only concern. The pressures experienced during the subsequent kill operation should never become so large that the formation strength is exceeded and the formation fractures. To minimize casing pressures, early kick detection, and shut-in are imperitive. If the well is allowed to continue flowing, a larger pit gain will obviously occur due to larger amounts of low density formation fluids displacing the higher density drilling fluids. The influx of low density formation fluids will lower the hydrostatic pressure exerted by the mud column in the annulus, and require a higher casing pressure to prevent any additional influx.

Common kick detection systems in use today include pit gain or differential flow measurements. Pit gains or losses are most often measured by floats located in the rigs mud pits. These floats generally have recorders and alarms to monitor any unusual gains or losses in surface mud volumes. These gains or losses can signify either a kick or lost circulation respectively. Schafer, et.al.[1] provided an evaluation of various flowmeters currently being used as kick detection tools. Inflow meters discussed were mud pump stroke counter, pump rotary speed transducer, magnetic flowmeter, and a Doppler flowmeter. Outflow meters discussed were the conventional paddlemeter located in the mud return line, a commercial acoustic level meter, and a rolling float meter. The major drawback of the pit level measuring device, and most of the flowmeters is the requirement of mud circulation during drilling operations.

Codazzi, et.al.[2]. and Stokka et.al.[3] reported on acoustic devices which rely on the increase of sonic propagation time observed when gas is in the wellbore. Codazzi’s method uses pressure pulses from the mud pumps to supply the sonic pressure waves required, while Stokka’s “Gas Kick Warner” generates a pressure pulses at the standpipe. These pressure pulses travels down the drillstring, through the bit, and up the annulus to the surface where it is detected by pressure transducers located on the bell nipple a few feet below the flowline. The main principle is that possible free gas may be detected by measuring the pulse travel time. These systems claim to detect all free gas in the system, normally being in the annulus.

Both of these methods work on sound principles and have been thoroughly tested; however, they both rely on mud circulation. This means that they cannot be applied during drilling operations with complete lost returns or while tripping pipe. Possibly, the best early kick detection system would involve using one of the systems mentioned above along with a liquid level measurement package.

Bang, et.al.[4,5] discuss the use of wellhead sonar for early detection of gas kicks. This method does not rely on pressures produced at the standpipe, but at the wellhead on the annulus side. Pressure pulses are sent down the mud column in the annulus, reflected of the bottom of the hole, and the travel time from generation at the wellhead to detection of the reflection back to the surface by pressure transducers. Since pressure pulses are not generated at the standpipe, mud circulation is not required, and the equipment can be utilized during tripping operations. The equipment described by Bang is similar to an echo-sounder device, however, they do not discuss the use of this device for kick detection when the wellbore is not full of drilling fluid such as when experiencing severe lost returns. All of the other kick detection devices require at least the ability to circulate, or stated another way, the hole must be full of drilling fluid.

This paper describes an acoustic kick detection system that operates without circulation, and without the requirement of the annulus being full of drilling fluid. Commercially available acoustical well sounders or wellhead sonar has been routinely used for years, primarily as an aid in analyzing well performance of normal pressure oil producers. Fluid levels in the wellbore were determined by generating a pressure pulse at the surface-directed down the wellbore-and recording the echoes from the collars and ultimately any liquid level existing in the wellbore. (**Fig.1**) A microphone wellhead attachment converts the pulses, reflected by collars, liquid or other obstructions, into electrical signals which are amplified, filtered, and recorded on a strip of paper. [6-7]

Digital signal processing and the availability of small lap-top computers have resulted in significant advances and improvements in acoustic well sounding. Echo-sounders[8-9] have been developed for use with a portable microcomputer and an integrated data acquisition package which allows real-time visualization of pumping well performance.[10] This system can process acoustic data digitally to obtain more accurate liquid level depths, automatically. In addition, the computer offers automatic operation of equipment in that the computer can be programmed to perform well soundings on command, without operator attention.[9]

An actual test using a commercially available acoustic sounder was conducted at a well in the Austin Chalk/Giddings field that was experiencing total lost returns. The purpose of the test was to determine the ease of set-up on existing wellbore equipment, affects of background drilling noise on the acoustic measurement, and relative consistency of the acoustic measurements conducted under different drilling operations.

This paper will also present how the information obtained by the equipment utilized in the test can be interpreted for early kick detection in wells experiencing complete loss of returns during both drilling and tripping operations.

Principle

Liquid level measurement through the use of acoustic waves is based on a very sound principle. An acoustic pulse generated at the surface travels through the wellbore. Any obstructions in the wellbore, i.e., casing collars or liquid, will cause reflections in the acoustic wave that can be detected at the surface. (**Fig. 1**)

Using the computer-based acoustic measurement system, data are recorded past the time liquid level detection is expected. The automatic selection of the liquid level reflection is undertaken by a pattern recognition scheme that involves the amplitude, polarity, width, and phase shift of the received signals. The software scans the digitized record and selects all the signals and the pattern requirements, then selects the most probable to present to the operator.[10] The advantage of the computer-based model is that it enables the operator to receive real-time information.

Description of the System

The Electronics Package. The acoustic liquid level measurement system used in this study consists of an electronic package that includes an IBM-compatible laptop computer, analog to digital converter, amplifying and conditioning circuits. This is connected to the wellhead assembly with interlocking cables. (**Fig. 2**)

The Acoustic Source and Detector. This wellhead assembly consists of a microphone, solenoid gas valve, pressure transducer, and volume chamber. If the casing pressure is less than 200 psig, an external gas supply is used to charge the volume chamber. C02 and Nitrogen are readily available and commonly used. (**Fig. 3**)

Signal Acquisition, Processing, and Recording. The electronics package is powered by a 12-volt, 100-amp hour, deep-discharge, marine/ car battery which also recharges the computer's self-contained battery. Operating life from one 12 volt battery averages about four days.

Transducers. A strain gauge pressure transducer provides a signal proportional to pressure. Direct connection to the wellhead is through a quick-connector so that the casinghead pressure can be monitored continuously throughout the test. A thermistor is mounted within the transducer housing to determine the current operating temperature and to introduce appropriate zero and sensitivity shift corrections.

Data Processing. The computer program has the multiple functions of controlling the well testing sequence, acquiring, storing and analyzing the data, and generating tabular and graphical outputs.

Presentation of Results. At any time during and/or after the test it is possible to obtain graphical or tabular presentation of the data and the calculated results. The type of presentation is selected from options in the data presentation menu.[6] For our analysis, the following apply:

Casinghead Pressure vs. Time
Liquid Level vs. Time
Transducer Temperature vs. Time
Acoustic Time vs. Time

Rig Facility and Experimental Setup

Since in the majority of these applications the system will operate in a noisy environment, the remote-fire gun should be installed as directly as possible to the wellbore with the shortest section of full bore pipe available. Installation should consider the pressure rating of the gun, which is typically 1500 psi, in relation to the pressure rating of the rest of the installation. Connection to the wellbore should be through a full opening shut-off valve so that the gun can be removed from the well at any time if it becomes necessary to service it during the test and pressure is present in the wellbore. When using the remote-fire gun, the well analyzer can be located several hundred feet from the wellhead. The preferred gas source is a nitrogen bottle with sufficient volume and pressure to last for the estimated duration of the tests.[11]

System Setup. Since the program is designed to be used for liquid level monitoring in open hole as well as in closed wellbores with very variable wellbore configurations it calculates the depth to the fluid level from the pulse travel time and acoustic velocity of the wellbore gas. The DE program determines the correct acoustic velocity prior to initiation of the liquid tracking tests. The special processing features of this program are used in conjunction with known depth markers to calibrate the acoustic velocity for the particular installation. The velocity is then input to the LT program during the set-up procedure.[11]

The acoustic liquid level measurement system was a relatively easy installation. The remote fire gun was connected to the wellbore through the B-section of the wellhead. (**Figs. 4-5**) The casing valve provided a full-opening shut off valve that could isolate the remote fire gun from wellbore pressures in case of the need for removal of the unit for servicing. The compact unit was easily mounted to the B-section using a hammer union. The well analyzer was connected to the remote fire gun using the interlocking cables. (**Fig. 60**). The total installation time was less than 10 minutes and, importantly, required no down time for the drilling rig.

Operation. After the connections to the remote-fire gun and the gas supply are made, the system is checked using the DE program. The position of the fluid level is identified and the travel time is recorded for future reference as well as the acoustic velocity to be used for subsequent tests. The liquid tracking program is executed by typing LT at the DOS prompt from the Echo directory. This will bring up a display which gives the user the option of starting a new test or recalling old data to review.

The principle parameters for data acquisition include:

Acquisition time. This is the length of time during which acoustic data will be acquired. It is a function of the depth to the fluid level and acoustic velocity. It is determined from the liquid level measurement taken with the DE program during the set up.

Mute time. This is the time interval during which the software will not try to identify the liquid level signal. it starts when the shot is fired and stops after the time interval entered. It is used to eliminate the possibility of selecting signals from other reflectors that are located up the hole.

Acoustic velocity. The velocity of sound in the well gas, in ft/sec. Determined from prior measurements using the DE program, or estimated. It is used to convert the time to liquid to a depth to liquid.

Shot frequency. The time interval between measurements, in minutes.

Liquid specific gravity. The average specific gravity (water = 1.0) of the liquid in the wellbore. It is used in computing the pressure at the depth of the pressure datum.

Pressure datum. The depth, in feet, from the surface to the point where the pressure is calculated.

After entering the data, the program is ready to acquire data. After leaving the screen by striking the ESC key, the program will start by pressing any key. The well analyzer initiates the firing sequence and continues at the rate indicated by the shot frequency. A graphical presentation of the data shows the liquid level vs. time. Program execution is terminated by striking the ESC key.[11]

Setting of Alarm Limits. It is possible to set alarm limits so that if the fluid level is not within a specified depth interval an alarm will be displayed on the screen with an audible signal. In addition, a solid-state relay will be closed to provide an external control to additional alarms.[11]

Discussion of Results

A short-duration test was conducted at a drilling location in the Austin Chalk/Giddings field. The Austin Chalk is a carbonate formation. With little to no porosity, production from the formation is through vertical fractures and vugs. The area where the re-entry well is located has been previously developed by vertical wellbores. The fractures previously developed have fracture gradients less than the hydrostatic head of the fresh water in the wellbore. The well in which our test was run was one such re-entry.

Since the test was of short duration, many factors affecting the system have not yet been determined. Extended experimentation of the acoustic system is recommended before implementation. Factors not researched include the effects of an influx, gas or liquid, on the liquid column and the possibility of determining the type of influx based on the effect on the liquid column. Also, the test was not conducted during tripping operations, a time in which statistics show that as many blowouts occur as when drilling.

The short-duration test did show, however, that the system functioned extremely well during the different drilling situations that occurred during liquid level shots. Based on these positive results, further experimentation should yield an early kick detection system that will increase the efficiency and safety of drilling operations under severe lost circulation conditions.

During the course of the test, we determined the liquid level in the wellbore several thousand feet below the surface. Liquid level measurements were taken during different drilling situations.

The first liquid level shot was taken while the drillstring was rotating and mud pumps were circulating fluid downhole. From the recorded acoustic signals during this shot, (**Fig. 7**) it is evident that background noise was recorded; however, the conditioning circuits filtered these recordings, thereby diminishing the effects on the liquid level measurement. It should also be noted that while the drillstring was being rotated, we could not accurately identify the external upsets on the drillpipe. In this case, we cannot determine the depth by counting the external upsets of the drillpipe above the liquid level and calculating the exact depth on basis of the average joint length. The acoustic liquid level measurement program allows for the calculation of depth of the liquid level based on acoustic velocity. For this case, we estimated an acoustic velocity based upon the composition of the gases in the wellbore. Since the exact composition of the wellbore gases is not known, an assumption must be made which may lead to some error. Liquid level of 2752 ft below the surface was recorded.

The next liquid level shot was conducted while the drillstring was stationary and mud pumps were circulating fluid downhole. Since the drillstring was stationary, we counted the number of tool joints to the fluid level and then calculated the depth of the liquid level based on the average length of each joint. This liquid level measurement was then compared to the measurement determined through acoustic velocity. (**Fig. 8**) This comparison allows for a calibration of the acoustic velocity for more accurate liquid level measurements. Liquid level on this shot was calculated to be 2722.2 from the surface.

The following liquid level shot (**Fig. 9**) was recorded while the drillstring was stationary and mud pumps were not circulating. The background noise recorded during this shot was virtually nonexistent. The liquid level of 2728.5 ft was easily determined by average tool joint length and acoustic velocity.

A second shot was recorded approximately five minutes later to determine the drop in the fluid level in the wellbore. (**Figs. 9-10**) The data show that the fluid level had dropped significantly (2728.5 ft to 2751.5 ft from the surface) between the two liquid level shots. This is thought to be due to transient effects as fluid movement in the annulus due to cessation of mud circulation.

After a short shut-in period, normal drilling operations were then continued while the acoustic system ran in automatic mode, conducting liquid level shots at two minute time intervals. The program then displayed the liquid levels on a graph of liquid level depth versus time, (**Fig. 11**) allowing real-time visualization of the liquid level in the wellbore. Not enough shots were taken while shut-in to determine a static liquid level, however Fig. 8 shows the liquid level had dropped to approximately 3080 ft below the surface. As circulation was resumed, three more shots were taken, indicating a rise in fluid level to approximately 3025 ft from the surface. At this time the small bottle of nitrogen being used was emptied, and a static circulating level was not reached. The rising level during the automatic mode is again believed to be due to transient effects in the fracture near the wellbore.

As stated earlier in the discussion, background noise associated with the rotating pipe had negligible effects on the liquid level measurement.

Field Applications

Although a full scale test using this echo-sounder device was not conducted, the results presented here leave little doubt that this type of system could aid immensely in the early detection of kicks in drilling wells while experiencing total lost returns. During drilling operations, circulation and rotation can be stopped, and several shots taken to determine the static liquid level. Using the driller's drillpipe tally, and the number of tool joints detected by reflection, an accurate fluid level can be determined. From this data acoustic velocity in the wellbore gasses can be calculated for use when noise due to pipe rotation precludes depth measurements based on average joint length of drillpipe.

With the equipment in automatic mode, circulation and drilling can be commenced, and a "steady state" circulating level can be determined. An influx of formation fluid will result in an increase in fluid velocity in the annulus, causing another transient period similar to when the circulation was started after a brief shut-in period. (**Fig. 11**) The increased in annular fluid velocity due to the influx should cause a measurable rise in the annulus fluid level. Alarms on the equipment can be set to notify the drilling crew of such a rising fluid level, allowing prompt action to be taken to properly handle the kick.

Using conventional kick detection methods discussed previously, this kick may go undetected until the influx volume is so large that mud returns are seen at the surface. On the well on which this equipment was tested, the influx volume would have had to be large enough to raise the mud level approximately 2700 ft. This large influx could be enough to result in loss of control of the well.

During normal tripping operations, it is standard procedure to fill the hole with drilling fluid as the drillstring is removed from the well. The volume of fluid to fill the hole should be equal to the volume of steel removed. When the volume to fill the hole is too small, a kick is indicated, and when the volume is too large, loss of fluid to the formation is indicated.

For many wells where total loss of returns is occurring, the hole cannot be filled to the top, and a kick during tripping operations will go undetected until mud is being unloaded from the well. What is often done in situations where total lost returns occurs, is to pump the calculated displacement of the drillpipe plus some arbitrary volume to replace the mud lost to the formation. For a well like this, the echo-sounding device tested in this paper can be utilized in kick detection.

A “static” level can be measured or an optimal level can be determined. As the drillstring is being withdrawn from the wellbore the distance the fluid level has dropped can be measured with the echo-sounder, and a volume based on this drop in fluid level can be pumped into the well. This method will result in lower chance of an undetected kick, and also more efficiently determine the proper volume to pump into the wellbore to replace the steel being withdrawn plus the volume of mud being lost to the formation.

Conclusions

We were able to conclude that the system set-up was very simple. The time required to install the remote fire gun to the existing wellbore was less than five minutes and involved only one connection. The entire system was operational in less than ten minutes.

The test enabled us to determine the background noise from pipe rotation and the mud pumps had negligible affects on the acoustic measurement. The system also functioned extremely well under different situations.

Early kick detection by monitoring the liquid level in the wellbore during tripping or drilling operations without circulation or returns to surface can be effective using this system. With this ability, drilling operations will continue with increased effectiveness and safety in concern of well control.

Because of the short duration of the test, we would recommend further testing and analysis before implementation. Under a more strict environment, we would like to determine the accuracy of the liquid level measurement and the effects of an influx into the liquid column.

Acknowledgments

The authors would like to express our gratitude to Mr. Dieter Becker, Echometer Co., for allowing us to use their equipment to test our idea, and for his help in setting up the equipment and interpreting the results. We would also like to thank Mr. Jim Stanley, Union Pacific Resources, for allowing us to install the equipment on one of their wells.

References

1.Schafer, D.M., Loeppke, G.E., Glowka, D.A., Scott, D.D., and Wright, E.K.: "An Evaluation of Flowmeters for the Detection of Kicks and Lost Circulation During Drilling," IADC/SPE 23935, Presented at the LADC/SPE Drilling Conference, New Orleans, Louisiana, February, 1992.

2.Codazzi, D., Till, PK., Starkey, A.A., Lenamond, C.P., and Monaghan, B.J.: "Rapid and Reliable Gas Influx Detection," IADC/SPE 23936, Presented at the LADC/SPE Drilling Conference, New Orleans, Louisiana, February, 1992.

3.Stokka, S., Anderson, J.0., Freyer, J., and Welde, J.: "Gas Kick Warner - An Early Gas Influx Detection Method," SPE/LA-DC 25713, Presented at the SPE/LA-DC Drilling Conference, Amsterdam, February 23-25, 1993.

4.Bang, J., Mjaaland, S., Solstad, A., Hendriks, P., and Jensen, L.K.: "Acoustic Gas Kick Detection With Wellhead Sonar," SPE 28317, Presented at the SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, September 25-28, 1994.

5.Bang, J., Mjaaland, S., Jensen, L.K., and Hendriks, P.: "Brief: Acoustic Gas-Kick Detection With Wellhead Sonar," SPE 30072, *JPT* (Feb 1995) 111-112.

6.McCoy, J.N., Podio, A.L., and Becker, D.: 'Pressure Transient Digital Data Acquisition and Analysis From Acoustic Echometric Surveys in Pumping Wells," SPE 23980, Presented at the SPE Permian basin Oil and Gas Recovery Conference, Midland, Texas, March 18-20, 1992.

7.Weeks, S.G., Podio, A.L., and McCoy, J.N.: 'Fluid-Level Determinations Through Internal Flush Tubing Without Depth, Temperature, or Pressure Limitations," SPE 12912, Presented at the SPE Rocky Mountain Regional Meeting, Casper, Wyoming, May 21-23, 1984.

8.McCoy, J.N., and Podio, A.L.: "Well Performance Visualization and Analysis," SPE 20126, Presented at the SPE Permian Basin Oil and Gas Recovery Conference, Midland, Texas, March 8-9, 1990.

9.Podio, A.L., McCoy, J.N., and Becker, D.: "Integrated Well Perforrnance and Analysis," SPE 24060, Presented at the SPE Western Regional Meeting, Bakersfield, Califoniia, March 30-April 1, 1992

10.Podio, A.L.: “Computerized Well Analysis," SPE 21174, Presented at the SPE Latin American Petroleum Engineering Conference, Rio de Jeneiro, October 14-19, 1990.

11. "Liquid Level Tracking Program (LT) Operation Manual," Echometer Co., Witchita Falls, TX (January 1997).

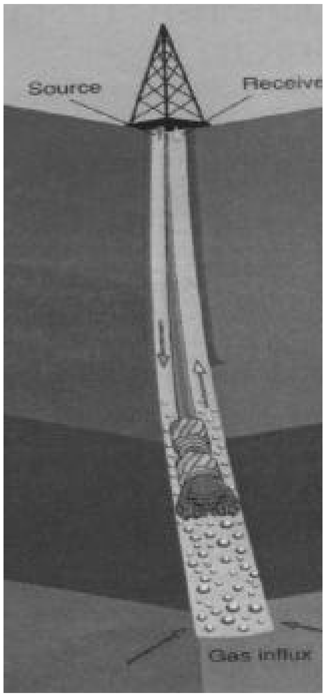

Fig. 1-Principal of acoustic liquid level measurement

Fig. 2-Electronics package

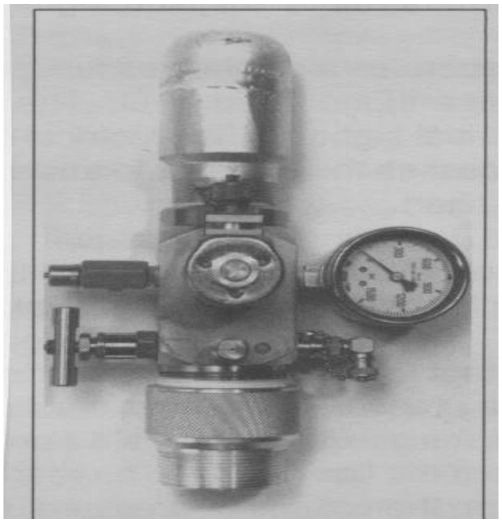

Fig. 3-Acoustic source and detector

Fig. 4-Remote-fire gun connected to wellhead.

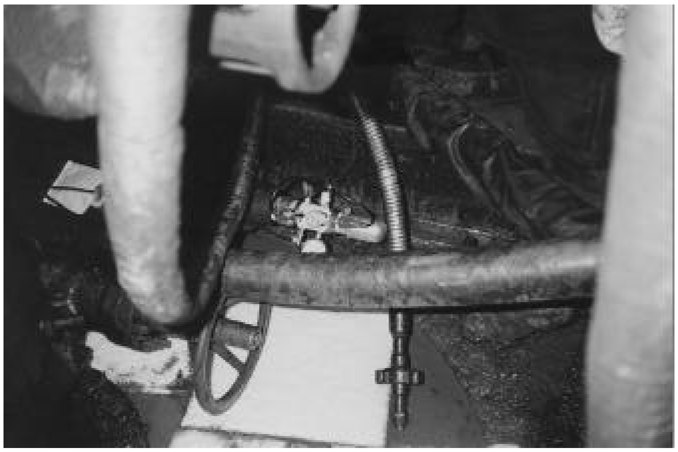

Fig. 5-Remote-fire gun connected to wellhead.

Fig. 6-Well Analyzer location during field test.

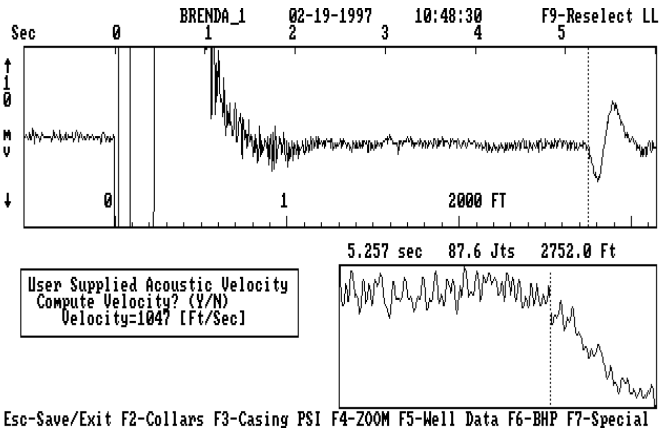

Fig. 7-Liuid level recording of acoustic shot performed while rotating pipe and mud pumps were circulating fluid downhole.

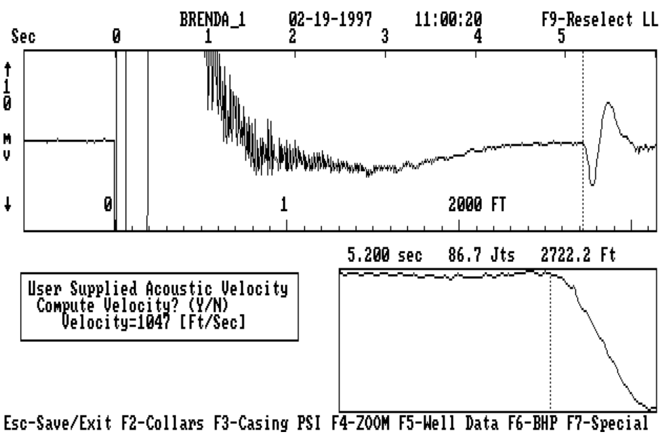

Fig. 8-Liquid level recording of acoustic shot performed while drillstring was stationary and mud pumps were circulating fluid downhole.

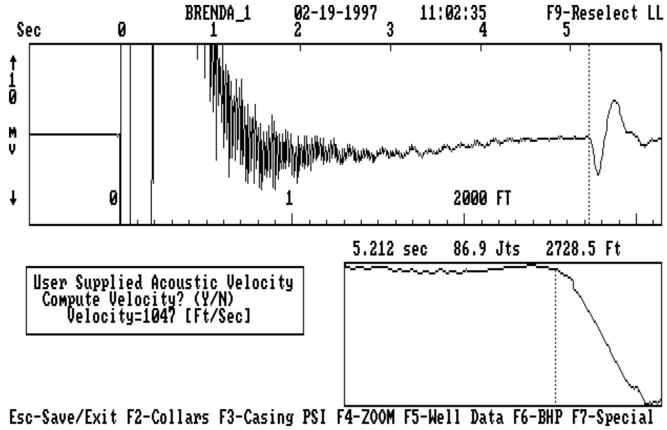

Fig. 9-Liquid level recording of acoustic shot performed while drillstring was stationary and fluid was not being circulated downhole.

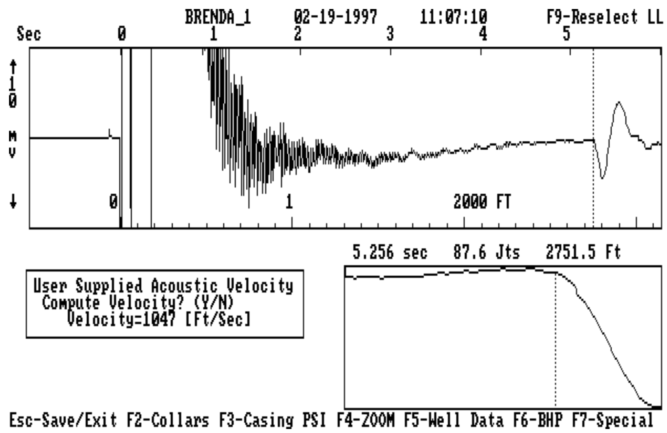

Fig. 10-Liquid level recording of acoustic shop performed approximately five minutes after shot illustrated in Fig. 8

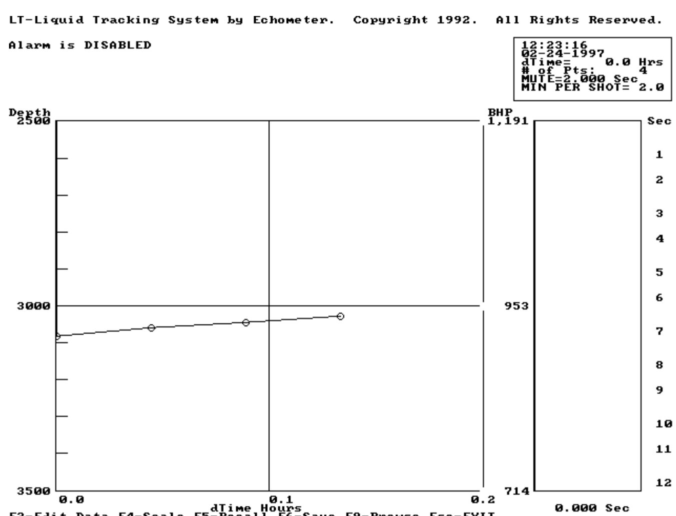

Fig. 11-Example liquid level tracking program, which displays liquid level depth vs. time.