SANDIA REPORT

SAND2009-5878
Unlimited Release
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Overview of Geologic Storage of Natural Gas with an Emphasis on Assessing the Feasibility of Storing Hydrogen

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Abstract

In many regions across the nation geologic formations are currently being used to store natural gas underground. Storage options are dictated by the regional geology and the operational need. The U.S. Department of Energy (DOE) has an interest in understanding theses various geologic storage options, the advantages and disadvantages, in the hopes of developing an underground facility for the storage of hydrogen as a low cost storage option, as part of the hydrogen delivery infrastructure.

Currently, depleted gas/oil reservoirs, aquifers, and salt caverns are the three main types of underground natural gas storage in use today. The other storage options available currently and in the near future, such as abandoned coal mines, lined hard rock caverns, and refrigerated mined caverns, will become more popular as the demand for natural gas storage grows, especially in regions were depleted reservoirs, aquifers, and salt deposits are not available.

The storage of hydrogen within the same type of facilities, currently used for natural gas, may add new operational challenges to the existing cavern storage industry, such as the loss of hydrogen through chemical reactions and the occurrence of hydrogen embrittlement. Currently there are only three locations worldwide, two of which are in the United States, which store hydrogen. All three sites store hydrogen within salt caverns.

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1. Introduction

The concept of storing natural gas underground in geologic formations arose from the need to supply gas to consumers during periods of high seasonal demand. The storage of natural gas is also an insurance policy against accidents and natural disasters. There are currently several types of underground storage used for natural gas with the three prominent types being depleted gas reservoirs, aquifers, and mined salt caverns. The U.S. Department of Energy (DOE) Hydrogen Program has an interest in understanding these types of underground storage options in the hopes of developing their own underground facilities in the near future to be used as storage for hydrogen gas. This report describes geologic storage, the various storage types, and the advantages and disadvantages of different geologic storage.

Storage of natural gas is used to meet both base load and peak load requirements. Base load storage facilities, such as depleted reservoirs and aquifers, have the large capacity to meet seasonal demands. Gas within these facilities is generally withdrawn once or twice a year. Peak load storage facilities are designed to meet short-term demand. Gas can be withdrawn multiple times at high rates over short periods of time. Salt caverns and occasionally aquifers can meet these high turnover rates (www.naturalgas.org; Beckman et al., 1995).

A number of key publications describe the history and fundamentals of natural gas storage. Walters (1976) is one of the earliest to compare underground storage of hydrogen with existing natural gas storage facilities. Carden and others (1979) investigated the possible avenues of gas loss from storage reservoirs. Brookhaven National Laboratories (Foh et al., 1979) presented extensive detail describing geologic storage, the various storage types, and the advantages and disadvantages of the different geologic storage types as they relate to the storage of hydrogen gas. Taylor and others (1986) investigated the economics of developing and operating the three main underground storage types.

Currently the National Energy Technology Laboratory (NETL; www.netl.doe.gov) is conducting investigations into alternate forms of underground natural gas storage. Such projects include investigating the potential for storing natural gas in the Columbia Basin volcanic deposits in the Pacific Northwest, where traditional forms of storage are not geologically available (Reidel et al., 2003). Alternatively, modeling and lab experiments have tested the feasibility of storing gas in caverns dissolved within carbonate formations using hydrochloric acid (HCl), (Castle et al, 2005). Finally, studies have determined the feasibility of commercializing refrigerated-mined rock caverns where gas is chilled before injected in order to utilize smaller cavern volumes (PB-KBB, 1998).

This report presents an overview of the various types of geologic storage currently in use for the storage of natural gas. The intent is to give an understanding of geologic storage, to describe the different storage types, and to state the advantages and disadvantages of different geologic storage types as they relate to natural gas. In addition a section has been included that addresses the possible geological, geomechanical, geochemical and operation issues that one may encounter with the storage of hydrogen gas.

2. History

The first successful underground storage of natural gas occurred in 1915 in Weland County, Ontario, Canada, using a depleted natural gas reservoir. Approximately a year later, in 1916, the United States developed its first natural gas storage field near Buffalo, New York. This field, known as the Zoar Field, is still in operation today (Beckman et al., 1995; www.naturalgas.org). By the 1930's there were nine fields in six states (www.naturalgas.org).

After World War II there was an increase in post war production and expansion. It was not possible to construct pipes for transporting the gas with enough capacity to accommodate the demand. In response, a large number of additional underground storage fields were developed (Beckman et al., 1995).

In 1946, the first aquifer storage field was developed in Kentucky. Natural gas was first stored in solution-mined salt caverns within bedded salt in 1961 in Michigan (Foh et al, 1979). The first storage of gas within a salt dome occurred in 1970, in Mississippi, as a backup for hurricane disruption (Beckman et al., 1995). Today there are over 400 underground natural gas storage fields across the United States that range in volumetric capacity between < 1 and > 50 BCF (EIA, www.eia.doe.gov).

3. Types of Underground Storage

The concept of storing natural gas underground in geologic formations arose from the need to supply gas to consumers during periods of high seasonal demand. The storage of natural gas is also an insurance policy against accidents and natural disasters. There are currently several types of underground storage used for natural gas with the three prominent types being depleted gas reservoirs, aquifers, and mined salt caverns. The U.S. Department of Energy (DOE) Hydrogen Program has an interest in understanding these types of underground storage options in the hopes of developing their own underground facilities in the near future to be used as storage for hydrogen gas. This report describes geologic storage, the various storage types, and the advantages and disadvantages of different geologic storage.

3.1 Current Geologic Storage Options

3.1.1 Depleted gas/oil reservoirs

Depleted gas and oil reservoirs have been the most prominent and commonly used reservoir for natural gas storage to date. Depleted reservoirs are old gas and oil fields, located thousands of feet underground, where most of the recoverable product has been extracted. Locations of the current U.S. oil and gas fields are displayed in Figure 1. Generally, the reservoirs are easy to develop, operate, and maintain due to the existing infrastructure (www.natrualgas.org). Natural gas stored in depleted reservoirs is intended to meet base load needs and is generally cycled once a year during the winter season (PB-KBB, 1998).

Geologically, the reservoirs have proven capable of holding gas, since the reservoirs once trapped hydrocarbons that migrated up from the underlying source rock. However, some reasons for caution should be noted. In a few instances, reservoirs that once held gas actually continuously lost gas over geologic time up to the time of production. In other cases loss of gas occurred until the pressure dropped below the caprock threshold pressure – the pressure required for gas to displace capillary water. In this instance loss of stored natural gas would occur once operating pressure was increased (Foh et al., 1979).

To contain gas the reservoir must have high permeability and porosity and successful traps to seal the gas within the reservoir. The high permeability and porosity allows for large volumes of gas to be stored and for the operation of high gas injection and withdrawal rates (www.naturalgas.org; Foh et al., 1979). Traps that successfully contain gas are either structural, such as an anticline, or stratigraphic, such as an impermeable layer (Foh et al., 1979).

To maintain reservoir pressure and adequate withdrawal rates, 50% of the reservoir volume must contain cushion gas. However, once a producing reservoir is abandoned, the reservoir will still contain quantities of gas/oil and water. The abandoned natural gas can be used toward the cushion gas requirement (Foh et al., 1979; www.naturalgas.org).

In reservoirs that must use cushion gas to maintain appropriate pressure needs, cushion gas is a capital loss. Aside from the loss of gas as cushion gas, the most likely path for gas to escape is through leaky wells. Other, most likely, insignificant losses of gas can occur through the caprock, dissolution into connate water, diffusion into the surrounding groundwater, and contamination with pre-existing hydrocarbons (Carden and Paterson, 1979; Foh et al., 1979).

It is also possible to incur gas loss through fingering of gas with the surrounding reservoir water. Fingering is a problem when the mobility of the gas being injected is greater than the mobility of the water being displaced. This instability between gas and water can cause the gas to travel down structure and become unrecoverable (Carden and Paterson, 1979).

Numerical modeling has shown that injecting aqueous foam into a reservoir with a potential for fingering can prevent the migration of gas beyond its designated storage area. The foam is injected right above the gas-water interface which will prevent the migration of gas from the injection well and coning of water into the withdrawal wells (Persoff et al., 1989).

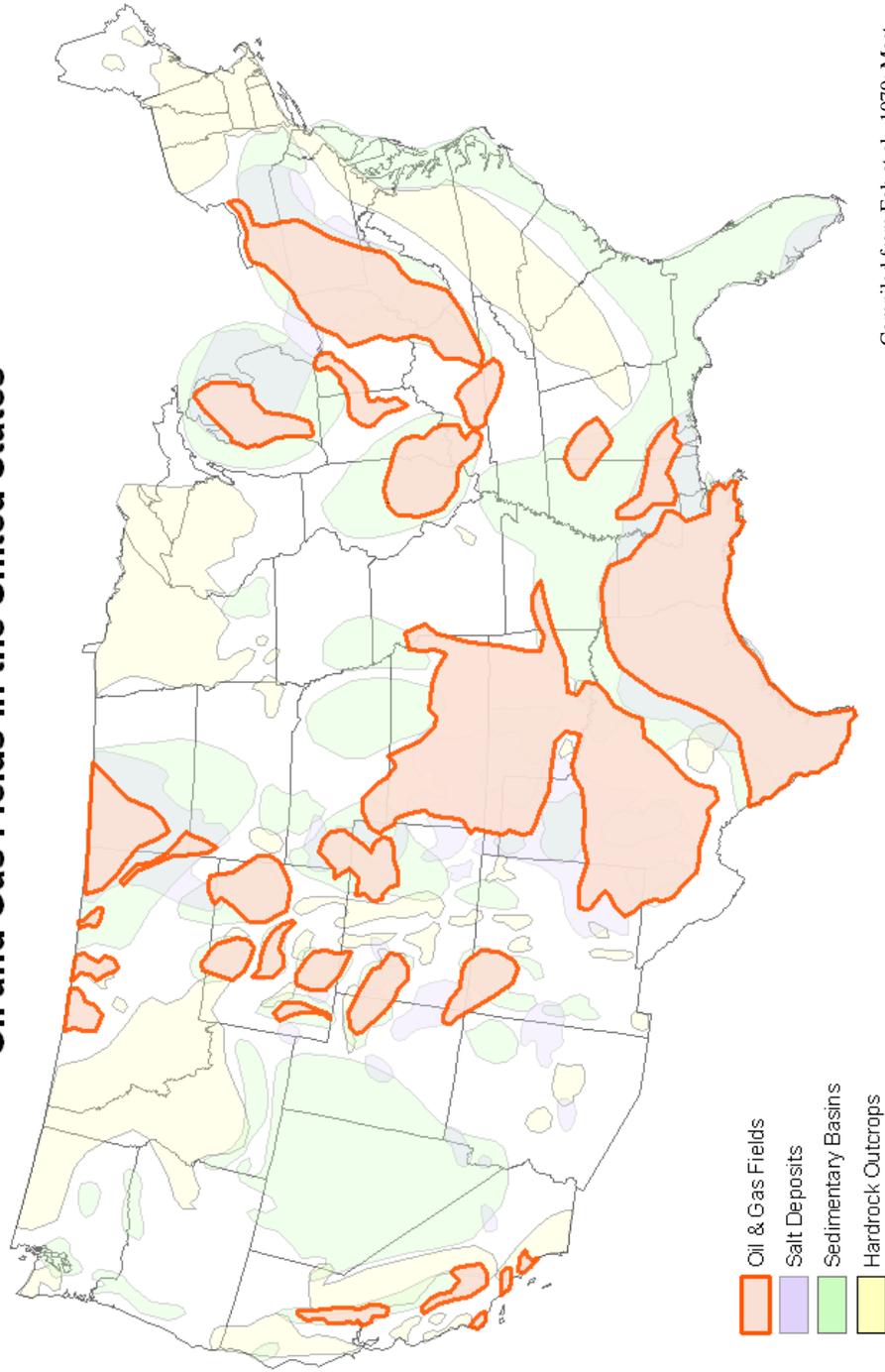**Oil and Gas Fields in the United States**

Oil & Gas Fields
Salt Deposits
Sedimentary Basins
Hardrock Outcrops

Compiled from Foh et al., 1979; Mast et al., 1998; Gillhaus et al., 2006

Figure 1. Location of major oil and gas fields across the United States.

3.1.2 Aquifers

In regions where depleted reservoirs are not available (see Figure 2), such as the Midwestern United States, aquifers can be developed for natural gas storage. Aquifers are water-bearing porous rocks, such as sandstone, typically located thousands of feet underground (EIA, www.eia.doe.gov; Beckman et al., 1995). A suitable aquifer for storage will have geology similar to depleted gas reservoirs. The potential reservoir must have ample porosity and permeability with an existing formation pressure and large reservoir capacity. Gas stored within aquifers are typically drawn down once during the winter season. However, aquifers may be used to meet peak load rates (PB-KBB, 1998; www.naturalgas.org). Delivery rates can be enhanced by an active water drive, using water to displace gas by filling previously gas-filled pores (EIA, www.eia.doe.gov; Foh et al., 1979).

Aquifers are more expensive to develop than depleted reservoirs due to uncertain geology and lack of infrastructure. Geologic characteristics are uncertain and data must be acquired to determine that the formation can trap and seal in gas (naturalgas.org, Beckman et al., 1995). Ideal gas traps are structural highs such as anticlines, impermeable caprock, and sufficient surrounding hydrostatic and threshold pressures (Foh et al., 1979).

Additional expenses will include the construction of the above ground infrastructure, since equipment such as wells, pipelines, and injection systems need to be constructed (Walters, 1976). Additionally, a system must be emplaced that will dehydrate gas (Foh et al., 1979).

Cushion gas requirements for aquifers are greater than those for depleted reservoirs. The amount of cushion gas required may be as high as 80% of the total reservoir volume (www.naturalgas.org, Beckman et al., 1995). Unlike depleted reservoirs, aquifers do not contain existing naturally occurring gas to offset the cushion gas needs.

As with depleted reservoirs, loss of gas is inevitable. In reservoirs that must use cushion gas to maintain adequate pressure and withdrawal rates, cushion gas is a capital loss. Extraction of cushion gas may damage the reservoir formation. The most common loss of gas is through leaky wells. Smaller and usually negligible gas losses occur through caprock, by dissolution into connate water and diffusion into the surrounding groundwater. Fingering between gas and water can cause the gas to travel down structure and become unrecoverable (Carden and Paterson, 1979; Foh et al., 1979).

Sedimentary Basins in the United States

Compiled from Foh et al., 1979; Mast et al., 1998; Gillhaus et al., 2006

Sedimentary Basins
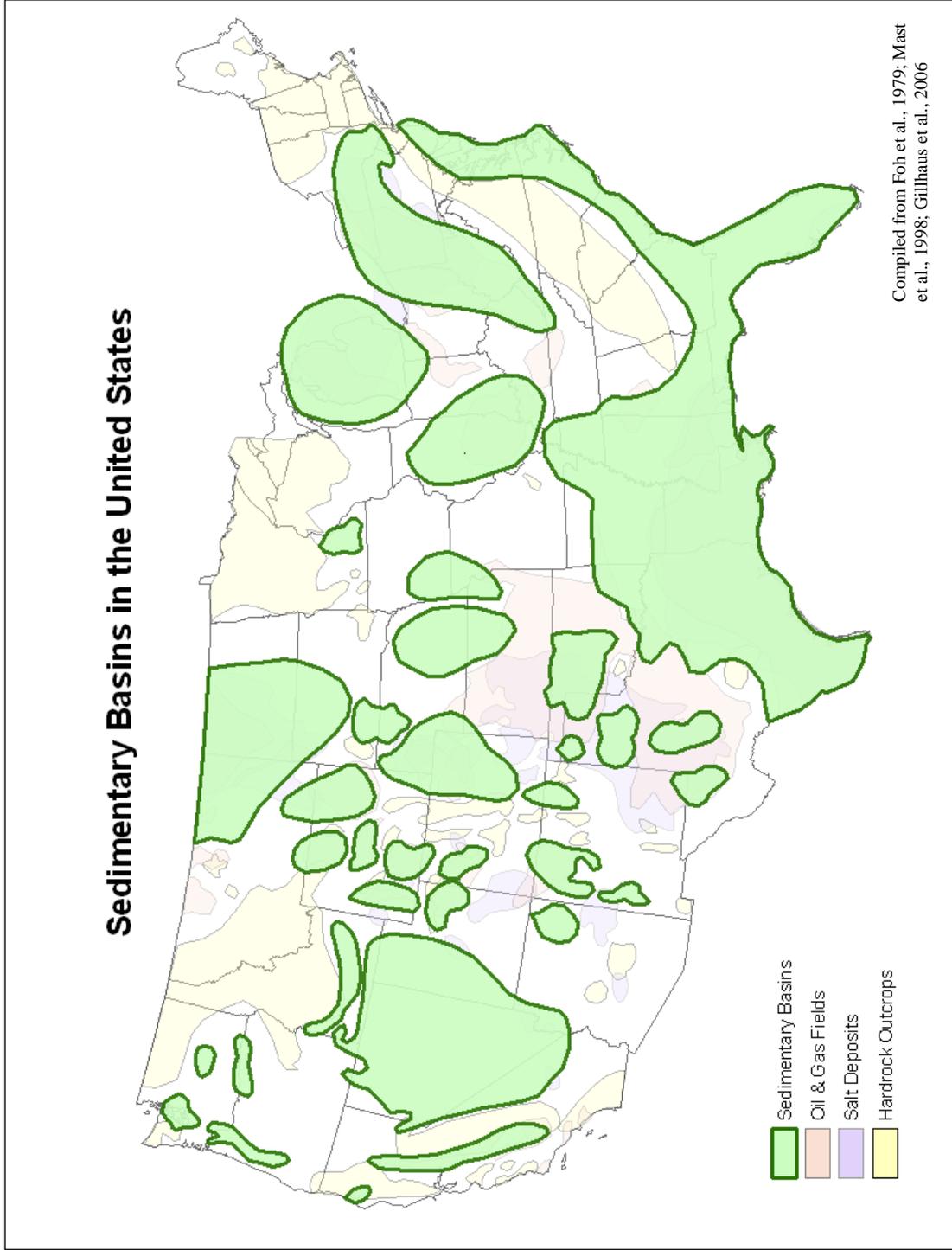Oil & Gas Fields
Salt Deposits
Hardrock Outcrops

Figure 2. Location of major sedimentary basins across the United States.

3.1.3 Salt Caverns

Caverns constructed within salt formations offer another option for underground storage of natural gas. Use of salt caverns occurs in regions like the Great Lakes where porous reservoirs are not available and along the Gulf Coast where salt domes are plentiful (see Figure 3). Salt caverns do not come close to matching the capacity of reservoirs and therefore cannot be used to meet base load needs. However, salt caverns are excellent candidates for peak load cycling and gas can be released within hours of notification at high delivery rates (www.naturalgas.org).

Salt caverns are solution mined by leaching out large cavities by injecting fresh water. Caverns can be created within salt domes or within bedded salt deposits. The salt surrounding the caverns is highly impermeable and virtually leak proof (www.naturalgas.org). Most likely the only avenue for gas loss is escape through leaky wells.

Cushion gas requirements for salt caverns is small or unnecessary. Caverns can be operated under variable or constant pressures (Foh et al., 1979). Under variable pressures approximately 1/3 of the cavern volume will contain cushion gas (Beckman et al., 1995). As working gas is withdrawn the pressure decreases and the amount of cushion gas needed is based on the minimum pressure needed to prevent salt creep which compromises cavern integrity (Foh et al., 1979; NETL, www.netl.doe.gov). Caverns operated under constant pressure are injected with saturated brine while withdrawing gas in order to maintain a constant pressure and cavern stability. Cushion gas is not needed under these operating conditions (Foh et al., 1979; Taylor et al., 1986).

Salt domes are thick homogeneous bodies located largely along the Gulf Coast. Due to the salt's homogeneous nature and thus isotropic properties caverns created within domes are structurally stable above a depth of 6000 ft (Bruno et al., 2002). Below 6000 ft salt deformation is great and cavern stability is difficult to maintain. Bedded salts used for storage are thinner and are typically found at much shallower depths than domes. Bedded salt formations alternate between salt and non-saline beds such as dolomite, anhydrite, and shale (Foh et al., 1979; Han et al, 2006). Structurally, caverns created within bedded salt formations may not be as stable as those created within salt domes due to heterogeneity of rock types present (Bruno et al., 2002; Han et al, 2006).

Creating structurally stable caverns within bedded salt is challenging. Bedded salts are thin and typically no thicker than 1000 ft (www.naturalgas.org). Caverns are designed to be thin and laterally extensive. Developed caverns will possibly intercept various lithologies within bedded salt formations and each layer will contain its own set of properties that affect creep rates, deformation, and slip between bedding planes (Han et al., 2006). Slip between bedding planes can cause gas to migrate laterally. Operating pressures will be limited to 1) the fracturing pressure of the weakest lithology within the bedded salt formation, 2) the minimum pressure to prevent roof creep and instability, and 3) below the maximum threshold pressures that could induce bedding plane slip (Bruno et al., 2002).
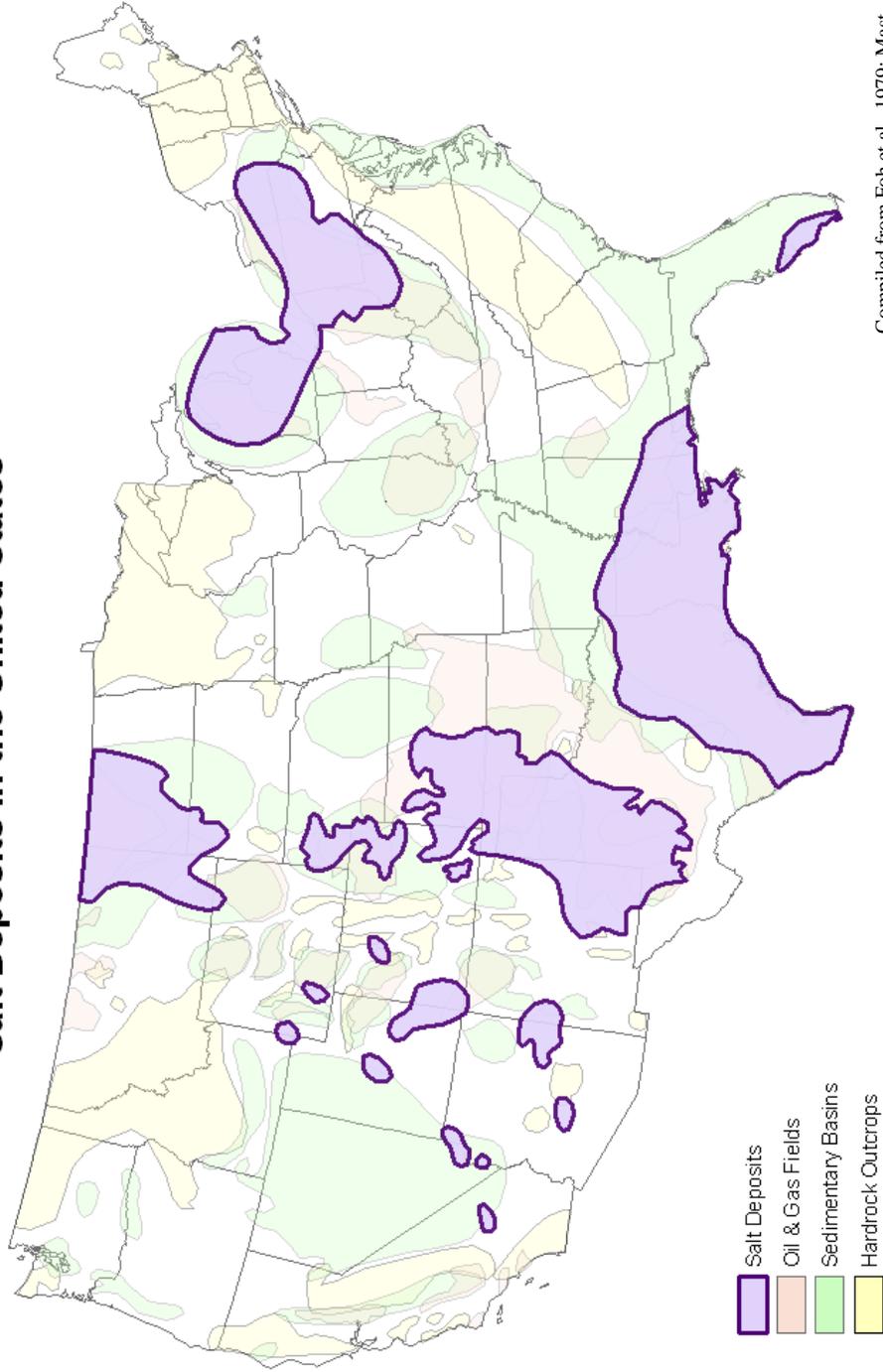
Salt Deposits in the United States

Salt Deposits
Oil & Gas Fields
Sedimentary Basins
Hardrock Outcrops

Compiled from Foh et al., 1979; Mast et al., 1998; Gillhaus et al., 2006

Figure 3. Location of salt deposits across the United States.

3.1.4 Limestone Reservoirs

In a few instances limestone reservoirs are being used to store natural gas. However, public information regarding these reservoirs is sparse. The limestone reservoirs currently in use are described as possessing high permeability and the capability of being operated over multiple cycles. In addition new research has recently been conducted into investigating the creation of caverns within limestone formations by dissolution using hydrochloric acid.

In New York, there are two fields currently in operation that store natural gas within permeable reef structures. The Adrian field and the Thomas Corners field are both located in Steuben County. The Thomas Corners field is 175 ft thick and bound by impermeable shale and a limestone reef platform. The field has the capability to be operated over multiple cycles to meet winter and summer gas demands (Steuben Gas Storage marketing brochure, 2004).

In Italy the Rivara limestone reservoir is under development. The reservoir is naturally fractured and has the capacity to hold a large volume of gas. Gas can be injected and withdrawn rapidly to meet seasonal demands. The use of cushion gas is negligible and may only take up to 14% of the reservoir capacity. The reservoir will rely on hydrostatic pressure from the aquifer below to deliver gas quickly at high rates (www.rigzone.com, www.investegate.co.uk).

New research has recently been conducted into the development of caverns within limestone formations by dissolution using hydrochloric acid (Castle et al., 2005). This avenue of research is in response to the high demand for gas within regions where other traditional storage operations are not available.

Limestone caverns are created by drilling to depth, fracturing the rock and injecting hydrochloric acid to dissolve the limestone to a desired cavern volume. The caverns should be developed within formations with low porosity and permeability (Castle et al., 2005). As seen with limestone reservoirs, the caverns will have the same capability of being cycled multiple times annually to meet summer and winter gas demands.

3.2 Alternative Storage Options

In regions such as the Northeast, Southeast Atlantic, and the Pacific Northwest, large sedimentary basins and salt deposits suitable for natural gas storage are not available (NETL, www.netl.doe.gov). In these regions the geology can consist of coal, shale, or igneous and metamorphic rocks. See Figure 4 for the U.S. locations for useable igneous and metamorphic rocks (i.e. hard rocks). Demand for natural gas storage in these localities has forced adoption of technologies such as storing gas in either abandoned mines or into the excavation of caverns within hard rock that can either be sealed by creating an increased flow of water towards the caverns or lining the rock with an impervious layer. Also, the volume of caverns to be excavated can be reduced by injecting refrigerated gas into storage. Coal

Hardrock Outcrops in the United States
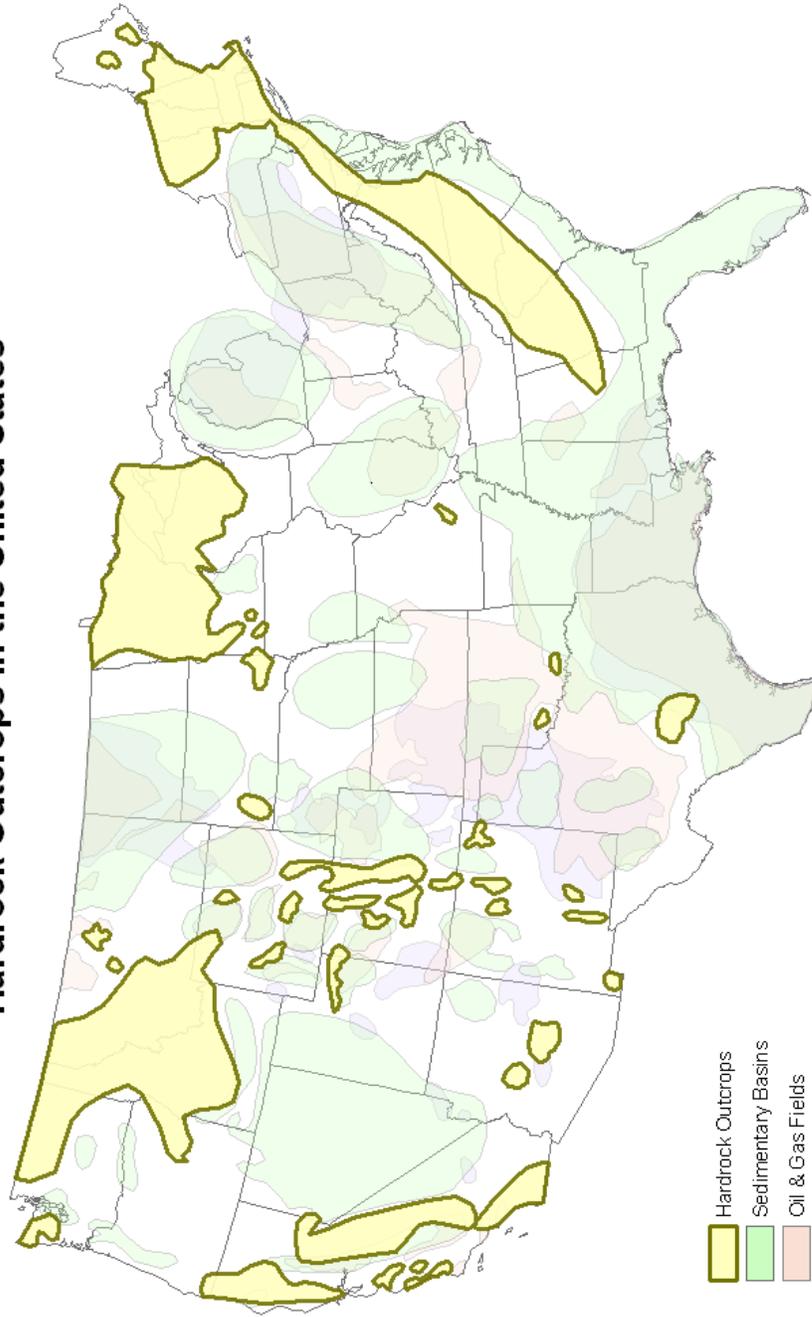
Hardrock Outcrops
Sedimentary Basins
Oil & Gas Fields
Salt Deposits

Figure 4. Location of favorable outcrops of igneous and metamorphic rocks across the United States.

mines, lined hard rock caverns, and refrigerated mined caverns are discussed below, as well as a technique using water pressure to prevent gas escape from excavated hard rock caverns.

3.2.1 Coal Mine

Abandoned coal mines have been used to store natural gas underground. Two mines were located in Belgium and one in Colorado. Currently all three have been decommissioned (MJMEnergy, 2007). However, abandoned coal mines are still being considered as an alternative option for storing large volumes of gas (e.g. 2.60 BCF at Leyden mine). Coal mines have the flexibility to be cycled multiple times annually (Raven Ridge, 1998).

The suitability of a coal mine for natural gas storage is determined by studying the mine history and surrounding geology. The mined coal seam needs to be surrounded by impermeable layers to ensure gas containment. The geology and surrounding hydrostatic pressure will determine at what pressure the mine can be operated (MJMEnergy, 2007).

The volume of natural gas that can be potentially stored in a coal mine is based not only on the volume mined, but also on the adsorption rate of the unmined coal. Methane adsorbs on the surface of coal within its micropore structures. Distrigaz, which operated the mines in Belgium, determined that the adsorption rate in their coal mines increased their gas storage by a factor of ten (Raven Ridge, 1998).

The Leyden coal mine located outside of Denver was used for the storage of natural gas. The Leyden mine was sealed by an underlying aquifer and overlying impermeable claystone. The abandoned shafts were sealed with alternating layers of concrete and gravel (Raven Ridge, 1998). The mine was originally used to provide gas two to three times a year during the winter heating demand. Eventually the mine was cycled over 100 days annually meeting daily fluctuations in gas demand (Raven Ridge, 1998).

3.2.2 Water Curtain Technique

Excavated rock caverns are never completely impermeable. Containment of gas in these excavated caverns is sometimes accomplished by using the water curtain technique. The water curtain is a series of horizontal holes surrounding the excavated caverns through which water continuously flows towards the cavern. The water injected through the holes prohibits loss of gas by flowing into surrounding fractures (Sofregaz and LRC, 1999). Development of caverns must be deep enough to ensure that the hydrostatic pressure of the infiltrating water is greater than the pressure of the stored gas.

A water curtain system is designed to function in three ways. First, the curtain maintains water saturation in the rock fracture system during cavern excavation. Second, the water pressure surrounding the caverns can be regulated to prevent gas breakthrough. Thirdly, the water curtain produces an artificially high water pressure around the caverns so gas can be stored at higher than normally feasible pressures (Lindblom, 1985).

However, in many instances the water pressure can be high enough that water infiltrates into the caverns. An injection of fine-ground cement slurry or chemicals into the fractures can narrow the fractures to approximately one half their original sizes. These injections will

reduce the water flow into the caverns and create a steep gradient in the rock near the gas interface (Lindblom, 1985).

3.2.3 Lined Hard Rock

In regions where porous sandstone and salt are absent, a newly tested storage alternative may exist. Recently, technology has been explored in the excavation of caverns in hard rock and encasing those caverns, in their entirety, with steel or plastic liners. The lining acts as an impervious layer and will completely contain the gas. Caverns designed in this manner will also be operated at much higher pressures than unlined caverns, which are not completely impervious. As with salt caverns, lined hard rock caverns can be withdrawn over multiple cycles and can deliver gas at high rates (Sofregaz and LRC, 1999).

Development of a lined cavern consists of excavating into an igneous or metamorphic rock and constructing a layer of concrete between that rock and the lining that is impermeable and will contain the stored gas (MJMEnergy, 2007; Sofregaz and LRC, 1999). The host rock must be able to withstand and absorb the pressure load. The magnitude of the rock deformation will ultimately contribute to the strain of the lining (Sofregaz and LRC, 1999). The concrete layer is designed to transfer the pressure load from the cavern to the surrounding rock as well as provide a smooth surface to adhere the lining. The lining must be gas tight and chemically resistant. The lining is not designed to carry any load but should be able to resist general elastic and plastic deformation occurring at the rock face (Glamheden and Curtis, 2005; Sofregaz and LRC, 1999). Liners can either be created out of stainless steel or polypropylene plastic. Since hard rock caverns are structurally stable, the need for cushion gas is minimal. In addition, a groundwater drainage system is emplaced around the perimeter of the cavern to reduce the hydrostatic pressure drive against the lining during depressurization of the cavern (Sofregaz and LRC, 1999).

In 2004 the first lined rock cavern became operational, in Skallen Sweden, consisting of an excavated 40,000 m^3 cylindrical cavern lined with steel. A tunnel connects the cavern with the ground surface. The cavern was excavated, within good quality gneiss exhibiting very few fractures, at a depth of 375 ft, and is approximately 165 ft high with measured diameter 120 ft (Glamheden and Curtis, 2005; Sofregaz and LRC, 1999). The cavern went through rigorous testing for approximately 1.5 years. High pressure tests were conducted to test the cavern tightness. Cavern stability was monitored during construction. Currently the cavern is in commercial operation at 2900 psi as part of the Swedish gas grid (Glamheden and Curtis, 2005).

3.2.4 Refrigerated Mined Caverns

Hard rock caverns are generally economically infeasible. However, the development of refrigerated mined caverns will reduce the cost of construction by reducing the amount of rock that must be excavated (NETL, www.netl.doe.gov). The idea behind this technology is to chill the gas before emplacing it into storage. As gas is cooled it compresses and takes up less volume. If gas is cooled to -40° F, the required space for storage would be reduced by 50%. Refrigerated mined caverns also allow for great flexibility with multiple cycle capability and high delivery rates. The caverns are great substitutes for salt storage where salt deposits are not available (PB-KBB, 1998).

Refrigerated mined caverns are not lined and must be developed in competent rock. The rock should be igneous or metamorphic and must be impermeable and strong enough to be self supporting. The host rock should be homogeneous with no faults, joints, or shearzones (PB-KBB, 1998).

Development of caverns should be limited to depths at 2500-3000 ft. Maximum operating pressure should not exceed the hydrostatic pressure. Caverns will need to be operated using cushion gas. A minimum amount may be used in order to reduce the influx of surface water through fissures and cracks. A larger percentage of cushion gas will eliminate recompression of the gas as it is withdrawn. However, a smaller percentage of cushion gas allows for smaller caverns with more working gas (PB-KBB, 1998).

4. Costs

Underground storage fields have different costs associated with their development and operation. Costs are estimated by the type of storage facility to be developed and its intended use. Expenses include development of caverns and/or above ground infrastructure, the amount of cushion gas required, and the cost of operation for a single cycle facility versus a multi-cycle facility. General cost comparisons among the four major types of reservoirs are discussed below and are visualized in Figure 5. In the figure, plant costs represent the cost to erect the facility, cushion gas cost is based on actual examples and are not directly comparable, and operation costs incorporate facility performance, maintenance, and cost of utilities. Aquifers are generally the most expensive to develop, whereas salt caverns are the most economic to operate.
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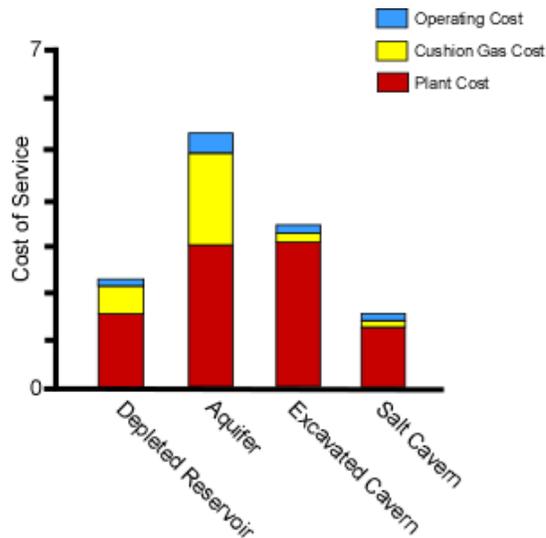
Adapted from Foh et al., 1979

Figure 5. Cost comparison ($/Mcf) for the development and operation of various natural gas underground storage options.

Aquifers have the highest cushion gas requirements and longest development times. It typically takes five years to develop an aquifer due to reservoir characterization and constructing the above ground infrastructure. Operating costs (in $/Mcf) are slightly higher than depleted reservoirs (Beckman et al., 1995).

Depleted Gas Reservoirs are generally cheaper (in $/Mcf) to develop and operate than aquifers. The reservoirs have an existing infrastructure in place and are already proven to trap and contain gas. Most depleted gas reservoirs contain residual natural gas that was never recovered from production. The abandoned gas can be used to meet cushion gas needs, thus reducing the cost and amount of cushion gas that must be injected (Beckman et al, 1995).

Salt Caverns are the most economical option for underground natural gas storage. However, the development ($/Mcf) of the caverns and related infrastructure is a large capital expense. Development of caverns within bedded salts will generally be a greater expense than those leached within domes. The increase in cost, for the development of bedded salts, is due to the heterogeneity and sometimes lack of a location for brine disposal (Taylor et al., 1986; Beckman et al., 1995).

The large reduction in cost in storing gas in salt caverns compared to other storage options is based on the minimal cushion gas requirements and the low cost of operation. Salt caverns are cycled multiple times a year resulting in a high annual gas turnover, which significantly reduces the operational expense (Taylor et al., 1986; Beckman et al., 1995).

Excavated Rock Caverns can be uneconomical depending on the volume to rock needed to be excavated. Removal of hard rock is more expensive than solution mining (Taylor et al., 1986). However, studies have concluded that indicate cooling gas before injection can reduce the volume of rock to be removed and cut expense of cavern development. When compared to other storage options, excavated caverns are second only to aquifers in expense (Foh et al., 1979).

In summary, looking at the overall cost (in $/Mcf) of each storage option, aquifers will be the most expensive. Aquifers use a great deal more cushion gas than the other options, whereas excavated caverns cost the most to develop. For peak load needs salt caverns are the best value, as are depleted reservoirs for base load operations. A more in depth economic analysis will be presented in a following report.

5. Possible Issues with Hydrogen Storage

The U.S. Department of Energy (DOE) Hydrogen Program has an interest in developing underground facilities in the near future to be used as storage for hydrogen gas. However, the storage of hydrogen within the same type of facilities, currently used for natural gas, may add new operational challenges to the existing cavern storage industry. Hydrogen is a small, light molecule that reacts with other elements and steel at high pressures and temperatures possibly creating geological, geomechanical, and operational issues.

5.1 Rock Properties

Salt properties, specifically permeability, may be affected by 1) large deviatoric stresses, and 2) gas or fluids under high pressure (Fokker, 1993). Large amounts of stress can cause crystal boundaries to open and let in fluids, which can lead to salt creep. As shear deformation increases these newly formed pores can become interconnected and increase with size. The pores can dilate enough that fluids from outside the cavern will move in and the cavern becomes unconfined.

It has been demonstrated that when fluids under high pressure infiltrate salt crystal boundaries, rather than support the salt crystals, the fluids decrease the intercrystalline stresses. During normal salt creep the pores close and become virtually impermeable. However, salt can become permeable when fluid pressures are greater than the stress of the salt (Fokker, 1993). In other words, salt properties could possibly be altered and become permeable if gas is stored at a pressure greater than the confining pressure.

5.2 Chemical Reactions

Another possible issue to consider is the interaction of hydrogen with chemical species present in the underground reservoirs. The possible chemical reactions could cause the production of toxic gas as well as the loss of hydrogen (Foh et al, 1979). The rock that host these reservoirs or excavated caverns, with the exception of salt, are generally composed of nonreactive and stable silicate minerals. The concern is with possible sulfide, sulfate, carbonate, and oxide minerals that may be present on the surface of the silicate minerals. However, it has been determined that reaction with these chemical species would be unlikely because the reservoir temperatures would not be high enough to catalyze a reaction. This study was conducted assuming a reservoir temperature of 298K (77°F) and pressure of 2000 psi (Foh et al, 1979). However, Foh and others noted that an increase in pressure and temperature by 50 °F would not catalyze a chemical reaction.

5.3 Hydrogen Mixing

Hydrogen stored in depleted oil/gas reservoirs may be subject to mixing with remnant natural gas, which could affect the hydrogen purity. The hydrogen end use needs to be determined, which will dictate purity requirements, in order to decide whether depleted oil/gas reservoirs will be a viable storage option.

There are several full scale storage operations that have had success in full conversion from one gas to another gas possessing different properties from the first. Gaz de France was successful in converting three fields, 1) the Beynes field, 2) the Gournay field, and 3) Cerville field. Of particular interest is the Beynes field where manufactured gas, which contains hydrogen gas, was converted to natural gas (Fasanio and Molinard, 1989).

In 1973 Gaz de France, which operates the Beynes Field, near Paris, decided to convert its storage field of manufactured gas to natural gas. Manufactured gas is composed of 50 – 60 % hydrogen gas. The reservoir consists of non-consolidated sands with porosity between 25 and 30 percent and possesses a high permeability. The goal was to ensure that at a maximum 3 % or less of the gas withdrawn contain manufactured gas. If this criterion could be met

then a gas treatment facility would not be needed (Foh et al., 1979; Fasanio and Molinard, 1989).

The conversion to natural gas was made by continually injecting natural gas and producing the manufactured gas. A numerical model suggested that 25% of the cushion gas should contain natural gas and this would prevent the manufactured gas from mixing with the top gas in production (Fasanio and Molinard, 1989).

For a period of time the homogeneous aquifer contained both manufactured and natural gas. Before the conversion was complete, natural gas was withdrawn during the winter season and it was discovered that less than 1% of the withdrawn gas contained the manufactured gas (Foh et al., 1979). Once conversion was complete it appeared that injecting the 25% of the cushion gas had prevented the manufactured gas from migrating upwards and mixing with the natural gas (Fasanio and Molinard, 1989).

Numerical models have been utilized by operators, such as Gaz de France, to provide information to help minimize mixing in the underground. A paper by Kilinçer and Gümrah (2000) describes modeling that incorporates both a numerical gas reservoir simulator and a transport model to determine what conditions must be met to control mixing of more than one gas in underground storage reservoirs. In this study 22.6% of the cushion gas was replaced with nitrogen gas in a limestone reservoir with an average of 21% porosity and an average permeability of $3.5 \times 10^{-14} \, \text{m}^2$. The results implied that mixing can be controlled by production rate.

5.4 Hydrogen Mobility

Gas leaks from the underground storage of hydrogen may be greater than leaks involving natural gas. Hydrogen is a small molecule which lends to high mobility and to an increase risk in leaking from underground storage (Crotogino and Huebner, 2008).

Assuming typical storage conditions of 1500 psi (10 MPa) and 85 F (300 K), the viscosity of hydrogen gas is one half that of natural gas. Therefore, the mobility of hydrogen is twice that of natural gas. These traits suggest that the potential for hydrogen gas to leak may be greater than that of natural gas (e.g. Webb, 2006). Additionally, due to higher mobility and low viscosity, fingering of hydrogen gas will more easily penetrate the surrounding water therefore increasing the chance of gas loss down structure.

5.5 Hydrogen Embrittlement

One of the largest concerns, operationally, is hydrogen embrittlement. Hydrogen embrittlement is a term used to describe "a variety of effects of hydrogen on the physical and mechanical properties of metals" (Foh et al., 1979). The presence of hydrogen can cause metal to crack, blister, and lose its strength and ductility, especially in the use of high-strength steels. Such effects could hamper operations, especially with regards to the above ground infrastructure (Foh et al., 1979; Leighty, 2007).

Hydrogen embrittlement in the form of hydrogen chemical attack, loss of ductility, and hydrogen stress-cracking should not be an issue to sites with an existing infrastructure if the

operating pressures are kept below 1200 psi and the storage temperature below 500 °F. However, if would be prudent to inspect and possibly replace weldments and flaws which are highly sensitive to hydrogen attack even below 1200 psi. It is also advised that methane compressors be replaced with hydrogen compressors (Foh et al., 1979).

In storage reservoirs or caverns where high pressure operation is required then a complete replacement of construction materials is necessary. The infrastructure should be constructed using steel that is free of defects and possesses low-yield-strength. The materials should be heat-treated and fully annealed. Great care must be taken in the welding of materials to avoid hard spots and flaws (Foh et al., 1979).

6. Examples of Hydrogen Storage

In the U.S. two companies, ConocoPhillips and Praxair, currently store hydrogen underground. The hydrogen is stored in salt caverns, both which are located within the Clemens salt dome in Texas (Leighty, 2007). ConocoPhillips has been storing hydrogen gas for several decades for use as a buffer to store hydrogen gas when their hydrotreating equipment is down or to provide hydrogen when the ethane crackers are not operational (www.internationalpipelineconference.com).   The ConocoPhillips cavern is 1000 ft tall with a diameter of 160 ft and is located at a depth of 2800 ft.

Praxair's cavern became fully operational in 2007 (www.praxair.com) and is the first storage site to serve the industrial gas industry (www.roads2hy.com). The cavern geometry is probably similar to the cavern operated by ConocoPhillips (Leighty, 2007).

Currently, outside the U.S., Sabic Petrochemcials is the only other company storing hydrogen.   Hydrogen is stored in three small and shallow salt caverns in Teeside, U.K. The three caverns are at a depth of 400 m and each cavern stores about 70,000 m3 of hydrogen gas at 50 bar (Crotogino et al, 2008, Panfilov et al., 2006).

In the past manufactured gas has been successfully stored underground within both aquifers and salt caverns. Manufactured gas, typically referred to as "town gas", is comprised of 50-60% of hydrogen. Manufactured gas has been stored in France, Czechoslovakia, and Germany (www.roads2hy.com; Panfilov et al., 2006).

7. Conclusions

In many regions across the nation geologic formations are being used to store natural gas underground. Natural gas is stored to meet seasonal demands and to protect against accidents and natural disasters that could cause a disruption in supply. Storage of natural gas is used to meet both base load and peak load requirements. Storage options are dictated by the regional geology and the operational need.

Currently, depleted gas/oil reservoirs, aquifers, and salt caverns are the three main types of underground natural gas storage in use today. The other storage options available currently and in the near future, such as abandoned coal mines, lined hard rock caverns, and refrigerated mined caverns, will become more popular as the demand for natural gas storage grows, especially in regions were depleted reservoirs, aquifers, and salt deposits are not available.

Underground storage must have adequate capacity and containment of gas. The storage formation must have high permeability in order for gas to be injected and extracted at adequate rates. Porous reservoirs such as depleted gas reservoirs and aquifers must possess an impermeable caprock along with a geologic structure to contain and trap gas. Mined caverns such as salt caverns contain gas by the impermeability of the surrounding host rock.

Aquifers and depleted reservoirs possess the largest capacity and require the greatest volume of cushion gas. The reservoirs are typically cycled once annually and are used to meet base load demand. Unlike depleted reservoirs aquifers must be proven to trap and contain gas.

Salt caverns are solution mined and hold a fraction of the gas volume than that of depleted reservoirs and aquifers. Salt caverns are typically used to meet peak load demands by possessing multi-cycle capabilities and providing high delivery rates.

Excavated caverns within rocks such as coal and granite contain volumes less than aquifers and depleted reservoirs and are generally developed in regions where reservoirs are not available. Excavated caverns by nature are not completely impervious to gas loss. Several techniques have been developed to insure gas containment, such as lining caverns with steel and increasing the hydraulic pressure surrounding the caverns.

Economically, aquifers cost the most to develop and operate. The major costs contributed to the large cushion gas requirements and the need to verify the reservoirs capability to contain gas. Salt caverns are the most economical, due to their multi-cycle capabilities and high annual throughput of gas. Salt caverns are typically used to meet peak load demands.

The storage of hydrogen within the same type of facilities, currently used for natural gas, may add new operational challenges to the existing cavern storage industry, such as the loss of hydrogen through chemical reactions and the occurrence of hydrogen embrittlement. However, it has been shown that if the underground storage of hydrogen is operated at pressures below 1200 psi and at temperatures below 500° F there may be little need for concern. It is encouraged that all steel used in the storage and operation of a site be free of defects and posses low-yield- strength.

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