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Emission-Free Sampling and Well Testing System

Arild Fosså, Halliburton Energy Services, Inc.

Abstract

The emission-free sampling and well-testing system discussed in this paper is one of the first systems available to the oil industry that can meet current environmental regulations as well as provide fluid samples and pressure transient data.

This system can provide PVT samples, bulk samples, initial reservoir pressure, permeability, skin, solids identification, and flowing and static bottomhole temperatures. These data will allow accurate assessment of a formation so that the most efficient production strategies can be put into place.

In addition to the emission free capabilities of the system, it will also provide a reduction in operating expense for oilfield operators.

The new system meets the four requirements determined by a joint industry project that are considered critical to satisfying current formation evaluation needs. Additionally, the system meets other criteria that are considered desirable. These include:

- Real-time data collection
- Limited rate control
- Collection of single phase samples.

This system has been designed as a multi-component tubing-conveyed, cased-hole system for liquid reservoirs and in addition to cost efficient assessment of formations, meets the current industry directives for environmental protection.

Introduction

Since the last half of the 90’s, the oil industry worldwide has noted increased stringency in regulatory standards to protect the environment. During this time frame, the industry has also seen an era of greater volatility in oil prices.

These changes have required greater focus on activities targeted at increasing environmental safety as well as those that can promise a reduction in operating expense. While all segments of the industry have felt the trends, well testing has been particularly affected. This fact has been evidenced in the Gulf of Mexico and the North Sea by the fact that fewer “in depth” well tests are being run. Instead, less accurate methods to obtain fluid samples and other reservoir data have been employed. Unfortunately, decisions for developing the fields have been based on data generated by these less accurate methods that have not provided the accuracy necessary for making efficient production decisions.

To comply with the changing trends in the oilfield and investigate methods that could provide greater well testing efficiency, several international oil companies initiated a joint project to determine the criteria needed in a test system to meet the two primary drivers — environmental protection and cost efficiency. Four features were considered critical in a well testing system. These were:

1. Representative reservoir fluid samples (PVT quality and 1-20 bbl bulk)
2. Near wellbore reservoir parameters
3. Productivity potential
4. Fluids and solids identification.

In addition, a list of non-critical but desirable features was also developed. These features were real-time data collection, rate control, limits testing, sanding potential, rigless testing capability, single-phase samples, and multi-phase measurement.

An emission-free sampling and well testing system was developed to meet the four critical components and some of the non-critical features.

The new system is tubing-deployed and was developed as a cased-hole, closed-chamber test system for use in liquid, and in certain situations, gas condensate wells.

The system consists of annulus-pressure-operated tools and a perforating system. PVT samples are taken with acoustically triggered single-phase samplers, while the bulk fluid sample is taken in the string with a closed, variable-sized sample chamber. The system features two-way command and control communication to surface with acoustical signals. It can perform a simple well test based on the analyzing technique for short drawdown, long-buildup pressure data.

Industry Drivers

As stated earlier, the principal industry drivers in today’s oilfield strategies for formation evaluation are 1) more stringent environmental regulations, and 2) reduced operating expense. By attaining these needs, the advantages of improved return on investment (ROI), reduced operating expense, improved asset-utilization, improved personnel safety, and reduced risks to the environment will result. These environmental risks particularly target flaring practices. **Fig. 1** is a photo of a typical offshore flaring operation.

The regulatory agencies have not been the only driving force in the attainment of more restrictive environmental regulations; the oil companies have also been drivers.

An example of this is shown by the recent directive put in place by oilfield operators concerning flaring. Several companies have initiated review of the processes that require flaring. Before these processes can be employed, internal justifications must prove that the planned flaring operation to gain information about a well or field will outweigh the increased costs, safety liability and potential environmental damage associated with flaring a well.

Other companies have decided to suspend flaring altogether. One company has mandated that it will cease flaring of liquid by 2001 and gas by 2005, while another company uses internal CO_2 quota trading between projects to reduce emissions.

On the government side, taxation or outright bans on flaring of liquids, gases or both in combination with other emission restrictions are the methods employed to reduce harmful flaring.

Norway and Denmark charge CO_2 taxes based on the amount of hydrocarbons burned. In other areas, countries have increased permit costs if flaring while testing takes place. In parts of the Caspian Sea, there is a ban on any discharge to sea, while the Middle East is heading in the same direction as California, banning all flaring if possible.

During the time frame in which the above direction has taken place, the oil companies and the industry in general has had to weather a substantial lowering of oil prices. This has intensified the industry's need for more efficient operation and cost cutting. This pressure has not eased although oil prices have now recovered.

Improved ROI achieved by faster decision making, reducing OPEX, and improving efficiency in asset use efficiency are some of the methods now being employed in the fight for operational strategies that can increase profit margins. This has been manifested by the interest operators have shown in any technology that promises to cut rig-time, reduce financial risk in field development, and shorten the time between data gathering and decision making.

The industry also has demonstrated the desire to improve personnel safety. Although the industry as a whole has already achieved a lost-time incident rate that is less than industry average for any given country,[1] it continues to pursue improvements in this area.

During the last decade, although emphasis has been placed on reduced financial, environmental and personnel exposure risk, the industry has still experienced increased costs. The question is — *Why*?

Unforeseen Operational Problems

The increase in expense has occurred because of development decisions that have been made on insufficient test data. Thus, environmental penalties, and clean-up charges that were not anticipated have occurred. Cost related to these events can be a significant factor in increasing operational economics.

Governments worldwide now realize the extent of the problem, and the consensus is that the oil industry must develop and produce a non-renewable resource. Authorities such as the Norwegian Petroleum Directorate are pushing harder and harder for developing and producing resources in the most efficient manner. In addition, most international oil companies are also emphasizing this need since this will improve their reserves and their profits by adding production and improving field life. The steadily increasing reserve depletion efficiency seen in the North Sea fields is an example of this. New technologies such as enhanced production resulting from microbiologically induced surface tension reduction in combination with more traditional water and gas injection methods are showing an improved ratio between total reserves in place and producible reserves in place. Twenty years ago, a good field would yield approximately 35% of the initial reserves in place; now, however, the industry is targeting a 70 to 90% depletion of the initial reserves. To plan advanced methods properly, accurate data and a better understanding of the reservoirs are essential. This will provide an important answer to the question of how bottom-line figures can be improved.

Industry Conflicts

The second industry conflict concerns the environment. More stringent environmental regulations such as zero emissions, no flaring of oil, no discharges to sea, CO_2 tax and other environmental considerations are forcing the oil industry away from traditional well-testing and formation-evaluation techniques. This increases the financial risk to the industry, and over time, could result in less efficient resource utilization. Reliance on testing methods that might not provide accuracy in data collection has been pushed by the industry's drive for improved environmental performance and cost cutting on an operational level.

The alternative but less accurate reservoir evaluation methods have given certain short-term benefits to the industry. The operational efficiency has improved because less time-consuming methods to evaluate the field prospects have been used. In addition, the personnel and environmental safety records have been improved due to the exposing of fewer personnel to uncertain well conditions and testing of the wells with processes that draw less fluid from the reservoirs. There are some immediate financial benefits gained since the cost of the alternative evaluation methods is normally less than a full-scale traditional well test, and the technical requirements to the rigs are less. The speed of decision making has also improved since less data to evaluate is gathered, and the equipment for these tests has been improved. Although these methods have yielded some improvements in the short-term earnings of the oil industry, the long-term downside is that the oil industry as a whole is exposing itself to higher and higher risks because the generated data often do not allow accurate assessment of the reservoir.

The ultimate challenge to the industry, therefore, is to find an answer to the question of how industry drivers can be merged in a coherent approach to formation evaluation. The conflicts between various drivers need to be minimized or completely removed so that overall financial benefits can be maximized.

During the last five years, these conflicts have required the well-testing service providers as well as the operators to rethink their operational strategies.

Industry Requirements

In 1998, operator, government, and service company representatives met in Ballater, Scotland for a workshop to begin investigating methods to develop new formation evaluation tools. This workshop, sponsored by the Well Testing Network, focused on a range of issues from more efficient burners, limited entry testing, wireline formation testers, and environmental concerns. The overriding outcome of this meeting was the need for testing systems that could eliminate or considerably minimize flaring. A subsequent meeting was held in 1999, but primarily built upon the results of the first meeting. As a result of these meetings, a joint-industry project generated by six major oil companies requested that three service companies provide proposals on how they could develop alternative testing systems.

During the initial design stage for the system, a comprehensive survey of industry requirements for such a system was undertaken. This resulted in two sets of system criteria — critical and desirable. These needs are identified below:

<u>Absolute needs</u>

- Representative reservoir fluid samples, needed in two forms:
  1) Small sample collected under flowing reservoir conditions suitable for PVT analysis
  2) Large sample of 1 to 20 bbl (depending on customer preference) for refining studies.
- Near wellbore reservoir parameters, which include:
  1) Initial reservoir pressure,
  2) Static and dynamic bottomhole temperature
  3) Permeability
  4) Skin
- Productivity potential
  1) Estimates of possible production rates from a well
- Fluids and solids identification
  1) A determination of the presence of hydrocarbons, the presence of water (connate or filtrate) and the type of solids present. If solids are recovered, a sieve analysis should be provided

<u>Desirable needs</u>

- Real-time data collection
- Rate control
- Limits testing
- Assessment of sanding potential
- Testing without a rig
- Single phase samples
- Multi-phase measurement

With this basic information along with logging and seismic data, most customers would have the majority of the information required to decide whether or not to proceed with further development of the well or field.

History of Available Systems and Development of New System

As a short-term solution, Halliburton elected to re-develop their “Perforate, Test and Sample” system. In the late 1980s, this system was introduced in the Gulf of Mexico and was a system that perforated, tested and sampled the formation. Known as the PTS system, it had been designed for operating companies that wished to obtain data similar to that obtained with wireline formation testers but recovered in PVT style and bulk reservoir fluid samples.

Through the PTS System development, techniques for sizing junk and surge chambers, formation analysis for surge testing and demonstration of the use of the technique in unconsolidated formations was proven. The PTS system coupled with formation analysis techniques, provided representative information about the reservoir, particularly for oil producers.

Formation analysis of a PTS System test would typically provide initial formation pressure, formation permeability, skin and the fluid-flow pattern within the formation. Production rates were calculated during the limited flow periods, and material recovered from the junk chamber was used for solids analysis.

However, the PTS System had several limitations: 1) surface readout was not incorporated; 2) surface indication of equipment operation was not available; and 3) flow control and sampling methods were somewhat limited although able to provide representative data.

The analyzing technique used in conjunction with the PTS system has been used for years and is well documented.[2,3,4,5,6,7]

Description of the New System

The PTS System was used as the basis for the new system, which is a tubing-string-mounted, multi-component testing system. It includes at least one retrievable packer, tubing-conveyed guns with a firing system, a single-shot surge valve, and a multi-cycle surge valve with circulating capabilities, a telemetry system, single-phase samplers, electronic memory recorders, a mechanism for isolating bulk samples, flow vents, a downhole choke, and an auto-fill valve. A configuration of the system is shown in **Fig. 2.** The system consists of three surge chambers that perform different functions. The initial surge chamber below the tubing conveyed perforation guns is used to remove the mud from the annular volume below the packer to the bottom shot of the TCP guns and to provide a clean up of the formation.

The second or main surge chamber provides the main pressure transient data used for the near wellbore data analysis. In addition, this chamber contains a flow-measurement device capable of giving flow-rate estimates.

The third variable-size chamber uses the piping to surface as the chamber. This chamber can be used as a dual purpose chamber and can gather a large bulk sample and provide additional pressure transients that can be analyzed.

Below the main surge chamber, single-phase samplers have been included for PVT sampling purposes. In addition, an acoustic telemetry system capable of bi-directional communication has been included to provide surface read-out and command-and-control capabilities. The single-phase samplers can be activated by this acoustic telemetry system and can communicate back to surface. In addition, several other alternative methods for sampler activation have been included in the system. The new system can also be run in memory mode without the surface read-out capability.

The philosophy behind system development was to use existing, proven technology wherever possible to create a new system with the highest possible operational reliability.

Operation

The system operates as follows:

1. The assembly is run to the desired depth on tubing, and the retrievable packer is set. (Additional packers, either retrievable or drillable may be run when necessary for isolating a zone of interest.) An auto-fill valve allows the string to fill while it is being run in the hole. (**Fig. 3)**
2. Annulus pressure is used to fire tubing-conveyed guns and to open top and bottom flow vents. A first surge is taken into a chamber that is sized to hold any initial solids production or perforating debris, and after a 5 to 6 minute delay, this surge is continued up against the bottom of the Lower Surge/Circulating valve. Downhole electronic memory recorders are used to record pressure and temperature information from the second phase of the initial flow and pressure build-up, and wireless telemetry transmits the recorded information to surface. (**Figs. 4 and 5**)
3. Annulus pressure is used to move the bottom surge/circulating valve into the well test position. The well test position permits a controlled flow into the next chamber for the second flow and pressure build-up. The pressure and temperature information from the second flow and pressure build-up are recorded using the downhole electronic memory recorders, and the information is transmitted to surface by wireless telemetry. (**Fig. 6**)
4. Annulus pressure is applied to open the upper surge valve. Opening this valve allows a controlled flow of the large-volume fluid sample into the tubing. The produced fluid is segregated from tubing fluid. If a third flow and pressure build-up period is desired, it can be done at this time with a surface closure. (**Fig. 7)**
5. During the flow of the large-volume fluid sample; telemetry activated, string-mounted, isobaric samplers are used to take PVT samples.
6. Annulus pressure is used to cycle the bottom surge/circulating valve to the circulating position, and the large-volume fluid sample is reverse circulated to surface. (**Fig. 8**)
7. The tubing string is retrieved, returning to surface for recovery of the PVT samples and electronic gauge data.

Technical Data Summary

The new system has been designed as a 15,000-psi system for cased-hole oil wells. The data the system yields are summarized in **Table 1**.

The pressure transient analysis technique that is used yields the following main near wellbore results:

- Flow regime
- Formation permeability
- Skin factor
- Initial reservoir pressure.

A new suite of cased-hole tubing-string mounted equipment has been designed to streamline the closed-chamber, well-testing method. To facilitate the system's sampling capability, new activation devices for the single-phase samplers have been designed.

One of the significant aspects of the new system is that it can be used as a non-flaring system if the bulk sample is small enough to allow transfer straight to a closed transport container. If the bulk sample should be larger, then a small amount of cold vented gas will be emitted.

In addition, the system uses equipment for surface pressure control and has a multitude of options.

The options include the possibility for real-time transfer of data to the client with direct load-up to analyzing software. This feature has been designed to enable better decision-making and enable the reservoir engineers to reduce the length of the test when the test objectives have been reached, thus reducing operating expense. A qualitative ranking of formation evaluation methods available today is shown in **Fig. 9**, and a complete comparison of the capabilities of the new system with those indicated by the industry as requirements and desirable attributes for a testing system can be seen in **Table 2.**

Conclusions

This new formation evaluation system provides a safe, reliable, and effective reservoir-fluid sampling and testing technique that can completely eliminate emissions in most cases[8] and significantly reduce the emissions in the remaining cases. The system does not require any flaring.

In addition to improved well-site safety, the system reduces overall well testing costs as the crew size compared to normal drill-stem testing is reduced. The system also reduces the amount of hydrocarbon at surface and offers improved control of processes.

While it is a new product, the techniques and equipment used in its development have been well proven in the industry.

The analyzing techniques used to interpret the pressure transient data[2,3,4,5,6,7] are well proven and provide an accurate method for obtaining near well-bore formation data.

Many of the hardware components in the system are based on modifications of existing tools that have a long history of durability and reliability in the challenging environment of well testing.

The system meets the four main requirements given by the industry, and some of the additional requirements.

As can be seen in Fig. 8, the method employed fills the gap between the various openhole logging methods of obtaining reservoir and fluid information and the more traditional cased-hole well tests.

This new method meets modern industry "Mission Statements"[9] that call for shortening decision-making time and the industry need to pursue a real-time-operations mode.

Nomenclature

CO_2 = carbon dioxide
DST = drill stem test
k = permeability, mD
LTI = Lost Time Incidents
OPEX = operating expenditures
P_I = initial reservoir pressure
PVT = pressure, volume, temperature
PTS = perforate, test, and sample
RDT = reservoir description tool
s = wellbore skin

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9 "Halliburton Energy Services. Inc. Mission Statement," November 1999.

Table 1- Technical summary

Technical Summary	
Pressure Rating:	15,000 psi for entire system except the Auto-Fil Valve 10,000 psi for Auto-Fil Valve
Temperature Rating:	330°F (Limited by acoustic system)
Service:	NACE MR-01-75 above 175°F
Data Transfer:	Near Real Time (data batches every 2 minutes) from downhole Real Time satellite or data link to other locations
Data Back-up:	Memory (up to 800,000 data points per pressure recorder)
Control:	Real-time acoustic telemetry control of each of the Single Phase Samplers with confirmation from bottom hole to surface. Annulus Pressure control of tools and firing heads
Area of use:	Oil reservoirs
Deliverables:	600 cc PVT samples (single phase) 1 to 20 bbl bulk fluid sample Formation solids sample Pressure and Temperature data in ASCII format Analysis reports (optional)

Table 2- Features vs. requirements comparison

“Must have” client Requirements	FasTest™ System covers:	Comments
Small Volume PVT Sample	X	3 ea. 600 cc samplers
1-20 bbl Bulk Sample	X	Maximum determined by tubing string size
Near wellbore reservoir parameters (Pi, S, k, T)	X	Initial Pressure, Skin, Permeability, Temp.
Productivity potential	X	Flow rate from down-hole choke estimates
Fluids and solids identification	X	Content of “junk” chamber and samples
Additional Desirable, but not necessary features		
Real-time data collection	X	With ATS™ system in the string
Rate control	(X)	Limited, various choke sizes can be installed
Limits testing		Not possible with FasTest™ system
Assessment of sanding potential	(X)	Limited, amount of solids, plus drawdown gives indication
Testing without a rig		Not possible with current FasTest™ system
Isobaric / isothermal samples	X	Single Phase samplers and heated bottles
Multi-phase measurement		Not possible with FasTest™ system

Fig. 1 - Photo of a typical offshore flaring operation.

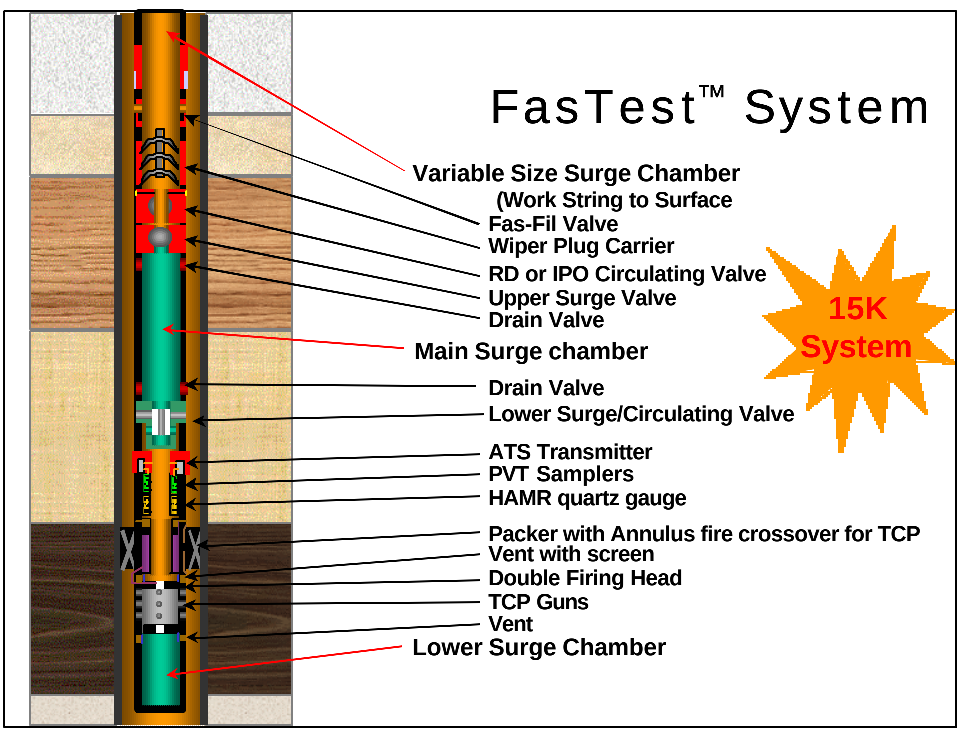

Fig. 2 - Configuration of the system.

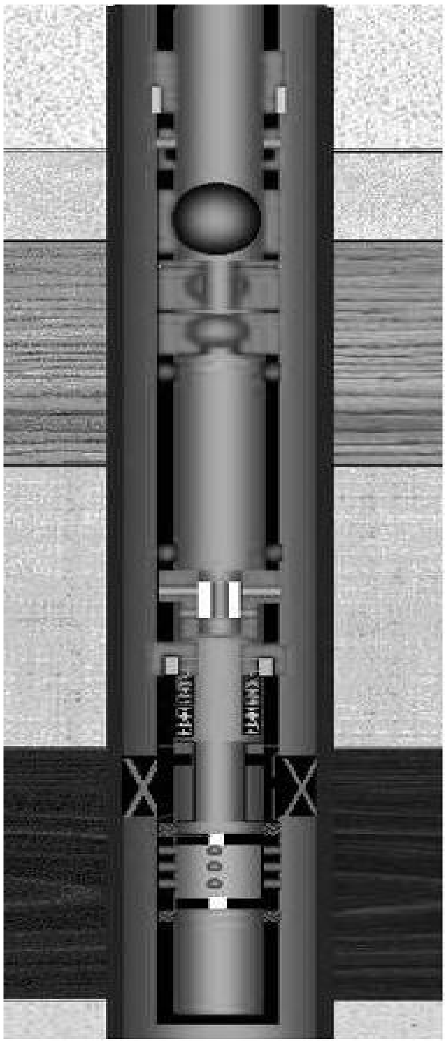

Fig. 3 — Annulus pressure is applied to activate the firing head and open top and bottom flow vents, allowing junk and mud to go to the lower chamber.

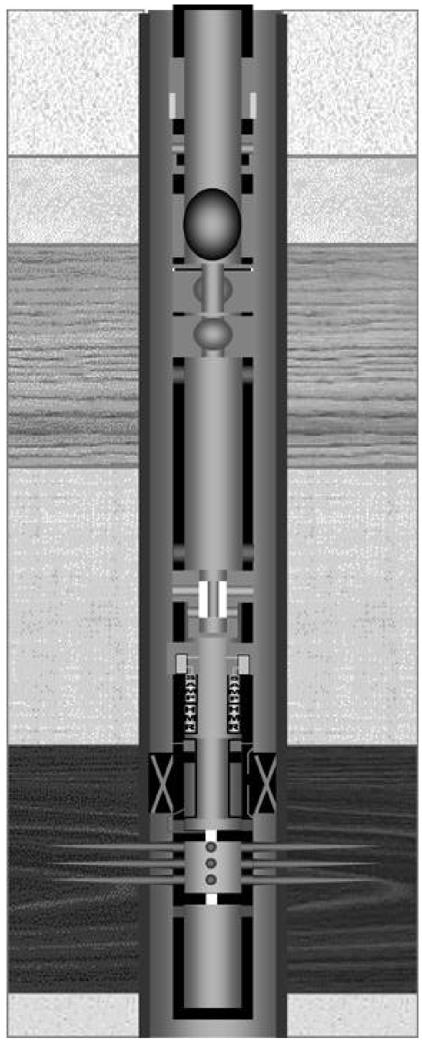

Fig. 4 — Perforating.

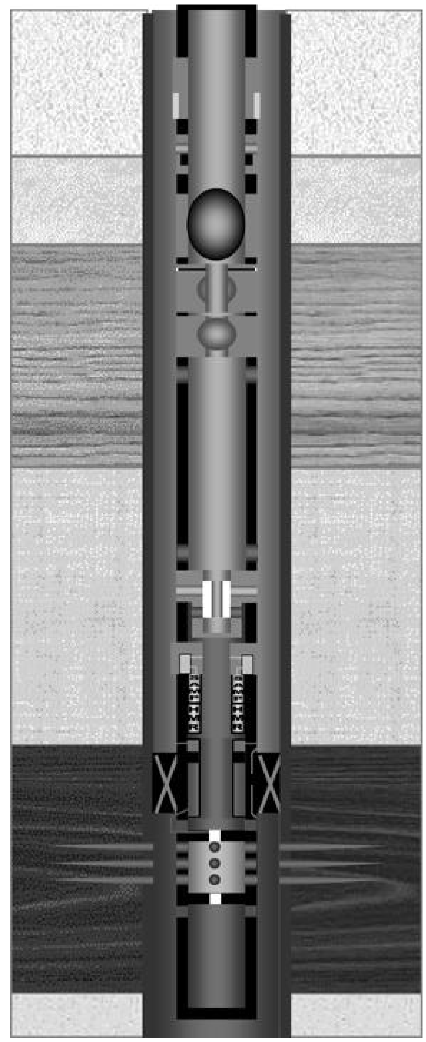

Fig. 5 — Starting Initial surge and pressure build-up period.

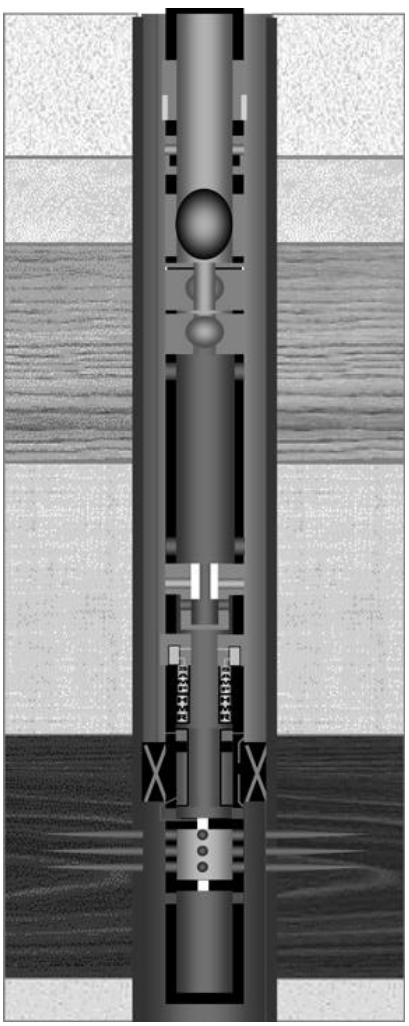

Fig. 6 — Annulus pressure is reapplied to shift the lower surge/circulating valve to the well test position, starting the second surge and shut in period .

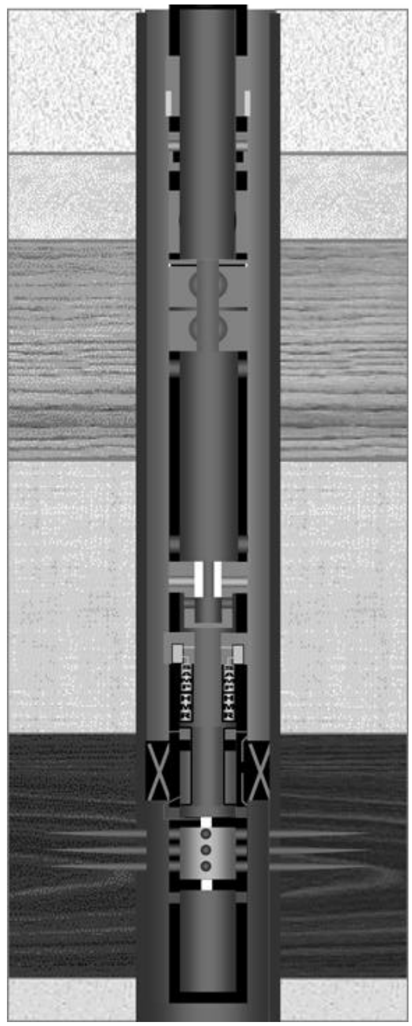

Fig. 7 — Annulus pressure is reapplied to open the upper surge valve, starting the third surge/flow period. Well is circulated, and a large volume sample is recovered at surface.

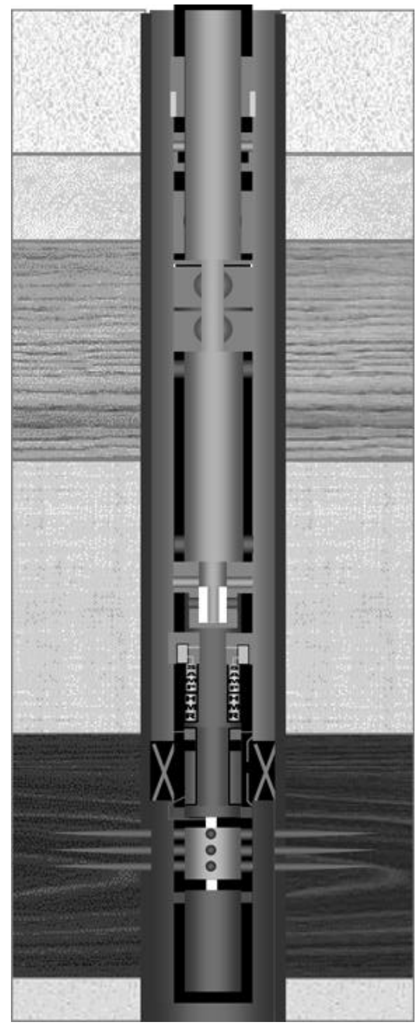

Fig. 8 — Circulating the well.

Qualitative ranking of Formation Evaluation methods

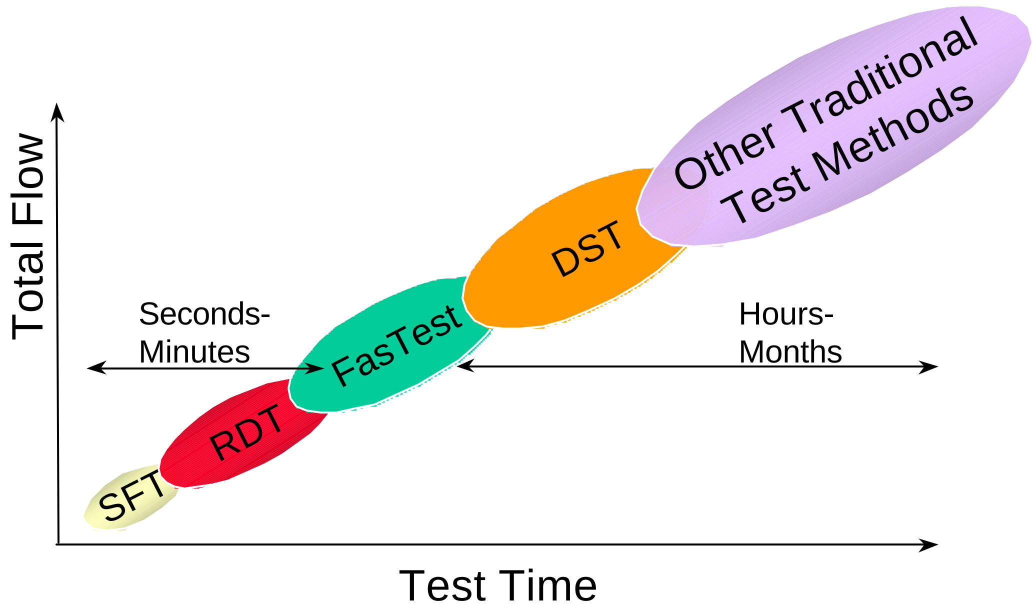

Fig. 9 — Emission free sampling and testing method in relation to other methods.