7 WELL INSTRUMENTATION

The presence of sand in heavy oil apparently does not cause difficulties with any properly designed conventional instruments because there is no abrasion or blocking that takes place (obviously, this will not apply to gas wells or high rate oil wells). However, the complex nature of the produced heavy oil slurry makes interpretation of many types of measurements more difficult. In the CHOPS industry to date, instrumentation has deliberately been kept simple, direct, and inexpensive because of the traditionally narrow profit margins in heavy oil exploitation.

7.1 Downhole Measurements

7.1.1 BHP Gauges

Downhole pressure gauges (Figure 6.5) are more frequently being mounted outside the tubing in the annular space, where they do not come into direct contact with sand. These gauges measure the level of fluid in the annulus as well as the pressure just above the PC pump in the production tubing. These BHP measurements, brought to surface through a shielded carrier, can be used to reduce risk and optimize production.

The fluid level in the annulus is directly measured using the annulus pressure. This electronic input can be used to control the pump speed to maintain the desired fluid back-pressure on the well and eliminate the chances of surface gas breakthrough to the pump. The tubing pressure can be used as well to detect blockages that on rare occasions may suddenly develop within the tubing. For example, if the “steady-state” range of fluid (sand-oil-water-gas) density in the tubing averages 1.1 g/cm^3 at a depth of 600 m, the static tubing pressure should be 6.5 MPa. A maximum operating pressure limit, say 8.0 MPa at the pump outlet, can be programmed into an alarm system to notify the operator, and a level of perhaps 9.5 MPa could result in immediate pump shut down to avoid torquing off the rotor or drive rods.

For BHP devices that require direct fluid contact, the orifice that is necessary to connect the gauge to the slurry inside the tubing appears not to plug, even though the amount of sand can be substantial. It is also possible to use devices that are immune to plugging. Thus, no significant difficulty arises in bottom hole pressure (BHP) or temperature measurements in CHOPS wells, even if the sand contents are high and the behavior strongly nonlinear (non-linearity of the slurry should not affect most measurements).

7.1.2 Other Downhole Measurements

Vibration instrumentation using accelerometers was installed in four wells in Morgan Field (1999) on the bottom of PC pumps, 0.5 m below the tailpipe base, coupled to the casing with belly springs, and connected to the surface with a cable, allowing continuous measurement of the acoustic emissions from both the formation and from the pump. There were no operational problems with these instruments as a result of fluid characteristics, sand erosion or sand impingement. Failures in instrumentation on two wells was linked to leakage of the data cable rather than because of operating problems.

The small triaxial accelerometers now available give a continuous readout of the vibration level on three separate orthogonal axes at rates ~10,000 16-bit samples per second per channel. Because of the huge data rate (more than 60,000 bytes per second), sophisticated on-line, continuous surface analysis is required. (e.g. a dedicated Pentium IV computer that provides continuous spectral analysis, data quality control assessment, and a number of other functions).[50] Vibrational information in averaged form may allow direct assessment of the condition of the PC-pump, helping with early identification of problems (symptom or precursor detection algorithms), or direct measurement of gas slugging from the formation into the well, and other factors.

An advantage of the accelerometer installation is its possible co-use as a method of monitoring formation response as stick-slip shearing events take place in the inter-well region. These wave trains can be detected and the pump vibrations filtered out. If three or more such systems are installed in a field, inter-well reservoir behavior may be deduced from focal point mapping combined with amplitude, spectral, and hodographic analyses. In the future, this may be a method of overcoming part of the uncertainty about the nature of the processes in the reservoir remote from the wellbore.

[50] The huge quantities of data are not stored: rather, averages over various time intervals of the relevant parameters are continuously calculated and stored, giving data storage requirements of less than 0.01% of the data rate.

With modern instruments, there appear to be few limits to the sensors that can be installed (densimeters, chemical state probes, water content probes…), but installation of these at hole bottom seems to have no major advantages at this time.

7.2 Surface Monitoring Equipment

Direct measurements of surface pressures, torque, temperature and so on are straightforward, and are being increasingly used to manage PC pumping systems. Many companies collect other information at the surface, such as densimeter readings, which are used in a semi-quantitative manner to evaluate production behavior.

The requirement to keep track of production for economic and conservation purposes[51] means that the volumes of oil produced must be measured with reasonable accuracy. PC pump rates, densimeters, stocktank measurements and other near-wellhead devices have not proved sufficiently accurate. Even the simple task of determining fluid levels and sand levels in stocktanks has not been fully automated. This is partly because of climate problems (water freezes in static level tubes, oil becomes almost solid at -30°C), but the simultaneous presence of sand, gas, emulsion, viscous oil and water has repeatedly confounded attempts to meter tank levels with reasonable precision at all times. The reasons are not associated with sand abrasion or sand blocking orifices or flow tubes, but with viscosity and the presence of many different phases.

7.2.1 Fluid Production Metering

The fluid being drawn into the PC pumps is a complex compressible mixture, and the efficiency of a particular pump is never known precisely; therefore accurate volume tracking, even of total fluid produced, is not possible using the PC pump rotation speed alone. Combining a surface density measurement of total produced fluids, a bottom-hole tubing pressure measurement, and the PC pump rotation speed cannot solve this difficulty. The fluid entering the base of the PC

[51] Conservation authorities require monthly reports of oil and water production from each well for regulatory purposes, including setting of allowable production limits, equitable allocation of pipeline capacity, and so on. The EUB also wants gas-oil ratios to be reported if such data are determined. Sand quantity reporting on a per-well basis is not mandated. In theory, each producing company must file an audit on sand produced on a field-wide basis annually, but this is not enforced. Produced sand volumes are measured from truck tickets during tank cleaning, a method that is subject to errors of ~10%.

pump is highly compressible, and as the pressure builds-up with the lifting of the fluid, the gas compresses and is partly driven back into solution, the density changes, and there is fluid slip between the rising cavities. Since the gas cannot be driven into solution rapidly, the density at the outlet of the PC pump cannot be calculated, nor can the phase ratios be calculated from any set of density values and rate information. Fluid frictions in the tubing change because of changes in phase content (more sand = more friction), making downhole density measurements inaccurate indicators of phase volumes.

Measurements from direct flow meters or nuclear densimeters on the flowline, or any other flowline device for that matter, cannot be uniquely interpreted in terms of oil, water, gas and sand rates because the multiphase nature of the produced fluids require at least three independent measurements for the different phase volumes, or require some assumptions as to the ratios of phases. Assumptions of constant phase ratios in general are not valid; for example, in the surface flowlines there is 0 to 60% volumetric gas content, and the ratio may change on a minute-to-minute basis. The sand content may vary in a similar fashion.

Field calibration of densimeter readings using direct flowline sampling and phase analysis is contentious because of short-term fluctuations in sand, water and gas content that are observed at all time scales (chaotic behavior). Gas cannot immediately be separated from the liquid stream in CHOPS because the gas is present as evenly dispersed small bubbles along with occasional large bubbles. Also, because of the slow rate at which gas exsolves, no system can separate gas from the oil in "real time". Thus, the volumetric gas content of the produced fluids is not constant, and this makes field calibration of a gas sampling and separation system impossible.

A test separator can be used in conventional oil production to achieve reasonable and rapid segregation of the phases, or at least to calibrate a measurement system, but this cannot be used to calibrate instruments used in heavy oil production for the reasons mentioned above. Thus, because of the foamy nature of the gas and because of the long times required to achieve gas phase equilibrium after a change of pressure, gas content cannot be determined dynamically.

The difficulty of quantifying phase production rates in heavy oil can be clearly appreciated if a sample bottle is filled from a flow line. For example, a 250 cm^3 sample of produced slurry, placed in a liter bottle, may weigh only 150-200 gm because of entrained gas bubbles. It may swell to a volume of 400-600 cm^3 as the free gas bubbles expand and as the gas dissolved in the heavy oil phase slowly comes out of solution. The pressure in the bottle will rise substantially if it is kept sealed. After many hours, the sample volume will gradually decrease as gas bubbles coalesce, rise to the surface, and break. True gas-liquid equilibrium may not be reached for a day or two, depending on viscosity and temperature.

Because of this behavior, volumetric measurements taken at short time intervals on the flow lines are almost meaningless. Note that in the stocktank, because the temperature is raised to values of 60-80°C, time to equilibrium is reduced by more than an order of magnitude compared to separation at temperatures of 20-30°C.

There are basically two reasonably reliable methods of determining oil production: regular collection and analysis of samples from well flow lines (see below), and issuance of truck tickets at the batteries (see above). Most companies use the latter method for oil and water production rates, although once water and oil are clearly separated in stocktanks, the volumes can be metered fairly precisely. When tank trucks take oil from stocktanks, the oil withdrawn is metered with reasonable accuracy because there is no more gas in solution in the oil phase, but it is the battery truck tickets based on direct weighing that are honored for financial and resource management purposes.

For many years the heavy oil industry has searched for an automatic meter that can be placed on flow lines to accurately measure water content in produced fluids. Because of the similarity in the density of the oil and water (e.g. 0.95 and 1.02), the presence of free gas in the flow line, and varying quantities of sand, no technology has yet emerged that can be widely applied.

One technology called "Flo.Point" has some promise.[52] It is based on travel time of radio waves through the medium, but this technology is not widely used and its reliability is not yet known. This is an area where developments would be of substantial benefit, as metering the water content in the flow line to within 1-2% would allow well behavior to be more clearly understood, would allow "alarms" if sudden water influx occurs, and would permit more accurate tracking of phases.

There is ongoing research in many companies and research organizations to develop an automatic fluid measuring system at the surface that could measure sand, oil, water and gas contents continuously. For example, radio-frequency dielectric permittivity measurements determine water contents, and nuclear densimeters continuously record total bulk densities , but because there is an additional unknown in the equations of mass and volume, even if the densities of all the phases are stipulated, at least one other consistent measure is needed. Direct phase volume determination on line has been an elusive but enticing goal. This is an area to monitor, and this problem will likely be solved in the next decade.

7.2.2 Stocktank Measurements

Careful stocktank phase level measurements can probably achieve better than 95% accuracy (with adjustment for the amounts removed regularly by the oil tanker trucks), but stocktank levels are used only as rough estimates of total production rates (oil + water + sand), and as a means of managing the stocktank to avoid problems that might arise from sudden sand influxes. Typically, stocktanks are equipped with a total liquid level float connected through a pulley and a weight to an exterior scale, and ports are available on the sides of many tanks to withdraw fluid. A man-hole sized port at the top of the tank is used to determine sand and water levels manually.

On sites where oil production from more than one well is collected in a single stocktank, either the volumes produced are prorated empirically, using knowledge of well performance, or a test separator is used occasionally to give better quantification of the per-well rates.

The EUB in Alberta does not require a well on a single, dedicated stocktank to be tested with a separator, as the stocktank itself acts as a separator. However, if several wells are manifolded to a large produced fluids tank, each well must be placed on a test separator for 48 hours each month. This regulatory requirement is for resource management and royalty determinations. This requirement may be onerous in the case of heavy oil; in any case, the tanker truck tickets provide excellent production rate information for well and lease resource management. If the test separator time requirements were relaxed, more economies of scale could be achieved in materials management, using fewer stocktanks and more manifolded production. Operators have

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[52] ESI Environmental Services Inc., email: info@esica.com

enough incentives to collect the relevant well behavior data in order to make optimal decisions for well management.

7.3 Gas Sampling

Systematic determination of the gas/oil ratio (GOR) in the produced fluids from CHOPS wells provides important data that can be related to the behavior of the fluids in the formation. For example, if the GOR is rising, it is clear that gas is separating from the fluids and flowing to the wellbore more rapidly through a large and continuous gas phase. This is evidence of the generation of an interconnected gas phase in the far-field beyond the wellbore; a behavior commonly seen in conventional oil production as depletion occurs. In CHOPS wells, because of the foamy flow process and the extremely slow equilibration time, GOR values have been known to remain stable for years, indicating that a continuous gas phase is not being generated in the wellbore region or in the far field. As long as no continuous gas phase exists, gas expansion drive continues to be highly efficient. Changes in GOR can be used to help track the long-term behavior of wells and help decide optimum workover strategies.

The best way to measure gas content is to take bulk samples at the surface sampling port. The sample is allowed to achieve phase equilibrium before any attempt at measurement. Long delays are required to achieve equilibrium; thus "real time" monitoring for pumping optimization on the lease is not possible. However, in CHOPS wells, annulus production of gas occurs in all wells; it can be metered easily if desired with a gas flow meter. No CHOPS wells at present are metered in this way, yet the rate of gas evolution in the annulus against a constant pressure could be valuable to help manage pump strategy.

Other than a production test separator, which is either a dedicated site unit or a large truck-transported system used only occasionally on each CHOPS well, the only reliable and feasible way to determine GOR values systematically over time is to analyze samples taken from the flow line in vacuum sample bottles. The laboratory that performs the analysis must be prepared to cope with the particular difficulties associated with heavy oil. Specifically, the gas-liquid system must reach equilibrium before quantitative gas measurements are made, requiring more time as well as methods that are not used in conventional oil GOR measurements. For example, a diluent method may be used to allow the gas in the heavy oil to exsolve more rapidly; this may yield more satisfactory results than through conventional approaches.

An additional complication in many CHOPS wells is that the annulus produces appreciable quantities of gas, particularly under conditions of low drawdown. It is believed that this occurs because of partial phase separation in the near wellbore environment (Figure 7.1). The separation eventually leads to a gas "bubble" that intersects the uppermost perforation, at which point the gas enters the well annulus suddenly, giving high but temporary gas production from the annulus until the pressure is relieved. Also, if there is a low fluid level in the annulus, this gas can simply enter the PC pump and be produced until pressure is depleted and fluids can enter the intake again. Therefore, if highly accurate GOR values are needed, not only must samples be taken systematically from the flowline, but the annulus gas production rate must also be measured (PVT metered at the wellhead) and the data corrected for the additional annulus gas.

During the operation of a PC pump in a gassy heavy oil reservoir, it is not uncommon for the pump to suddenly produce large volume fractions of gas (gas slugging) for a short time until liquids once again dominate. This is also explained by the mechanism outlined above, where a gas bubble accumulates locally and is episodically relieved.

The chaotic behavior of sand is known, but the detailed behavior of the gas content in CHOPS production has apparently never been studied at the same time scale (at least, no such data have ever been published). Because of the nature of the gas in solution in the oil phase, it is expected that the GOR remains constant, and therefore that daily gas production will be a very close match to the daily oil production.[53]

Gas meters can also be placed on stocktanks to obtain time-averaged measurements of gas evolution. Combined with annulus gas measurements and known oil volume sales, these measurements can give reasonable values of GOR over time. These data would be valuable in helping understand CHOPS processes and individual well behavior.

The entire area of sampling and quantitative gas metering could be substantially improved at little extra cost, giving better data that would soon pay for itself in terms of better field management and workover decisions.

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[53] The solubility of CH_4 in H_2O is about 1/20th its solubility in oil; therefore the amount of gas in solution in the water phase can be neglected unless the well produces mainly water.

7.4 BS&W Measurements

Accurate measurements of basic sand and water (BS&W) produced in individual wells are valuable for well management and workover decisions: these are obtained by analyzing samples collected at the flowline. Although many companies do not measure gas contents or sand volumes systematically, there are relatively simple methods to obtain reasonably accurate data.

Sand tubes are used to determine sand volumetrically using weighed flow line samples. A small bulk sample from a 12 mm tap on the primary flow line is weighed. The sample is placed in a tube with a conical volume-calibrated bottom, a solvent is added, the tube is agitated, and then it is centrifuged (Figure 7.2). Clean sand accumulates at the bottom and its volume is read and recorded. The porosity in the sand tube is ~35-36%, compared to the *in situ* porosity in the reservoir of 28-32%; therefore a correction factor should be used if sand volume estimates collected this way are to be used for inference related to volumetric changes happening at depth.

Another approach to determine sand cuts systematically is to develop and execute a methodology that is based mainly on the determination of accurate weights:

- An accurately weighed sample of largely gas-free produced fluids is used. The total sample from the flow line must be used to ensure a representative measurement; the larger the sample, the more representative it is.
- The sample is mixed with solvent to leave clean sand in the bottom of the tube after centrifuging.
- The liquid is poured off, and the sand is dried and weighed. The weight fraction of produced solids is calculated directly as $w_s\% = (100 \cdot w_s)/w_t$.
- Because phase densities are generally extremely well known for a particular CHOPS well (i.e. the densities of produced sand, water, and dead oil are almost invariably stable over time) simple equations can be used to determine phase volumes without complex corrections.

The total weight and volume of the weighed gas-free sample are:

$$w_T = w_o + w_w + w_s$$

$$V_T = V_o + V_w + V_s = w_o/\rho_o + w_w/\rho_w + w_s/\rho_s$$

Since the total weight and the sand weight are known, either w_s or w_w has to be determined by another method. If the water/oil ratio of the well is relatively constant, it can also be roughly estimated with a solvent-sand tube. The sample is shaken with the solvent and centrifuged. The water separates and forms a distinct layer between the oil and the sand phases. Thus, the volume of the water can be directly determined for the sample, and a known water/oil ratio can be calculated. Then, the known phase densities can be used to back-calculate the volume of the oil, sand and water:

$V_{o+w} = w_{o+w} / \rho_{o+w}$, therefore

$V_T = V_{o+w} + w_s/\rho_s$

Other simple equations can be derived if more accurate BS&W values are needed in order to study CHOPS processes or to maintain a data bank that could help in deciding workover strategies when problems develop (lack of detailed BS&W history or gas/oil ratios over time seriously hampers diagnostic efforts when problems develop).

7.5 Risk, Chaotic Behavior, Sampling

7.5.1 Risk from Sanding

There are risks associated with sanding, despite the lack of erosion problems and the low gas contents and pressures in the heavy oil fields in the Heavy Oil Belt. For example, if a sudden influx of sand occurs, it can fill the stock tank prematurely or cause burn out of the fire tube. Furthermore, decisions on workovers carry economic risks. Regular, careful sampling and proper use of the data are required to manage risk. Choosing the right workover method is a CAN$5,000 – 30,000 decision, exclusive of the costs of a new PC pump.

7.5.2 Chaotic Behavior and Sampling

BS&W measurements in CHOPS wells show chaotic behavior (Figure 7.3). To demonstrate this, 15-minute interval flowline samples were taken (over several hours) from a CHOPS well during "steady-state" production (i.e. continuous oil and sand production after the initial period of high sand influx had passed). Each sample was analyzed for sand, water and oil content, but no GOR values were determined. The results were plotted in time series at various intervals, and it became apparent that the level of "noise" was approximately the same for each time series. This constant noise level over different sampling intervals indicates that the sand influx is chaotic, and that the entire set of sand liquefaction and flow mechanisms to the well bore during steady-state is characterized by a spatially distributed set of "stop-and-go" mechanisms that allow sand to move, stop, and move again. One may envision this process as a series of random events that occur at different distances from the wellbore and liberate different amounts of sand that is entrained in the slurry. At the wellbore, this is evidenced as a chaotic sand influx.

Theoretically, if samples are taken regularly (e.g. every week), the chaotic behavior will have no effect on the computation of long-term, steady state sand production. In other words, random sampling of a chaotic pattern that fluctuates around a mean will yield a statistically correct estimate of the average. Furthermore, if there is a gradual temporal evolution of the mean sand production, this should also be captured in the data determined from periodic sampling. A difficulty arises if there is a sudden change in the sanding rate that occurs over a time that is a small multiple of the sampling interval. Because of random fluctuations, a number of samples must be treated with a moving average approach to give a reliable measure of the evolution of the mean; this requires sampling as frequently as one-tenth to one-fifth of the time interval over which the change is expected.

Examples may clarify sampling requirements. If the sampling interval is one week and a well suddenly starts producing twice as much sand per cubic metre, it may be three to five weeks before this appears in the time series. Therefore, better averaging methods than simple moving averages on flow line samples are needed. There are three typical methods for averaging. First, stocktank sand levels are an excellent average of the total sand produced over time. If the sand level in the stocktank is measured regularly, unexpected changes in levels provide clear evidence that sand influx has changed. Of course, stocktank measurements should be corrected for porosity (stocktank porosity is likely ~36-38%, *in situ* porosity is ~30%).

The other two methods involve flowline sampling. In one case, sampling frequency is increased, but this also increases the costs of analysis. In the other case, a bulk sample is collected over a time interval as the aggregate of a series of small samples, and then only one analysis is done on the homogenized bulk sample. This has the effect of generating a value that is already time-averaged. Furthermore, if the scale of chaotic behavior is the same for a 10-minute return period as for a 5-day return period (as suggested by studies), then a series of random samples taken over a short time interval will give a statistically good estimate of the long-term mean. For example, bulk sample composed of 200 cm^3 samples taken from the flow line every two minutes for 20 minutes will give a bulk sample that will yield a good average.

7.5.3 Recommended Sampling Program for a CHOPS Field

Specific decisions on the nature of the sampling program and the analyses to be used depend on field and well performance. For new CHOPS fields, or in areas where sand production technology is just beginning, there is a great incentive to collect information so that a baseline of "typical" well behavior may be established. The following approach is recommended for these cases:

- During the early phase of CHOPS well production when sand influx is high (typically several weeks to several months): time-averaged samples (100-200 cm^3 every minute for 10 min) are collected every day or two on all wells.
- Sand contents are determined using a simple settling tube and dilution method; water content is determined by heating to 105°C for a standard time.
- Vacuum bottle samples for gas contents are collected and analyzed once a week.
- During "steady-state" production (some months after start-up): flow-line sampling is reduced to every 7-14 days and gas sampling to once a month. These data are used in making decisions on well management and on workovers
- Occasionally, provision is made for a "scientific" study of a CHOPS well to determine short-term phase production behavior. Alternatively, several wells in a field can be identified as detailed study wells and monitored more carefully.
- Test separators are connected to the well every 2-4 months to determine oil, water, sand, and gas production rates over a period of many hours. (Note that this may conflict with regulatory guidelines, as in Alberta.)

In any case, no matter what the conservation authority regulations are, there is an incentive on the part of the operator to take measurements to determine individual well behavior so that rational decisions concerning workover tactics can be chosen. It is believed that careful sampling (Figure 7.4) can reduce workover costs because better data will yield better decisions.

7.6 Requirements for Reporting to Regulatory Agencies

In theory, the Alberta Energy Utilities Board (AEUB) has the authority to require operating companies to provide full audits of sand, stable emulsion, and gas production, as well as oil and water production, for each well over time. This requirement has not been enforced for heavy oil operations, perhaps because of the difficulties involved and the low profit margins in heavy oil operations. However, the EUB does enforce full audits for any service company that handles wastes as specified in Guide 58 and other documents (see other chapters). This in principle does not seem equitable.

Figure 7.1: Gas Segregation in the Near Wellbore Region

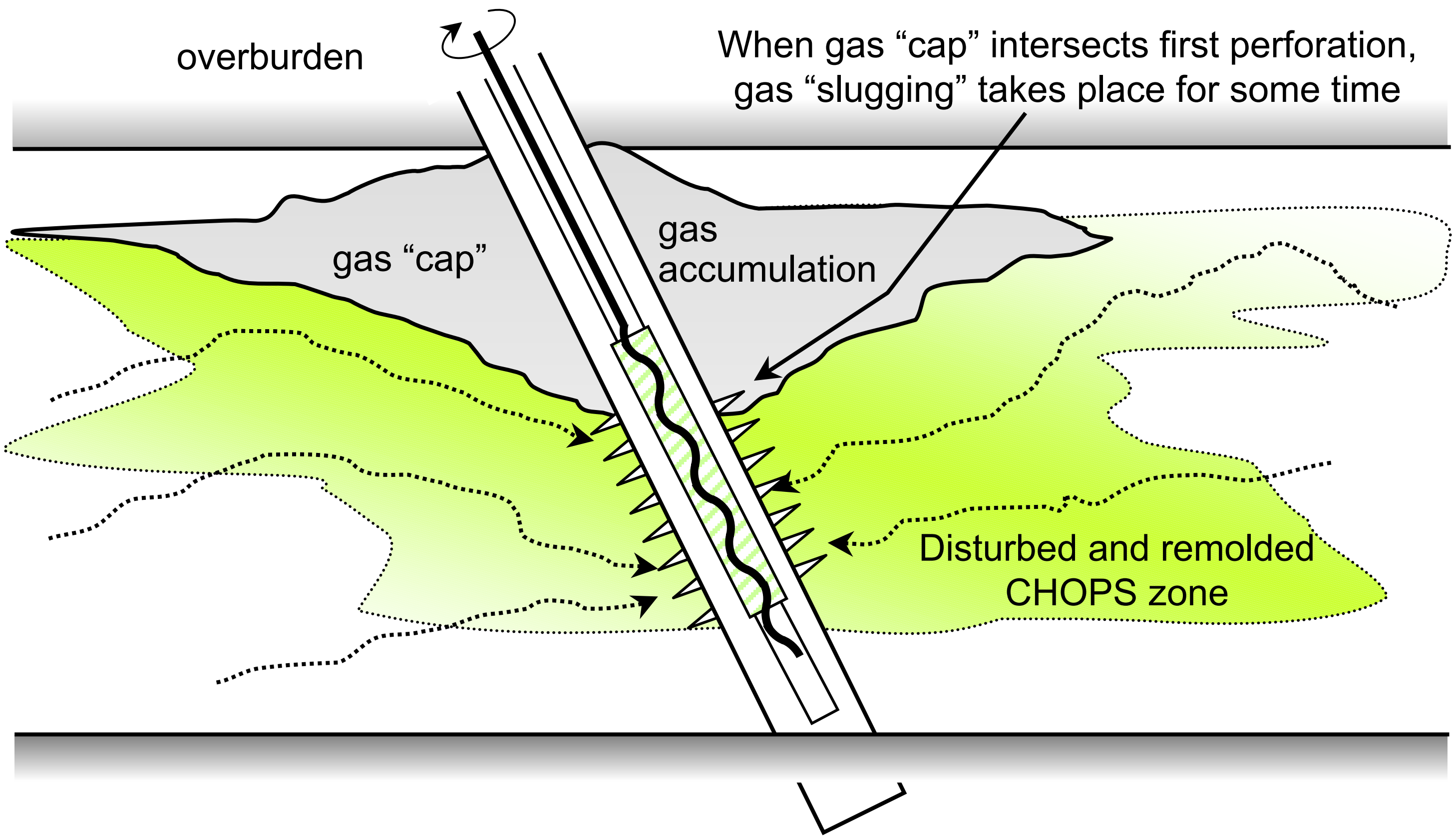
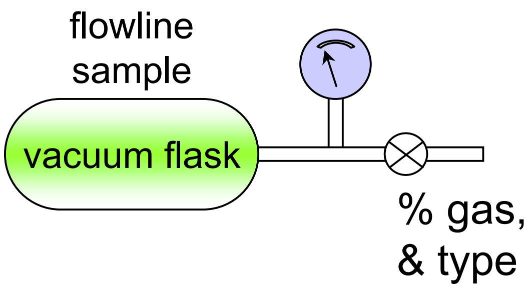


Figure 7.2: Sand and Water Settling Centrifuge Tube, Gas Analysis…

- Dean-Stark for precise oil and water content determination
- Sand settling tubes for sand volume percent, water cut
- To measure gas cut, the flow line is opened to a vacuum bomb, sealed, and sent for analysis
- Clay % as well? Useful for shale content assessment



+ Dean-Stark for precise oil content and water percent

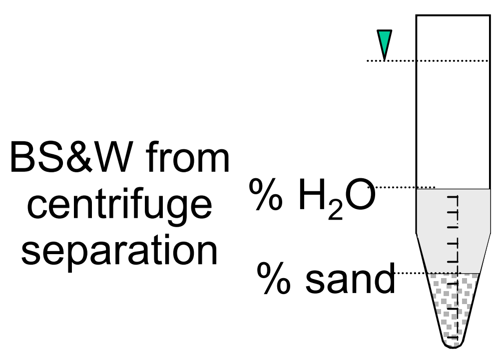


Figure 7.3: Chaotic Behavior of Sand Influx (and other phases)

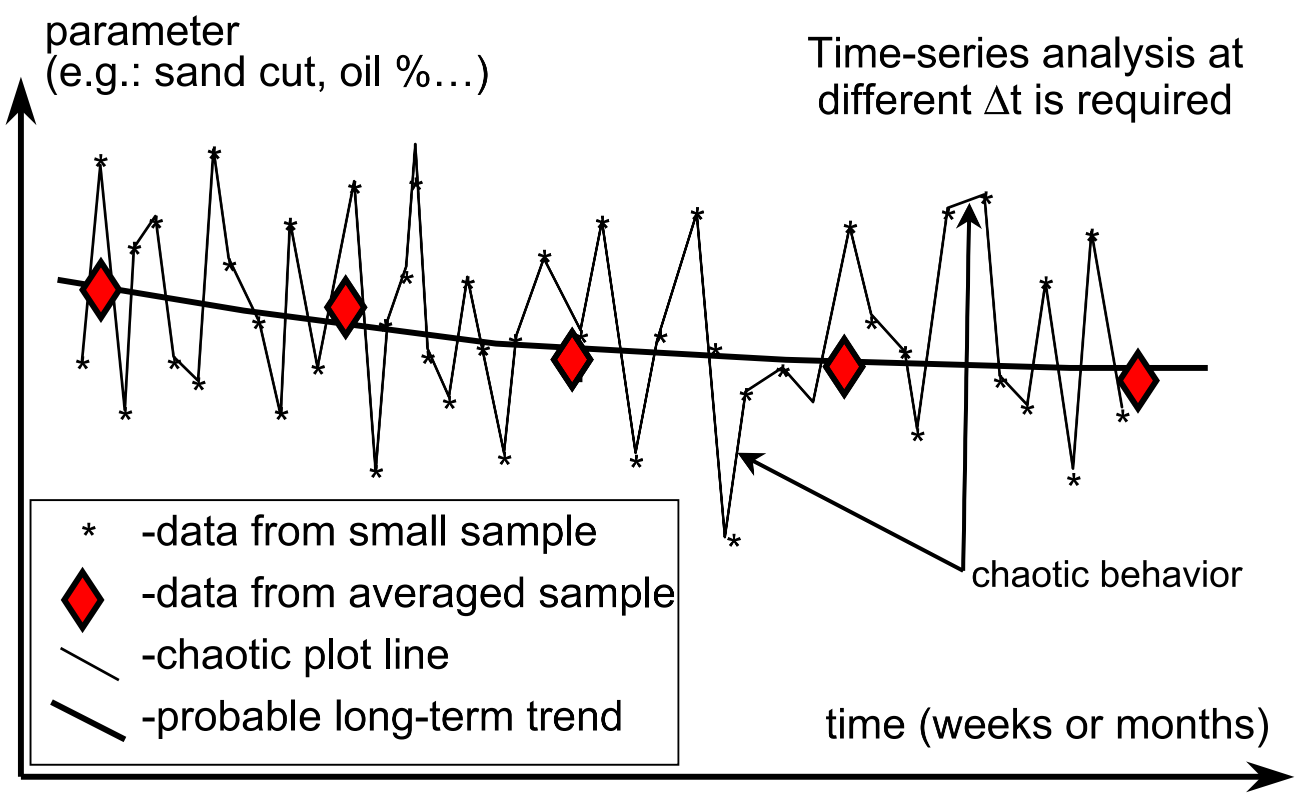


Figure 7.4: Monitoring a CHOP Well