Mechanisms of Product Leakage from Solution Caverns

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ABSTRACT

The manner in which solution caverns fail and the way in which migration of stored products occur in the event of such failure is generally misunderstood. It is necessary that the stresses imposed on a solution cavern as a result of storage operations be thoroughly understood and put in context with the various mechanisms of cavern failure before adequate precautions can be made to prevent failure. Eleven potential failure modes are discussed herein. The manner in which crude oil could migrate from the cavern in the event of failure, the degree to which such migration might progress, and the eventual accumulation of stored crude oil in natural occurring traps is also discussed. The migration of crude oil is used as an example because of the major emphasis now being placed on the Strategic Petroleum Reserve Program and the general body of knowledge relating to the characteristics of oil trapping phenomena on or adjacent to domal salt formations. The migration of gaseous phase stored products and those having a low specific gravity or high vapor pressure could be quite different from crude oil. One scheme for storage cavern wellhead instrumentation and controls sufficient to restrain operating conditions within safe limits is covered.

INTRODUCTION

There are presently some 350 MM barrels of operational underground storage in the United States. This storage has been developed by private industry reacting to its own needs as dictated by market conditions or operational necessities. It has been constructed over a period of some 25 years, and additional underground storage space is coming on stream as the need arises. The 1979 Gas Processors Association publication of North American storage capacity for light hydrocarbons shows 410,929,000 barrels for 1979; 354,035,000 barrels for 1977.

The Strategic Petroleum Reserve Program (SPR) of the United States Government is giving a tremendous impetus to the underground storage industry. A complete review of all facets of underground storage systems has taken place and a tremendous volume of information relating to design, construction, instrumentation and operation has been and is being generated. The manpower and technical resources of the underground storage industry in the United States have been mobilized and utilized to an astounding degree. It is particularly gratifying to me, as an individual who has spent more than 25 years in this field of endeavor, to have been deeply involved in the SPR Program almost since its inception. Gulf Interstate Engineering Company (GIEC) is the Department of Energy's Executive Engineer for the SPR Program and I am the Project Director for GIEC. It is an especially interesting experience to be involved in studies relating to the conversion of four dry mines as well as numerous existing solution cavities having a wide variety of configurations. The variety and range of problems studied and resolved in dry mine conversion and operation have advanced the state of the art to a very significant degree. New ultra large volume, high flow rate, solution cavern design and development using leach/fill or leach and fill techniques is also an extremely interesting aspect of the program. Problems involved in the design, drilling, completion and operation of high injection rate (30 MBPD) brine disposal wells in sand sections have also been most challenging.

It should be of interest to this group to have a brief review of the various industries using underground storage, their peculiar requirements as to operating procedures, storage space and geographical location, and the possible future trends in development and utilization of underground storage systems.

Most of you are quite familiar with the underground storage of domestic LPG and the need for such facilities to level out the constant production versus cyclic demand inherent in this industry—the latter effect is expected to become even more pronounced if domestic production decreases and the "highest beneficial use" concept is put in force. The importation of propane or mixed LPG is getting a great deal of attention because of our expanding needs and the world surplus of these commodities. Underground storage for surge capacity is a necessity in such ventures to obtain maximum utilization of tanker fleets, and to store mixed LPG's to allow for optimization of fractionating plant design.

Natural gas storage in solution mined caverns is getting more attention, in particular, because of increasing gas value and the almost prohibitive dead investment involved in the "heel" gas required in new aquifer storage systems. There seems to be a tendency to operate new solution cavern gas storage "wet" (i.e., brine displacement) instead of by compression/decompression. It is possible imported LNG will be stored in liquid phase (refrigerated) in dry mines developed in suitable formations or in gaseous phase in solution caverns—the principal impetus being the optimization of tanker utilization and reduction of port time, as well as elimination of heel gas requirements.

The availability of underground storage to support large olefins (ethylene) plants has almost become a prerequisite to plant location and has a definite impact on operational economics. Domestic and/or imported raw feed reserves adequate to cover production or transportation interruptions is vital. Storage of ethylene for system balance during production or consuming plant turnarounds is extremely important.

Crude oil imports going into domestic distribution systems (as opposed to the Strategic Petroleum Reserve) of the United States will require underground storage support, particularly as the daily volume of imports increases. LOOP is putting underground storage in at Clovelly dome and some dry mines are being considered for use as transshipment sites. An offshore salt dome in about 90 feet of water could be used to considerable advantage for storage and transshipment in support of ULCC or VLCC inbound movements and outbound movements of conventional tankers to ports in the United States.

Several hundred million barrels of new storage capacity must be developed if the Strategic Petroleum Reserve Program goal of one billion barrels is to be met. Some of this storage will be developed by expansion of existing sites in the program, but some new sites undoubtedly will be required. Most of the new storage will likely be on the Gulf Coast, since solution mining in salt domes can be used to develop more storage space in less time and at less cost than in dry mined storage. It is possible there will be some storage in inland bedded salt sections west of the Alleghenies or converted dry mines east of them, which could satisfy the political demand for East Coast regional product storage.

Historically, most oil imports to East Coast refineries have arrived via conventional tanker either direct from foreign origins or from transshipment ports and almost all crude oil imports destined for Midwest refineries arrive at Gulf Coast ports and move up the Seaway, Texoma and Capline pipeline systems. The Gulf Coast and East Coast ports have docks and shore facilities sufficient to receive present import levels and presumably room for future expansion, but presently have water depths sufficient to accommodate conventional tankers only. The DOE is building two new docks at St. James. In the event of a supply interruption, DOE's docks are also designed to load out conventional tankers. It is presumed also that Seaway, Texoma, and Capline (St. James) will make dock space available to DOE for loading conventional tankers destined for East Coast refineries in the event of a supply interruption or other emergency affecting imports to the United States. SPR oil will move from underground storage up the three pipeline systems to the Midwest. Oil for tanker cargoes will move back through the existing (fill) lines to docks made idle by the embargo, thence to East Coast ports to offset the effects of the supply interruption.

Apparently, the Energy Research and Development Administration (or its successor) has plans to support a pilot plant STOR/AIR system to demonstrate to the power industry the economics of this procedure for leveling power grid loads.

The preceding discussion was intended as a general review and update of trends in the underground storage industry as a prelude to my technical discussion.

FORCES ACTING ON UNDERGROUND STORAGE SYSTEMS

It seems logical that some comments be made relating to the various dynamic and static forces involved in the injection to, storage in, and recovery of materials stored in solution mined caverns, prior to the discussion of conceivable failure modes and solution cavern protective devices. Indeed, it is necessary to have a thorough understanding of the nature, magnitude and the limits within which these forces should be restrained before a suitable system can be developed to control them so that the storage system is not endangered.

The most critical point in a solution mined underground storage cavern is the casing seat of the final cemented casing string and the cement sheath behind it, which isolates the cavern from zones of porosity and permeability above the top of the salt. It is normally presumed that the salt itself has negligible porosity and permeability. It is also generally presumed that the geostatic forces exerted by the overburden that lies above the casing seat must exceed any fluid pressure exerted at that point, otherwise the overburden might be lifted (fractured) and the storage cavern rendered useless. The "in situ" stresses in the salt differ in bedded salt and salt domes, and this factor affects to some degree the pressure at which fracturing will take place and the direction in which it will be propagated. Most authorities consider fracture will take place at pressures equal to or above 1.0 pounds per foot of overburden over salt domes and somewhat less over bedded salt sections. GIEC made a review for the Department of Energy of hydrostatic testing pressures used by various members of the industry to establish the integrity (pressure tightness) of a solution cavern intended for underground storage use. These factors range from 0.7 to 0.9 pounds per foot of overburden. GIEC has tested most of the existing solution caverns to be used in the SPR Program to 0.9 pounds per foot of overburden.

DYNAMIC AND STATIC FORCES

One of the basic decisions that must be made in the design of a solution mined cavern is the maximum flow rate required during the injection and withdrawal of stored products. Once these rates and the erosion velocity limit have been set for any given product, the casing seat point of the final cemented casing string has been established (either by choice or necessity), the total depth of the cavern picked, and the operating safety factor is specified, then the flow areas required for product and brine can be calculated. An operating safety factor (S.F.) may be defined as the hydrostatic test pressure, measured at the casing seat of final cemented casing string, divided by the maximum operating pressure at design flow rate (measured at that same point) when the storage cavern is at the product fill point. The maximum operating pressure can occur either during injection or withdrawal. It usually occurs during injection; however, some operating requirements might result in the withdrawal mode being the greater. The magnitude of the safety factor depends to a great degree on the operating philosophy of the owner. Existing solution caverns to be utilized in the SPR have been tested such that a 1.2 to 1.3 S.F. is possible. When existing solution caverns are tested for conversion to underground storage use, it is not always possible to have the casing seat at the ideal depth. In this situation an upper limit is set on the hydrostatic pressure test applied (e.g., 0.9 pounds per foot at casing seat depth) and flow rates at various fill volume adjusted to give a reasonable margin of safety.

The maximum allowable operating pressure can be designated in PSIG on the product side at the wellhead. The maximum operating pressure is, of course, the static differential pressure (computed at the wellhead) between the product and brine when the cavern is at the fill point, minus the pressure drop in the product annulus (if the injection mode is used as basis), plus the product weight bearing on the casing seat plus the pressure drop in the brine return system (tubing pressure drop plus brine system back pressure), all at design injection rate. A variety of pressure drop formulae are being used for the annular pressure drop (equivalent diameters, wetted perimeter, empherical equations, etc.) but calculation of the tubing and flow line pressure drops is quite straightforward. Some of the equations used are shown in Exhibit A. Most designers would limit velocities in the system to 15 feet/second or less.

FAILURE MECHANISMS

There are at least two other significant dynamic effects that might occur within a storage system and could affect its integrity. Properly designed and maintained controls on the wellhead and in the surface piping will prevent the storage system from being damaged by these forces.

Pressure surge. Pressure surges could damage the wellhead valve fittings and accessories and the tubing (brine return string). The time interval within which they act can be a fraction of seconds to seconds. It is not likely that properly cemented casing would be damaged and doubtful that pressure surges exiting the end of the final production string would have any appreciable effect on the casing seat or cavern.

Rapid depressurization. Rapid depressurization of a cavern takes place when the pressures normally created within the cavern and annulus by the brine column in the tubing string is sharply reduced. This could take place if the tubing parts within the stored product interval, if the cavern is "overfilled" and products "come around" the end of the tubing string or if the wellhead were sheared off. The probability of the latter taking place is, from a practical sense, infinitesimal. Pressure reductions on the order of 95% could take place if natural gas was being stored. With propane storage, the reduction could be on the order of 42% and with crude oil approximately 30%. This pressure reduction is not instantaneous because of the salt, brine and stored product compressibility. The time interval within which it would take place depends on several factors: The product compressibility; volume of product in storage at time of failure; product specific gravity (at bottom hole pressure); and, the surface brine return system back pressure, length, and volume. In general, this effect can be assumed to take place over a period of a few hours to a day or more, and can be prevented or controlled within safe limits by properly designed and maintained wellhead controls. At the present time there is no practical system existing to shut off flow in event the wellhead is sheared off.

Rapid depressurization could affect a cavern by causing roof sag or rock falls and might trigger minor slabbing from the sidewalls. The effect on cavern integrity might be significant in cases where the cavern had an unusually thin ceiling combined with a large roof span. Obviously, no prudent operator would deliberately subject a cavern of the latter configuration to such a negative pressure.

SLOW DEPRESSURIZATION

A much less severe depressuring effect can result from numerous thread leaks, one or more holes in the tubing string due to abrasion, erosion, or corrosion, etc. This becomes somewhat of a nuisance due to return of products to the brine pit, contamination of the atmosphere, etc. It poses very little threat to the cavern. A properly designed tubing string will practically eliminate such problems. If storage system controls are to be completely effective, they must be designed to control rapid as well as slow decompression effects. There are a number of dynamic effects in underground storage systems that can create some rather strange phenomena but pose little or no danger to the system. These effects are usually related to the compressibility of the stored products and the salt body, compressibility of trapped product and/or dissolved gases released from fresh water as it takes salt into solution, temperature and brine saturation equilibria, etc. Such effects are much more pronounced in large cavities (10 MMBBL +) than in small ones (1 MMBBL −). When hydrostatic tests are made on solution caverns, the volume of brine required to bring it up to test pressure can be considerably greater than anticipated and the pressure rise per thousand barrels injected is not linear. During hydrostatic tests in existing solution caverns we have found that it takes approximately 350 barrels for each 10 psig rise in a 10 MMBBL cavern, up to approximately 300 psig, and approximately 250 barrels per 10 psig up to 550 psig, with corresponding lesser volumes as the cavern pressure increases. We have found the average volume of brine required per 10 psig rise to be 950 barrels in a 30 MMBBL cavern versus 250 barrels in a 5 MMBBL cavern. The effect is not particularly surprising, since the compression volume would be a function of the salt face area exposed to compression, the pressure increase with depth, the temperature of the salt mass, the saturation equilibrium of brine at surface temperature coming to bottom hole temperature, etc. We have also found that it is almost impossible to set an open hole plug, above a large cavern, without some mechanical backup. If the pressure is increased on the cavern, even on the order of ounces, the cavern will expand a significant degree (in relation to the volume of the plug) and a "free-floating" plug will drop out or disintegrate. When a storage well is shut in, after a displacement cycle using fresh water, it will take a substantial volume of water to bring it back up to operating pressure on the next withdrawal cycle. This could cause a substantial pressure reduction. The effect is due to decompression of the stored products, the brine and the salt mass, as salt goes into solution creating more occupied space than that existing when the well was shut in. Storage wells will also "bleed" brine to an open discharge line as forces due to pressure drops in the system are relieved, and salt creep takes place at the end of an injection cycle.

Salt creep and temperature rise possibly should be considered dynamic effects. They might cause a shut-in well to "pressure up" to the degree that damage to the storage system conceivably could occur. The casing, tubing, wellhead and surface support facilities normally have a safety design factor of 1.5 to 2.0; however, good operating practice dictates excess cavern pressure be relieved, by releasing brine through the tubing such that operating safety factors are not exceeded. The principal static force imposed on the solution cavern is the geostatic head of the overburden above it.

One of the things the operator of a storage system agonizes over most is that of the possibility of leakage of products from the cavern. The mechanisms of cavern leakage and the probability of it ever occurring in a properly designed storage system seem to be generally misunderstood.

The most obvious preventive measure is to design, construct and operate the system in such a manner as to reduce to a bare minimum the possibility of any leakage occurring. If good quality casing is used, properly formulated cement mixtures placed behind the final cemented casing string without channeling and with a good bond to formation and casing and in sufficient quantity to give adequate length of cement cover above the end of the casing and across zones containing corrosive water, then the major precautions will have been taken to minimize the risk of leakage from this source. In reference to the latter comment above, the long term integrity of the storage system is probably more dependent upon casing security in an area containing flowing corrosive waters than in any other feature of design, construction or operation. If it is at all possible there should be at least two casings across this zone with a cement sheath between the outer and inner one as a minimum (preferably two cement sheaths). Flowing corrosive waters are invariably present in loss of circulation zones encountered during drilling operations within the cap rock of a salt dome or at the cap rock/salt interface. Some operators include the final cemented casing string in their cathodic protection system.

Most underground storage operators consider the salt surrounding the cavern to be of negligible porosity and permeability. If a cavern passes the hydrostatic test, it is considered that products will not escape thereafter to or through the salt body itself. If the cavern sidewalls were close to the edge of the dome, or if fragments of formation (having porosity and permeability) originally laid down with the salt were in contact with the edge, cavern extension by freshwater displacement could conceivably intersect such areas to create a potential escape route. The skirts of salt domes quite often are "faced" with shale or anhydrite and if this condition existed at the contact point mentioned above, it would block any such escape. This leakage mechanism is similar to that shown in Figure 2.

OIL TRAPS

It should be emphasized that discussions relating to the mechanism of leakage which follow apply only to salt dome solution caverns containing stored *crude oil* (see Figs. 1, 2, 3, 4, and 5 referred to below). Most of these effects would be quite different if products of high vapor pressure were in storage.

It is a generally accepted fact that solution channels and vugs in cap rock as well as subsurface formations having porosity and permeability, are filled with some type of fluid or gases. They are generally filled with water and all are under some pressure due to the geostatic overburden, the reservoir pressures exerted by the "up dip" column on the fluid, or a pressure created by the difference in specific gravity of fluids and gases (or oil). A classical example of the latter is the reservoir pressure in a salt dome "overhang" that creates a gas or oil trap (see 4, Fig. 1).

In respect to the actual mechanism of product "escape" from the cavern: It should be obvious that a certain magnitude of force must act on the oil to drive it through an escape route and that it must go somewhere once it has left the cavern. The compressive forces in the salt mass, the brine and the crude oil are three such forces. These forces might be depleted fairly quickly. The only remaining force would be the small head differential between the oil and the fluids above it. In the latter case the direction of migration would certainly be upward. Figure 1 shows the various "traps" that are known to occur around a salt dome and it is almost a certainty one or more of them would exist there. If oil did escape it would eventually accumulate in such "traps." There is no reason to believe the oil could not be recovered—oil operators have been producing hydrocarbons from such traps for years.

Casing seat failure. Assume the casing seat of a crude oil storage cavern fails (see 2, Fig. 2) while the well is "shut in" which creates an oil escape channel into a loss of circulation (L.C.) zone 300 feet above the casing seat, and that this loss of circulation zone will support a column of brine to within 100 feet of ground level. Oil will move out of the cavern, due to relieving of its compression and that of the salt envelope, until the pressure previously exerted by the 100-foot column of brine (approximately 52 psi) is balanced out. At that point only salt creep forces act to drive more oil from the cavern. It is a definite possibility that oil could also escape by displacement—for each barrel of water that flows from the loss of circulation zone into the cavern, a barrel of oil will be "displaced" from it through the escape channel. Displacement could continue to take place until sufficient oil has accumulated in the L.C. zone to "cut off" water flow into the cavern. The surface manifestation of such an incident would be oil side wellhead pressure drop to zero (or on a vacuum), a brine side wellhead pressure drop to zero (and on a vacuum), the brine in the tubing would drop to 100 feet below ground level, the oil/brine interface in the cavern would rise by the amount of oil loss to the escape channel (as determined by an interface survey and in reference to the sonar caliper "strapping"). Decompression "escape" could take place fairly rapidly depending on the flow area (pressure drop) of the channel, the volume of oil and brine in storage (volume of decompression) and the size of the cavern (volume of salt decompression). The volume of oil escaping due to displacement would likely be at a much slower rate and would be a function of the escape channel size—this slowing of escape rate could be detected by frequent (or constant) interface survey. Where would the oil go? Naturally, since it has a lesser specific gravity than water, it would rise to the highest point occupied by water in the L.C. zone. Presuming the L.C. zone was not in communication with formations above it having porosity and permeability, oil would continue to move into that space until decompression and/or displacement had caused it to fill the volume occupied by the water in the L.C. zone. When the water was displaced back to its point of exit in the down dipping permeable sands at the skirts of the dome the escaped oil would be for all intents and purposes, a potential oil producing zone with a water drive. There are several cap rock oil fields on salt domes of the Gulf Coast that came into being, obviously as a result of natural forces, in this very manner. It might be difficult to locate the high point of the "oil trap" and the trap might have to be produced by pumping after a short flowing interval; but a fair percentage of the escaped oil could be recovered. Incidentally, if the displacement waters were removed from the cavern by a bottom hole pump, at the same rate as they were entering, the oil remaining in the cavern (after decompression) would stay in place.

Washout to edge of salt dome. It is doubtful that any appreciable volume of oil would escape to a sand having porosity and permeability that was intersected by a cavern washout to the flank of a salt dome (Fig. 3). Most of these sands are tilted upward by salt plug penetration, have appreciable bottom hole pressure, are "pinched off" by the impervious salt mass and are overlaid by impervious beds of shale. Oil would float on top of the formation water and

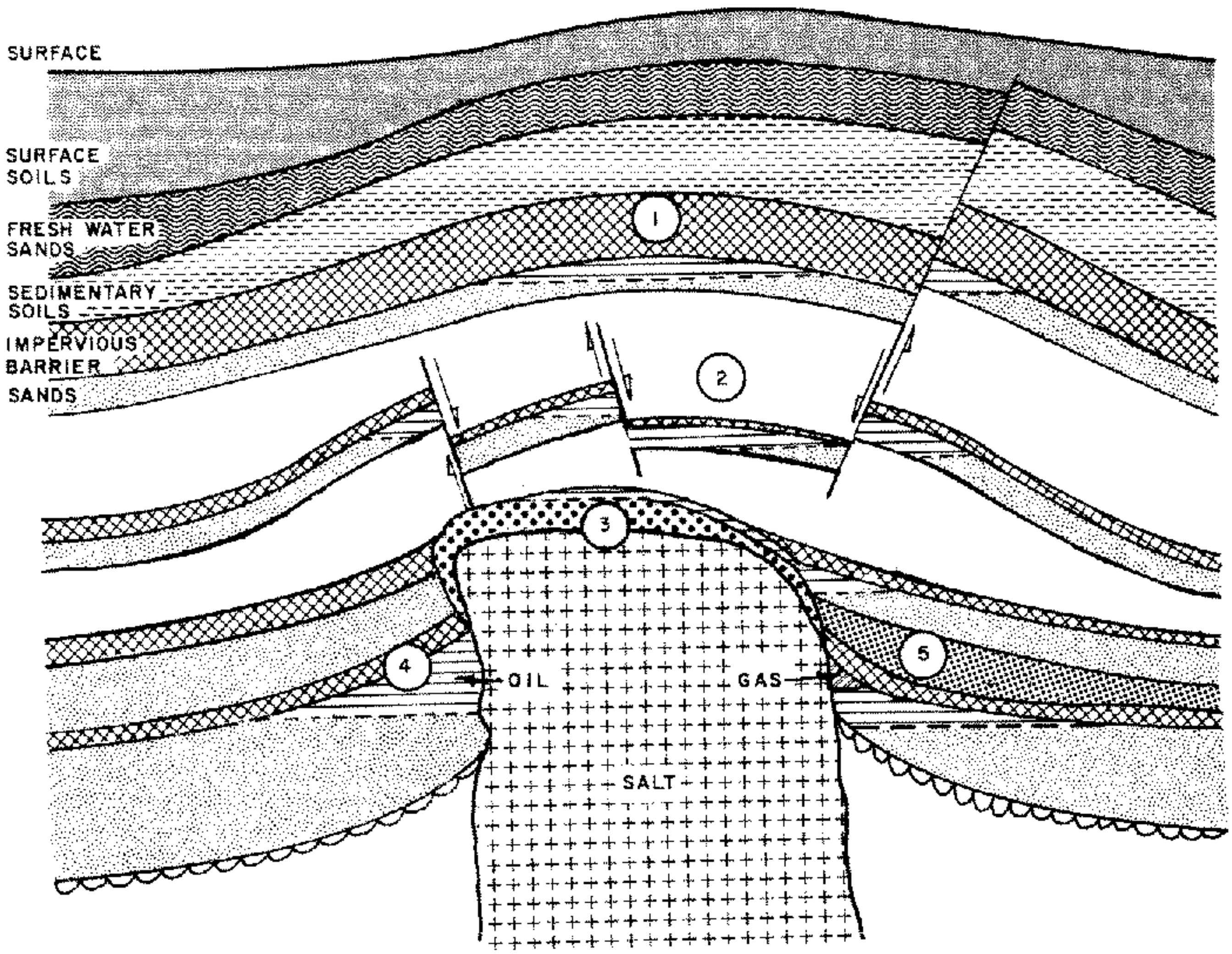


Figure 1. Types of hydrocarbon traps associated with salt domes. 1) domal anticline draped over salt, 2) graben fault over dome, 3) porous cap rock with oil at high point, 4) trap beneath overhand and 5) trap uplifted and buttressed against salt plug.

could move into such sands until a pressure equilibrium were reached. The remaining stored oil could be pumped (not displaced) from the cavern with essentially zero loss. If the sand zone extended above the washout point, oil would "float" into that area until the oil level in the cavern was at the same elevation as the upper edge of the escape route (Fig. 3). In this instance, the oil filled sand section would be a typical salt flank oil trap and could be produced by conventional methods, and the oil in the cavern above the upper edge of the escape route could be recovered by pumping.

Casing leaks. If the borehole has been cased and cemented across the loss of circulation zone in the approved manner (i.e., with an outer casing in contact with the corrosive waters and an inner casing with a cement sheath between it and the outer one), the likelihood that the inner final cemented casing string would be subjected to corrosion is extremely remote; however if only one casing were set and a hole did develop in it opposite the L.C. zone, oil could escape from the cavern. The comments made in reference to oil movements from a casing seat leak would hold equally true; however, the rate of loss would be much lower, depending on the size of the hole, both during decompression and displacement. This type of leak could be repaired with oil in the cavern and can be detected and located by various means.

Wellhead failure. If a wellhead were sheared completely off, the volume of stored oil escaping should equal the decompression volume. After this volume had been released, the oil pressure at ground surface would become essentially zero; however, low pressure low flow rate oil escape could continue until forces causing salt creep are equal to the oil head. The volume of the dike around the wellhead(s) of a cavern should be designated to contain this volume. Exhibit B contains formula that can be used to compute this volume.

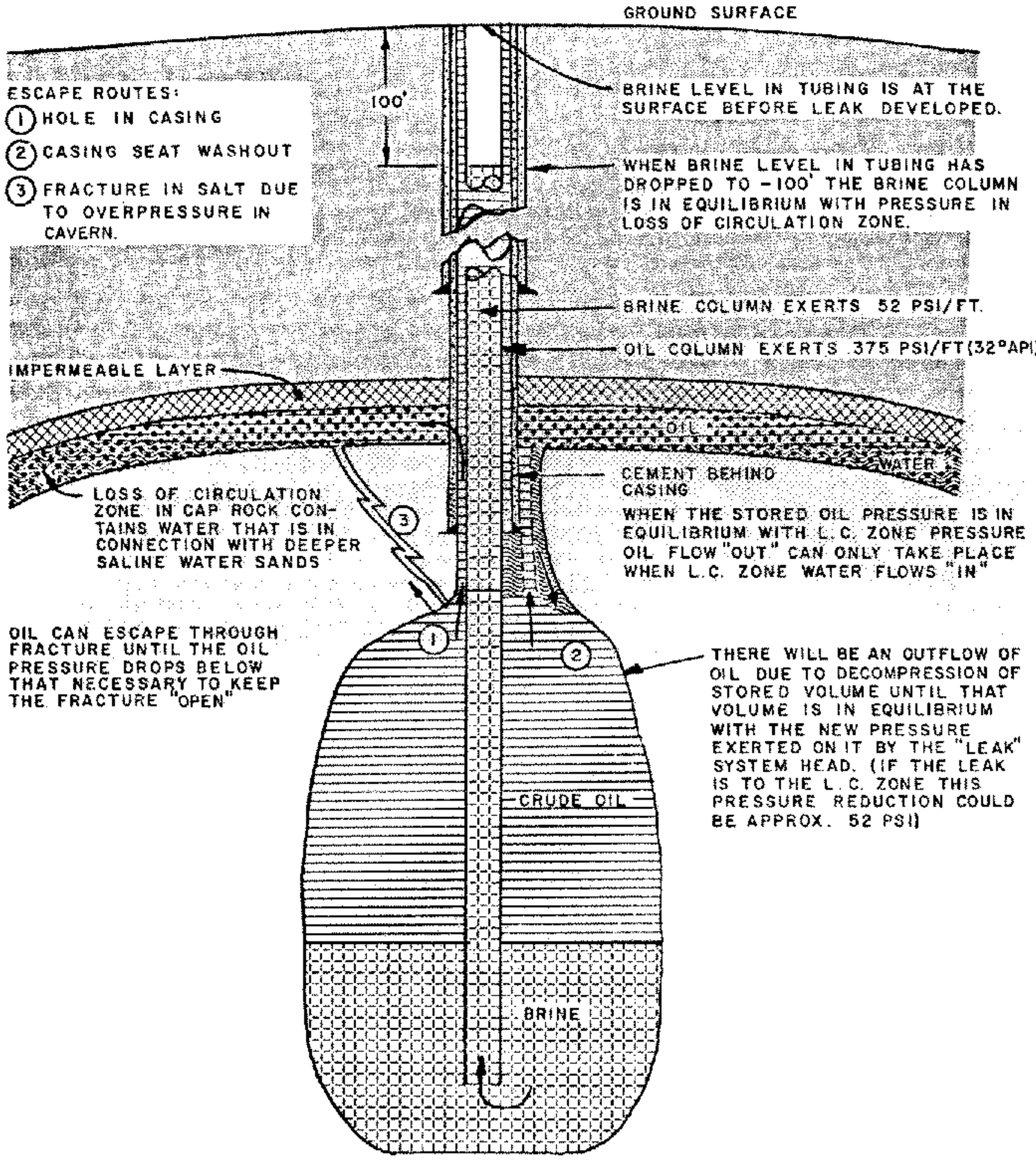


Figure 2. Movement of oil from cavern in event of leak assuming loss of circulation zone in cap rock is at top of salt (see upper left of page for escape route).

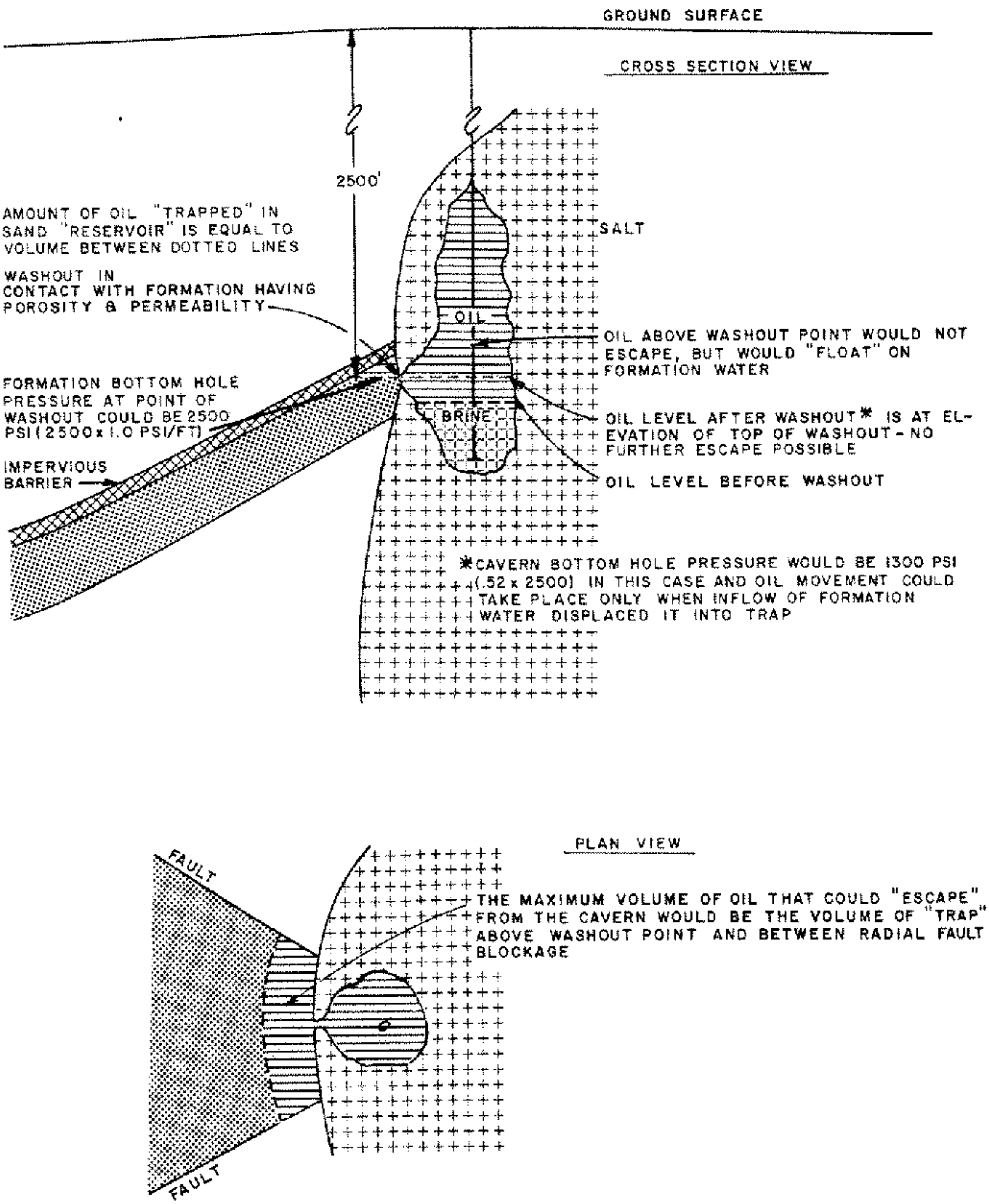


Figure 3. Movement of oil from cavern in event of "washout" to skirt of salt dome.

CAVERN CEILING FAILURE

The question usually arises as to what would happen to oil stored in a cavern in the event failure of the roof caused massive movement of the overburden into the cavern and resulted in formation of a crater on the surface. The uninformed consider this type of failure as being possible and indeed probable. The probability of such an event occurring in a properly designed solution cavern in a salt dome for all practical purposes is nil. There are numerous solution caverns in salt domes having roof spans in excess of 500 feet that are completely stable and usable for or being used in storage service. It is undoubtedly true that a roof fall could occur in a cavern whose ceiling diameter exceeded a certain value; but what is that limiting dimension? Theoretical rock mechanic formulae used in conventional dry mine stability analysis might give some approximation of this limiting span; however, those results seem to be ultraconservative in view of ceiling spans that currently exist in stable caverns. Most theoretical calculations are based on competent homogenous rock and might not be directly applicable to a liquid filled cavern in deep domal salt. It is reasonable to expect that certain stresses would be generated in a flat ceiling and that they could exist in some pattern, perhaps that of the convex surface of a spherical segment, or spheroid. If a roof fall occurred in a solution cavern located a considerable distance within the salt mass, it would be expected that the ceiling would reach a self supporting arched form as the stress field was relieved (see 1, Fig. 4). Since good practice would dictate that the ceiling be protected from further leaching, it would not be expected that further significant stresses would be generated and the roof could be deemed stable.

Can the diameter-to-height ratio of a (spherical segment) roof fall be calculated? If the salt roof fall penetrated to the cap rock/salt interface, what would be the form of the stress pattern in the liquid supported area of the cap rock? Would the cap rock fail in vertical shear? Would a series of roof rock falls occur until a stable roof arch was formed or would they progress to the degree that a substantially sized "hole" through the cap rock were created through which unconsolidated sands and gravels could "flow" into the cavern? (Fig. 5.)

Some cap rock isopach and contour maps show the cap rock to be arched in the vertical cross section. This is not surprising if it is accepted that most of the cap rock is residue left behind as the upper portions of the salt plug were dissolved by flowing waters in formations it penetrated in its upward movement. It may also be presumed that, during the growth phase of the salt plug, a positive force in excess of the geostatic head was exerted on the cap rock in contact areas no longer subject to ground water leaching. The forces exerted by the salt plug on the underside of the cap rock are either greater than or equal to the geostatic head at that point depending on whether the plug is still moving upward or has become static. If the salt ceiling above a solution cavern is of sufficient thickness to transmit or maintain these salt plug forces on the underside of the cap, most authorities would agree there is little danger from failure of the cap rock in the reverse direction. If the thickness of the cavern salt ceiling continually decreased until the underside of the cap rock were exposed, the cap rock (arch) would be subjected to a force equal to the difference in weight between a brine column (.52 psi/ft.) subtracted from the geostatic column (1.0 psi/ft.). Assuming the arched cap rock body were a rigidly held plate, 8000 feet in diameter, 500 feet thick (150 feet of competent anhydrite as its base rock) and the depth to the top of the salt were 600 feet, it would seem a 300-foot diameter exposure of the cap rock, supported on its circumference by the surrounding salt mass, would not fail in vertical shear under a 290 psi load. If it is accepted as "doubtful" that the exposed cap rock would fail, under the conditions set out above, then any increase in thickness of the salt ceiling should progressively reduce the probability of that occurrence. Any knowledgeable salt producer or storage cavern developer will maintain a minimum salt ceiling thickness by adjusting the oil or gas "pad" to such an elevation it will prevent salt solutioning closer than 100 feet to the casing seat of the final cemented casing string to prevent washouts behind the casing and movement of fluids upward through such channels into the L.C. zone above the salt. The salt interval between the casing seat and the top of the salt is considered a "seal area," and is a security measure. Most salt producers set the final cemented casing string at least 150 feet inside the salt, whereas storage operators would set it at least 300 feet inside—and considerably deeper if required to give an acceptable safety factor for casing seat operating pressures.

It should be emphasized again that the following comments are based on crude oil as the stored product. In any event, and regardless of the mechanism of failure or the probability of it ever occurring: Assume that cratering to the surface did occur outside an area where surface waters could enter the crater. (If surface water were allowed to enter the crater at an unlimited flow rate and volume, the oil displaced from the storage cavern could spread over a very large surface area.) Oil would be displaced from the cavern by the formations falling into it. If a substantial volume of fragmented rock fell into the cavern, some "bulking" would take place, but its interstitial space would eventually be filled by inflowing formation water. Most of the oil in the cavern would be displaced from it by rock, sand or gravel and water. The initial appearance of oil at the surface would likely be in the form of a jet spurting above ground level before cratering had progressed to any substantial degree. This would be a manifestation of the sudden decompression of the oil volume and the upward velocity it had attained rising through fluidized formations of much higher specific gravity which would exist in the collapse vortex. This flow might continue for a matter of hours but

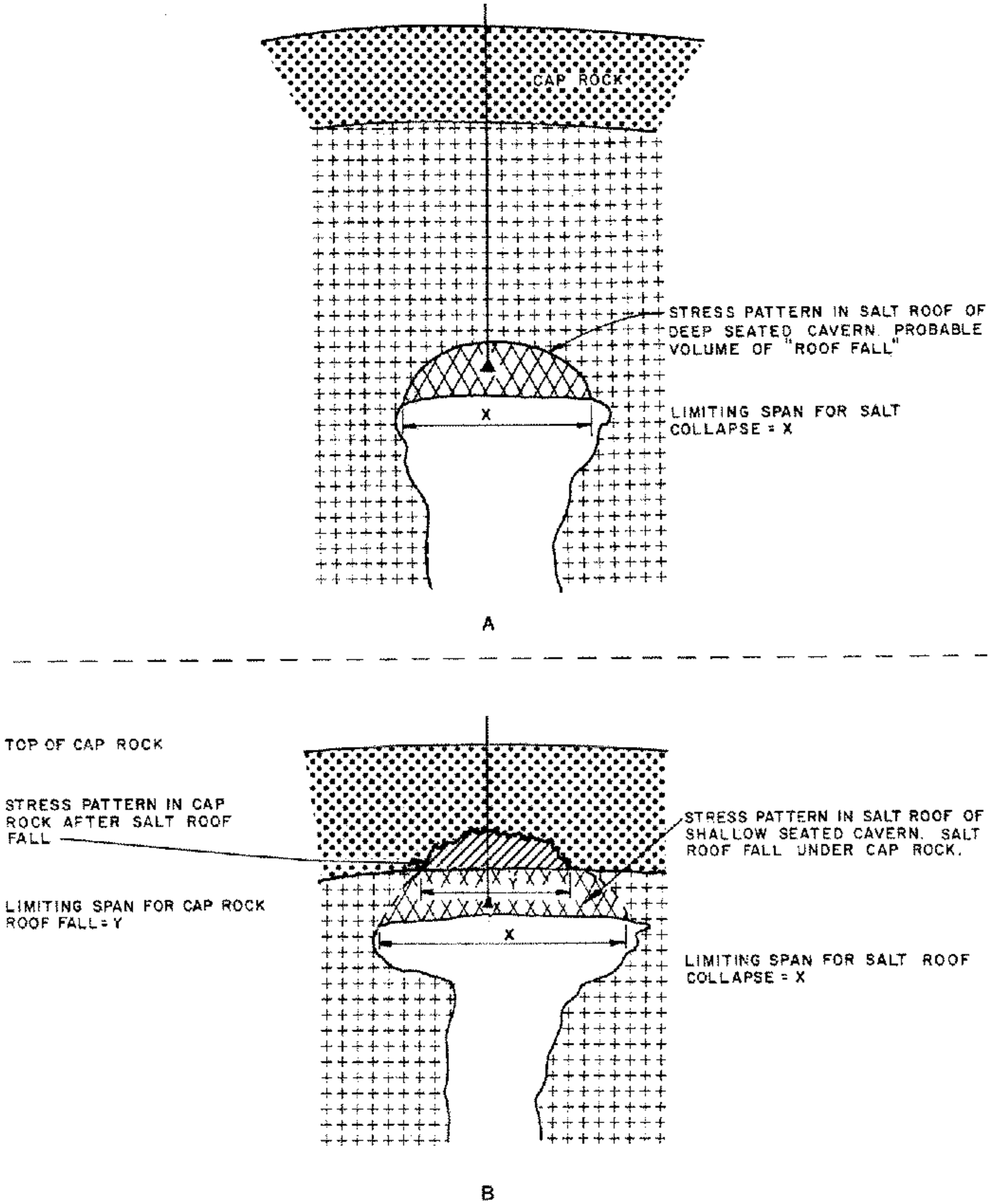
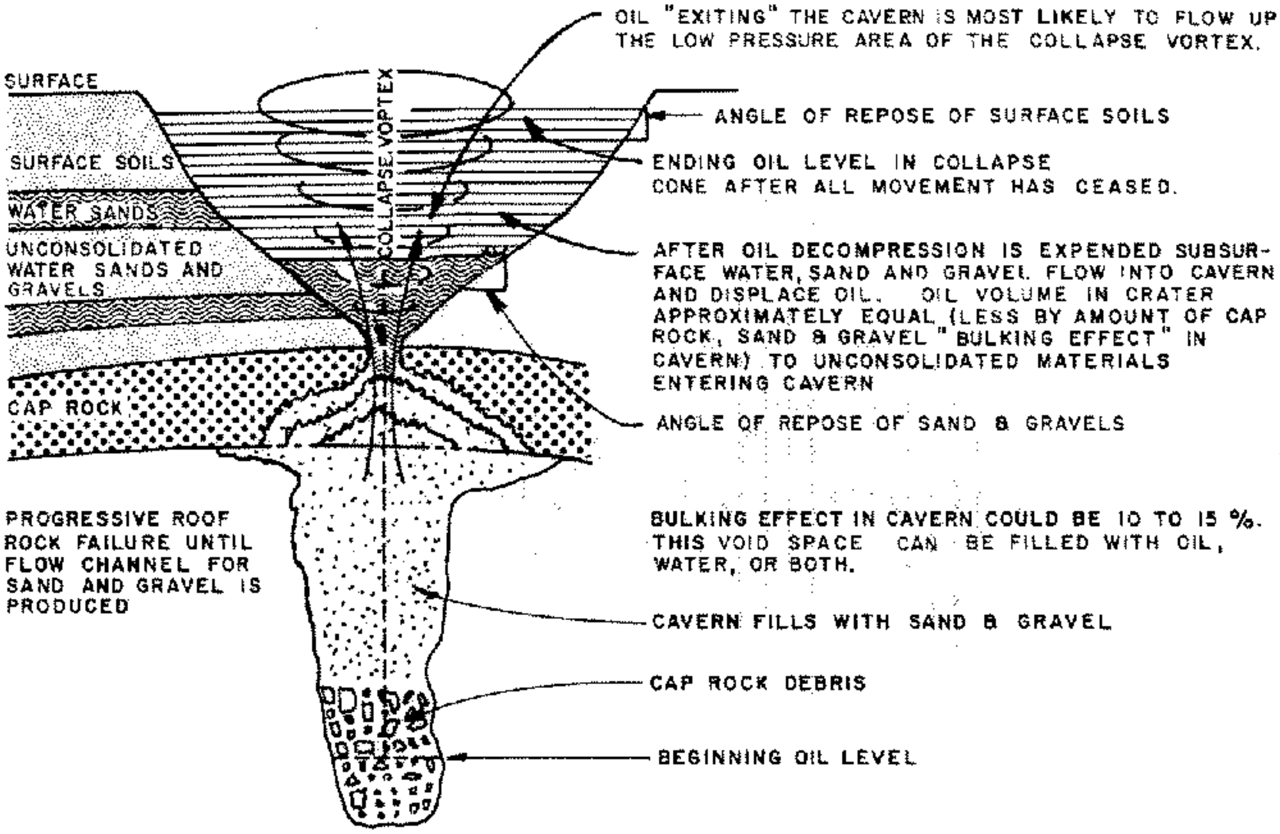


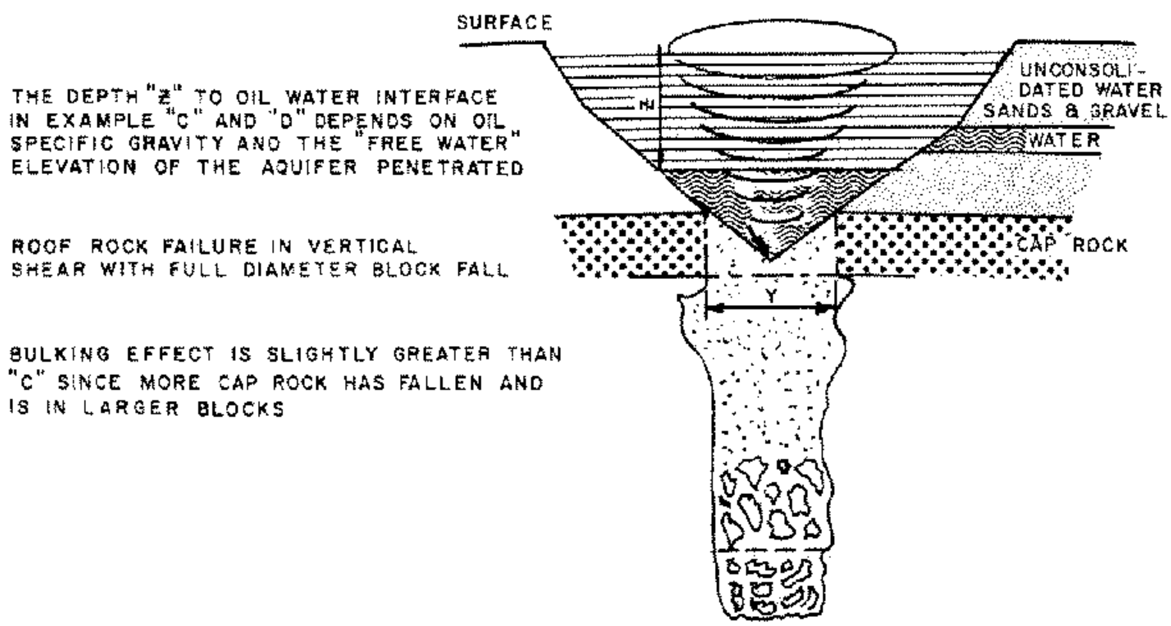
Figure 4. Modes of cavern roof failure. a) Deep seated cavern. b) Shallow seated cavern. c) Progressive roof failure producing flow channel. d) Full block form of cap rock failure.

Fig. 4/Continued



MOST LIKELY FORM OF CAP ROCK FAILURE SHOWN IN THIS ILLUSTRATION

C



FULL BLOCK LIKELY FORM OF CAP ROCK FAILURE

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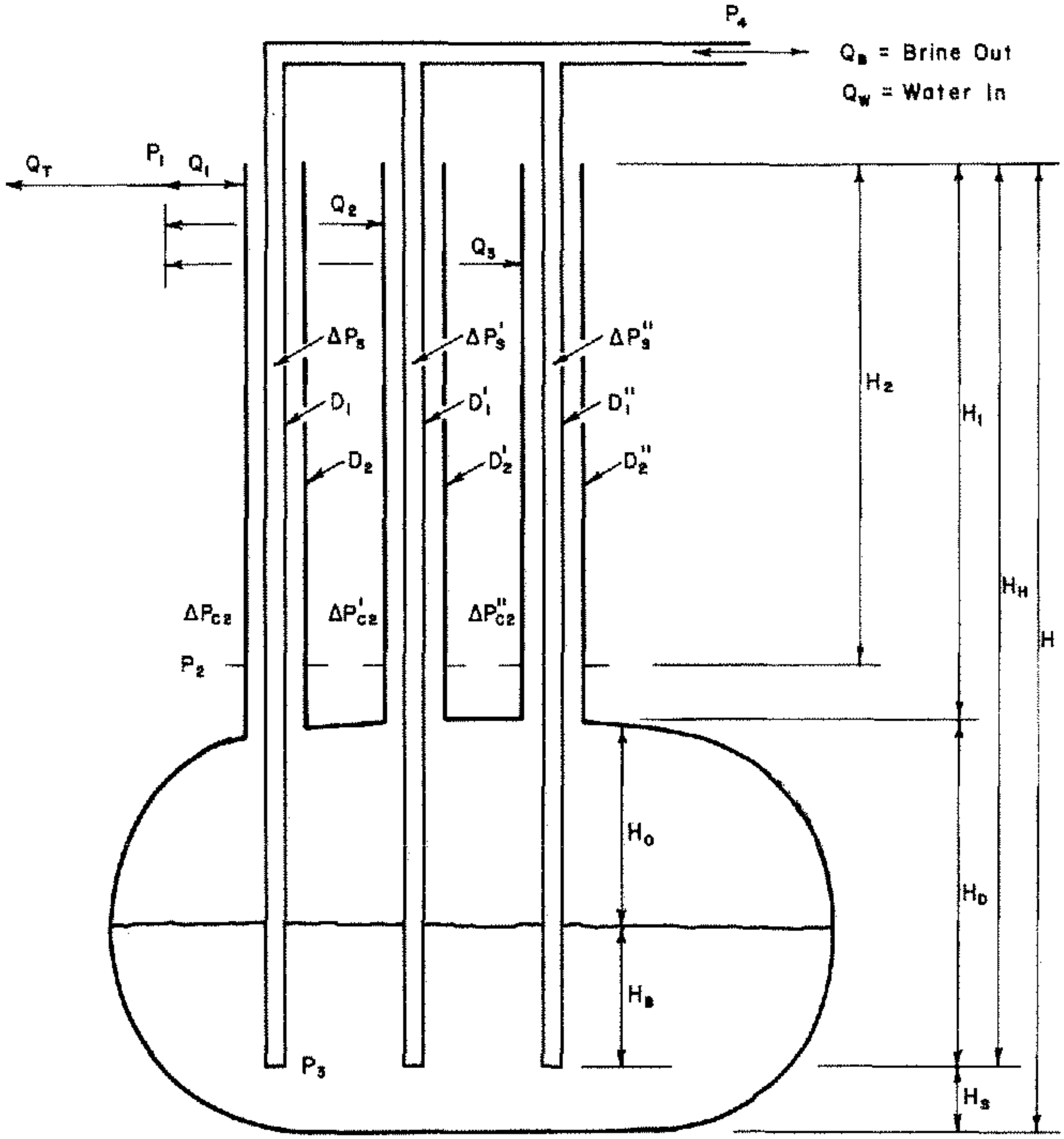

Figure 5. Well hydraulics.

emergency dikes could prevent its spread to drainage courses in the area. As the crater continued to increase in depth and diameter, the decompression forces had been exhausted, and some degree of bulking had taken place inside the cavern—the oil level could drop below the lip of the crater then slowly rise at a rate equal to the maximum production of the subsurface aquifers discharging water into spaces in the cavern that still contained oil. At some point in time, most of the oil would have been displaced from the cavern, the sides of the collapsed cone would have reached their angle of repose and the system would be in a static condition. The oil volume displaced from the cavern would likely fill the crater and might overflow it if the oil head on the aquifer was not enough to offset its reservoir pressure. The size of the crater would naturally depend on the volume of the solution cavern and the degree of bulking the fill material would have taken. The amount of oil in the crater would depend on the volume in storage at the time of the "collapse." The water sands over most salt domes likely would be somewhat convex and would follow the regional dip in areas not affected by the salt dome structure. It is extremely unlikely any oil would "escape" to these water sands—it would instead float on top of the water exiting from them into the crater. How much oil would be lost? Very likely, less than 1% of the volume in storage, presuming all the oil exiting due to decompression could not be recovered or were unusable after recovery, and that some semblance of retainage dikes were thrown up around the crater before the decompression flow stopped. In effect, there would be a "lake" of oil in the crater that could be picked up with pumps and reinjected into other caverns or sold in the marketplace.

FRACTURING OF CASING SEAT OR SALT BODY

It is possible the salt/cement contact area, a vertical or inclined zone of weakness in the salt body, or a combination of the two, could be "fractured" if a pressure of sufficient magnitude were exerted on them (see 3, Fig. 2). If the fracture propagated until it intersected an "escape" route and the pressure necessary to cause flow through the fracture were continuously maintained, oil would leave the cavern. This situation is very "iffy." Centrifugal pumps would normally be used in high flow rate system designs. If the pump was matched to the storage system, it would not be able to put up the head necessary to create a fracture—if they were not "matched", the pump discharge high pressure shutdown and/or relief valve should be set below fracture pressure. The high pressure shutdown on the individual storage cavern wellhead should be set to trigger shut before fracture pressure could be reached. At such time as pumping were stopped or the pressure dropped well below fracture pressure, the fracture would start to close because of the plasticity of the salt and the fact that it was not "propped" open. The fracture could close completely in a relatively short time but would open up at a somewhat lower point if it were overpressured again. In an extreme situation the cavern could become inoperable—particularly if multiple fractures resulted in such a zone of weakness that the cavern could not resist pressures involved in the injection or withdrawal of oil. In the event less than saturated brine were pumped through the fracture, in sufficient quantities to open it up, an unacceptably long period of time might be required for plastic flow to close it and abandonment of the storage cavern would be necessary.

FAILURE BETWEEN ADJACENT CAVERNS

If a solution cavern in storage service were at the same depth or deeper than an adjacent *unusable* cavern and the salt "web" between them were penetrated by solutioning, fracturing, or failure due to its instability, it would be possible for oil to flow across the web area into the unusable cavern (see Fig. 6). Assuming the worst case leakage mechanism—that of a large washout around the casing seat of the *unusable* cavern communicating with a loss of circulation zone—oil moving from the storage cavern would end up in the L.C. zone and be trapped as previously discussed. Under static conditions, and assuming the L.C. zone would support a column of brine to within 100 feet of ground level, the differential pressure across the web between the two caverns would be very nominal—on the order of 100 psi. Under flowing conditions this pressure might be 150 psi. Neither of these forces are significant in terms of a fracture gradient. The hydrostatic pressure test likely would have produced a differential pressure between the two of 2 or 3 times the latter amount. The stresses in the pillar tending to cause buckling (as in an air-filled mine) would also be less due to the brine head. A prudent operator would sonar caliper the usable well after each withdrawal cycle if he were using fresh water for displacement. The web thickness remaining can be determined by comparing previous surveys, corrected for the azimuth and deviation in both boreholes, with the current one. Any unusual solution extensions into the web could be detected. We are still waiting for the theoreticians to develop a rationale that will define the required web thickness-to-height ratio required for stability in a double involuted [ ) ( ] pillar subjected to perpendicular forces decreasing from bottom to top at a rate of 0.52 psi/ft. In adjacent usable caverns these forces would be equal and opposing—there might be some eccentric force, as much as 100 psi difference between the opposing forces, if the adjacent cavern were in communication with an L.C. zone. Leakage through the web is of little consequence if both chambers are storing the same product and the cavern stability is not negated by the coalescence.

We have discussed the following potential leakage mechanisms in solution caverns:

1) Overpressure resulting from surge, 2) Slow decompression, 3) Rapid decompression, 4) Oil trapping (Fig. 1), 5) Casing seat washout (Fig. 2), 6) Washout to edge of salt dome (Fig. 3), 7) Casing leaks, 8) Wellhead failure, 9) Cavern ceiling failure (Figs. 5, B and C), 10) Fracturing of casing seat or salt body (overpressuring) (Fig. 2), and 11) Failure between adjacent caverns (Fig. 6).

The author has presented a paper entitled "Instrumentation and controls for Solution Mined Caverns" in this Symposium Proceedings. It contains discussions and exhibits relating to controls that react to prevent or minimize the effect of failure modes discussed above.

Table 1 shows a list of control and alarm features that could be provided so the storage site operator can detect potential problem areas at the earliest practical time and take the proper action to prevent a crisis.

This paper is not intended as a definitive work on the subject of Leakage Mechanisms or as an assessment of the probability of any particular failure mechanism occurring.

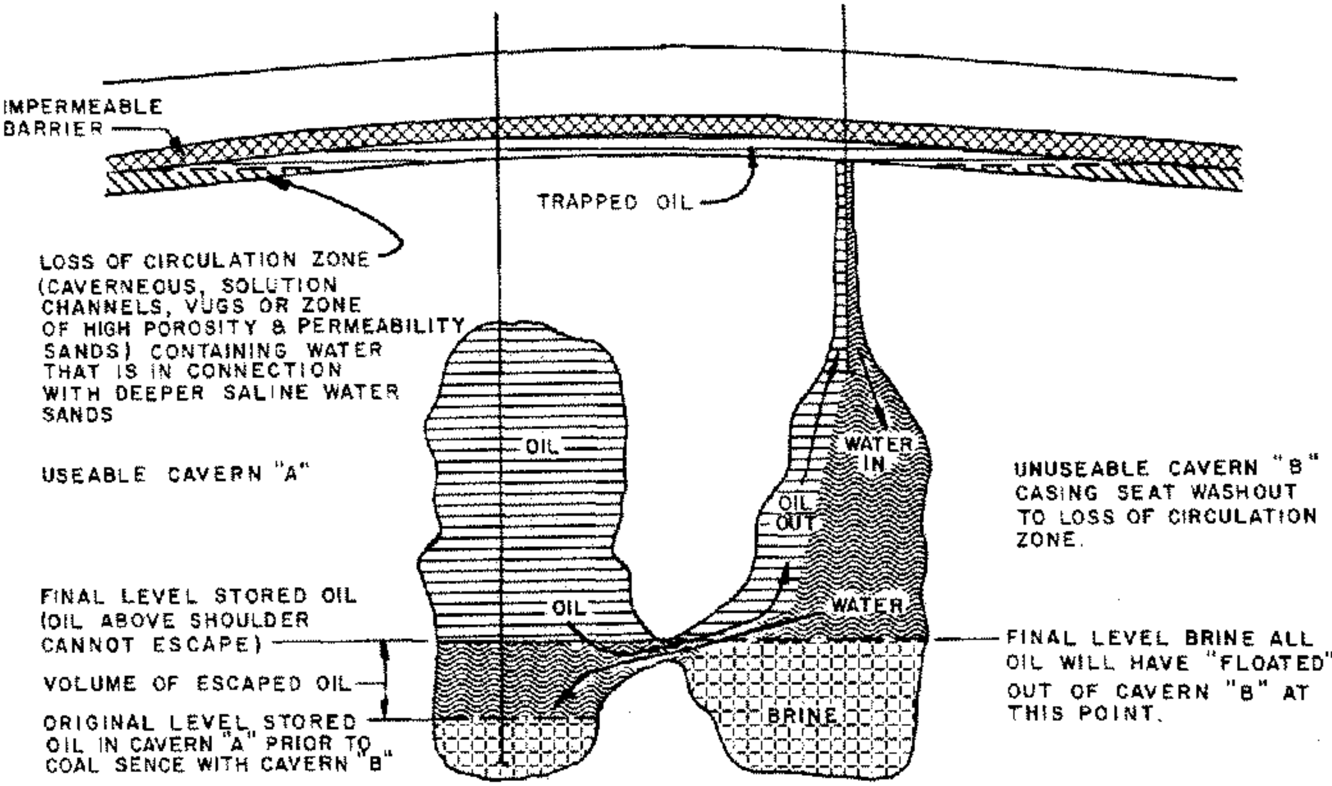

Figure 6. Oil storage configurations in salt domes.

TABLE 1

Storage Cavern Wellhead Instrumentation

Indicators	Local[1]	Console[2]
Oil Injection Cycle		
Wellhead, storage cavern in use 1,(2),(3),(4), etc., on line		IL
Valve position, oil		IL
Valve position, brine		IL
Pressure, oil (casing)	PIT	PR
Pressure, brine (tubing)	PIT	PR
Meter, flow rate, oil in		FI
Meter, flow rate, brine out		FI
Meter volume, oil in, accumulator readout		MTP
Meter volume, brine out, accumulator readout		MTP
Alarms		
Wellhead, Storage Cavern		
Remote Master Shutdown has been triggered		IL (blink)
Wellhead, storage cavern in use 1,(2),(3),(4), etc., off line		IL
Emergency Shutdowns		
Master	ESD	ESD
Wellhead, storage cavern		
Close oil and brine valves		ESD
Pressure, oil, above/below preset limit	ESDA	
Flow rate, oil in, above/below preset limit	ESDA	
Flow rate, brine out, above/below preset limit	ESDA	
Flow rate, oil in versus brine out, variance above preset limit	ESDA	ESD

TABLE 1 (continued)

Indicators	Local[1]	Console[2]
Oil Recovery Cycle		
Wellhead, storage cavern in use 1,(2),(3),(4), etc.		IL
Valve, position, oil		IL
Valve, position, brine		IL
Pressure, oil (casing)	PIT	PR
Pressure, brine (tubing)	PIT	PR
Meter, flow rate, oil out		FI
Meter, flow rate, brine in		FI
Volume, oil out, accumulator readout		MTP
Volume, brine in, accumulator readout		MTP
Alarms		
Wellhead, Storage cavern		
Remote Master Shutdown has been triggered		IL (blink)
Storage well in use 1,(2),(3),(4), etc. Off Line		IL
Emergency Shutdowns		
Master (and remote masters)	ESD	ESD
Wellhead, storage cavern		
Close oil and brine valves		ESD
Pressure, oil, below preset limit	ESDA	
Flow rate, oil out, above/below preset limits	ESDA	
Flow rate, brine in, above/below preset limits	ESDA	
Flow rate, oil out versus brine in, variance above preset limit	ESDA	ESD
Status Panel[3]		
Status lights (lamp "first" out stays lit)		
Pressure, oil, high		IL
Pressure, oil, low		IL
Pressure, brine, high		IL
Pressure, brine, low		IL
Flow direction, oil		
In		IL
Out		IL
Flow rate, oil, high		IL
Flow rate, brine, high		IL
Flow rate, brine, low		IL
Flow rate, oil in/out versus brine out/in exceeds preset limit		IL
Lamp test circuit button		
Local Emergency Shutdown Button (also "test" shutdown valve and sensing end device operation with time delay)		
Non-Standard Instrument Abbreviations Used in Figure 2		
ESDA—Emergency Shutdown—Automatic Trip		
ESD —Emergency Shutdown—Manual Trip		

[1]At or near the storage cavern wellhead
[2]In the operations room
[3]Near the storage cavern wellhead

The discussion of the consequence of such a failure is based strictly on logical reasoning and is not a description of an actual incident. References made to particular situations that could lead to cavern failure make no inference, expressed or implied, that any underground storage cavern or system the author or his company have investigated in the past or during the present time are in such a category. The paper is likely to generate more questions than answers; however, there is a distinct need for resolution of the specific questions raised herein. It should be emphasized also, if there is any doubt in this regard, that the author is not, and does not profess to be an authority on rock mechanics. In some 25 years of involvement in salt solution mining for purposes of developing underground storage caverns, the author has seen, or has personal knowledge of, a wide variety of individual and group cavern configurations that are physical evidence that refutes some of the ratios relating to stability that are derived from classical rock mechanic theories. It is not the author's intention to become embroiled in a controversy with rock mechanics specialists; however, it appears illogical to think solely in terms of "beam strength" when considering the failure mode of roof rocks over salt dome caverns. It would seem anhydrite, which invariably overlays domal salt, should be considered as a plate of infinite dimensions when compared to the diameter of the ceiling of a solution cavern below it. Perhaps calculations using this rationale might explain why there has been but one "crater" type ceiling failure in salt dome solution caverns, whereas many caverns have spans far in excess of that considered tolerable when conventional beam strength formulae are used. It is also difficult not to be skeptical regarding concepts such as pillar over diameter and height over diameter ratios, commonly quoted as prerequisites for solution cavern stability, when there are so many caverns exceeding these ratios which are stable and have been for 20 years or more. Large sums of money have undoubtedly been spent by industry to locate surface facilities outside the potential crater "cone of influence" of a cavern considered to be on the verge of failure, because of undue emphasis on p/d or h/d ratios and "excessive" ceiling spans.

The author has experienced or has knowledge of a few of the specific types of failure mechanisms discussed herein such as leaks from threads, holes in tubing or casing, casing failure, casing seat washouts, and cavern coalescence. It should be understood, however, that in every instance they have been due to poor design, improper or inadequate cementing, or improper (uncontrolled) leaching techniques.

EXHIBIT A

Equations used.

Cavern Storage

A. Flow Pressure Drop Through Tubing

The Darcy Formula will be used to calculate the pressure drop through solution tubing and on-site piping for all fluids, which are, in most cases, brine or brackish water for solution mined sites.

1. The Darcy Formula is:

$$\Delta P = 0.01146 \frac{f s Q^2}{D^5}$$

where:

ΔP = Pressure drop in pounds per square inch (psi) per 1000 equivalent feet
f = Friction factor
s = Specific gravity of fluid
Q = Flow in fluid barrels per day
D = Inside pipe diameter in inches

2. The friction factor, f, is obtained by the following Colebrook-White function:

$$\frac{1}{\sqrt{f}} = -2 \log_{10}\left(\frac{\epsilon/D}{3.7} + \frac{2.51}{R_e\sqrt{f}}\right)$$

where:

ϵ = Absolute roughness of pipe
R_e = Reynolds Number, dimensionless

An alternate method for obtaining f is the use of the L.F. Moody Chart, which shows f as a function of both R_e and ϵ.

An absolute roughness factor, ϵ, of 1600 microinches should be used for cavern tubing.

3. The Reynolds Number, R_e, is obtained as follows:

$$R_e = 92.2 \frac{Q}{DZ}$$

where:

Q = Flow of fluid in barrels per day
D = Inside pipe diameter in inches
Z = Fluid viscosity in centistokes at operating temperature

B. Flow Pressure Drop Through Annulus

The Darcy Formula is used for determining the pressure drop through the annulus, defined as the flow area between the well casing and the well tubing, for solution mined sites. Normally, crude oil is injected and withdrawn through the annulus.

1. The Darcy Formula is:

$$\Delta P = 1.1461 \times 10^{-5} \quad \frac{f L_e S Q^2}{D_e^5}$$

where:

ΔP = Pressure drop in psi
f = Friction factor
S = Specific gravity of fluid (oil)
Q = Flow of fluid in barrels per day
L_e = Equivalent length of casing in feet
D_e = Equivalent diameter in inches

2. The friction factor, f, is determined as given in 3.03, A, 1, a, 2).
3. The absolute roughness factor, ϵ, of 1600 microinches is used for pipe annulus
4. The Reynolds number, R_e, is calculated by the following formula:

$$R_e = 92.2 \quad \frac{D_e Q}{Z(D_2^2 - D_1^2)}$$

where:

D_e = Equivalent diameter in inches
Q = Flow in barrels per day
Z = Fluid viscosity in centistokes at operating temperature
D_2 = Inside diameter of casing in inches
D_1 = Outside diameter of tubing in inches

5. The Equivalent Diameter, D_e, for the annulus is determined by the following equation:

$$D_e = [(D_2 - D_1)^3 (D_2 + D_1)^2]^{0.2}$$

where:

D_2 = Inside diameter of casing in inches
D_1 = Outside diameter of tubing in inches

6. The *total* flow pressure drop through the annulus is determined by:

$$\Delta P_{annulus} = \Delta P_{casing\text{-}tubing} + \Delta P_{casing\text{-}collar}$$

where:

$$\Delta P_{casing\text{-}tubing} = 1.1461 \times 10^{-5} \quad \frac{f\, L_e\, SQ^2}{D_e^5}$$

$$\Delta P_{casing\text{-}collar} = 1.1461 \times 10^{-5} \quad \frac{f\, L_e'\, SQ^2}{D_e^5}$$

L_e = $0.979\ H_2$
L_e' = $(0.02014 + 0.02778\ D_1)\ H_2$

where:

H_2 = Length of casing in feet
D_1 = Outside diameter of tubing in inches

C. Well Hydraulics

A typical solution storage cavern for hydraulic calculation purposes is shown in Figure 5.

The legend for Figure 5 is as follows:

H = Total distance from surface to bottom of cavern in feet
HH = Distance from surface to bottom of tubing (stringer) in feet
H_1 = Distance from surface to top of cavern in feet
H_2 = Distance from surface to bottom of casing in feet
H_0 = Height of oil in cavern in feet
H_B = Height of brine in cavern in feet
H_D = Distance from top of cavern to bottom of tubing (stringer) in feet
H_s = Distance between bottom of cavern to bottom of tubing in feet

Oil injection and oil withdrawal for multiple wells is:

$$Q_T = Q_1 + Q_2 + Q_3 \text{------} Q_n$$

where:

Q_T = Total oil flow for cavern in barrels per day
$Q_1, Q_2, Q_3, \text{------} Q_n$ = oil flow for given well
n = number of wells

For all cavern wells, flow pressure drops through casing are equal and flow pressure drops through tubing (stringer) are equal,

$$\Delta P_c = \Delta P_c = \Delta P_c = \Delta P^n_c, \text{ and}$$
$$\Delta P_s = \Delta P_s = \Delta P_s = \Delta P^n_s$$

where:

$\Delta P_c, \Delta P_c, \Delta P_c, \Delta P^n_c$ = Pressure drop through well casing (annulus) in psi
$\Delta P_s, \Delta P_s', \Delta P_s'', \Delta P^n_s$ = Pressure drop through well tubing (stringer) in psi

1. Oil Injection

P_4 = Desired brine out wellhead pressure in psi (Normally, P_4 = 25)
$P_3 = P_4 + 0.433\ S_B\ .HH + \Delta P_s$
$P_2 = P_3 - [0.433\ S_B\ .H_B + 0.433\ S_o\ (H_0 + H_1 - H_2)]$
$P_1 = P_2 - 0.433\ S_o\ H_1 + \Delta P_c$

where:

P_1 = Oil wellhead pressure in psi
P_2 = Pressure at casing bottom in psi
ΔP_s = Pressure drop through tubing (stringer) in psi
ΔP_c = Pressure drop through casing (annulus) in psi
S_o = Specific gravity of oil (heavy or light)
S_B = Specific gravity of brine

Maximum: Cavern full and light oil injected

$$P_1 = P_4 + 0.433\ HH\ (S_B - S_o) + \Delta P_s + \Delta P_c$$

Minimum: Cavern empty and heavy oil injected

$$P_1 = P_4 + 0.433\ H_1\ (S_B - S_o) + \Delta P_s + \Delta P_c$$

2. Oil Withdrawal:

P_1 = Desired oil wellhead pressure in psi
$P_2 = P_1 + 0.433\ S_oH_2 + \Delta P_c$
$P_3 = P_2 + [0.433\ S_oH_o + 0.433\ S_w\ H_B]$
$P_4 = P_3 - 0.433\ S_w\ HH + \Delta P_s$

where:

P_4 = Pressure at brine/water wellhead in psi
S_w = Specific gravity of water (brackish)

Maximum: Cavern empty and heavy oil withdrawn

$$P_4 = P_1 - \Delta P_5 + \Delta P_6 + 0.433 \, [HH \, (S_B - S_w) - H_2 \, (S_B - S_o)]$$

Minimum: Cavern full and light oil withdrawn

$$P_4 = P_1 + \Delta P_5 + \Delta P_6 - 0.433 \, HH \, (S_w - S_o)$$

3. Maximum allowable pressure at casing point

$$P_{max} = 0.9 \, H_2$$

where:

P_{max} = Maximum allowable pressure at casing bottom in psi
H_2 = Distance from surface to bottom of casing in feet

Design pressure at casing point:
$P_{max} = 0.9 \, H_2 \times 0.9 = 0.81 \, H_2$

If P_{max} exceeds P_2 in performing well hydraulics for a particular cavern, then an additional new well will be required.

4. Brine/Brackish Water Flow
Oil Injection:

$$Q_T = Q_B$$

where:

Q_T = Total oil flow into cavern in barrels per day
Q_B = Total brine flow from cavern in barrels per day

Oil Withdrawal:

$$Q_w = 1.05 \, Q_T$$

where:

Q_w = Total brackish water flow into cavern in barrels per day
Q_T = Total oil flow from cavern in barrels per day

EXHIBIT B

RELEASE VOLUME FROM A CRUDE OIL FILLED SOLUTION CAVERN UPON TOTAL DECOMPRESSION

There have been no wellhead failures recorded by industry. Wellheads are generally the most overdesigned portion of the storage system having S.F. of from 3.0 to 5.0. They have a low profile and high mass. It is deemed highly unlikely that any accidental failure of a wellhead would occur.

Oil spillage determination. The loss of oil is based on the decompression of the stored oil, the brine, and the salt surrounding the cavity. The compressibility effects are additive. The calculation basis is given below.

1. Crude Oil

$$\Delta V = 5 \times 10^{-6} \, \Delta v/v/psi \times \Delta P \times V$$

where,

$5 \times 10^{-6} \, \Delta v/v/psi$ = compressibility of oil
V = volume of oil in cavern, barrels
ΔP = oil wellhead pressure drop, psi or average pressure difference of stored oil at operating and static conditions, psi
ΔV = oil losses, barrels.

2. Salt Cavern

$$\Delta V = 2.9 \times 10^{-7} \, \Delta v/v/psi \times psi \times V_s$$

where,

$2.9 \times 10^{-7} \, \Delta v/v/psi$ = compressibility of salt (see notes 1, 2, 3)
V_s = volume of surface salt under imposed stress, barrels
psi = oil wellhead pressure drop, psi, or average pressure difference of cavity at operating and static conditions, psi
ΔV = oil losses, barrels

and,

$$V_s = 0.18 \, A \times D \text{ (see note 4)}$$

where,

A = surface area of cavern, $ft.^2$
D = depth of salt under imposed pressure, ft.
0.18 = conversion factor ($ft.^3$ to barrels)
Let D = 10 feet conservative or worst case.

3. Brine

$$\Delta V = 2.1 \times 10^{-6} \, \Delta v/v/psi \times \Delta P \times V \text{ (see notes 1 and 2)}$$

where,

$2.0 \times 10^{-6} \, \Delta v/v/psi$ = compressibility of brine
V = volume of brine in cavern, barrels
ΔP = pressure difference of brine in cavity at operating and static conditions, psi
ΔV = brine losses, barrels.

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4. The degree of uncertainty as to the coefficient of compressibility of in situ domal salt and its elastic/plastic behavioral characteristics at depths where the great majority of solution caverns are developed is very significant. Considerable empherical data is being generated in the SPR Program.