Type of Gas blow out with Case Studies in Iran and the other Country

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Abstract: Underground blowouts can occur in wells, and are thought to be the most general in the latter because of tubulars corrosion in older completions. Two factors make shallow gas drilling a difficult challenge. First, unexpected pressure at the top of the gas bearing zone, due most often to the "gas effect" dictated by zone thickness and/or natural dip, can be significant. This pressure is usually unknown, seismic surveys being often unable to give an idea either about thickness or in-situ gas concentration. In more complex situations, deep gas may migrate upwards along faults. Gas blow out is one of the dangerous event that may happen in all of the gas or oil wells. This kind of blow out is a one of unknown and uncontrolled event that can be accurate in all fields. In this article we study a biggest experience of NIODC, JOHN WRITS CO. About gas blow out and controlling well and safety. In these case studies we try to show a process of blow out signs and controlling safety in blow out event. These processes are experiences of biggest company that we gather together experiences for best recipe. This recipe should be use for design initials processes that we need for a controlling blow out. This recipe talks about a first emergency work that do in the gas blow out for controlling blow out. Basis our knowledge it’s a first research for provide a gas blow out's recipe.

Key words: Underground gas blow out, shallow gas blow out, gas effect.

INTRODUCTION

Underground blowouts between subsurface intervals are common and can result in a significant escalation threat if not recognized quickly and controlled correctly.

This part of article provides basic information for recognize an underground blowout and methods that can be used to regain well control (John Wright, 2004).

Underground blowouts involve a significant downhole flow of formation fluids from a zone of higher pressure (the flowing zone) to one of lower pressure (the charged zone or loss zone.) They are the most common of all well control problems. This phenomenon differs from crossflow, which typically occurs within a long perforated interval and involves little or no reserves loss or escalation hazard.

Underground blowouts can occur in drilling wells or producing wells, and are thought to be the most common in the latter because of tubulars corrosion in older completions. Unfortunately, no statistics on underground blowouts are available because most go unrecognized or unreported. What is known is that many surface blowouts begin as underground blowouts. And prompt, correct reaction to an indicated underground flow can prevent an even more serious and costly surface blowout. That leads to the observation that "experience is the best of schoolmasters, only the school fees are heavy." (John Reese, et al., 2001)

Recognition:

Underground blowout may occur in a production well or drilling well. But field personnel commonly fail to recognize the symptoms-most often; in drilling well they are focused on curing presumed loss circulation. The following events indicate underground flow:

- An initial increase in drill pipe and casing pressure following by a decrease. Typically, initial shut-in drill pipe pressure will drop to zero. Casing pressure may not change very much initially, but will steadily increase with time (Neal Adams and Mehran Mackvandi, 2007).
- Gas, oil or saltwater will surface via drill pipe. Mud jetted out of drill pipe by the underground flow will be replaced with flowing zone fluids (no drillstring check valve).
- Unable to get mud returns with blowout fluids at surface in annulus. Mud flows to loss zone with blowout fluids.
- Able to strip up or down with no change in annulus pressure. Controlling pressure is fracture pressure or pore pressure at the loss zone (Robinson, J.D. and Vogiatzis, J.P., 1972).
Thermal anomalies are apparent on temperature log. Higher temperatures occur opposite shallower loss zone when flow is from bottom up. Lower temperatures occur opposite loss zone if flow is from top down. Spinner logs and other production logs may also provide indications.

No direct indication of pressure communication between drill pipe/tubing and annulus.

Lower than normal shut-in tubing and annulus pressures on a producing well (Warren and Tommy M., 1981).

Sudden change in GOR or WOR in a producing well with annulus pressure.

Christmas tree or BOP vibration of shut-in well.

Sudden tubing or drill pipe vibration and/or drag when pipe is lowered past point in the well where flow is occurring (ehsan momeni, et al., 2008).

Cases and Type:

Most underground blowouts that occur while drilling result from lack of sufficient kick tolerance. Kick tolerance is the kick intensity (amount of underbalance) that can be shut-in without exceeding the fracture pressure of the weakest exposed formation after taking a given volume kick.

Lost returns occur when kick tolerance is exceeded. But sometimes lost returns may occur before the kick is taken and an underground blowout will result. An example is drilling with excessive mud weight and surging the hole on a trip in. Resulting lost returns drop fracture pressure from breakdown pressure to a lower fracture extension pressure. This induces a kick that starts underground flow to the fractured zone. Another cause might be losing returns to a depleted reservoir with high pressure permeability exposed elsewhere in open hole.

During drilling, casing holed by drill pipe wear or pipe defects can result in sudden lost circulation and an underground blowout. In producing wells, internal tubing corrosion or pipe defects can lead to failure and sudden imposition of tubing pressure on production casing. Defects or external corrosion of this outer casing can lead to either a subsurface or surface blowout depending on depth of the flowing zone.

Gas flow after cementing is a major cause of surface annular blowouts. Less recognized is that annular bridging or top-out cement jobs can divert gas flow underground. Surveys of many multi-well gas fields indicate some underground flow likely occurred after cementing. Natural formation bridging and scale deposition shut off most of this flow.

Many operators have been surprised when a temperature or noise log run in a shut-in well years after completion indicates crossflow. Generally, such flow is of little consequence. But there have been instances when this flow has led to surface broaching, fresh water aquifier contamination and shallow supercharging. Identification is difficult as temperature and noise logs must be run in a stable shut-in wellbore.

Significance:

Besides losing reserves to charged zones and possible environmental impacts (fresh water aquifier contamination, shallow supercharging), there have been cases when gas or water have flowed into partially depleted oil reservoirs. In one instance, a deep H2S gas reservoir in Iran flowed for over a year into a shallow sweet oil reservoir. Six nearby oil wells began producing nearly 100% H2S, which was flared to limit expansion of the gas migration front until flow could be stopped by a deep relief well.

Gas migration into a zone can be mapped using modern seismic techniques. This can assist greatly in locating a relief well or determining if flow is continuing after the well bridges or kill operations have blocked the surface flow path. It was constructed from seismic during a North Sea blowout. Note increasing migration of the gas with time. It should be pointed out that charging was occurring up dip from the wellbore. No gas is charging down dip of the wellbore.

Many surface blowouts through drill pipe from high temperature-high pressure wells are caused when a deep underground flow at FBHP lowers the drill pipe mud column. The mud column will fall until it equalizes with FBHP and slowly be replaced by blowout fluids if mud pumps are shutdown. As drill pipe pressure drops due to this fluid exchange, the borehole can become unstable and collapse around the bottomhole assembly. This "bridges off" the flow and allows FBHP to build back to SIBHP. Drill pipe hydrostatic which is equal to FBHP thus is subjected to the higher SIBHP. If the bit is below the annular bridge and no check valve is in the drillstring, drill pipe pressure will increase rapidly. Fluid hammer can occur when mud in the drill pipe is pushed rapidly to surface by formation fluid entering through the bit. A surface blowout then occurs if rig pump pop valves open and/or surface valving fails (cuts out or cannot be closed against the flow).

This type of blowout will generally sustain if little surface solids production occurs. Fig. 14 shows flow discharge from a pop valve in just such a case. In this well, two kelly cocks and one standpipe gate valve were cut out by fluid hammer, leaks of gas and 17.9 ppg hematite oil mud.

Surface broaching of an underground blowout can lead to loss of rig and severe environmental impact. As surface access is unavailable after surface broaching, flow must be controlled by a relief well.
Control Methods:
In the below paragraph we see a program 'This was developed by Mobil E&P Services' drilling technology group based on Wessel and Tarr's paper.

Initial steps are to mobilize on location cementing pump(s), additional mud storage, and cement batch mixer(s) if available. Mix and store at least one additional hole volume of mud on location. While mixing mud, bullhead water down the annulus to the loss zone to minimize annulus surface pressure and prevent subjecting casing, wellhead and BOPs to gas. This will assist temperature log interpretation by defining a temperature gradient at the loss zone. Consider running a calibrated rate gyro to provide better relief well targeting. Fracture extension pressure can be estimated by adding surface pumping pressure to water hydrostatic to the loss zone. The top kill attempt consists of the following steps:
1. Slow annulus pumping rate, continue annular water injection with cementing pump.
2. Pump water or mud down drillstring at 90% of maximum possible rate using rig pumps until pressure stabilizes. Record stabilized pressure and rate. Increase pump rate to maximum and record stabilized pressure and rate.
3. Stabilized drill pipe pressure is a function of the annulus two-phase (mud and gas or mud and oil) flow, hydrostatic and friction. If single-phase mud flow is attainable in the annulus, then the well is dynamically killed. Drill pipe pressure for single-phase flow can be accurately determined. If this pressure is achieved, the well is killed.
4. Lost circulation materials can be added to the mud to obtain a static kill after pumps are shut down.
5. If a dynamic kill with water or mud is not achieved, the recorded stabilized two-phase flow pressures developed during the attempted kill, in combination with results of the pressure/temperature log, can be accurately analyzed, to determine what will be required.

In kangan23 well in south of Iran and cratered well is a two big blow out that kill with relief well.

Alternate Kill Methods:
If a top kill is impossible and normal hydrostatic control can't be restored, other procedures can be tried. A major complication to restoring normal circulation with a single weight uncontaminated fluid is possible supercharging.

Supercharging can make it impossible to achieve a normal hydrostatic kill without first isolating the flowing zone from the charged zone. This procedure is used as the primary kill method when a dynamic kill attempt cannot be completed or converted to a normal static kill without re-start of flow by the supercharged zone. Isolation can be accomplished by bridging (natural or induced), plugging (lost circulation materials, soft plugs), blocking (gunk, sodium silicate, cement) or mechanical means (openhole packers, cased hole packers).

Natural bridging controls most underground blowouts because exposed shales cannot withstand resulting pressure differentials. Natural bridging can sometimes be induced to shut off underground flow by reducing FBHP via surface venting. FBHP can be high if flowing zone permeability is high and high wellbore fracture pressure limits FBHP - which can be sufficient to support exposed shales. Surface venting at a high rate can drop FBHP below fracture pressure and cause bridging.

Plugging the flow path or the charged zone with lost circulation materials, barite plugs or diatomaceous earth squeezes is rarely effective in controlling significant underground flow, particularly if FBHP is equal to formation fracturing pressure. Tremendous quantities of drilling mud and lost circulation material have been pumped away in attempts to plug off a charged zone. Many times these are attempts to "regain circulation" when an underground blowout went unrecognized. Barite plugs are generally effective only if hydrostatic control is regained long enough to allow barite to settle. As with lost circulation material, use of barite plugs to control a severe underground blowout is generally a waste.

Blocking the flow path with reactant plugs of fast-setting cement, gunk or sodium silicate reacted with cement or C aC12 brine can be effective. Gunk was first developed by Goins as a means for squeezing off a lost circulation zone.

Gunk generally consists of 150 ppb bentonite and 150 ppb cement mixed in diesel oil and reacted with a fresh water drilling mud. The reaction is nearly instantaneous at a 2:1 to 1:1 gunk-to-mud ratio. The firm "breadough-like" mixture of hydrated bentonite and cement can be easily drilled, but will handle high differential pressures given sufficient plug length.

Alternately, 200 ppb guar gum and up to 100 ppb of fine lost circulation material can be used in diesel for a gunk plug that will react with saltwater flows, brines or salt muds. Guar gum can be replaced with modern high molecular weight polymers. Using these polymers with powdered CaCO3 as the lost circulation material produces a gunk that is 98%+ acid-soluble when reacted with brine.

Invert gunk consists of 275 ppb of amine clay (amine-treated bentonite) mixed in water and reacted with an oil flow or oil mud. Mixing a water mud as a primary kill fluid that contains 50 ppb amine clay is useful in killing oil flows. The amine treated clay will react when mixed with oil and markedly increase viscosity of the water-based kill fluid. This provides greater annular friction and helps limit mud losses after the well is killed.
Plugs of sodium silicate solution reacted with CaCl2 brine have also been used. Less recognized is that a mixture of 3:1 cement-to-sodium silicate will flash-set. Densified and highly retarded cement is generally used to obtain sufficient pumping time.

Any of these reactant plugs requires:

- Two independent flow paths- drill pipe and annulus, for example -to allow subsurface mixing at the desired point. Snubbing or stripping operations may be required to get the two flow paths. In some extreme cases, direct intersection with a relief well may be required to get the second flow path. Mixing must occur near the flow zone and between the flowing and charged zone.
- Cement batch mixers are used to mix and store unreacted gunk mixtures. Independent pumping systems are needed to prevent surface mixing.
- All lines must be flushed and cleared to prevent surface reaction and line plugging.
- Adequate diesel spacers (minimum 10 bbl) to isolate gunk.
- Consideration of environmental aspects in selecting gunk vs. sodium silicate. Gunk has been made and successfully applied using ester-based environmentally acceptable oil to replace diesel.

Reactant plug use to control severe underground blowouts should be done with the assistance of personnel experienced in their application. Misapplication can plug off the well above the underground flow and isolate the surface from the problem. This has generally been the case when cement was pumped without first controlling the flow.

Mechanical isolation using packers snubbed in below a hole in tubing or casing and set to isolate the hole has been done. Open-hole packers have been snubbed in and set near the flowing zone. Modern open-hole packers are available to handle high differential pressures (7,000 to 9,000 psi) if annular clearance between packer and hole is limited.

Coiled tubing has been used with these packers for control of underground flow in a few cases. A major difficulty is that once the packer is set and now is controlled, the situation is much like having a "bull by the horns" as hydrostatic control or bridging/plugging isolation is still needed.

Shallow Gas Blowouts:

After underground blowouts, shallow gas blowouts are the second most common type of blowout and the most common type of surface blowout. Loss of rig, platform and life has resulted from shallow gas blowouts. Invariably, the well is lost. Little time and effort has been expended on shallow gas hazards, although industry has put a great deal of time and effort into analysis of kick control and blowout disaster mitigation. Preparing for shallow gas can save lives and rigs. This article examines the dangers of shallow gas, precautions and procedures for shallow gas drilling, and disaster mitigation.

Dangers:

Two factors make shallow gas drilling a difficult challenge. First, unexpected pressure at the top of the gas bearing zone, due most often to the "gas effect" dictated by zone thickness and/or natural dip, can be significant. This pressure is usually unknown, seismic surveys being often unable to give an idea either about thickness or in-situ gas concentration. In more complex situations, deep gas may migrate upwards along faults. In Sumatra for instance, an influx could not be stopped even with 10.8 ppg mud at very shallow depth; the bit had crossed a fault plane. Second, low formation fracture gradients are a predominant factor in shallow gas operations.

Reduced Safety Margins:

These two factors result in reduced safety margin for the driller. Minor hydrostatic head loss (swabbing, incorrect hole filling, cement slurry without gas-blocking agent), any error in mud weight planning (gas effect not allowed for), or any uncontrolled rate of penetration, with subsequent annulus over-loading, will systematically and quickly result in well bore unloading.

Shallow Gas Flows Are Extremely Fast Developing Events:

There is a short transition time between influx detection and well unloading, resulting in much less time for driller reaction and less room for error. Poor quality and reliability of most kick-detection sensors worsens problems.

Severe Dynamic Loads:

Past history has disclosed the magnitude of severe dynamic loads applied to surface diverting equipment, and the high resulting failure probability. One of the associated effects is erosion, which adds high potential for fire and explosion from flow impingement on rig facilities.
**Rig Cratering:**

The risk of cratering is a major threat for bottom supported units. As it is impossible to eliminate them (most shallow gas-prone areas are developed from bottom supported units) emphasis should be put on careful planning and tight monitoring during execution.

**Rig Selection:**

When selecting a rig, two facts should be kept in mind.

First, major shallow gas fields (in particular in Indonesia) have been explored, appraised and developed from bottom supported units.

Second, the most conspicuous disasters due to controlled shallow gas blowouts have involved drillships and semi-submersibles.

Two support types are particularly exposed and should be avoided: mat supported jackups and drillships. These rigs are not designed to ensure proper stability and/or to withstand heavy loads imposed by a boiling gas plume. They are, therefore, prone to take on water, catch fire, lose stability and eventually capsize.

Whatever the facility offered by semi-submersibles to move off location in case of uncontrolled gas flow, the questionable condition of the rig's mooring and release hardware, and the general unreliability of most semi-submersible surface diverting equipment, requires careful consideration.

Rig selection for shallow gas areas should take into account: Selection of a "safe" drilling location, according to seismic survey mapping Design of an engineered drilling program, with priority given to permanent hydrostatic control of the well.

Comprehensive assessment of pre selected rigs, with final rig selection based on past experience and competence in shallow gas drilling, and also on diverting equipment fitness for purpose, layout, and structural ability to withstand a gas blowout long enough to permit a safe evacuation. (Fig. 1 and Fig. 2)

Fig. 1: Model FSP bag diverter system provides automatic venting when piston closes packing.

Fig. 2: Flow Selector, left, directs flow from FSP Diverter to one of two opposed vent lines for down-wind line selection.
**Diverter Systems:**

It is worth considering positive safety improvements which can be expected from more rational use of field proven diverter equipment. Traditional diverters: In the past, traditional diverters have failed due to shearing of insert-packer-element latching dogs caused by high thrust loads. Catastrophic loss of the Petromar 5 rig in the South China Sea resulted from this type of failure.

**Bag Diverters:**

By nippling up a field proven sealing element, e.g., standard spherical type bag preventer, with a properly sized diverter spool just above the conductor pipe, the following could be achieved:

- Higher structural closing and diverting capacity, able to support heavy dynamic loads.
- Closing time should, nevertheless, be reduced, as it would be excessive in shallow gas.
- All prone-to-leak telescoping joints, required to adjust flowline slope, would not be exposed below the sealing element.
- Properly sized, supported, secured and absolutely straight vent lines makeup.
- Newly developed, integral closing and diverting systems could be used, Fig. 16. In this equipment, an integral piston below the annular packing unit rises to open the vent line as the packing unit closes. This has the obvious benefit of the absence of valving, and control system simplification. Maintenance is simplified, and chances of equipment failure, plugging and deficiency are drastically reduced. The use of a flow selector provides a method of directing flow to a downwind line.

This approach is commonly implemented by Total on North Sea platforms and in other areas, e.g., Indonesia, Thai land, Burma, onshore and offshore, where there is shallow gas risk.

**Subsea Diverters:**

Most floating drilling units have diverting and venting equipment which cannot be easily and efficiently modified. Many oil companies and contractors have by-passed these systems and changed procedures; reliance is put on quick move-off in case of gas influx.

If the first point is debatable, the second one is questionable; mooring and release systems are not absolutely reliable. A recent case history disclosed the low level of operator confidence in the move-off option when, with a huge gas plume adjacent to a semi-submersible, an airborne evacuation was preferred.

The best floater, shallow-gas blowout protection is subsea diversion. Total and Sedco Forex, and a few others, have selected this option for exploration and appraisal drilling activities offshore Kalimantan (Indonesia). Although thrust loads, erosion, fire and explosion cease to be applied to surface equipment, care should, nevertheless, be given to closing speed of the subsea bag preventer and shear ram, and to riser (or wellhead) connector release time.

In addition, attention should still be paid to rig ESD systems, to the mooring lines release system, to firefighting and sprinkling capabilities, to location of the various remote controls, to available means allowing communications in a highly noisy environment, etc.

**Procedures:**

The following is a summary of the recommended approach, used and progressively improved during more than 20 years drilling in shallow gas prone areas.

Prior shallow seismic surveying: This is probably the only discipline which continues to progress and has the industry's unanimous support. Depending on field specifics, in particular, water depth and ease of access to the location, different techniques may be used, including HR surveys or 2-D and 3-D seismic surveys with specific reprocessing for shallow structures.

Common procedure is to position the rig outside the mapped hazardous area, which may entail directional drilling to reach the initial target. Pre selection of one or more gas-free locations is also recommended for relief well drilling should the need arise.

Shallow gas drilling requires, more than any other drilling or well servicing activity, comprehensive training for drilling personnel Pilot hole drilling.

This option is often considered, but for different reasons. The first is the need for logging to calibrate seismic survey information. This is often difficult, as soft, shallow formations tend to slough, making successive control trips and logging hazardous. The second reason claims that dynamic killing in a pilot hole might successfully stop a shallow gas blowout; this reasoning is now widely questioned. While it is difficult to kick a shallow gas sand from the effect of drilled gas only, drilled gas can be a serious problem with uncased shallower sands above the gas sand being drilled. Finally, the only benefit of a pilot hole is in limiting total volume of gas-filled porosity to be drilled. Limiting penetration rate in normal hole sizes may be just as viable an option.
Hydrostatic Control:
The permanent maintenance of hydrostatic control of the well is a must in any drilling situation. Selection of proper mud weight according to the gas effect assessment is essential. Failure to do so has caused major blowouts and capsizes. In addition, to maintain hydrostatic control, the following must be considered:

- Avoidance of swabbing and hole imbalance
- Avoidance of losses (controlled ROP, solids control, deeper conductor pipe shoe, etc.)
- Avoidance of gas influx during cement setting
- Limitation of penetration rate in gas-filled porosity.

Careful planning will help minimize risk of an uncontrolled gas flow. However, there have been cases where little could be done to prevent it, e.g., in Malaysia and India, with highly tilted layers, or in Indonesia with deep gas migrating along faults.

On floating equipment, heavy mud can be pumped with returns lost to the seabed in riserless mode, or a lighter mud (designed according to the "gas effect" concept) may be pumped with the riser in place. The most important thing to remember is that the well will inevitably blowout, should seawater only be used to drill riserless shallow gas-bearing formations (Robert, D. grace, 1994, 2004).

Disaster Mitigation:
Two tools should be provided to drilling personnel to help prevent disaster escalation. First, the operator should design, with the drilling contractor, a common and realistic emergency procedure. It should be remembered that "emergency" status follows very closely the influx detection. Most procedures do not contemplate shallow gas, and pre spud meetings are usually so short dated prior to start-up date that contractor personnel have virtually no time to properly "digest" procedures or specific risks. Second, as many drills as are necessary should be authorized and carried out to ensure that emergency procedures are known, understood, well implemented, and that emergency equipment is working and reliable. Realism should prevail in emergency drills and procedures. Case histories have disclosed that, once the well has been unloaded, there is virtually no chance to recover control until it collapses by itself or depletes.

Options:
Depending on the type of available diverting equipment, two basic options are recommended:

1. With unreliable equipment onsite (which should mean that, at the very outset, shallow gas was not expected and/or that proper equipment has been overlooked) no chances should be taken; the site should be abandoned immediately.
2. Alternately, should suitable equipment be available onsite, an attempt to kill the well may be initiated with some chance of success, provided that:
   - Detection has been almost immediate (rely on the flow detector)
   - The crew is speedy and orderly
   - The well is quickly diverted but not yet unloaded.
   - There is, in particular, no time for multiple instructions to the driller, requesting countless phone calls, inopportune flow checks, or a time consuming rush to modify suction valving.

Regarding support type, instructions should acknowledge the respective and inherent weaknesses of the following:

1. For a bottom supported unit, with the possibility to improve design and load-bearing capacity of equipment, a well killing attempt may be contemplated under conditions defined above, provided that a nearly immediate swap to heavy kill mud is feasible. This type of old-fashioned, dynamic kill (heavy mud pumped as fast as possible, as soon as possible) has been successfully implemented during the past year. Unfortunately, rarely has there been a successful application of this method before the well cut out the diverter system, bridged or burned.
2. With a floating unit, assuming a subsea diverter is used and the influx detected soon enough, a well kill attempt may be contemplated as above. Should the riser be in use and locked to the wellhead with a pin-connector only, no kill should be attempted; immediate riser disconnection should be triggered and rig move-off initiated. If the influx is actually confirmed, move-off can be carried out.
3. Finally, with sufficient understanding of local fracture mechanics, it may be safer to shut-in some shallow gas kicks than to let them blowout through poorly designed diverting systems. In one instance, a blowout loss of $200 million was experienced when a shallow gas kick was diverted, resulting in fire and extensive platform damage. If the flow had been initially shut-in, the estimated surface pressure on conductor casing at the time the flow was first discovered would have been less than 100 psi.

The best of all worlds would likely include a sound diverter system above a conventional pipe ram and choke line. This would allow initial well shut in and conventional circulation, if the kick were detected early. If the well was to broach, or the kick were not detected quickly, it could be reliably diverted. This is a controver-
sial issue that is now under study by one major oil company after experiencing several large losses from diverted shallow gas blowouts.

**Conclusion:**

Underground blowouts are a growing problem because of aging wells. Operators need to closely monitor existing producing wells for signs of problems. Most of the well control work done by author Flak last year involved producing wells and tubulars corrosion was the single largest cause.

Operators many times fail to respond immediately and correctly when an underground blowout occurs. That makes control more difficult as flow paths erode, downhole tubulars degrade (erosion added to corrosion) and supercharging occurs. In a drilling well, early recognition is a problem because indications of underground flow are masked by operations to restore circulation. The list of well conditions provided herein can be used to determine if an underground blowout exists. The flowchart provides step-by-step instructions for implementing a top kill to control the blowout.

If a top kill is impossible, alternatives exist particularly if there are two independent flow paths to allow mixing of reactant plugs into the flow. This has been accomplished with coiled tubing, snubbing and directional relief wells. Mechanical plugs also have been used to isolate the flowing zone. Experienced personnel are required to simulate flow paths, make kill calculations and apply reactant plugs.

Shallow gas drilling requires, more than any other drilling or well servicing activity, comprehensive training for drilling personnel. Rig personnel should be taught about:

- The origin of shallow gas
- The gas effect concept and the consequence of haphazard mud weight selection
- The irrelevance of standard well control procedures
- The realistic procedures needed to face a fast-development event
- The necessary care and maintenance of diverting and emergency equipment
- Possible improvements which may help to reduce failure hazards
- Real case histories.

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