Recommended Practice for the Design of Solution-mined Underground Storage Facilities

API RECOMMENDED PRACTICE 1114
SECOND EDITION, JANUARY 2013

AMERICAN PETROLEUM INSTITUTE

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Downstream Segment

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Recommended Practice for the Design of Solution-mined Underground Storage Facilities

1 Scope

This recommended practice (RP) provides basic guidance on the design and development of new solution-mined underground storage facilities. It is based on the accumulated knowledge and experience of geologists, engineers, and other personnel in the petroleum industry. Users of this guide are reminded that no publication of this type can be complete nor can any written document be substituted for qualified, site-specific engineering analysis.

All aspects of solution-mined underground storage are covered, including selecting an appropriate site, physically developing the cavern, and testing and commissioning the cavern. Additionally, a section on plug and abandonment practices is included.

This RP does not apply to caverns used for natural gas storage, waste disposal purposes, caverns which are mechanically mined, depleted petroleum reserve cavities, or other underground storage systems which are not solution-mined.

See API 1115 for guidance in the operation of solution-mined underground storage facilities.

2 Normative References

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

API Recommended Practice 5A3, *Recommended Practice on Thread Compounds for Casing, Tubing, and Line Pipe*

API Recommended Practice 5C1, *Recommended Practice for Care and Use of Casing and Tubing*

API Bulletin 5C3, *Bulletin on Formulas and Calculations for Casing, Tubing, Drill Pipe, and Line Pipe Properties*

API Specification 6A, *Specification for Wellhead and Christmas Tree Equipment*

API Standard 1104, *Welding of Pipelines and Related Facilities*

API Recommended Practice 1115, *Recommended Practice on the Operation of Solution-Mined Underground Storage Facilities*

ASME[1] , *Boiler and Pressure Vessel Code*, Section IX, “Welding and Brazing Qualifications”

3 Terms and Definitions

For the purposes of this document, the following definitions apply.

3.1
blanketing material
A fluid less dense than water and incapable of dissolving salt.

NOTE This is usually a light hydrocarbon liquid injected as a protective barrier between the solution-mining brine and casing-salt interface is usually used to control cavern development.

[1] ASME International, 3 Park Avenue, New York, New York 10016-5990, www.asme.org.

3.2
brine
A saltwater solution said to be saturated when the maximum salt per unit weight has been dissolved [approximately 26 % by weight at 68 °F (20 °C)].

3.3
caprock
A mantle composed chiefly of anhydrite, gypsum, and limestone.

3.4
casing seat
A cement base formed at the bottom of the casing, providing both an anchor and pressure containment barrier.

3.5
casing, conductor
The pipe placed within the drilled hole intended to protect the shallow water sands against contamination and to protect the drill site from sloughing-in during shallow drilling operations.

NOTE Line pipe is typically used for this large outside diameter pipe string.

3.6
casing, intermediate
The casing placed in the top of competent salt that covers all lost circulation zones to ensure complete cementing on the production casing.

3.7
casing, production
The principal casing forming the annulus through which stored products pass. Its diameter should be large enough to accommodate hanging of solution-mining and brine strings.

3.8
casing, surface
Casing that is set to a depth below potable water strata and cemented to the surface to protect all potable water sands against contamination and the borehole against lost circulation.

3.9
cavern storage
An underground cavity developed either by solution mining (leaching) of a salt formation or by conventional excavation for the purposes of storing liquid or gaseous products.

3.10
christmas tree
An assembly of valves, actuators, sensors, chokes, pressure gauges, and spools installed on top of the wellhead to control flow into and out of the tubing and tubing-casing annulus.

3.11
circulation, direct
The flow during solution mining in which fresh water is introduced into the salt formation through the center string with the brine then returned through the casing or string annulus.

NOTE This is the opposite of reverse circulation.

3.12
circulation, reverse
The flow during solution mining in which fresh water is introduced into the salt formation through the casing or string annulus, with the brine then returned through the center string.

NOTE This is the opposite of direct circulation.

3.13
collapse pressure
Pressure that, when applied to the exterior of a pipe or vessel, causes the pipe or vessel to collapse.

3.14
competency
A term applicable to geological formations indicating a relative degree of mechanical and structural integrity.

3.15
convergence
The time-dependent decrease of cavern storage volume due to creep. It is also dependent upon the internal cavity pressure.

3.16
creep
The geological process that causes salt and other evaporatives to flow into subsurface voids that are operated at a significantly lower pressure than the pressure exerted on the walls of the cavity by the formation.

3.17
dispersant
A material used to lower the consistency of cement to allow turbulent flow at lower pumping rates and to reduce pumping pressure.

NOTE Common dispersants include alkyl aryl sulfonate, polyphosphate, lignosulfonate, and certain organic acids.

3.18
effluent
The brine formed during the solution-mining process that may carry along an amount of insoluble material for surface disposal.

3.19
gradient, operating
The pressure gradient [pounds per square inch (psi) at the casing seat per foot of overburden] existing during cavern operation and is a function of the mode of operation (brine, product injection, or withdrawal), the rate of fluid injection or withdrawal and its relative density, and the tubing or casing string sizes.

3.20
gradient, pressure
A parameter expressed as the ratio of pressure per unit depth (usually pounds per square inch per foot) and is used to determine the stress limitations of an underground formation.

3.21
solution mining
The process of dissolving a solid material, generally for the purpose of forming a void or cavity.

NOTE An example is the creation of underground storage in a salt formation through fresh-water injection and brine removal.

3.22
lenticular
Lens-shaped.

3.23
lithology
The study or characterization of rock formations.

3.24
log
A graphic representation of a subsurface feature obtained through any of several techniques (for example, gamma-ray absorption or sonar).

NOTE Typical applications are density logs for locating cavern tops or casing setting depths; sonar logs for internal cavern configurations; and interface logs that, when plotted against metered volume, can provide a guide for determining product volume.

3.25
mud
The material used to facilitate the drilling process through cooling and lubricating action, removing cuttings from the hole, controlling subsurface pressures, cleaning the bottom of the hole, and releasing cuttings at the surface.

3.26
overburden
The strata lying above the salt formations, generally sedimentary in character and composed of sands, shales, limestones, chalk, and anhydrites.

NOTE The depth of the overburden may vary from a few feet to several hundred feet.

3.27
piercement
A descriptive term applied to salt domes that have pierced subsurface formations.

3.28
pillar
A descriptive term applied to the residual structural salt that acts as both separating wall and roof support in adjacent, communicating cavern spaces.

3.29
pozzolan
A cement additive of siliceous or aluminous material, including fly ash, used to provide increased resistance to sea water, sulfate bearing soils, reactive aggregate, or natural acid waters.

NOTE Substituting pozzolan materials for equal weights of cement increases the relative bulk of fine material, thereby improving workability and reducing bleeding and segregation.

3.30
porosity
The ratio of the aggregate volume of interstices in a rock or soil to its total volume, or the percentage of void space in the formation.

3.31
product
Refers to material stored in a cavern, usually a liquid or gaseous hydrocarbon.

3.32
product string
An uncemented string hung inside the production casing, concentric with and outside of the brine string which allows product production or injection without allowing the flow to contact the production casing.

NOTE 1 This is also known as blanket string.

NOTE 2 This string is useful in cases where severe corrosion might occur or where it is desirable to be able to remove the casing for inspection along with the brine string.

3.33
rheology
The science of dealing with the deformation and flow of matter.

3.34
salt, bedded
A type of salt basin resulting from compressive tectonic forces (halotectonism).

3.35
salt, domal
A type of salt plug resulting from autonomous, isostatic salt movement (halokinesis).

3.36
seal-pad material
Synonymous with blanketing material (see 3.1).

3.37
sonar caliper
A device using acoustical wave reflection technology to ascertain the internal configuration of an underground space.

3.38
spool
A general term applied to a short pipe section that is flanged at both ends and used to couple other functional piping elements.

3.39
stope
Steplike excavations or formations relating to cavern geometry.

3.40
string
A general term applied to piping or casing suspended from the wellhead. The centermost string extends close to the cavern bottom and is used for brine injection and removal in operational caverns.

3.41
tubing (brine) string
The last string of pipe or casing placed in the well and is run inside the production casing to near the bottom of the cavity.

NOTE 1 Tubing is designed to be retrieved from the well and differs from other tubular strings that are normally cemented in place.

NOTE 2 Tubing that meets API standards normally ranges up to 4$^1/_2$ in.; however, for high-rate application, substantially larger pipe sizes may be required. In these instances, casing that meets API standards may be used as tubing.

NOTE 3 Nomenclature “tubing string,” “displacement string,” “brine string,” and “displacement string” are used synonymously in this document.

3.42
web
The in-situ mass separating adjacent underground caverns and is subject to pressure differentials resulting from varying modes of cavern operation.

3.43
well
The cased hole created to provide access to an underground cavern.

3.44
wellhead
The ground-level surface equipment used to maintain control of the well, including the connecting casing heads, tubing head, and christmas tree.

4 Overview of Underground Storage

Storage of products in solution-mined salt caverns has been utilized in the United States since the late 1940s. Today, storage of hydrocarbon liquids and liquefied petroleum gases in caverns developed in both domal and bedded salt formations is utilized throughout the world.

Salt caverns can act independently as long term, seasonal storage vessels; or they may serve as short term, operational storage. Caverns can also be inserted into the production plant/pipeline systems to prevent supply interruptions when maintenance or emergency shut downs occur or to "float" on pipelines to optimize operations.

Site selection for solution-mined underground storage is based on numerous considerations, including a study of the geologic formation to be utilized. Proper drilling and casing-cementing procedures are essential to ensure the integrity of the storage cavern. Cavern development is accomplished by injecting water to dissolve the salt mass and displace the resulting brine.

Before the product is injected initially, the storage cavern is full of brine. Injecting product displaces brine and maintains a liquid filled cavern. Product is withdrawn from the cavern by displacing it with brine or water.

5 Applicable Rules and Regulations

The creation or operation of solution-mined underground storage facilities is often regulated by federal, state, or local codes, regulations, ordinances, or rules. A review of the applicable rules and regulations is required prior to or in the initial stages of design of a solution-mined underground storage facility.

6 Salt Storage Overview

6.1 General

A solution-mined salt cavern for commodity storage is created through the planned solutioning of a naturally occurring bedded or domal salt formation. Solution mining simply requires exposing the salt formation by drilling a well, circulating fresh or low-salinity water in the well, and withdrawing the brine from the cavern. The salt in the formation dissolves, enlarging the well bore to form an even larger cavern.

The shape of the cavity depends on the solutioning procedure employed. The typical storage cavern resembles a cylinder, with the height several times greater than the diameter. The relatively small roof area enhances the probability of effective product recovery and minimizes the probability of the roof collapsing during service.

Concentric tubing strings are generally used to move stored product in and out of the cavern. A large U-tube is created for the flow, and because of the differences in densities between the product stored and the brine, a manometer effect is created. A simplified salt-dome storage cavity is illustrated in Figure 1.

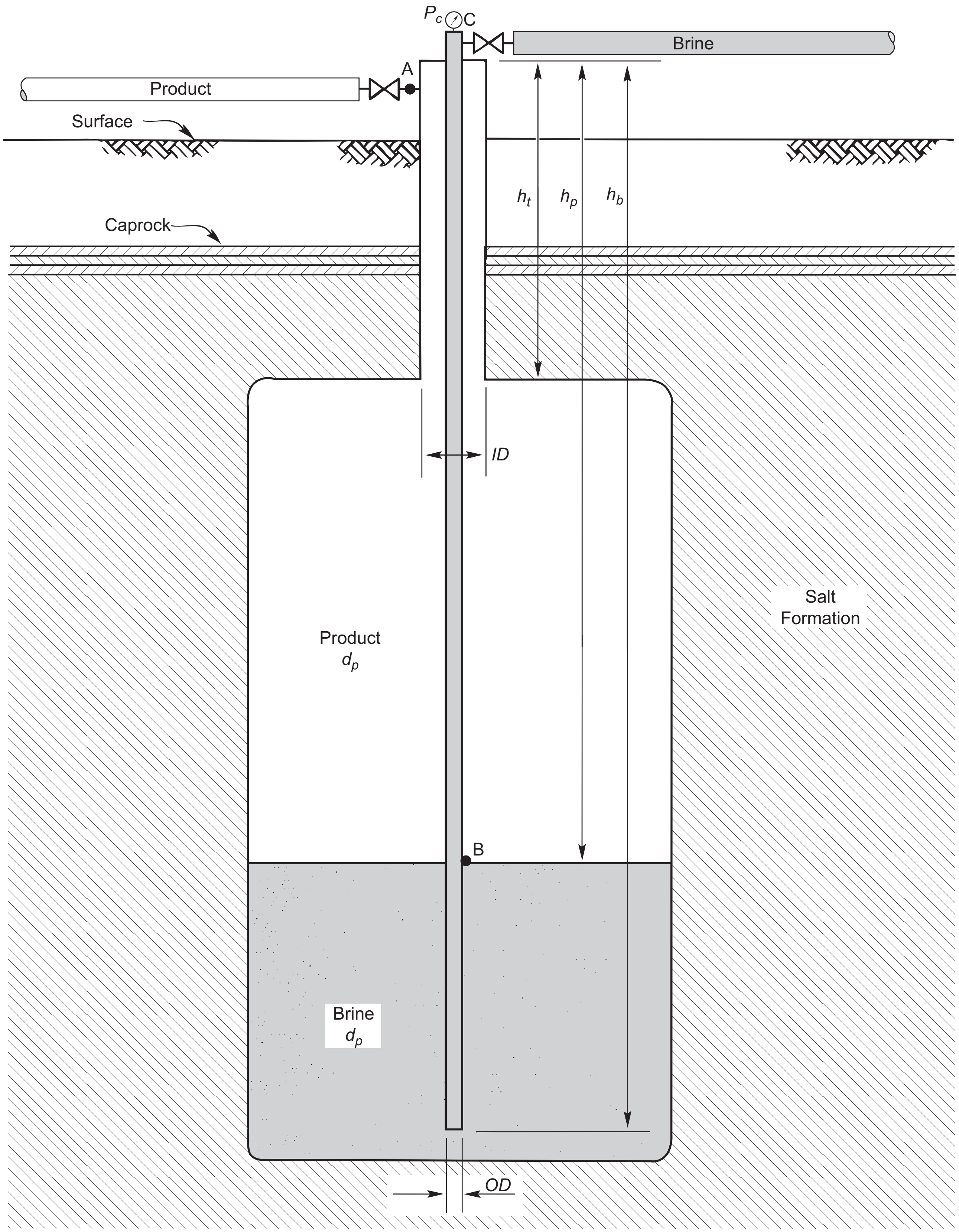


Figure 1—Simplified Salt Dome Storage Cavity Schematic

Injecting product is accomplished when the product is supplied to the wellhead at sufficient pressure to allow movement down the production casing and tubing annulus into the top of the cavity. This forces a corresponding movement of brine or water out of the cavity up the brine tubing string.

Product is withdrawn by reversing the injection process. In this case, brine is pumped into the cavity, forcing a corresponding movement of product out of the cavity up the tubing casing annulus.

Dry caverns do not use a displacement fluid and instead rely on downhole pumps to deliver product from the cavern. Dry caverns may be appropriate where high-ingress but low-egress flow rates are required.

6.2 Components

6.2.1 Tubing Strings

The common tubing string configuration includes a single tubing string (brine string) concentrically suspended within the production casing or a combination of a tubing string and a blanket string concentrically suspended in the production casing. The blanket string should be considered if high corrosion rates are expected or if it is desirable to pull and inspect the casing at a later date. The production casing, tubing, and blanket casing (if so equipped) shall be designed to accommodate the required flow rates, cavern pressure limitations, and surface equipment capability.

6.2.2 Wellhead Equipment

The wellhead equipment must be designed to properly contain, direct, and isolate the flow of stored product and displacement fluid into and out of the storage cavity. The wellhead equipment must be capable of withstanding the maximum possible product pressure on both the brine and product sides to provide protection against overfilling or tubing failure. Wellhead pressure sensing equipment must be provided that will aid in detecting leaks in the brine string, leaks in surface product or brine lines, or overfilling with product.

Shut-in valves capable of being remotely actuated should be provided on the wellhead. For some possible failures, these actuated valves should be automatically controlled (for example, in the event of low or high pressures, outside the safe operating range, in either the surface product or brine lines).

Another consideration in the wellhead design is the production casing pack-off (or secondary) seal. This seal is exposed to high-pressure product for the life of the well. Consider making this a highly reliable seal such as an elastomer with adequate extrusion control devices. If a blanket string is installed, it is usually hung in a mandrel much like the brine string.

6.2.3 Surface Facilities

6.2.3.1 General

Surface facilities to be considered for solution-mined cavity storage projects may include brine and fresh water systems; flare systems; product piping; injection pumps; compressors; product dryers and related equipment; pipelines and pipeline meter stations; and general support facilities such as control buildings, roads, and fire protection.

6.2.3.2 Brine and Fresh-water Systems

The brine system may require each of the following elements.

a) A brine sourcing or producing facility, such as a dedicated source well or storage cavity under development.

b) A brine storage facility, such as a surface brine pit.

c) A brine distribution facility, with brine pump or pumps to provide the pressure necessary for product displacement and a degassing facility.

d) A fresh-water flushing system to periodically dissolve incrusted salt in the brine tubing strings and return lines.

e) A brine disposal facility to accommodate the excess brine normally generated from storage operations. Disposal could involve the sale of brine, injection into approved subsurface strata, or approved disposal at sea.

6.2.3.3 Flare Systems

A properly designed flare system shall be provided to burn or contain the flammable gases that may be released from the brine system. The flare system should also be designed to handle the volume of gas that will have to be vented in all emergency shut-in situations. This will include the flare rates that will occur between the time a wellhead shut-in occurs and the product fill system can be shut down, and the flare rates that will occur between the time a tubing overpressure is sensed and the wellhead can be shut-in.

6.2.3.4 Product Piping and Related Equipment

All product piping and related equipment shall be designed, installed, and operated in accordance with appropriate industry codes and/or government regulations.

7 Design Parameters

7.1 General

Salt storage caverns can be used for hydrocarbon storage when a suitable salt formation is conveniently located, when the volume of storage required is sufficiently large, when the product to be stored is compatible with the salt, and when the hydraulic requirements can be economically satisfied. The project life must be identified in the project definition stage.

7.2 Available Salt Formations

The first requirement is a suitable salt formation at an acceptable depth at the required location. Maps showing locations of suitable domal and basin salt formations are available through geological data sources.

7.3 Product Characteristics

The stored product must be nonreactive with salt, water, or carbon steel and can be considered only slightly soluble in salt or water.

The physical and chemical properties of the stored product must be known, including gravity, viscosity, compressibility, solubility, pressure-volume-temperature (PVT) characteristics, and stability in water. In liquid products, the volume of entrained free water must also be known.

Stored products will absorb compounds from the salt formation and/or the displacement fluid. With high-purity products, these trace materials can affect product quality. Salt dome structures differ in the nature and quantities of these contaminants (such as methane, carbon dioxide, hydrogen sulfide, and heavier hydrocarbons). These trace gases and liquids are produced into the brine and are then transferred into the product or can be directly produced from the cavern into the product. The product can also absorb contaminants, not introduced by the salt formation, from the displacement fluids. Dissolved oxygen or nitrogen from sourcing or surface storage of brine can also be transferred into the product.

7.4 Storage Volume Required

7.4.1 General

Setting the required cavern volume should be based on the overall logistics plan for the stored product, including provisions for fluctuating demand and supply or transportation delays or restrictions. Special considerations inherent in the design of a salt storage cavern are discussed in 7.4.2 through 7.4.6.

7.4.2 Displacement-fluid Handling Facilities

Except for dry caverns, salt caverns require displacement-fluid handling facilities. The capacity of the cavern itself must be matched with a combination of brine storage, a brine disposal system, and a brine sourcing system.

7.4.3 Compressible Fluids

Storage cavern capacity normally is stated on a volumetric basis, such as barrels. However, with highly compressible fluids where density varies with pressure and temperature, consideration should be given to using a design based on mass. Where the storage pressure greatly affects the storage density (as with ethylene), cavern depth will greatly affect the mass storage capacity of a cavern for a given volume.

7.4.4 Intentional Operational Solution-mining

Cavity capacity can be deliberately solution mined while operating as a storage facility. One such method would be to initially solution mine a cavity to partial size, enabling product storage in the top of the cavern. Solution-mining tubing then is positioned to solution mine the bottom of the cavern to the desired shape and volume, with the stored product acting as a blanketing material. Another method would be to use fresh water as the displacement fluid until the desired cavity configuration is achieved. Both methods require carefully designed and controlled solution-mining programs to produce the desired cavern geometry.

7.4.5 Traps (Attics)

Care must be taken during solution mining to avoid the creation of traps (or cavity space) above the final product production casing string. During storage operations, such space will fill with product, which cannot be recovered. An insoluble hydrocarbon blanketing material should be used during the solution-mining phase to minimize attic creation. Provision should be made to monitor the level of the blanketing material during the solution-mining phase.

7.4.6 Cavern Dynamics

Cavern size will change over time due to two opposing processes: creep closure and operational solution mining. As discussed in Section 9, the formation of a cavern creates stresses in the salt formation causing creep of the salt to close the hole. This effect increases with greater depths (due largely to increased temperature) and with lower cavern operating pressures (relative to the in-situ pressure of the formation).

At the same time, displacement caverns continue to solution mine new space due to less than saturated brine and due to the introduction of free water in some stored products.

7.5 Displacement-fluid Characteristics

7.5.1 Saturation

Except in dry caverns, the displacement fluid will normally have a greater density than the product being stored. The common fluid material density of aqueous sodium chloride salt solutions varies from fresh water to totally saturated brine. The degree of saturation (density or gravity) will affect the hydraulics and operational solution-mining rate and is the most important displacement-fluid property to be considered during design.

7.5.2 Fluid Corrosivity

Displacement fluids may contain atmospheric gases, primarily oxygen (O_2) and nitrogen (N_2). High O_2 concentrations affect the corrosion rates on tubing strings and other elements of the system. Where O_2 concentrations are high, consider deoxygenizating the brine, special metallurgy, or coatings. Also, where high-purity olefins are to be stored and O_2 and N_2 concentrations were high in the fresh water used to solution mine the cavity, the brine remaining in the cavity after solution mining should be removed and deoxygenated prior to introducing product.

7.5.3 Rainwater

Atmospheric pits are commonly used to store brine. These pits will collect rainwater that will reduce the level of brine saturation. The difference between the anticipated rainfall and the evaporation rate for the site, together with the surface area of the brine pit, should be considered when evaluating the effects of operational solution mining on cavity design.

7.5.4 Hydraulic Restraints

The required flow rates in and out of a storage cavern must be identified to properly size the casing program operating tubing strings and brine pumps or the casing and downhole pump in the case of a dry cavern. Required operating pressure in a cavern must be known to help set the depth of the cavern. The properties of the product to be stored can influence the cavern depth and should be considered.

7.5.5 Project Life

The planned life of the cavern must be identified, both in terms of years and in terms of turnovers prior to commencing design work.

8 Required Knowledge of Salt Structure and Associated Geology

8.1 General

Prior to designing a salt cavern facility, knowledge of the structure, geometry, formation anomalies (including existing and planned storage caverns), tectonic-induced stresses, and fracturing must be obtained.

8.2 Geometry of the Salt Formation

8.2.1 Preliminary data

Information about the geology and geometry of the formation, including the overburden strata, should be accumulated prior to commencing design work on the salt cavern storage facility. All available information on the properties of the salt in the formation also should be collected. In established cavern fields, the location, depth, diameter, and operating pressure of all caverns within 10 diameters of the planned cavern should be gathered.

This information will often be available from old drilling logs, cores, and seismic work. When drilling the borehole, log data and cores should be correlated with the existing information and the design work confirmed.

8.2.2 Types

Salt formations are either bedded sedimentary formations or intrusive salt formations (including domes and ridges). Bedded formations often underlie large basins, with relatively thin salt beds [less than 1000 ft (about 300 m) thick] often separated by beds of porous or impervious layers of other sediments.

Domal salt formations have intruded from roots in deeply buried salt beds, and tend to be plugs a mile or more in diameter with great depth. The intrusion process of 10 displaced overlaying strata causes formations of strategic traps on the flanks of the dome, where oil and gas accumulations are often found. The overlying strata or caprock is often a complex, heavily fractured, and porous strata.

8.2.3 Depth and Thickness

Knowledge of the physical location and dimensions of the salt beds and any nonsalt layers that might become part of the cavern is critical to design work.

In bedded salt, knowledge of the depth and thickness of the overburden rocks is often required.

Domal salt geometry is often more difficult to define, as the flanks may be very irregular and even overhung and the caprock poorly defined. Seismic surveys may be required if the cavern is to be installed within 500 ft (approximately 150 m) of the flank of a dome.

8.3 Faulting and Structural Anomalies

Faults in the surrounding formations that intersect the salt formation should be noted and recognized as areas to avoid intersecting with a well bore.

Where possible, identify anomalies in the salt formation and consider them in the design. Insoluble layers or intrusions and any permeable layers must be considered in the design of the cavern.

8.4 Overburden Structure

Particularly in the development of bedded salt caverns, information on the thickness and strength of the overburden rock layers is required because these layers are part of the structural support for the cavern.

Any water-bearing strata must be identified and the drilling plan developed to ensure against introducing cross communication between water strata and between the water strata and the salt formation.

8.5 Location of Nearby Existing Caverns

The development of storage caverns in salt introduces stresses in the salt formation. The design of the cavern should consider the stresses induced by all caverns, operating or abandoned, within a radius equal to the height of the cavern.

Consider the interaction of all caverns in the formation when developing caverns in densely developed cavern fields.

8.6 Salt Properties

Proper design of a salt cavern requires knowledge of the in-situ stress state and the mechanical properties of the salt. In the case of high-purity products, knowledge of the entrained contaminants is also required.

While stress state and mechanical properties can be assumed for design, core samples taken in a manner to preserve in-situ conditions should be analyzed and compared with the design assumptions, when possible.

9 Cavern Design Criteria

9.1 General

In designing salt caverns for hydrocarbon storage, consider the cavern's salt formation geometry, the cavern operating pressures, the in-situ stress state, and the mechanical properties of the salt (and in some cases the mechanical properties of the overburden layer) to reduce susceptibility to possible cavern failures. The following failures must be prevented.

a) Fracturing the formation or casing seat by cavern operating pressures.

b) Loss of volume due to creep closure of the cavern system, with the potential for resulting surface subsidence.

c) Cavern roof collapse or sidewall slabbing with hazards to casing strings and the potential for surface subsidence caused by rapid depressurization of the cavern.

d) Washout to the edge of the salt formation.

e) Unplanned coalescing of adjacent caverns.

9.2 Setting Cavern Depth

The roof of the cavern must be set deep enough to accomplish the following.

a) Provide sufficient salt thickness between the cavern roof and the caprock to ensure adequate roof support of the overburden. In bedded formations, the strength of an impervious, overburden layer may be used to provide roof support.

b) In domal salt, the cemented production string should be deep enough to adequately seal in the salt below the caprock. The recommended depth of the production string is a minimum of 300 feet (about 100 meters) below the top of the salt. The cavern roof should be below the casing seat.

c) The production casing seat depth shall be set so that the formation fracture gradient exceeds the maximum cavern operating pressures.

The cavern bottom should not be set excessively deep because temperature increases with depth. As temperature increases, so do salt-creep rates and, therefore, closure rates. With displacement caverns, depth also increases the pressure required to inject into the cavern; and with dry caverns, increases the required downhole pump static head.

9.3 Cavern Shape Considerations

Theoretically, a spherical cavern is the most stable cavern shape. An inverted cone shape and arched roof is generally considered an acceptable alternative. While the arched shape of the roof is preferred, flat roof caverns can be designed to have adequate strength and integrity.

In designing and solution-mining the roof, care must be taken to prevent attics that will trap product. Shaping and control of the roof is generally achieved through control of the blanketing material fluid level during cavern formation.

In designing the cavern, develop space below the brine string to permit accumulation of insolubles, both from initial and operational solution-mining activities.

9.4 Cavern Spacing Constraints

9.4.1 Optimum Salt Formation Utilization

Suitable salt formations located in logistically important areas represent an extremely valuable resource whose use should be optimized.

9.4.2 Structural Integrity Concerns

9.4.2.1 Creep Closure

Increasing the density of caverns in a formation decreases the salt web area while increasing the differential stress in the salt formation. The differential stresses result from the difference between the in-situ pressure of the overburden on the web and the operating pressure of the open cavern. When these stresses exceed the octahedral shear strength of the salt, visco-plastic or elastic creep starts, resulting in lost cavern volume over time. If a cavern field is not properly designed, the salt creep can lead to both capacity loss and surface subsidence, which can cause excessive stresses on tubing strings in the immediate area.

Proper analysis of the design of a cavern field involves the following:

a) assessment of the in-situ lateral stresses;

b) the range of operating pressures in the cavern;

c) the structural properties of the salt over the full height of the caverns;

d) in bedded formations, the properties of the overburden rock layer in the stress field.

This analysis should be performed by engineers or geologists experienced in such work to determine the proper separation of caverns to prevent closure rates in excess of acceptable limits.

Generally speaking, the required separation distance between wellheads divided by the average diameter of the caverns (P/D) will increase with increasing depth in order to maintain adequate salt strength and cavern operating pressures.

The designer must consider the effects of operational solution mining over the life of the facility in determining the P/D ratios. The recommended approach is to use the final theoretical solution-mined diameter at the end operating life of the facility in determining D.

The designer should consider a master plan for a facility before the first cavern is designed.

9.4.2.2 Coalescing Caverns

Except where planned, care must be taken to prevent adjacent caverns from solution mining into one another to the point that the web thickness is no longer adequate to prevent the higher pressure cavern from flowing into the lower pressure cavern.

9.4.2.3 Salt Boundary Constraints

The properties of the salt formation may vary near the flanks of domal formation, and the salt may be more fractured or have inclusions not typical of the rest of the dome. Additionally, the shape and location of the flanks may be difficult to determine because of the potential for overhangs and other anomalies. Caverns solution mined within 500 ft (approximately 150 m) of a domal flank need to be carefully analyzed with additional core samples and side scan seismic mapping.

9.4.3 Property Limit Setbacks

Salt caverns in a salt formation interact and affect nearby caverns, regardless of ownership. Joint industry development plans may be required in maturing cavern fields to properly and safely develop the salt underlying the property boundaries. In the absence of agreement between adjacent property owners, wellheads should not be placed closer to any other cavern in the formation than twice the sum of the diameters of existing and planned caverns. In no case should wellheads be closer than 100 ft (approximately 30 m) from the property line, and the cavern walls must be not closer than 50 ft (approximately 15 m) from the property line.

Some regulations require certain setbacks and should be adhered to for that particular case.

10 Cavern Hydraulics

10.1 Static Pressure

Displacement caverns generally use concentric tubing strings to move stored product in or out and the displacement fluid out or in. During solution mining operations fresh water moves in and brine out through concentric tubing strings. Both operations create, in effect, a large U-tube for the flow and because of the differences in densities between the displacement fluid and the product (stored or produced), a manometer is created. In Figure 1, under static conditions (no flow) the pressure at point B, the product interface, is equal inside and outside the brine tubing string. This pressure equals ($d_b \times h_p$) + P_c, where d_b is the density of the brine, h_p is depth of the interface, and P_c is the static gauge pressure at point C. P_c is referred to as the brine wellhead pressure. It also equals ($d_p \times h_p$) + P_a, where d_p is the density of the product, and P_a equals the gauge pressure at point A. P_a is referred to as product wellhead pressure. By setting these equally, the static wellhead product pressure can be established as follows:

$$P_a = (d_b - d_p)\, h_p + P_c \tag{1}$$

where

P_a is the product wellhead pressure at point A;

d_b is the density of brine;

d_p is the density of product;

h_p is the depth of interface;

P_c is the static gauge pressure at point C.

It follows then that the static wellhead pressure of a cavity empty of product is determined by:

$$P_e = (d_b - d_p)\, h_t + P_c \tag{2}$$

where

P_e is the static wellhead pressure for a cavern empty of product at point A;

d_b is the density of brine;

d_p is the density of product;

h_t is the depth to top of cavity;

P_c is the static gauge pressure at point C.

and a cavity full of product is determined by:

$$P_f = (d_b - d_p)\, h_b + P_c \tag{3}$$

where

P_f is the static wellhead pressure for a cavern full of product at point A;

d_b is the density of brine;

d_p is the density of product;

h_b is the depth to bottom of brine string;

P_c is the static gauge pressure at point C.

Compressible fluids complicate this otherwise straightforward pressure calculation. For example, the density of a 3000-ft (1000-m) column of ethylene varies considerably from top to bottom, and the mean density must be calculated by iteration. Uncertain and changing product temperatures also reduce the accuracy of such wellhead pressure calculations. The accuracy of the wellhead pressure calculation is dependent on variations in brine gravity and product temperature such that calculated wellhead pressure more accurately should be given as a range for compressible fluids.

10.2 Flowing Pressure Drop

10.2.1 General

The displacement cavern tubing strings form a U-tube with displacement medium in one leg and stored product in at least part of the other leg. Flowing pressure drop is associated with cavity tubing strings and requires calculation of the drops in both legs of the U-tube. The common tubing string configuration involves one or two tubing strings hung concentrically within a casing cemented into the salt (see Figure 1).

Flow in one leg, therefore, will be annular flow that is calculated via the method shown in 10.2.2. The brine leg calculation involves a straight pipe pressure drop determination. For multitubing wells, the calculations involve parallel pipe flow.

As with any line sizing determination, operating cost (power) should be compared against initial capital cost (pipe size). With cavity tubing strings, the cost to drill and install larger tubing and casing increases with increased diameter. Cost data to drill and install various size tubing strings are typically evaluated to determine the most cost effective configuration.

Once the size of the cemented tubing string is determined, the sizing of the tubing string can be optimized. The cross-sectional flow area for the brine string generally will be greater than the annular section because of the higher brine gravity, viscosity, and extra pipe length, and because salt will tend to deposit on the brine string. During product filling operations, tubing strings act like an elongated shell-and-tube heat exchanger as the cool product exchanges heat with the earth-heated brine. As the brine cools and becomes supersaturated, the sale deposits on the inner walls of the brine string, reducing the cross-sectional areas and increasing the roughness factor. This leads to increasing pressure drop and, if not occasionally (or periodically) flushed with fresh water, eventually leads to salt bridges that block the flow. Oversizing the brine string flow area relative to the product flow area helps compensate for the higher true flow rates, particularly where cavity fill rates are critical.

When plotting cavity flow rates into a cavity against product wellhead pressure, a system curve typical of a piping system is generated. A plot of flow out of a cavity is similar to a centrifugal pump curve, reflecting the energy storage feature of a cavity. Generating curves similar to those shown in Figure 2 developed in 10.2.3 is required to design injection and shipping pumps and connecting pipelines.

Section 10.2.3 provides an example of pressure drop calculations.

The same hydraulic considerations discussed above govern operating storage cavities and brine production (including source well and cavities being solution mined for storage). The primary differences in brine production are as follows.

a) An insoluble solution-mining cap (usually fuel oil) must be maintained.

b) The solution-mining water is usually injected down the annular space, and the brine returns up the brine string. The solution-mining cap is usually maintained via the annular space between the cemented production casing and the largest hung string, thus reducing the available flow area for fresh water and brine.

Cavity tubing strings 20 in. (50.8 cm) and smaller are typically selected in accordance with API standards for casing. Wellbore tubing strings larger than 20 in. (50.8 cm), and all surface-flow line piping are selected in accordance with API standards for line pipe.

The pressure drop across the wellhead itself is not included in the above discussion. Proper selection of the wellhead must consider the pressure drop, and hydraulic calculations must account for these losses in the calculation.

10.2.2 Sample Problem: Establishing Cavity Depth and Tubing String Sizes

The following is the pressure drop calculation for an ethylene salt dome storage cavity.

Known Information:

a) required storage capacity = 100 million pounds (MM lbs);

b) maximum flow rate into storage = 100,000 pounds per hour (lbs/hr);

c) maximum flow rate out of storage = 100,000 pounds per hour (lbs/hr);

d) cavity temperatures = 90 °F to 120 °F;

e) brine temperatures: 50 °F to 90 °F;

f) pipeline ethylene temperatures = 50 °F to 80 °F;

g) brine gravity = 1.18.

Assume the producing plant's pumps can deliver 1700 pounds per square inch gauge (psig) at 100,000 lbs/hr hour at the wellhead. Also, assume the highest rate case consuming plant or plants require a minimum delivery pressure at the wellhead of 1300 psig at 100,000 lbs/hr.

Look at cavity depth, average diameter, and pressure drops, assuming 13 5/8-in. outside diameter with 0.480-in. wall thickness final cemented string and assuming no storage pumps or compressors will be required.

Step 1: Roughly calculate the depth of the cavity, assuming 100 psig flowing loss in tubing strings, as follows.

a) Empty cavern (top of cavity). A wellhead pressure of 1300 psig flowing or 1350 psig static (P_e) is needed on the product side. Assume 50 psig static (P_c) on the brine side of the wellhead.

$$P_e = (d_b - d_p)\, h_t + P_c \quad (4)$$

or

$$h_t = \frac{P_e - P_c}{d_b - d_p}$$

where (based on Figure 1)

P_e is the static wellhead pressure for a cavern empty of product at point A (1350 psig);

d_b is the density of brine (1.18×62.4 lb/ft^3 = 73.63 lb/ft^3);

d_p is the density of product (18.5 lb/ft^3). Assuming an average product pressure of 1600 psig and a temperature of 100 °F, the density is 18.5 lb/ft^3 (from the ethylene pressure enthalpy diagram);

h_t is the depth to top of cavity (to be determined);

P_c is the static gauge brine pressure at point C (50 psig);

$$h_t = \frac{(1350\ \text{psig} - 50\ \text{psig}) - (144\ \text{in.}^2/\text{ft}^2)}{73.63\ \text{lb/ft}^3 - 18.5\ \text{lb/ft}^3}$$

$$= 3395.6\ \text{ft.}$$

The approximate top of the cavity is 3400 ft.

b) Full cavern (bottom of brine string). A wellhead pressure maximum of 1700 psig flowing (to permit producer plant to pressure product into cavity in all cases) or 1750 psig static (P_f) on the product side is needed. Assume 50 psig static (P_c) on the brine side of the wellhead.

$$P_f = (d_b - d_p)\, h_b + P_c \tag{5}$$

or

$$h_b = \frac{P_f - P_c}{d_b - d_p}$$

where (based on Figure 1)

P_f is the static wellhead pressure for a cavern full of product at point A (1750 psig);

d_b is the density of brine (1.18×62.4 lb/ft^3 = 73.63 lb/ft^3);

d_p is the density of product (20.6 lb/ft^3). Assuming an average product pressure of 1923 psig based on an arithmetic average of wellhead and bottom pressures or (1700 + 2145)/2 = 1923. The bottom product pressure is the long column of compressible product or 1.18 x 0.433 $\times$ 4200 feet = 2145 psi. With a temperature of 100 °F, the density is 20.6 lb/ft^3 (from the ethylene pressure enthalpy diagram);

h_b is the depth to bottom of brine string (to be determined);

P_c is the static gauge brine pressure at point C (50 psig);

$$h_b = \frac{(1750 \text{ psig} - 50 \text{ psig}) - (144 \text{ in.}^2/\text{ft}^2)}{73.63 \text{ lb/ft}^3 - 20.6 \text{ lb/ft}^3}$$

$$= 4616 \text{ ft.}$$

The bottom of brine string should be no deeper than approximately 4600 ft.

From these rough calculations, the cavity can be set at a depth of approximately 3400 ft to 4600 ft and meet all the flow requirements, assuming adequately sized tubing strings are inserted.

Step 2: Size the cavity within the range of depths from Step 1 as follows.

Assume a cylindrical cavity with a midpoint depth of (3400 ft + 4600 ft)/2 or 4000 ft. At this depth, the average pressure will be 1.18 × 0.433 × 4000 ft = 2043 psi. At a maximum cavity temperature of 120 °F, the product density in the cavity would be 18.51 lb/ft^3. To store the 100 million pounds, the cavity must have a volume of 100 million/18.51 pounds per cubic foot = 5.4 million cubic feet.

Assuming that the site development plan calls for development of 100-ft diameter cavities at the depth interval, the cavity must be approximately 5.4 million cubic feet/100$^2\pi$/4 = 687 ft top to bottom, or 700 ft (rounded for this example).

Therefore, a 100-ft diameter cavity could be developed for any 700-ft interval between 3400 ft and 4600 ft. What needs to be assessed are such items as:

a) drilling and solution-mining costs (drilling an extra 500 ft in salt can cost several days of extra rig time alone);

b) the cavity site development plan (other cavities planned at set depth intervals); and

c) future changes in hydraulic requirements (future higher delivery rate flows or pressures).

Also, consider the possibility of developing cavities below the present cavities.

In this example, the assumption will be made that these factors dictate a 100-ft diameter cavity developed between 3500 ft and 4200 ft.

Step 3: Verify as follows the assumed flowing pressure drop of 100 psi thru the product and brine strings.

Looking at a 13^3/8 in. final cemented string, tubing string pressure drops can be investigated. Assume a 9^5/8 in. brine string.

a) Calculate the pressure drop in the product annulus at the maximum flow rate out of storage. Assume the inside diameter (ID) of the cemented string is 12.515 in. and the outside diameter (OD) of the brine string is 9.625 in. To calculate the pressure drop in the product annulus, use the Darcy-Weisbach derived formula as follows:

$$\Delta P = \frac{0.011553(SG)(f)(Q^2)(Y)}{X^3} = \text{psi / 1000 ft} \qquad (6)$$

where

f is the friction factor from Moody Diagram [with Reynolds number (RN) and relative roughness (E/D) from Moody Diagram];

SG is the specific gravity;

Q is the flow rate in barrels per day (bbl/d);

Y is the ID in inches of outer pipe + OD in inches of inner pipe;

X is the ID in inches^2 of outer pipe – OD in inches^2 of inner pipe;

$\frac{E}{D} = \left(\frac{E}{0.0833}\right)\left(\frac{Y}{X}\right)$ = relative roughness for product annulus;

$$RN = \frac{92.24(Q)}{[\text{viscosity of product in centistokes (cSt)}](Y)}$$

To obtain density, calculate average cavity pressure:

$$1500 \text{ psi} + (0.433 \times 1.18 \times 3500 \text{ ft})/2 = 1645 \text{ psi}$$

With an assumed average temperature of 120 °F, the density is 15.4 lb/ft^3 (from the ethylene pressure enthalpy diagram).

To obtain specific gravity:

$$SG = \frac{15.4}{62.4}$$

To convert flow rate from lb/hr to bbl/d:

$$(100{,}000 \text{ lb/hr})/15.4 \text{ lb/ft}^3 = 6500 \text{ ft}^3/\text{hr}$$

$$= 1157 \text{ bbl/h} = 27.8 \text{ Mbbl/d}$$

$$X = (12.515 \text{ in.})^2 - (9.625 \text{ in.})2 = 63.98 \text{ in.}^2$$

$$Y = 12.515 \text{ in.} + 9.625 \text{ in.} = 22.14 \text{ in.}$$

$$RN = \frac{92.24(27{,}800 \text{ bbl/d})}{(0.026 \text{ cSt})(22.14 \text{ in.})} = 4.45 \times 10^6$$

$$E = 0.00015 \text{ ft for steel pipes}$$

$$\frac{E}{D} = \frac{0.00015 \text{ ft } (22.14 \text{ in.})}{0.0833 \text{ ft/in. } (63.98 \text{ in.}^2)} = 0.00062$$

$$f = 0.018 \text{ from Moody Diagram}$$

$$\Delta P = \frac{0.011553(SG)(f)(Q^2)(Y)}{X^3} = \text{psi} / 1000 \text{ ft}$$

$$= \frac{0.011553(15.4/62.4)(0.018)(27{,}800)^2(22.14)}{(63.98)^3}$$

$$= 3.35 \text{ psi/1000 ft}$$

For the 3500 foot product annulus, the total pressure drop is as follows:

$3.35 \times 3.5 = 11.7$ psig

b) Calculate the pressure drop in the brine string at the maximum flow rate. Using Figure 3 (Brine String Pressure Drops) with maximum flow in thousand barrels per day (Mbbl/d), intersect the size of the brine string utilized and go across to read the psi per 1000 ft (psi/1000 ft). With 27.8 Mbbl/d and a $9^5/8$ in. brine string, the brine string loss is 5.7 psi/1000 ft (see note). This results in a brine string loss of $5.7 \times 4.2 = 23.9$ psig.

NOTE Two $9^5/8$ in. lines are shown on Figure 3. When the line on the right side is intersected, read the pressure drop from the right range of pressure drops (10 to 100).

The total pressure drop for the product and brine string to the wellhead is (product) 11.7 + (brine) 23.9 = 35.6 psig, which is less than 100 psig used in sizing.

Therefore, investigate the use of smaller, cemented casings and product string, smaller brine string, higher flow rates, or a more shallow cavity.

10.2.3 Sample Problem: Developing Cavity Flow Rate Versus Pressure Curve

The following is a step-by-step solution for developing the cavity wellhead pressure versus flow rate system curve similar to that shown in Figure 2.

Assume the following crude oil storage cavity:

a) size = 1,000 thousand barrels (Mbbl);

b) depth = 2000 ft (h_t) to 3000 feet (h_b);

c) brine gravity (SG_b) = 1.18;

d) crude gravity (SG_p) = 0.85;

e) crude viscosity = 20.5 centistokes (cSt);

f) production casing = 16 in. outside diameter (OD) and 15.01 in. inside diameter (ID);

g) brine string = 10.75 in. outside diameter (OD);

h) brine wellhead pressure (P_c) = 50 psig.

Step 1: Develop wellhead pressures at zero flow rate or static conditions as follows:

a) Full cavity static pressure (crude) at wellhead:

$$
\begin{aligned}
P_f &= (SG_b - SG_p)(h_b)(0.433) + P_c \\
&= (1.18 - 0.85)(0.433)(3000 \text{ ft}) + 50 \text{ psig} \\
&= 479 \text{ psig}
\end{aligned}
$$

b) Empty cavity static pressure (crude) at wellhead:

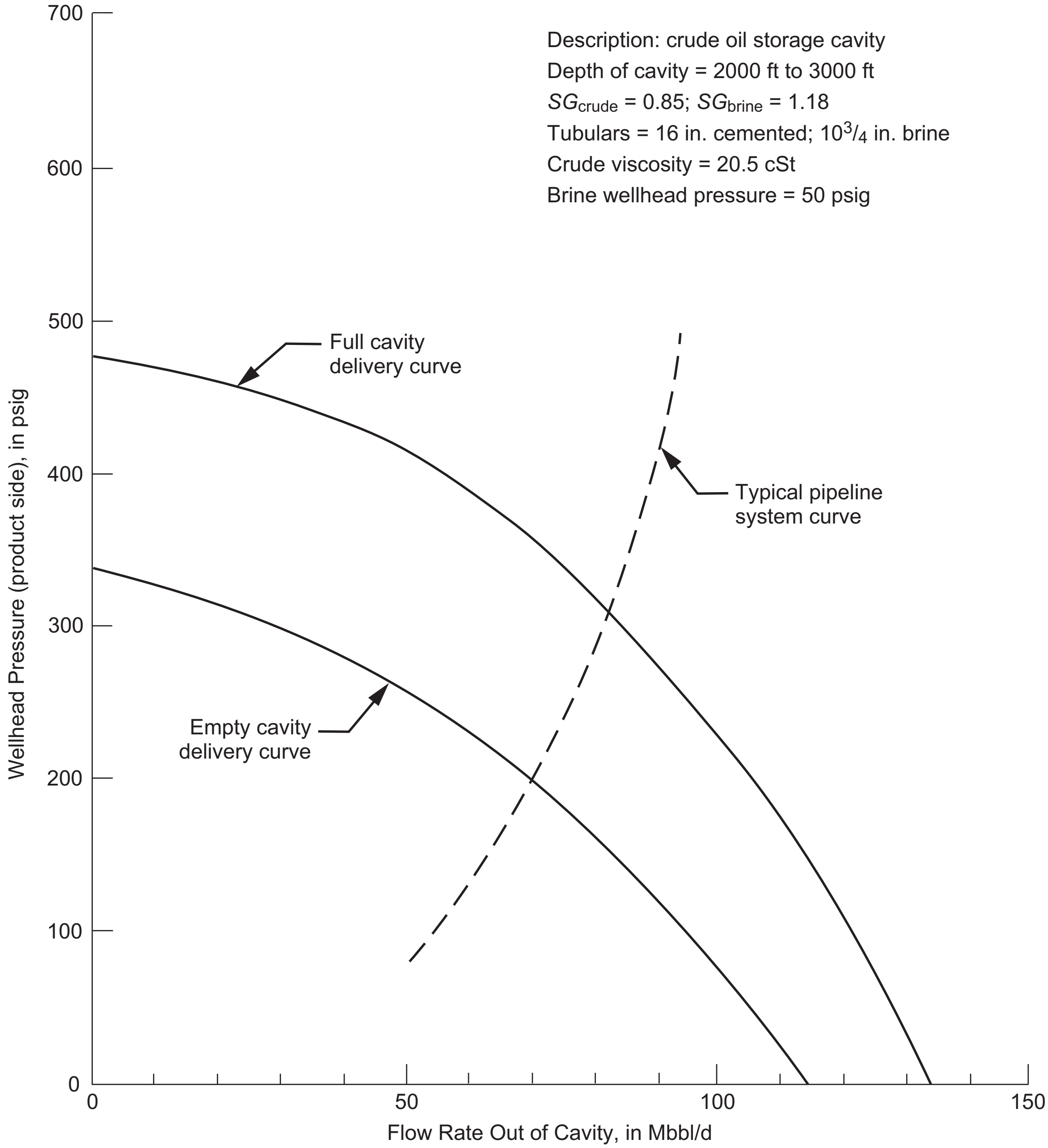


Figure 2—Wellhead Pressure Versus Flow Rate

$$P_e = (SG_b - SG_p)(h_t)(0.433) + P_c$$

$$= (1.18 - 0.85)(0.433)(2000 \text{ ft}) + 50 \text{ psig}$$

$$= 336 \text{ psig}$$

Step 2: Develop annulus pressure drop calculations at different flow rates as follows:

a) Assume 75,000 barrels per day (bbl/d) delivery rate:

$$\Delta P = \frac{0.011553(SG)(f)(Q^2)(Y)}{X^3} = \text{psi / 1000 ft}$$

$$X = (15.01\text{ in.})^2 - (10.75\text{ in.})^2 = 109.74\text{ in.}^2$$

$$Y = 15.01\text{ in.} + 10.75\text{ in.} = 25.76\text{ in.}$$

$$RN = \frac{92.24\,(75{,}000\text{ bbl/d})}{(20.5\text{ cSt})(25.76\text{ in.})} = 13{,}100$$

$$E = 0.00015\text{ ft for steel pipes}$$

$$\frac{E}{D} = \frac{0.00015\text{ ft }(25.76\text{ in.})}{0.0833\text{ ft/in. }(109.74\text{ in.}^2)} = 0.00042$$

$$f = 0.030\text{ from Moody Diagram}$$

$$\Delta P = \frac{0.011553(SG)(f)(Q^2)(Y)}{X^3} = \text{psi / 1000 ft}$$

$$= \frac{0.011553(0.85)(0.030)(75{,}000)^2(25.76)}{(109.75)^3}$$

$$= 32.3\text{ psi/1000 ft x 2000 ft} = 65\text{ psig}$$

b) Assume 100,000 barrels per day (bbl/d) delivery rate:

$$RN = \frac{92.24\,(100{,}000\text{ bbl/d})}{(20.5\text{ cSt})(25.76\text{ in.})} = 17{,}467$$

$$E = 0.00015\text{ ft for steel pipes}$$

$$\frac{E}{D} = \frac{0.00015\text{ ft }(25.76\text{ in.})}{0.0833\text{ ft/in. }(109.74\text{ in.}^2)} = 0.00042$$

$$f = 0.028\text{ from Moody Diagram}$$

$$\Delta P = \frac{0.011553(SG)(f)(Q^2)(Y)}{X^3} = \text{psi / 1000 ft}$$

$$= \frac{0.011553(0.85)(0.028)(100{,}000)^2(25.76)}{(109.75)^3}$$

$$= 53.6\text{ psi/1000 ft x 2000 ft} = 107\text{ psig}$$

c) Assume 50,000 barrels per day delivery rate:

$$RN = \frac{92.24\,(50{,}000\text{ bbl/d})}{(20.5\text{ cSt})(25.76\text{ in.})} = 8733$$

$$E = 0.00015\text{ ft for steel pipes}$$

$$\frac{E}{D} = \frac{0.00015\text{ ft }(25.76\text{ in.})}{0.0833\text{ ft/in. }(109.74\text{ in.}^2)} = 0.00042$$

$$f = 0.033\text{ from Moody Diagram}$$

$$\Delta P = \frac{0.011553(SG)(f)(Q^2)(Y)}{X^3} = \text{psi / 1000 ft}$$

$$= \frac{0.011553(0.85)(0.033)(50{,}000)^2(25.76)}{(109.75)^3}$$

$$= 15.8\text{ psi/1000 ft x 2000 ft} = 32\text{ psig}$$

Step 3: Calculate as follows the brine string pressure drop (in pounds per square inch per thousand feet) at different flow rates using the 10 3/4 in. brine string shown in Figure 3:

a) at 50 Mbbl/d = 11.6 × 3 = 34.8 or 35 psig;

b) at 75 Mbbl/d = 25.8 × 3 = 77.4 or 77 psig;

c) at 100 Mbbl/d = 44 × 3 = 132 psig.

Step 4: Add the crude and brine strings pressure drops for a total flowing pressure drop as follows:

a) at 50 Mbbl/d = 32 + 35 = 67 psig;

b) at 75 Mbbl/d = 65 + 77 = 142 psig;

c) at 100 Mbbl/d = 107 + 132 = 239 psig.

Step 5: Determine the wellhead pressures in Figure 2 at different flow rates for both a full and empty cavity.

a) For a full cavity, the wellhead pressures are as follows:

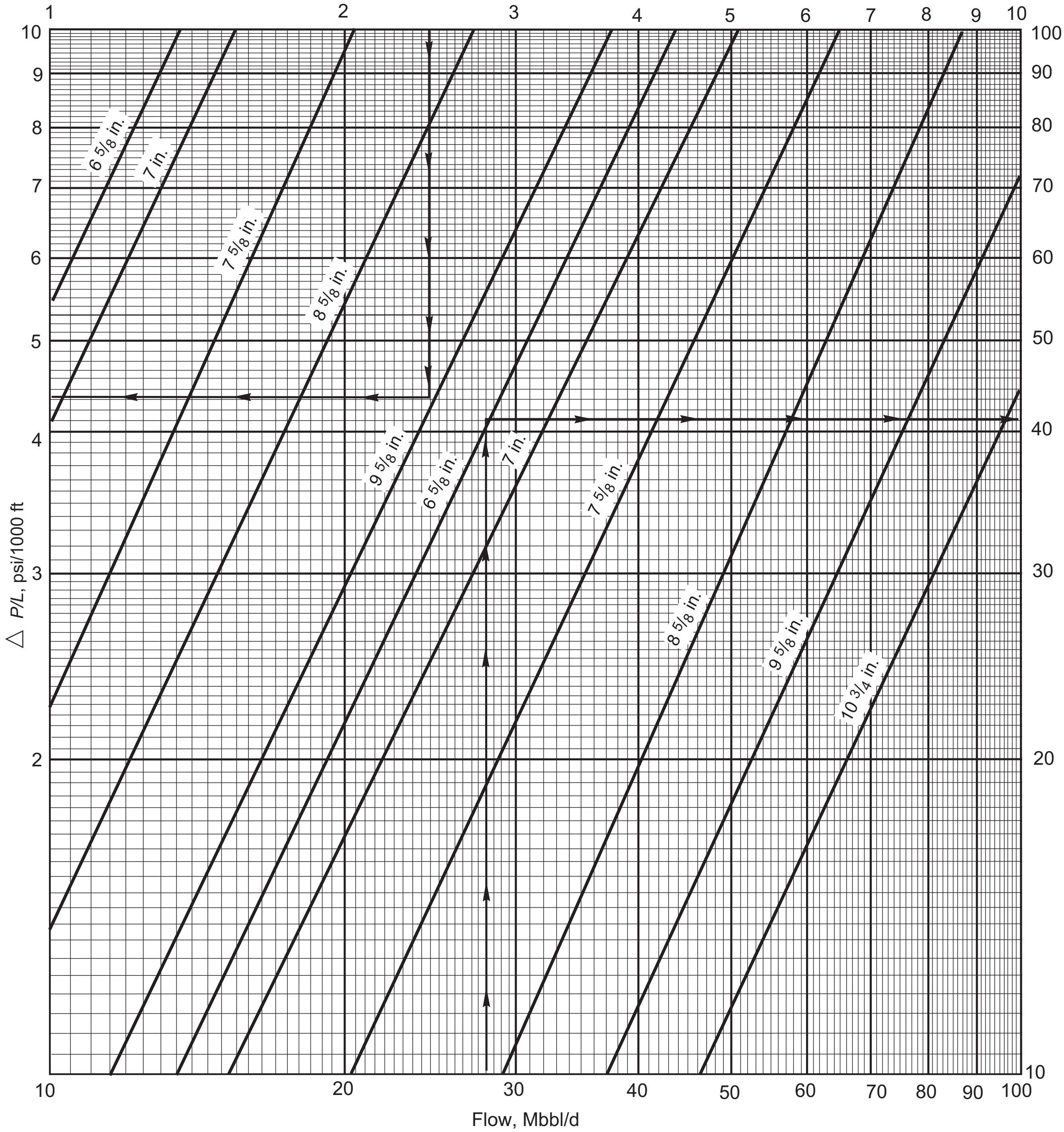
   1) static = 479 psig;

   2) at 50 Mbbl/d = 479 – 67 = 412 psig;

   3) at 75 Mbbl/d = 479 – 142 = 337 psig;

   4) at 100 Mbbl/d = 479 – 239 = 240 psig.

b) For an empty cavity, the wellhead pressure will be:



NOTE Based on Darcy–Weisbach E = 0.0004, heavy wall tubing strings.

Figure 3—Brine String Pressure Drops

1) static = 336 psig;

2) at 50 Mbbl/d = 336 – 67 = 269 psig;

3) at 75 Mbbl/d = 336 – 142 = 194 psig;

4) at 100 Mbbl/d = 336 – 239 = 97 psig.

11 Equipment and Materials

11.1 Wellhead

All wellhead components and wellhead valves shall be steel and shall be of sufficient strength to withstand the maximum operating pressure and provide for the maximum hydraulic shock loads anticipated.

The wellhead performance criteria for shock loading may be unique to the cavern storage application and should be explicitly specified to the manufacturer.

Wellhead design methodology does not specifically provide for hydraulic shock loads. Normal design practices typically include considerations of the effects of pressure containment and other pressure-induced loads. If the intensity of the shock load (anticipated or actual occurrence) exceeds the wellhead rated working pressure, higher working pressure equipment should be used or practices employed to reduce the shock intensity. Wellhead manufacturers' normal performance test requirements do not include verification for shock load conditions.

The brine side of the wellhead and brine valves shall be of the same pressure rating as the product side of the wellhead. All valves shall be a minimum of one rating above the maximum pressure requirements. Nonscrewed connections are recommended, such as flanged connections with ring joint gaskets. The pressure rating of the wellhead should be carried through all tree valves, both master and wing.

The manufacturer's hydrostatic body test pressure requirements must be in accordance with the latest edition of API 6A. All wellhead equipment shall meet the requirements of the latest edition of API 6A, and be API monogrammed. The wellhead shall permit monitoring for leakage from the production casing. In selecting the wellhead, flowing pressure drop through the wellhead must be considered.

11.2 Casings and Tubing Strings

API 5C3 should be followed for casing design programs. All casing must be selected with adequate collapse and joint strength for the installed depth as well as for burst strength meeting or exceeding all operating conditions (see API 5C2 and API 5CT for more information). Welder qualifications should meet criteria as prescribed in API 1104, ASME *Boiler and Pressure Vessel Code*, or other applicable standards.

The exact composition of the metal to be welded should be determined by mill test certificates or other means. Do not weld the casing with higher carbon content than K-55 grade. If back welding is planned on threaded casing, the grade of steel in the collars must be known.

Do not use wellhead and tube material whose chemical and physical properties cannot be identified.

Threaded joints should be assembled with thread compound as listed in API 5A3, except the bottom joint should be made with thread-locking compound to prevent its backing off while drilling. When thread compounds are used, internal and external threads of both the mill and field connection must be thoroughly cleaned with solvent before applying the compound. Joints should be torqued, as a minimum in accordance with API 5C1, or torqued in accordance with equivalent or superior torque methods.

In addition to the rated working pressure of the wellhead equipment, select appropriate material for the wellhead, valve trim, and metal or elastomeric seals. The temperature rating of the wellhead equipment must be specified for proper selection. Certain contaminants in the stored product, intentionally added or from the salt cavern, (such as methanol, CO_2, or O_2) can have detrimental effects on the long-term sealing ability of the critical elastomer seals in the valves and wellhead or can be corrosive. Appropriately resistant materials should be selected based on these environmental factors. The API tolerance for the outside diameters of casings, particularly for large diameter tubes, must also be taken into account during the selection of wellhead and casing hanger equipment. This is important to provide suitable equipment to inhibit elastomer seal extrusion or creep, with time and cyclical temperature and pressure loading.

11.3 Cement

Practically all cement used in construction of storage wells is Portland cement. However, much of this cement contains additives, which modify the properties of the mixture. For best results, the cement mixture should be chosen with proper density, consistency, strength, pumping time, bonding, free-water settling and fluid loss, and permeability. API 10A provides standards for well cements, well cement additives, and well cement testing procedures.

It is recommended that the cementing company or an independent cement lab perform tests on the planned cement mixtures sufficient to determine, among other cement properties, the waiting-on-cement (WOC) time required to achieve the desired compressive strength prior to commencement of casing test and other drilling operations.

12 Drilling and Completion

12.1 General

12.1.1 Design Considerations

The design of the solution-mined storage cavern should comprise all facets of storage including the storage cavern, the well (or wells) from the surface into the cavern, and the wellhead and wellhead valves. The design must be site specific, and different design parameters are often necessary for various sites. Design considerations include the following:

a) locale;

b) well spacing;

c) cavern depth;

d) span; and

e) size.

12.1.2 Wells for Storage Caverns

The well (or wells) for underground storage caverns shall confine the hydrocarbons to the storage cavern. The well (or wells) shall be cased and completed in accordance with the requirements of the applicable jurisdictional government.

12.1.3 Casing Requirements

The borehole (or boreholes) for wells shall be cased to protect all fresh-water strata and to isolate the storage cavern from all zones of porosity, if practical. In some areas of bedded salt, some zones of porosity may be exposed within the chamber. In such cases, storage procedures must be followed to prevent hydrocarbons from flowing into the zones of porosity.

12.1.4 Casing Design

In most wells, but not all, the casing design will include conductor pipe, surface casing, and production casing. In many wells, one or more strings or intermediate casing will be used. In some cases, the designer should consider designing the intermediate casing or surface casing to withstand full product pressure or installing a pressure control system on the annuli. This would minimize problems that could result from leaks or failure in the production casing.

12.1.5 Conductor Casing

The conductor or structural pipe is set to shut off unconsolidated shallow formations and may or may not be cemented. The conductor pipe is typically line pipe that may be set in a drilled borehole or it may be driven. In many hard rock areas, conductor casing may not be required.

12.1.6 Surface Casing

The surface casing is designed to protect all fresh-water zones. In some specific areas, regulatory agency rules and regulations allow production casing to also serve as surface casing. Also, in some wells the surface casing may not be set deep enough to cover all fresh-water zones, and an intermediate casing string may be used for that purpose. The surface casing shall be cemented from the bottom of the casing to the surface. If the surface casing is set into the salt, salt-saturated pozzolan or equivalent cementing materials shall be used. If the surface casing is set above the salt, a fresh-water pozzolan or equivalent cementing mix may be used.

12.1.7 Intermediate Casing

One or more intermediate casing string is sometimes needed for well completion and is recommended in those cases where it will improve long-term cavern security (such as providing two cemented casing strings through a caprock interval). The amount of cement used is based on the well design and locale, but, if practical, enough cementing material shall be used to bring cement up into the surface casing.

12.1.8 Production Casing

The production casing (final cemented casing string) shall have adequate tensile and collapse strength for the setting depth. When practical, it shall be cemented to the surface with salt-saturated cementing materials. In most areas the production casing should be set in salt; on salt domes, casing should be set at least 300 ft (approximately 90 m) within the salt (or as state regulations provide). In thin bedded salt areas, the production casing is set at the top of the salt; however, in such cases, the rock forming the cavern roof must be nonporous and impermeable and must be of sufficient strength to serve as the cavern roof.

The production casing shall be pressure tested before drilling out the plug (shoe). Incomplete cement bonding can occur if the pressure test is made after cement has started to set but has not yet developed enough compressive strength to withstand the test pressure. The casing test pressure shall be the higher of either that pressure required by state or federal regulations or 125 % of the working pressure. The test pressure should be maintained for a minimum of 30 minutes, or longer if required by government regulations.

The casing seat and cement of the production casing shall be pressure tested after drilling out. At least 10 ft (3 to 4 m) of salt below the casing shoe shall be penetrated prior to the test. The test pressure calculated at the casing seat, as a minimum, shall be the maximum operating pressure at that point. The maximum operating pressure will depend on area, depth, well, and salt characteristics and may vary widely. Storage pressures are currently in use to a gradient of 0.9 psi/f (0.2 bars/m) of depth to the casing shoe, but the maximum in some areas may be as low as 0.6 psi/f (0.14 bars/m) of depth.

Welding the production casing joints together is recommended, assuming the grade of the pipe and the welding procedures are appropriate. Experience has shown that collar leaks are not uncommon and can result in failing the mechanical integrity test. These types of leaks are very difficult to repair after the casing is cemented. Another consideration would be to use modified couplings with teflon seal rings to improve the production casing's leak resistance.

12.1.9 Product String (Blanket String)

An additional uncemented casing string is sometimes suspended inside the production casing. This string serves a purpose similar to the production casing. It is used if high corrosion rates are expected or if it is desirable to remove the inner-most casing string and the brine tubing for inspection. The blanket string results in no flow occurring on the production casing. The production casing should always have a static blanket of product between it and the product (blanket) casing.

12.1.10 Brine Tubing

This string of pipe is used to conduct water to or remove brine from the cavern during solution mining and to conduct brine into or out of the cavern during storage operations.

12.2 Preliminary Considerations

12.2.1 Permits

All necessary local, state, and federal permits must be obtained before drilling commences.

12.2.2 Site Layout

The main considerations for location should include rig and producing facility requirements, safety, and environmental protection while drilling and subsequently operating the site. Emergency and pollution control measures must be a part of the site layout plan.

12.3 Borehole Development

12.3.1 General

The borehole sizes drilled for placement of the casing shall be adequate to allow running of the casing. Drilling fluid may be mud or brine, but properties of the fluid should be maintained to prevent undue enlargement of the borehole. The deviation shall be controlled so that the cavern is located within the specified area.

12.3.2 Overburden Strata

Shallow formations encountered while drilling to set surface casing will usually be unconsolidated sand, clay, and gravel.

12.3.3 Caprock

Caprock, if present, is generally composed of gypsum and anhydrite. It is quite hard, may produce a large amount of sand, and often contains voids. The voids often cause a loss of circulation, and dry drilling with water or brine may be necessary.

12.3.4 Salt

Salt usually drills like soft rock. Bedded salt may have layers of hard or soft formations such as dolomite, limestone, or shale.

12.3.5 Deviation Control

Deviation shall be monitored and controlled during drilling to keep the borehole within a designated area. It is generally advisable to limit the deviation to a maximum of 1.5 degrees average inclination from vertical at the top of the salt, with a maximum change in angle of 2 degrees or less at any depth.

12.4 Mud Program

Typical drilling fluid properties and fluid hydraulics in the upper part of the hole should be maintained to minimize hole washout as an aid in the casing cementing procedure (see API 13D). A brine-saturated drilling fluid should be used when drilling below the production casing string to prevent solution mining around the casing shoe that could result in product leaks behind the shoe or to prevent the creation of an attic.

12.5 Cement Program

12.5.1 General

Cement is used primarily to isolate zones and secure the casing in the borehole. In addition, cement plugs may be used in the borehole or in casings as temporary plugs.

12.5.2 Primary Cementing

Primary cementing is the original cementing operation performed immediately after the casing has been run into the hole. The functions of primary cementing are as follows:

a) to secure the casing and support it at the desired location;

b) to isolate zones to prevent undesired migration of fluids from one formation to another through the annulus formed by the borehole and the outside of the casing;

c) to seal the cavern and prevent leakage of the stored product from the cavern to the annulus between the borehole and the casing;

d) to protect against corrosion with a continuous sheath of cement to prevent the casing from coming in contact with corrosive fluids.

12.5.3 Cement Plugs

Cement plugs may be used during construction or workover operations for the following purposes:

a) abandonment;

b) temporary abandonment;

c) lost circulation control;

d) testing;

e) recompletion.

12.6 Casing and Cement Placement

12.6.1 General

Sound installation depends on proper selection of casing and cement; proper manufacturing and handling of cement and casing before use, following industry-accepted cementing practices; correct borehole conditioning before running casing; correct placement of casing and cement; and adequate cement setting time.

12.6.2 Borehole Conditioning

Proper conditioning stabilizes the borehole, while running casing allows proper cement bonding to the formation.

12.6.3 Casing Placement

12.6.3.1 Preparation

All casing should be visually inspected for loose rust, scale, and out-of-roundness that may result from shipping or handling damage. Mill varnish should be removed from the outside of the casing to improve cement bonding.

API 5C1 should be used for casing. For welded casing, use welder qualifications as prescribed in API 1104, ASME *Boiler and Pressure Vessel Code*, or other applicable standards.

12.6.3.2 Positioning Casing in the Borehole

To minimize differential sticking while running casing and to improve displacement of the drilling fluid with cement, centralizers should be installed on the casing strings.

12.7 Cement Placement

12.7.1 Volume

See 12.1.6, 12.1.7, and 12.1.8 for the amount of cementing required for each casing string. Cement moving improperly through the mud in the annulus may leave channels of mud in the cement. These channels may allow communication.

Channeling may be minimized by the following techniques:

a) centering the casing in the borehole using centralizers;

b) proper cement pump rates;

c) rotation;

d) reciprocation.

12.7.2 Minimum Setting Time

Waiting-on-cement (WOC) time is the time between the end of cementing and the resumption of drilling to enable the cement in the well to harden sufficiently.

The minimum WOC time should be the longer of either government regulations or the time required for the cement to reach a minimum compressive strength of 500 psi (approximately 35 bars) at the prescribed temperature and pressure.

12.8 Testing Prior to String Placement

Government requirements for logging surveys vary with the state and the regulatory agency involved. In general, logging surveys are run at casing depths. These include electric logs and/or density logs and deviation surveys. A caliper log is typically run to assist in cement calculations.

13 Solution Mining

13.1 Basic Concepts

13.1.1 General

Solution mining is the process by which a void or cavity is created in an underground salt formation for storage purposes. This cavity is created by the dissolution of salt when fresh water is injected into the formation under controlled conditions. The resulting brine is displaced out of the developing cavern for further processing or disposal.

13.1.2 Water Injection and Removal

The injection of fresh water and removal of produced brine are accomplished through two pipe strings, which are usually suspended concentrically below the production casing string. Water is injected into the developing cavity through the wash string. Brine is removed from the cavity through the solution-mining string. The setting depths and position of these strings relative to each other and to the cemented production casing shoe are based on the desired shape and geometry of the storage cavern and on the solution-mining method employed. The absolute and relative position of wash and solution-mining strings may change several times during the course of the solution-mining program to control the shape and size of the cavern.

13.1.3 Blanketing Material

An essential part of the solution-mining operation is the placement and maintenance of a blanketing material in the annular space between the production casing and the suspended wash and solution-mining strings during the course of solution-mining operations. The blanketing material performs the following functions.

a) It prevents the removal of the salt-cement seal around the permanent cemented casing strings. The maintenance of this seal is necessary to preserve the integrity of the storage well in the vicinity of the cased hole.

b) It provides the means of limiting the upward growth of the cavern.

c) It may be used to control the shape of the cavern.

The blanketing material:

— must be insoluble in salt;

— be immiscible with water and brine, and its density or specific gravity shall be less than that of water;

— should not possess chemical characteristics or contaminants that would render it injurious to personnel, the well casing, or the storage cavern.

The most commonly used blanketing materials are hydrocarbons, ranging from liquefied petroleum gas to Number 2 fuel oil.

Care should be exercised to ensure that the target blanketing material and water interface level is achieved. The quantity of blanketing material required is based on estimates of the annular volume to the desired depth. The accuracy of such calculations should be verified after blanket placement with an interface log or weep hole.

13.1.4 Cavern Development

13.1.4.1 Controllable Factors

The development of the storage cavity is controlled by the following factors:

a) Fresh-water injection rate, which determines the rate of cavern growth (rate of salt dissolution). At 60 °F (15.5 °C), slightly more than 6 barrels of fresh water are required to produce 1 barrel or 5.6 ft^3 (0.16 m^3) of cavern capacity, if the brine produced is fully saturated. This ratio will vary depending upon the actual temperature, the circulation method, and other factors that affect brine salinity. In practice 8 or 9 barrels of fresh water will be required to solution mine 1 barrel of cavern.

b) Blanketing material and water interface level, which protects the cemented casing strings; establishes the upper limit of cavern growth; and, depending on the fresh-water injection point and rate, can exert a significant influence on horizontal cavern growth.

c) Fresh-water injection and brine removal points, whose absolute position and relative position to each other and to the blanket-water interface determine the shape of the cavern and are controlled by string placement and the method of circulation employed.

13.1.4.2 Other Factors

The combination of the factors listed in 13.1.4.1, Items a through c, to produce a cavern of a desired capacity and shape can be complex. While the factors described above are controllable, other factors, known or unknown, may affect cavern development and the solution-mining program. Some examples include the following:

a) insolubles in salt;

b) fractured salt;

c) layered or bedded salt;

d) salt that is more soluble than expected due to impurities.

13.2 Solution-mining Techniques

13.2.1 General

Solution-mining programs for storage caverns can be relatively simple or complex depending upon the desired capacity and shape of the cavern. Solution-mining techniques vary from the direct circulation method, which is relatively simple, to the more complex (and expensive) methods requiring multiple manipulations of string positions and blanket levels to achieve the greatest possible degree of control over cavern shape.

13.2.2 Direct-circulation Method

The direct-circulation method is the simplest and most conventional method of cavern development (see Figure 4). Fresh water is introduced at or near the bottom of the developing cavern and the brine is withdrawn near the top of the cavern. Two concentric tubing strings are used. The inner, or wash string, is set to inject the water near the desired bottom of the cavern. Upward circulation carries the water to the level of the outer, or solution-mining string, where it is discharged via the annular space between the wash and solution-mining strings. The blanket level is set to provide cemented casing protection, and the solution-mining string is set below this level. The upward circulation of the injected water results in increasing salinity from the point of injection to the point of discharge, although the use of this method does not always result in complete saturation of the brine. The end result is a teardrop or pear-shaped cavern.

13.2.3 Reverse-circulation Method

With the reverse-circulation method, the flow of water is the reverse of the flow in the direct-circulation method (see Figure 5). Water is injected near the top of the well. Upward circulation carries the water around the top of the well and down the cavern walls. The water becomes progressively more saline. The resulting brine is discharged through the solution-mining string set near the bottom of the cavern. Placement and control of the blanketing material is of greater concern because of the increased volume and turbulence of unsaturated water in the upper part of the cavern. Greater relative growth occurs in the top part of the cavern, resulting in an inverted pear or mushroom shape. This method results in a greater degree of brine saturation than that achieved with the direct-circulation method.

13.2.4 Complex Methods

The development of cavern shapes approximating cylinders, spheres, or other geometric shapes requires multiple adjustment of one or more of the controllable factors affecting cavern development during the course of the solution-mining program. Figure 6 provides a brief description and comparison of several such methods.

13.3 Factors Affecting the Solution-mining Program

13.3.1 Allowable Operating Pressures

The operating pressure limitations as discussed in Section 9 and Section 10 also apply to solution-mining operations. Operating pressure at any point within the developing cavern should not exceed the maximum allowable operating pressure at that point as determined from the allowable operating gradient (psi/f) (see 12.1.8.3).

13.3.2 Borehole Deviation

During drilling operations, the vertical deviation of the uncased borehole should be minimized. Any deviation, especially in the uncased borehole, will affect the orientation of the wash and solution-mining strings. This could result in asymmetric cavern development due to nonvertical discharge of water into the cavern. The degree of any significant borehole deviation should be determined before the solution-mining program begins.

13.3.3 Salt Anomalies

Cavern development can be significantly influenced by the presence and disposition of insoluble materials within the salt or by stratification of such materials within the salt as beds. Asymmetric cavern growth and internal collapse of unsupported insoluble masses due to dissolution of the supporting salt are potential problems. The presence of such impurities or beds should be considered prior to initiation of the solution-mining program.

13.4 Wash and Solution-mining Strings

13.4.1 Size Criteria

Design flow velocities should not exceed 15 ft/s (approximately 4.5 m/s) considering the increased potential for casing and tubing failure due to vibration and erosion at high flow velocities.

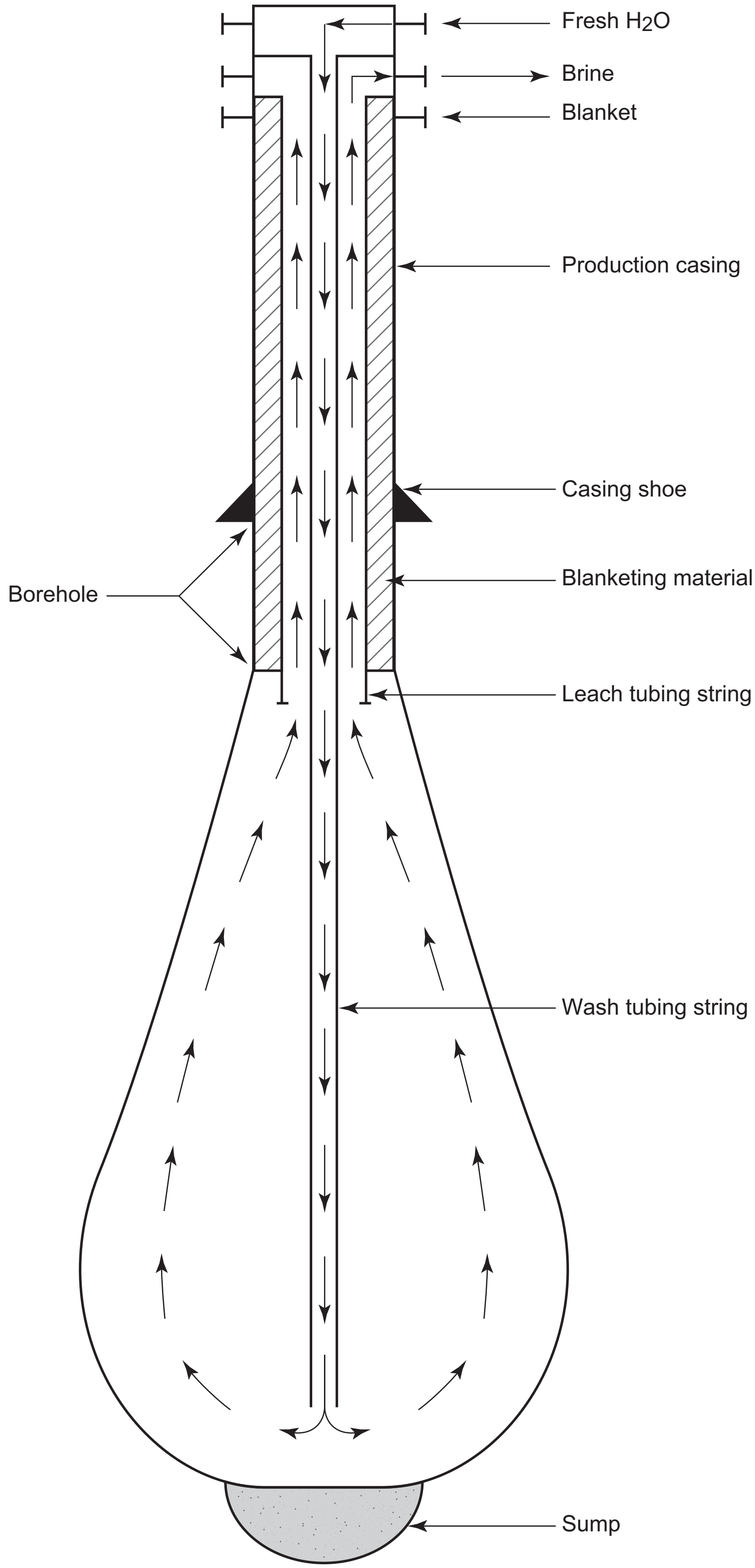


Figure 4—Solution-mining: Direct-circulation Method

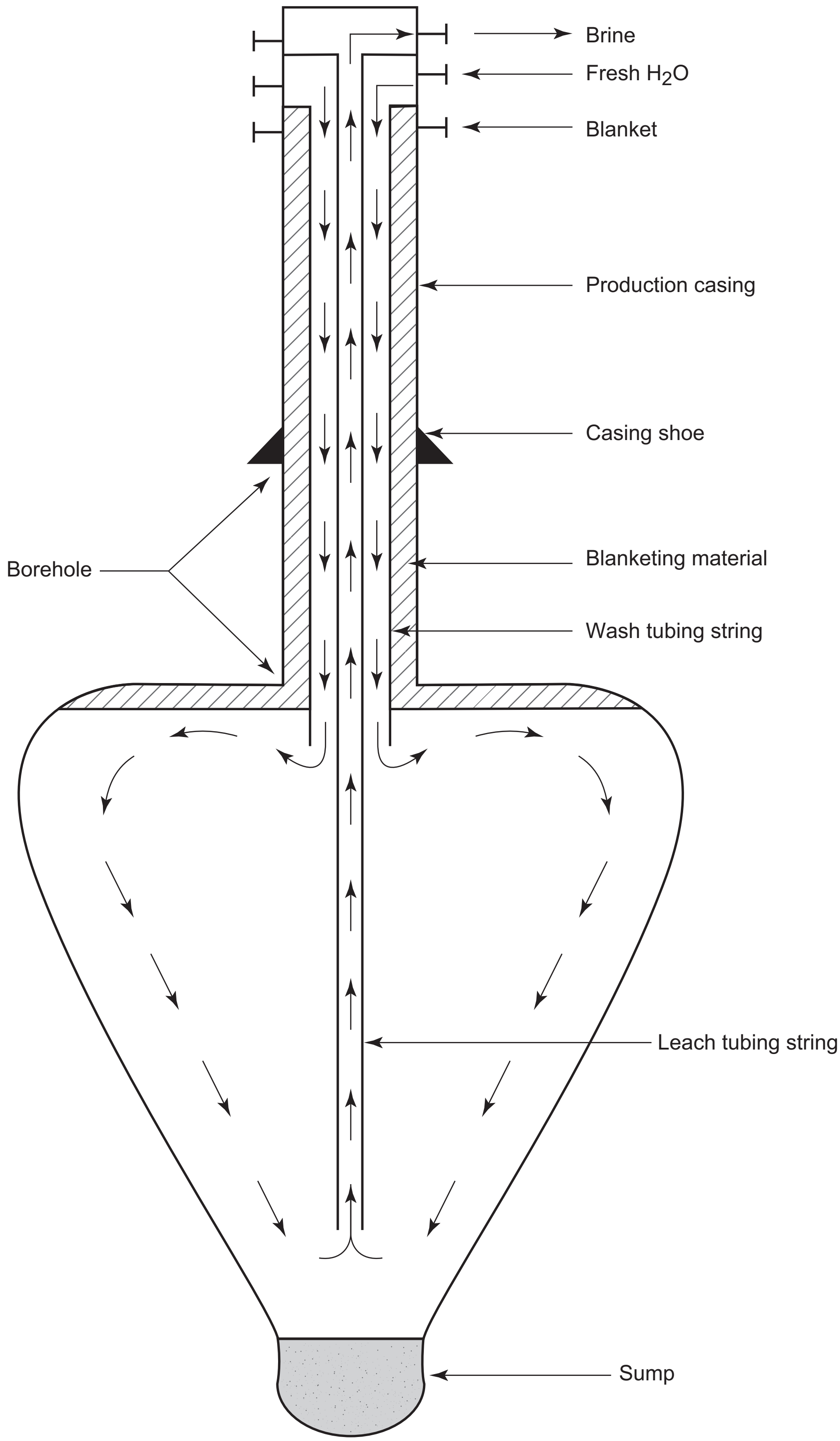


Figure 5—Solution-mining: Reverse-circulation Method

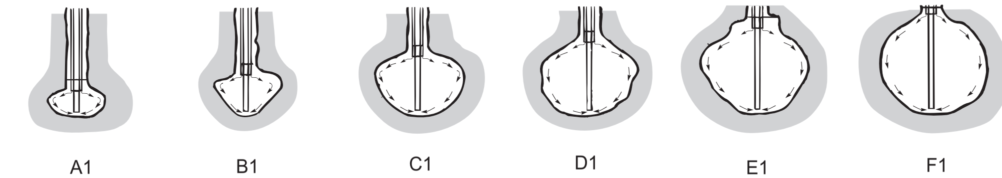
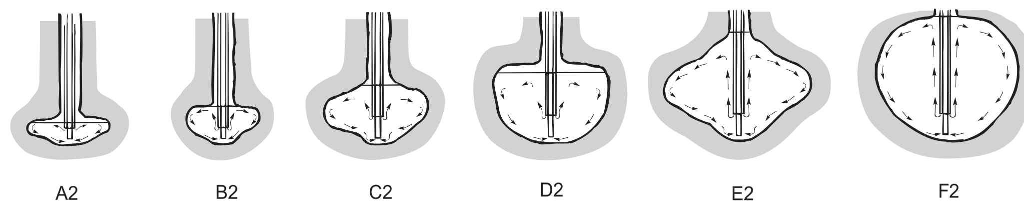
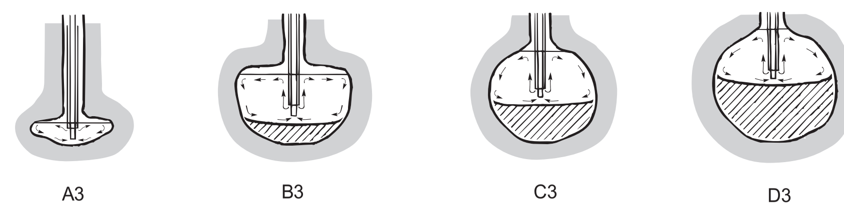
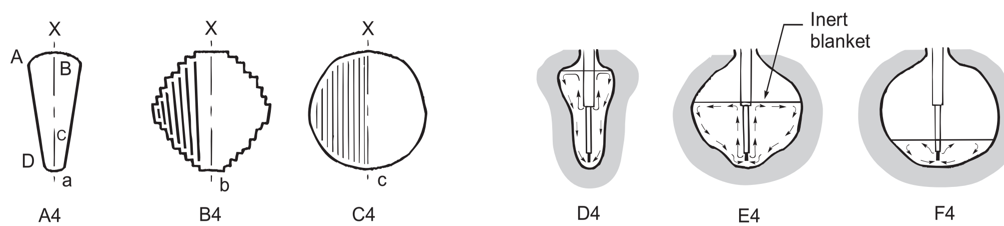
Method	Description	Illustrations
Floating String	1. Two concentric circulation strings. 2. Inner (leach or brine outlet) string stationary. Remains positioned at near total cavern depth. 3. Outer (wash or water injection) string moveable. Remains in close proximity to blanket and water interface. 4. Outer string and blanket and water interface positioned in stages. A1 through F1 illustrate progression of cavern development.	
Stationary Pipe	1. Two concentric circulation rings. 2. Inner (leach) string and outer (wash) string maintain constant position at near total cavern depth. 3. Blanket and water interface level moved in stages to provide shape control. 4. A2 through F2 illustrate progression of cavity development.	
Moveable Pipe	1. Two concentric circulation strings. 2. Both circulation strings and blanket and water interface are moveable. 3. Develops cavity in series of horizontal layers. Vertical boundaries are set by blanket level at top and saturated brine at bottom. 4. Provides high degree of control but pipe position is critical. High cost. 5. A3 through D3 illustrate progression of development.	
Layer	1. Illustrated by volume element formed by revolving quadrilateral ABCD about verticle axis X (A4). 2. Multiple revolutions of ABCD can create a spherical shape from successive thin wall segments if segment width and height are controlled (B4 and C4). 3. Using this method, multiple concentric strings may be used to eliminate need for pipe movement. 4. String position is constant. Blanket and water interface level is initially set at top of cavern and progressively moved downward in stages (D4 through F4).	

Figure 6—Solution-mining Methods

The wash and solution-mining strings should be designed to handle the stress imposed by the worst-case operating pressures in addition to string weight for each respective string.

13.4.2 Joints

Threaded connections for casing and tubing string segments facilitate string placement adjustments, provided that other design criteria can be met. Otherwise, welded connections should be used.

Each joint shall meet the performance criteria imposed upon the composite string of which it is a part. In the case of threaded joints, the combined effects of axial load and bending shall be considered with respect to joint strength and integrity against leakage.

Standard 8 round connections are generally adequate to prevent leaks between the brine string and the product or production casing string. Using short threaded or coupled (ST&C) connections is discouraged, as these connections are not recommended when bending of the pipe or whipping the brine string in the cavern can occur at high rates of product removal or installation. This can cause the bottom joint or joints of the brine string to back off and fall into the bottom of the cavern, resulting in loss of storage capacity.

13.5 Control of Cavern Development

13.5.1 Cavern Growth Prediction

The effective capacity of a storage cavern may be expressed as the sum of the following variables:

a) volume of salt removed with the effluent brine;

b) volume of salt in solution in the developing cavern;

c) volume of insoluble material removed with the effluent brine.

13.5.1.1 Salt Dissolution

The volume of cavern developed through salt dissolution cannot be determined by direct measurement of any single variable, such as volume of fresh water injected or volume of effluent brine produced, because an indeterminate amount of injected water insolubles and salt remain in the cavern in the form of brine. However, the properties of aqueous salt solutions are well documented in available literature. A reasonably accurate determination of total dissolved salt can be calculated using data derived from field measurement and brine tables.

The following data are required to calculate salt dissolution to predict cavern growth:

a) volume of injected water;

b) specific gravity and temperature of effluent brine;

c) density of the rock salt as determined from published tables or analysis of core samples obtained during drilling.

Brine tables, such as those contained in International Critical Tables, characterize the salt content of brine in terms of weight of salt per unit weight of brine, expressed as a fraction or as a percentage, over a range of specific gravities at one or more specified temperatures. The relationship between salt concentration in brine and brine specific gravity is strongly temperature-dependent. For this reason, field measurements of effluent brine specific gravity must be corrected from the flowing temperature to the base temperature used by the brine tables to avoid significant error in determining true brine concentration. The most useful available brine tables are expressed in terms of a base temperature of 60 °F (15.5 °C) for several reasons, including the following.

a) 60 °F (15.5 °C) is an accepted standard in defining base density of water and other liquids.

b) Most hydrometers are calibrated to indicate the density of the measured fluid relative to that of water at 60 °F (15.5 °C); the specific gravity of water at 60 °F (15.5 °C) is 1.0.

The brine tables normally supply correction factors to convert specific gravity data from flowing temperature to a base temperature of 60 °F (15.5 °C).

After correcting specific gravity data for temperature, the true percent by weight of salt in the brine is determined from the brine tables. The corresponding percent by weight (wt%) of water in brine is given by:

$$\text{wt \% water in brine} = 100 - \text{wt \% salt in brine} \tag{7}$$

The relative volume of salt to water in the effluent brine can then be determined as follows:

$$\text{wt \% of salt in brine / wt \% of water in brine} = V_s / V_w \times \text{density of salt / density of water} \tag{8}$$

or

$$V_s / V_w = (\text{wt \% salt in brine / wt \% water in brine}) \times (\text{density water / density salt})$$

The total volume of dissolved salt is then determined by:

$$V_{st} = (V_s / V_w) \times V_{wt} \tag{9}$$

where

V_s / V_w is the volume of salt per unit volume of water in brine;

V_{st} is the total volume of dissolved salt;

V_{wt} is the total volume of injected water.

Consistent units of measurement should be used when completing the above calculations.

The frequency with which the necessary field data should be gathered and calculations completed depends upon the immediate volume objectives to be attained, the rate of fresh-water injection, the accuracy desired from the dissolution calculations, and the resources available to carry out these activities. Generally, fresh water injection rates should be recorded continuously. Measurement of brine specific gravity and temperature should be monitored every 2 hours. The salt volume dissolved should be computed each day using the average specific gravities and temperatures over 24 hours.

13.5.1.2 Insolubles

Insoluble impurities exist in virtually all rock salt masses, domal or bedded. The major impurity is usually anhydrite ($CaSO_4$). The concentration and disposition of impurities varies with the location and geological characteristics of the salt mass. Dissolution of the surrounding salt results in the precipitation of impurities onto the cavern floor. A certain percentage of these insolubles will normally be removed from the cavern in the effluent brine. Their volume may be measured after they have been deposited in settling pits or tanks used for surface separation of insoluble material from the brine. This volume is usually negligible in comparison to planned cavern volume. The volume of the remaining insolubles should be considered with respect to their impact on planned cavern capacity, since the bulk volume of these insolubles may be 30 % to 40 % greater than their original volume. Estimates of the total percentage of insolubles in the salt mass should be determined from core samples taken during the drilling phase or from other reliable geological data.

13.5.2 Blanketing-material Control

13.5.2.1 General

The blanketing material and water interface should be carefully controlled and monitored to protect the production casing shoe during solution-mining operations. The blanket-water interface position also establishes an upper limit on vertical cavern growth. That fact may be significant in achieving the desired cavern shape, depending on the solution-mining technique employed and the complexity of cavern shape desired.

13.5.2.2 Positioning

The position of the blanket-water interface should be verified with an interface log or similar method. Depending on a calculated volume of blanketing material to provide dissolution protection to a specified depth can be risky, especially if target depth is in the uncased borehole or developing cavern.

13.5.2.3 Monitoring

During the course of solution-mining operations, the blanket-water interface level should be monitored periodically to ensure the desired level is being maintained. Upward movement of the blanket-water interface level is indicative of the following conditions.

a) Leakage in the wellhead components or the collars of the blanket string.

b) Enlargement of the uncased borehole and cavern above the blanket-water interface due to leakage of unsaturated water through defective joints or holes in the exterior suspended string.

c) Dispersion of blanketing material due to horizontal cavern growth or turbulence at the blanketing material and water interface due to circulation.

13.5.2.4 Handling

All blanketing material should be handled to guard the safety of workers and to protect the environment. Storage facilities should be planned to accommodate the characteristics of the material and applicable codes and regulations pertaining to its storage, handling, and disposition.

13.5.3 String Placement

13.5.3.1 General

The placement of the wash and solution-mining strings determines the fresh-water injection and brine removal points within the developing cavern. The depths at which these strings are positioned relative to the surface and to each other are influenced by overall cavern development objectives and the complexity of the solution-mining program required to achieve those objectives. Cost and the particular phase of cavern development are also factors in this analysis.

13.5.3.2 Positioning

The position of the wash and solution-mining strings determine the following.

a) The lower limit of cavern development, as the dissolution of salt below the deepest projection of the wash or solution-mining string continues only to a limited extent, regardless of the solution-mining technique employed.

b) The lower limit of blanket-water interface level, as containment of the blanketing material and the maintenance of a stable blanketing material and water interface requires positioning of the blanket-water interface level at a point above the end of the most shallow of the wash or solution-mining strings. Because the minimum depth of blanketing material is governed by the need to protect the cemented casing strings, the position of the shallow string essentially defines the range of the vertical interval to which the blanket-water interface level may be controlled. This constitutes a significant constraint on the use of the blanket-water interface level to limit upper cavern growth.

Multiple repositioning of the wash and solution-mining strings after initial placement can result in significant cost in equipment, manpower, and time. A cost-effective solution-mining program should seek to minimize the need for repetitive repositioning of these strings while achieving cavern development objectives.

13.5.3.3 Verification

The downhole position of the wash and solution-mining strings should be verified before the start or resumption of solution-mining activity. This may be accomplished by a summation of the measured lengths of each casing joint in the respective string prior to placement downhole. A collar locator or other suitable log may be used to verify the position after placement.

13.5.4 Fresh Water Injection Monitoring and Control

Salt dissolution and the resulting cavern growth are directly proportional to the rate of fresh-water injection.

Measurement of this variable must be accurate to ensure accurate salt dissolution calculations and to predict cavern volume. The injection rate and pressure should be controlled to provide uniformity in measurement and to prevent excessive pressure.

Water injection rates should be metered and recorded continuously throughout the solution-mining cycle. Temperature compensation should reflect all measurement relative to the base density of water at 60 °F (15.5 °C). Rate data should be converted to volumetric data via continuous integration using appropriate instrumentation. Instrumentation for flow control should be provided to permit adjustment and stabilization of flow rates in accordance with solution-mining program objectives.

Constraints on cavern operating pressures imposed by allowable operating gradients should be observed during the solution-mining phase of cavern development. Pressures within the storage cavern should be limited; the maximum pressure at the end of the deepest cemented casing string (the casing shoe) should not exceed the depth of this casing string multiplied by the allowable operating gradient. The corresponding pressure limit measured at the surface would be the calculated maximum pressure minus the incremental hydrostatic pressure imposed by the blanketing material from the surface to the casing shoe of the deepest cemented string. Instrumentation should be provided to monitor the pressure within the annular space occupied by the blanketing material. Abnormal pressures above calculated limits should trigger audible or visible alarms and isolate the cavern from the pressure source, preferably by shutting down the water injection pump. In general, abnormally high blanket pressure indicates flow restriction in the solution-mining string due to salt plugging or salt precipitating and adhering to the pipe wall. This phenomenon is caused by relatively rapid cooling of highly saline brine as it exits the storage cavern and is characteristic of the reverse-solution mining technique.

13.5.5 Control of Insolubles

The precipitation of insoluble material onto the cavern floor as a consequence of salt dissolution will reduce planned cavern capacity and inhibit lower cavern growth. In addition, it may result in flow restriction or plugging of the deep suspended tubing strings unless these insolubles are removed or otherwise controlled.

Insolubles control is achieved by the following:

a) removing the insoluble precipitates with the effluent brine;

b) allowing the insolubles to settle in a sump created below the maximum working depth of the storage cavern;

c) some combination of item a) and item b).

The selection of a primary method depends upon the estimated quantity of insoluble material, restrictions upon cavern geometry imposed by design or geological constraints, and any environmental restrictions associated with surface disposal of insoluble material.

A certain amount of insoluble material will normally be removed from the cavern in the effluent brine during the course of solution-mining operations. However, insolubles can be removed on a larger scale by creating sufficient flow turbulence within the cavern so that some of the insoluble precipitates will ultimately be discharged from the cavern with the effluent brine. Problems with separation of insolubles from the brine at the surface and subsequent disposal of insoluble material may be significant and should be reviewed.

A cavern sump, created below the maximum operating depth of the storage cavern, should be used as the primary means of insolubles control, if practical. Sump capacity should be based on the total bulk volume (rather than original volume) of the insolubles projected to be generated and precipitated to the cavern floor. In bedded salt, any estimate of sump capacity must include a consideration of the insolubles content of the layered salt plus the additional volume of sedimentary strata, which may collapse as a result of dissolution of the supporting salt.

13.6 Monitoring Cavern Growth

Cavern development should be checked periodically by sonar caliper or other suitable methods to verify that the size, shape, and direction of growth of the storage cavern are in accordance with solution-mining program objectives.

The sonar caliper tool uses sound waves to determine cavern shape. A sound pulse from the transmitter is reflected from the cavern wall and is detected by a receiver in the tool. The travel time of the sound wave indicates the distance traveled, since the velocity of sound in a fluid of given density is known. The transmitter/receiver unit can be rotated through 360 degrees in incremental steps of 5 degrees or less. At a given depth, a full rotation of the tool can provide a horizontal cross section of the cavern. By varying the setting depths of the tool incrementally over the total height of the cavern, a composite description of the cavern in terms of shape and direction of growth can be obtained. Additional computation can yield estimates pertaining to incremental volume-per-unit depth and total volume. In addition to its rotational capability, the tool can be vertically oriented incrementally from 0 degrees (horizontal) to +90 degrees (vertical). This permits mapping of the cavern roof to determine the presence of any irregularities that may affect the stability of the roof or may be potential entrapment sites for stored product during storage operations.

Cavern volume and shape may also be estimated from controlled displacement of the cavern with product; the product and brine interface location is subsequently determined for a specific volume of injected product. The location of the interface is then determined by an interface log or by computation using static well pressures and the density differentials between product and brine. Correlations between cavern depth may then be used to obtain approximate cavern shape. The feasibility of using this method during the solution-mining phase should be evaluated on an individual basis.

The frequency with which cavern growth is checked depends upon the method used and the complexity and objectives of the solution-mining program. Monitoring intervals should be adjusted to fit the requirements of the specific solution-mining program or regulations.

13.7 Conversion from Solution Mining to Product Storage

Converting the completed cavern to product storage involves the following steps.

a) Displacing blanketing material from the cavern and depressurizing the cavern to permit removal of suspended strings.

b) Removing the wash and solution-mining-strings and associated wellhead components.

c) Installing operational brine displacement tubing string or strings. Casing string joints should be inspected and tested before they are placed in the well. The position of suspended strings can be verified by logging after placement.

d) Installing the remaining wellhead components and associated wellhead isolation valves. The wellhead should be pressure tested after installation in accordance with applicable test procedures as defined by the manufacture or other authority having jurisdiction.

e) Installing the surface piping and instrumentation on the well.

14 Cavern Integrity and Testing

14.1 Testing Requirements and Purpose

Caverns shall be pressure tested before they are placed in hydrocarbon storage service and periodically thereafter in accordance with state regulatory requirements and the operator's own guidelines. The primary purpose of the test is to verify that the cavern and the cased well are capable of containing the stored commodity at design conditions. Pressure tests also ensure that the wellhead is properly installed.

14.2 Test Pressure Level

As a general rule, but one that may be altered based on site specific expert opinion and engineering judgment and analysis, the cavern roof and casing shoe test pressure should not exceed the maximum allowable pressure for which the cavern roof and casing shoe could be designed to operate. See 12.1.8.3 and API 1115 for more guidance on maximum allowable design pressure.

14.3 Nitrogen and Brine Test

14.3.1 Procedures

With the nitrogen to brine interface test procedure, the well is tested to the desired cavern roof and casing shoe pressure with brine in the cavern well and with nitrogen in the cased section of the well and extending several feet [perhaps 15 ft to 30 ft (approximately 5 m to 10 m)] below the casing shoe. During the test period, brine and nitrogen pressures are continuously recorded at the surface. The nitrogen and brine interface level is determined with a recording instrument, such as an electric line density log, at the beginning and end of the test period.

With the simplest type of storage cavern operation for liquefied petroleum gas (LPG), such as a cased well with a brine string, the nitrogen and brine interface test may be conducted as follows.

a) With the wellhead and brine string in place, fill the cavern well and casing annulus with brine and pressurize the brine to approximately the desired cavern roof and casing shoe pressure.

b) Inject nitrogen in the annular space between the brine string and the casing. Continued injection of nitrogen will displace the brine from the annular space.

c) Drain excess brine from the brine string at the wellhead.

d) As needed, lower the premounted interface detector through the brine string via a lubricator mounted on top of the brine string.

e) With the interface detector, track the nitrogen and brine interface until it is well below the casing seat, perhaps 15 ft to 30 ft (approximately 5 m to 10 m) below, then stop the nitrogen injection.

f) Pressurize the brine to the pressure level needed for the test and reconfirm or adjust the interface level.

g) Close surface valves.

This procedure performs an integrity test on the cavern, the cementing of the casing shoe, the well casing, and the brine string. Also, this subjects the brine portion of the wellhead to surface brine pressure and the product portion of the wellhead to surface nitrogen pressure.

14.3.2 Duration

A nitrogen and brine interface test of 24-hour duration is recommended. To eliminate the pressure effects of thermal contraction or expansion problems, it may be necessary to delay the actual start of the test until the nitrogen and brine temperatures equalize. Where possible, plan to inject the nitrogen at or near the brine temperature.

14.3.3 Interpreting Results

With this test, the beginning and ending pressure readings and brine and nitrogen interface depths should be essentially the same levels, with a reasonable deviation allowed, to prove cavern integrity. Although many variables may affect results, in general a variation of plus or minus 6 in. to 12 in. (approximately 15 cm to 30 cm) would be acceptable and a variation of perhaps 3 ft or 4 ft (approximately 1 m to 1.2 m) would indicate problems. If leakage occurs, the source of the leak may be indicated as follows.

a) If the brine string leaks, brine pressure will increase during the test and nitrogen can be detected at the surface in the brine string.

b) If the product casing or casing shoe leaks, nitrogen and brine pressure will decrease and interface will rise.

c) If the cavern leaks, nitrogen and brine pressure will decrease and interface will fall.

14.4 Liquid Pressure Test

If a hydrostatic test is to be performed with the wellhead in place, fill the well cavern, casing annulus, and brine string with liquid (brine, blanketing material, or the liquid hydrocarbon product to be stored), and pressurize to desired cavern roof and casing shoe pressure. After a stabilization period, pressurize to the desired test level and begin the test. The pressure should be recorded continuously for a minimum of 24 hours. A satisfactory pressure test is one in which the recorded pressures change no more than 2 psi (13.8 kPa) during the test.

14.5 Supplementary Information

14.5.1 Saturated Brine Needed

Brine should be as nearly saturated as practical so that reasonably accurate precalculations can be made to determine the surface pressure needed to obtain the desired cavern roof and casing seat pressure.

14.5.2 Engineering Consultation

Expert engineering consultation may be required to interpret the results of the integrity tests, regardless of test method, for the following reasons.

a) The very large volume of brine involved.

b) The effects of brine compression.

c) Plastic deformation of the salt envelope.

d) Brine, particularly in a new well, that may not be 100 % saturated, allowing some solution mining to occur during the test period, and making test results difficult to interpret.

14.5.3 Relieve Pressure Slowly

When a test has been completed, relieve pressure slowly to prevent possible damage to the salt envelope.

14.6 Regulatory Considerations

Where applicable, caverns shall undergo testing in accordance with federal, state, or local government statutes or regulations.

14.7 Final Report and Records Retention

A final report should be prepared upon completion of cavern integrity testing. This report should contain the following:

a) a description of the test procedures used;

b) a summary of all activities associated with the test progression;

c) a summary of the test data;

d) a narrative summarizing test data interpretation;

e) an assessment of test results;

f) as an appendix, all original field data to support the conclusion in the report.

These records should be retained for the life of the cavern.

15 Cavern Abandonment

15.1 Overview

The designer of a new cavern should be aware of the actions that must be taken to abandon a cavern at the end of its life or in the unlikely event that a solution-mined cavern is not completed successfully.

15.2 Action Required to Abandon Well

15.2.1 Regulatory Requirements

Where applicable, jurisdictional government agency regulations must be followed for the abandonment of solution-mined underground storage.

15.2.2 Acceptable Abandonment Procedure

In the absence of regulatory requirements, this section provides an acceptable abandonment procedure.

Remove the stored material in the cavern and well casing by displacing with saturated brine. Remove wellhead equipment and remove all tubing strings from the production casing string, if practical.

Place cement in the cased hole to form cement plugs as follows.

a) Install a bridge plug at, or near, the base of the production casing to prevent contamination of the first cement plug by gas migration. Place a cement plug on top of this bridge plug that will extend 50 ft (approximately 15 m) above the salt.

b) Install plugs that extend from 200 ft above to 100 ft below (approximately 60 m above to 30 m below) fresh-water zones.

c) Install plugs that extend 100 ft (approximately 30 m) down from about 5 ft (approximately 2 m) below the surface.

The casing between cement plugs should be filled with saturated brine or noncorrosive drilling mud of acceptable weight.

Cementing techniques or weights are available to place cement directly above a column of brine without a packer or separation device.

Install a steel plate over the casings about 5 ft (approximately 2 m) below the ground, then backfill.

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