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UNDERGROUND STORAGE OF NATURAL GAS

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UNDERGROUND STORAGE OF NATURAL GAS*

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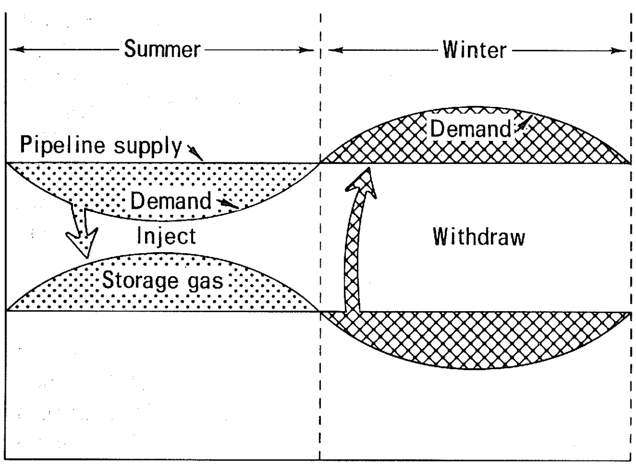
The underground gas storage industry has borrowed much of its technology from other industries—oil and gas exploration, oil and gas production, gas distribution, and ground-water utilization, for example. In addition to this borrowed technology, the gas storage industry has developed its own technology at its intersections with these other industries. I will give you some examples of both borrowed and new technology, and I hope to give you some ideas about areas where you may see opportunities for developing new techniques yourselves.

Most of you know why we need gas storage—storage gas is a stockpile that we build up near the point where the gas will be consumed, a stockpile that we build up in the summer and withdraw in the winter, when the demand for gas is high (fig. 1).



Storage Gas = "Stockpile"

Fig. 1 - "Stockpiling" storage gas in summer for withdrawal in winter.

And you know that gas can be stored in a depleted gas reservoir, in a depleted oil reservoir, or in an aquifer, that is, a water-saturated, porous rock. In addition, some gas is stored in mined caverns, salt solution caverns, and coal mines; also, storage in nuclear explosion caverns has been proposed (fig. 2).

Major

- Depleted oil reservoir
- Depleted gas reservoir
- Reservoir in aquifer

Minor

- Mined cavern
- Salt solution cavern
- Coal mine
- (Nuclear explosion cavern)

Fig. 2 - Kinds of underground gas storage.

The bulk of the storage in the United States is in depleted gas reservoirs and about one-fifth of storage capacity is in aquifers. But because of the importance of aquifer storage in our area, that is, the Midwest, and because I think that aquifer storage is going to be used more and more in other areas, I am going to concentrate on it in much of what I say here. I will end my talk with some ideas about the relation between underground gas storage and the current energy crisis.

*This text was the basis for 14 talks given at section meetings of the Society of Petroleum Engineers of AIME, as part of the 13th SPE Distinguished Lecturer Series, July 1973 to May 1974.

EXPLORING FOR GAS STORAGE RESERVOIRS IN AQUIFERS

Geologists explore for aquifer storage reservoirs in much the same way that they explore for oil and gas reservoirs. They use all of the tools that are listed in figure 3.

- Surface geology
- Coal structure maps
- Shallow structure tests
- Oil and gas tests
- Water wells
- Geophysical data (seismic, gravity, magnetic)
- Test holes in potential storage aquifer (core analyses, DST, pump or swab tests)

Fig. 3 - Exploring for aquifer storage reservoirs.

But even after the gas storage geologist has found a trap in a porous, permeable rock, he has a problem that the oil exploration geologist does not have—How can he tell whether or not gas will leak through the caprock above the reservoir? Figure 4 shows some of the things that he does.

- Special core analyses —permeability and threshold pressure
- Differences in water composition, above and below caprock
- Differences in head, above and below caprock (through geologic time)
- Pumping tests
- "Acid test" – inject gas, watch observation wells

Fig. 4 - Testing caprock above potential aquifer storage reservoir.

The first item listed is core analysis. Core analyses have some value, but the problem with core analyses is this: If the caprock leaks, it probably leaks through a fracture—and how do you sample all of the fractures in a reservoir so that they can be analyzed? Of course, you cannot sample all of them, so you supplement core analyses with other kinds of information.

For example, you can look at the composition of the waters above and below the caprock. A difference in composition is supposed to indicate that there is no communication across the caprock—otherwise water would have flowed from one aquifer to the other and the water compositions would have become the same. But in order for water to flow through a fracture and equalize compositions, remember that you have to have a difference in head across the fracture.

Some geologists and engineers have used the observed head difference between aquifers as an indicator for the absence of fractures in the caprock. They argue that if fractures exist in the caprock, the heads in the two aquifers should have equalized in "geologic time." But suppose that this difference in head has not existed through "geologic time." For example, we have evidence that some of the head differences between deep aquifers in the Illinois Basin have not existed through "geologic time" but are the result of modern pumpage. If the head differences have existed only, say, 25 to 50 years, you could have a fracture that is big enough to leak gas, but not big enough to allow the heads and the water compositions to be equalized in such a short time. In such cases, the water composition and head difference criteria may have doubtful value.

As far as pumping tests are concerned (fig. 5), the idea is simple—you pump water out of the proposed storage aquifer and observe the water level in an observation well in a porous zone above the caprock. To get the greatest response, with the greatest radius of investigation, you have to keep ΔZ* as small as possible, as Witherspoon et al. (1967) have pointed out. But if the compositions of the waters above and below the caprock differ, and if the densities of the waters differ, note that the difference

*ΔZ equals vertical distance from bottom of observation well, in upper porous zone, to top of storage aquifer.

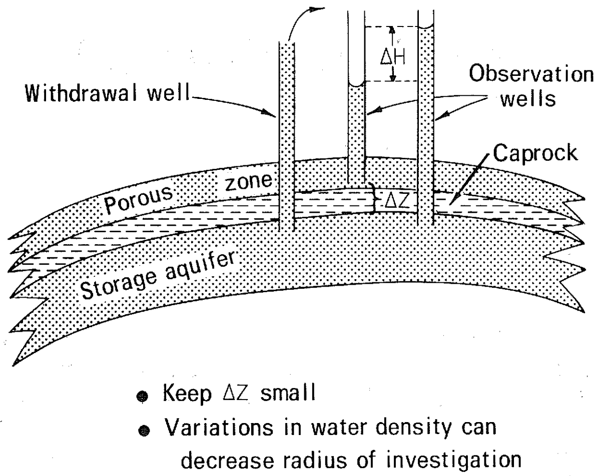


Fig. 5 - Pumping test for caprock.

in water density can cause a marked decrease in the response to pumping and in the radius of investigation (Bond and Cartwright, 1970).

The "acid test" of a caprock is to inject gas into the storage reservoir and watch for gas in observation wells in an aquifer above the caprock (fig. 6). Of course, even before you see gas in an observation well, you may get evidence of serious leakage if you observe a rapid increase in the water level in an observation well.

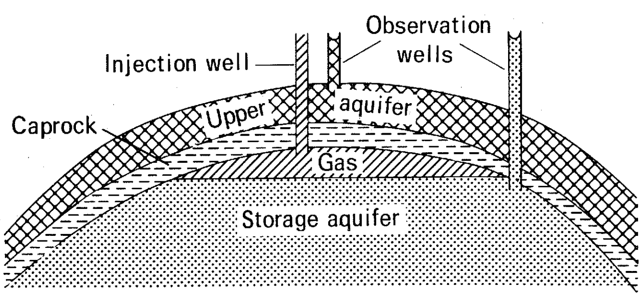


Fig. 6 - Testing caprock by injection of gas.

While we are talking about testing caprocks by injecting gas, I ought to mention two techniques that have been used to cut the cost of the gas that is used for testing (fig. 7). Many of you know about Northern Illinois Gas Company's use of inert combustion gas at Leaf River and Pontiac, Illinois (Wingerter, 1970). The Russians have even used air to test a caprock (Economic Comm. for Europe, 1966). They claim that when they injected natural gas later they did not have any problems with explosive mixtures but, of course, they do not have any

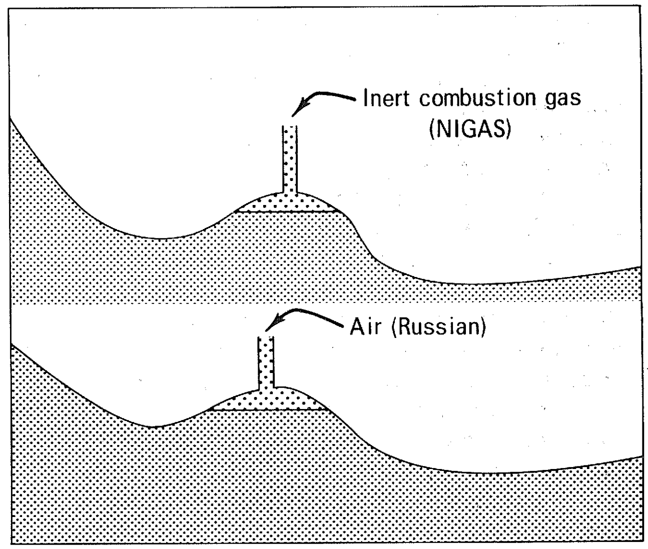


Fig. 7 - Methods of cutting cost of testing aquifers.

problems with the Federal Power Commission and the EPA and the OSHA people either.

Suppose that all of your testing indicates that the caprock is tight and you go ahead and inject gas into the reservoir. What injection pressure should you use (fig. 8)? You all know that you have to start applying pressure gradually and work up to a sand-face pressure that is perhaps 100 to 200 psi above the virgin reservoir pressure. And, of course, the gradient

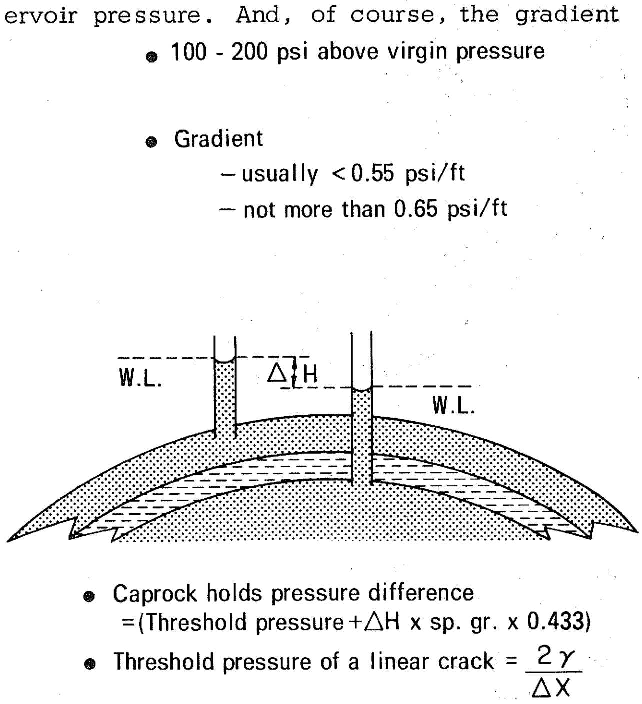


Fig. 8 - Factors that govern injection pressure.

should be kept at less than 0.65 psi per foot of depth, preferably at less than 0.55.

As far as threshold pressure is concerned, you probably have heard people say that the threshold pressure of the caprock determines the height of the gas column (or of the oil column, for that matter) that can be retained by a caprock. This is true only if the head difference across the caprock is zero; if the head difference is not zero, it can add to the effective threshold pressure or it can subtract from it. Furthermore, when leakage occurs, it usually occurs through a fracture. If you can estimate the width of the fracture, you can calculate its threshold pressure from the equation that is given at the bottom of figure 8.

How does the gas storage bubble grow? How does it shrink when gas is withdrawn? The storage bubble is a gas-saturated zone surrounded by a doughnut of compressible water-saturated rock, with a layer in between where gas and water flow in the same direction (fig. 9).

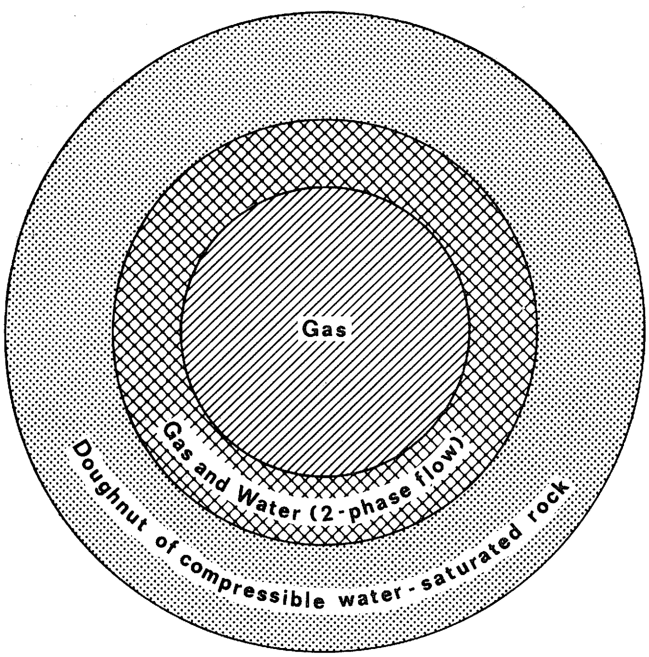


Fig. 9 - Flow regions in and around a gas storage bubble.

As you probably know, the storage people have borrowed from oil-reservoir technology, and they use the familiar Van Everdingen-Hurst method (1949) to estimate rate of growth of the gas bubble and rate of change of pressure (fig. 10).

$$W_e = 6.283 \phi c r_b^2 h (p - p_o) Q_t$$

$$p = p_o - \frac{25.15 e_w \mu}{Kh} P_t$$

Fig. 10 - Growth of storage bubble.

Ideally a gas storage bubble should look something like the bubble shown at the top of figure 11. But in practice the bubble often grows in an anomalous way, as Katz et al. (1963) have pointed out. In the early stages of development of the bubble, it may extend laterally much farther than you would anticipate. In later stages, you may find gas at a depth greater than you would expect. As Rzepczynski and Katz (1969) have suggested, some of this anomalous behavior may be caused by flow through a permeability path that is more permeable than the injection strata, or by permeability stratification. But I think that some of the anomalies also can be explained as results of gravitational effects (Bond, 1973). We have evidence that the water in some of these deep

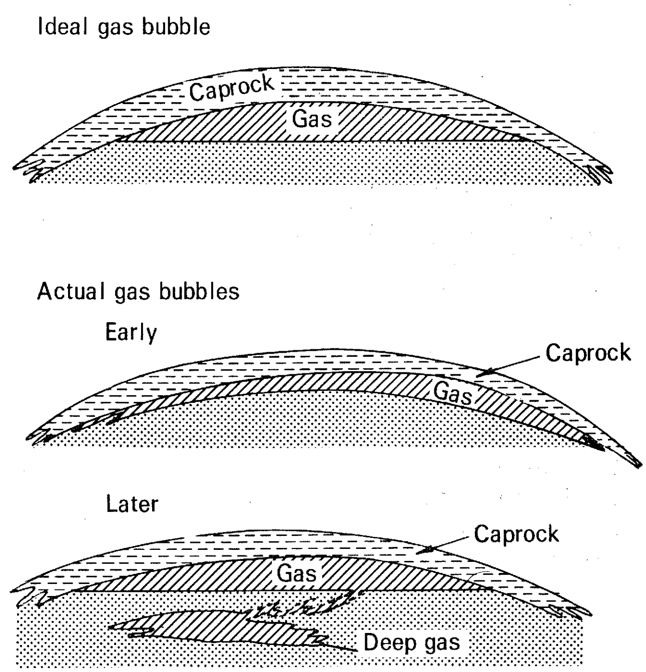
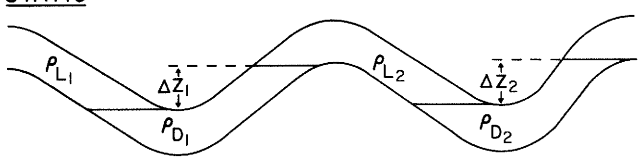


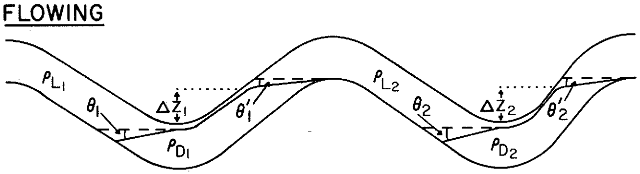
Fig. 11 - Anomalous growth of gas storage bubble.

aquifers is stratified, with dense water underlying a lighter water. In such an aquifer it is easier to move water laterally than vertically. Also, in a variable-density aquifer like this, inhomogeneities in the rock give the effect of troughs or U-tubes (fig. 12). When water flows, each trough exerts a certain difference in head. Head differences like this around the periphery of the storage bubble and under the bubble can prevent the head under the bubble from equalizing with the head outside the bubble. The head under the bubble is smaller than you would expect it to be. Thus, gas is able to migrate to depths lower than you might expect.

STATIC



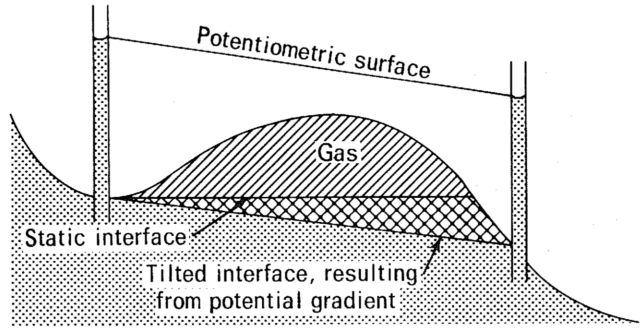
FLOWING



$$\Delta H = (\rho_{D_1} - \rho_{L_1})\,\Delta Z_1 + (\rho_{D_2} - \rho_{L_2})\,\Delta Z_2 + \dots$$

Fig. 12 - Head difference caused by gravitational effects in a variable-density aquifer.

A tilting potentiometric surface can tilt the gas-water interface and can add to, or subtract from, the capacity of a storage reservoir (fig. 13). For example, the capacity of the Pecatonica reservoir in northern Illinois is increased considerably because of a gradient in potential. This gradient can be the result of flow (as at Pecatonica). Or the gradient can result from gravitational effects of the kind that I described above; that is, you can have a tilted interface with zero flow rate. (And you can have a tilted interface with zero flow rate under a natural oil or gas deposit as well as under a gas storage bubble) (Bond, 1973).



- Potential gradient can change capacity of reservoir
- Gradient can result from flow, or from gravitational effects in variable-density aquifer

Fig. 13 - Effect of potential gradient on capacity of gas storage reservoir.

How do you determine what part of the reservoir contains gas? You can open observation wells and with the aid of packers you can see what the wells produce at different levels. Some workers have had fair success with neutron logs taken before and after gas injection (fig. 14). Recently some of the geophysics companies

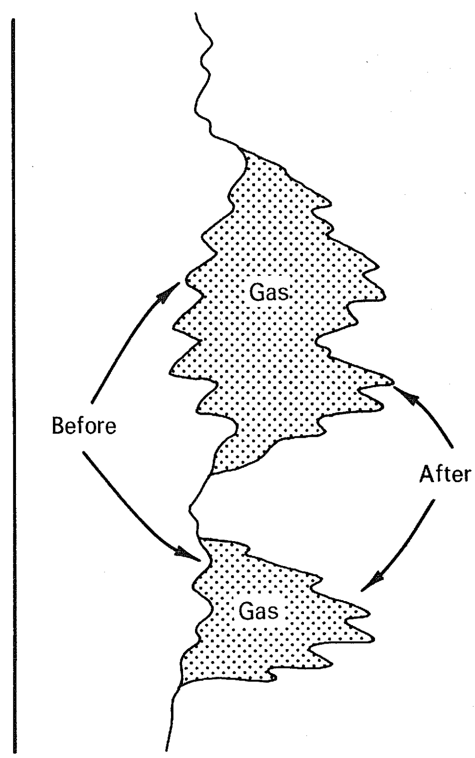


Fig. 14 - Neutron log detects gas fill-up.

have claimed that they can detect gas by seismic techniques with the so-called "Bright Spots" method. But we need a "before and after" test in a new gas storage reservoir to test the "Bright Spots" method. That is, we should run a seismic line across a proposed aquifer storage reservoir before any gas has been injected. Then we should run the same line after the reservoir has been filled with gas. If a difference is observed between the two seismic records, it should prove that the "Bright Spots" method can work.

I turn now to some of the techniques that have been used to prevent leakage of gas from storage reservoirs or to minimize the effects of leakage. You can withdraw water below the gas bubble, as is done at Manlove (Mahomet, Illinois) and a few other places (fig. 15). This lowers the pressure that is needed to supply a given reservoir capacity—at a lower pressure the caprock is less likely to leak.

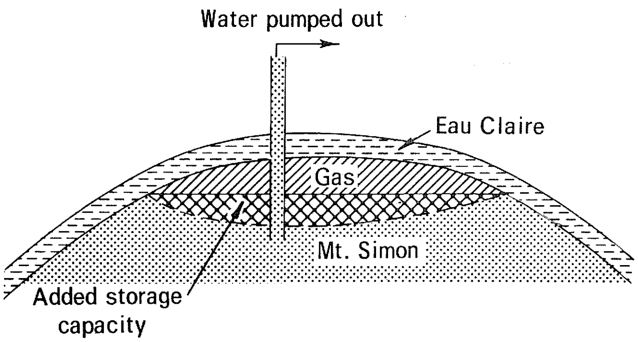


Fig. 15 - Withdrawal of water below gas bubble to increase storage capacity (e.g., at Manlove).

You can withdraw water from the periphery of the bubble, as is done at Herscher, Illinois (fig. 16). This procedure permits water to be displaced more freely and allows the bubble to grow laterally at a lower bubble pressure. You can dispose of the water that is withdrawn by pumping it into a porous rock above the caprock; injection of water above the caprock increases the effective threshold pressure and retards or prevents leakage. Another technique for reducing the injection pressure is the withdrawal of water from the top of the reservoir in the early stages of development to allow the storage bubble to grow faster (fig. 17).

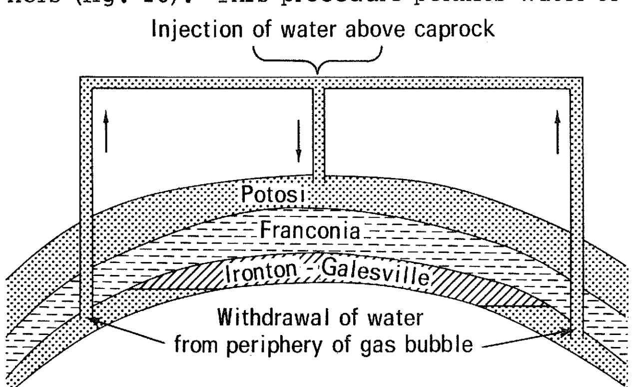


Fig. 16 - Withdrawal of water from periphery of gas bubble and/or injection of water above caprock to increase storage capacity (e.g., at Herscher).

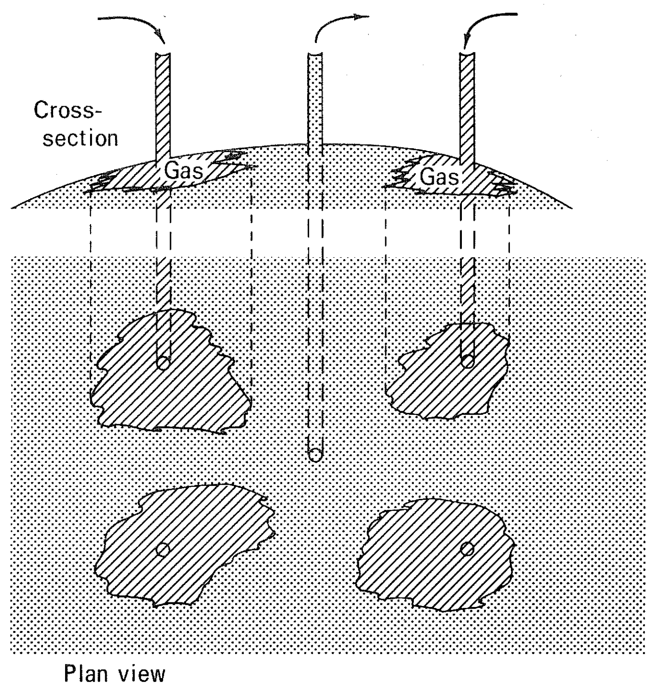


Fig. 17 - Withdrawal of water from top of aquifer to speed growth of storage bubble (e.g., at Manlove).

If gas does leak through the caprock, sometimes it can be trapped in an upper porous zone, as is done at Waverly and Herscher, Illinois (fig. 18). The trapped gas is then recycled into the storage reservoir or is sent to market. Explorationists routinely look for a possible secondary reservoir, with its own caprock, above the primary storage reservoir, to be available just in case the primary caprock does leak. If you have a leak, you might even try to find the location of the leak by injecting a tracer into the gas bubble at different points (fig. 19) (Nelson, 1966). And, finally, leakage is not necessarily all bad. In the Laclede Florissant project near St. Louis, gas that leaks from the St. Peter storage reservoir has repressured the

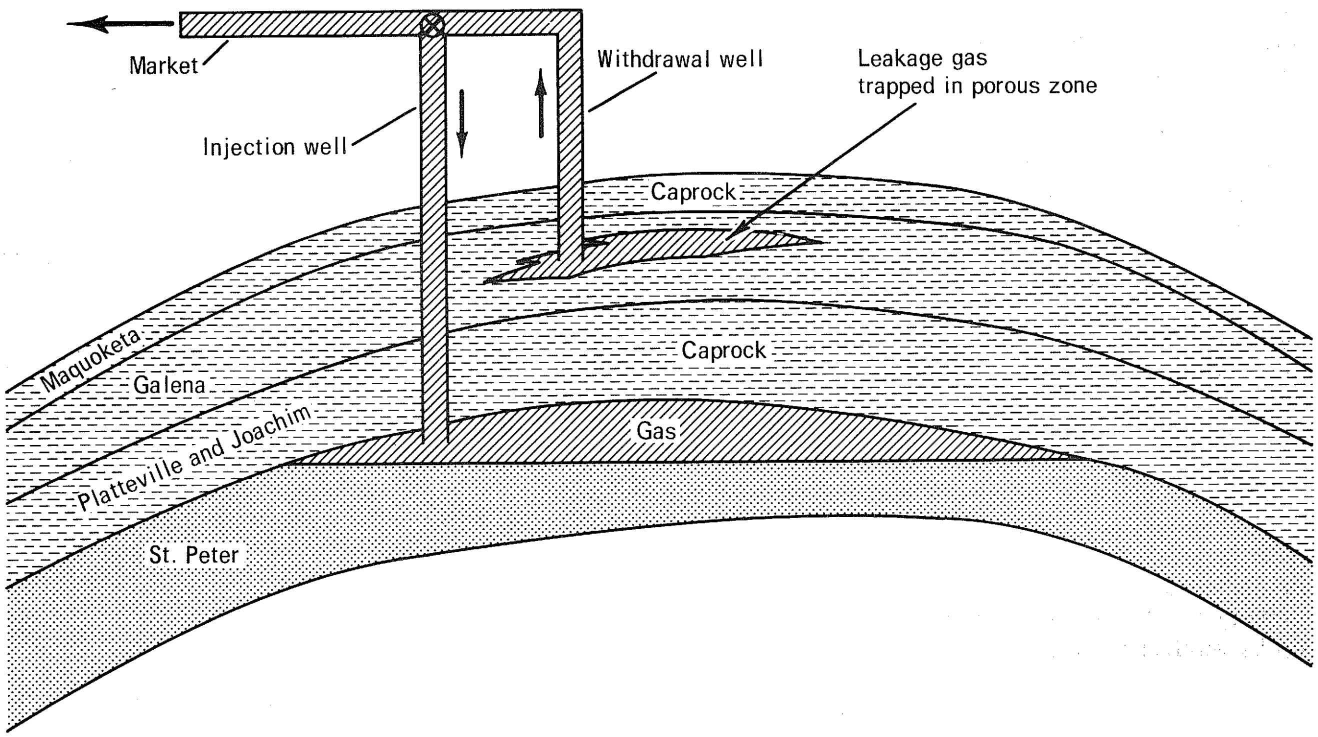


Fig. 18 - Recycling leakage gas (e.g., at Waverly).

Trenton oil reservoir above and thereby has increased the oil production rate considerably. Leakage can be a good thing—if you are lucky enough to have an oil deposit above the leaky aquifer.

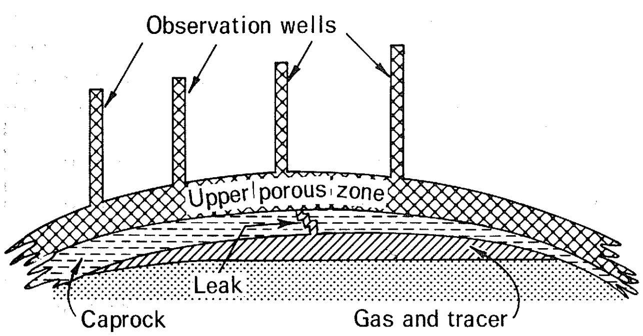


Fig. 19 - Use of tracer (e.g., propylene) to find leak.

Now I would like to discuss briefly several techniques that have been proposed for making storage reservoirs in aquifers that have little or no structural closure (fig. 20). Northern Illinois Gas Company has proposed a ring of water injection wells around the bubble of injected gas (Oil and Gas Journal, 1961). Continuous injection of water is supposed to keep the pressure in the "water-wall" high enough to prevent lateral migration of the gas.

Pure-Union Oil researchers have proposed achieving the same result with a "foam-wall" made by forming a viscous foam around a ring of wells surrounding the injected gas (Bernard, 1967; O'Brien, 1967). As far as I know, neither the "water-wall" nor the foam-wall" concept has been tested.

Evrenos, Heathman, and Ralstin (1970) have proposed using a solid gas hydrate to block the flow of gas near the spillpoint of an anticlinal reservoir. This technique might increase the closure and add to the storage capacity of the reservoir.

The main problem in any application of natural-gas hydrates lies in the difficulty of refrigerating the rock to a temperature that is low enough to cause hydrates to form. I suggest that in certain reservoirs this problem could be eliminated through the use of hydrogen sulfide hydrate. Hydrogen sulfide forms a hydrate at temperatures up to 78° F at pressures of 300 psi or less. If you used H_2S at reservoir temperatures below 78° F, you would not need to cool the reservoir in order to form the hydrate.

In any case, if you are thinking about doing anything with hydrates, remember that salt is a good antifreeze agent. You will want to form your hydrates in fresh-water aquifers rather than in salty aquifers.

I want to mention some work that Russian technologists have done in an aquifer where there was no structural closure (Charnyi et al., 1967). They report satisfactory results in two or three cycles of injection and withdrawal in such a flat system. If this process catches on, it might benefit those geologists who have trouble finding structures but can easily find lots of flat places; they ought to be in great demand.

Finally, we have the possibility of forming a storage reservoir by detonating a nuclear explosive underground (Witherspoon, 1966) (fig. 21). Studies show that such a reservoir could be economically feasible, but testing on this kind of reservoir has been held up by environmental considerations.

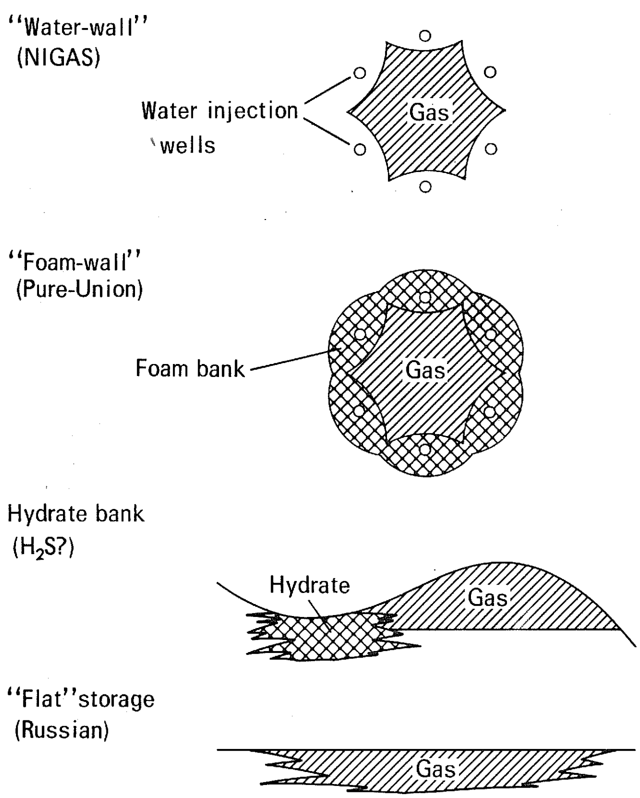


Fig. 20 - Novel means of creating gas storage capacity.

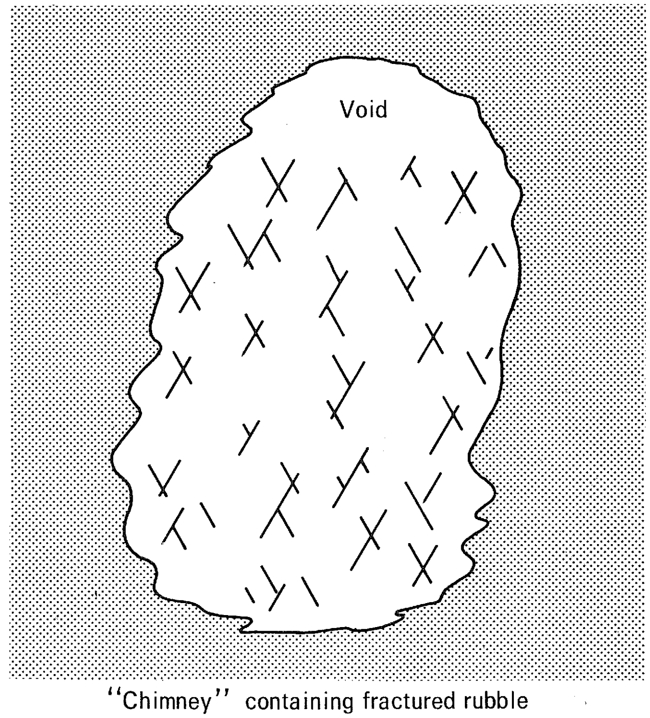


Fig. 21 - Gas storage cavern formed by underground nuclear explosion.

1. Stockpiling gas where most needed
2. Complementary use of underground and LNG storage
3. Storing SNG (from coal or naphtha)
4. Recovering oil as result of storage in depleted oil reservoir
5. Use of CO_2 from coal gasification or SNG manufacture:
   - A. Increasing permeability
   - B. CO_2 as oil recovery agent
   - C. CO_2 as cushion gas

Fig. 22 - Gas storage and the energy crisis.

GAS STORAGE AND THE ENERGY CRISIS

To conclude, I want to give you some ideas about the relation between gas storage and the current energy crisis (fig. 22). When you have energy in great abundance, you can afford to have some of it in the wrong place, at the wrong time. But when the supply of energy is short, you have to have it in the places where it will do the most good. You have to stockpile your energy where it can be used most efficiently. As far as gas is concerned, that means that you have to have the right amount of storage in the right place. This need for efficient stockpiling is going to place large demands on the gas storage industry for more storage and it is going to demand more innovative use of the storage that we already have.

Not all of this storage will necessarily be underground. As the price of cushion gas goes sky-high, the use of LNG to shave the needles off the peaks of your demand curves is likely to be more attractive in more places (fig. 23).

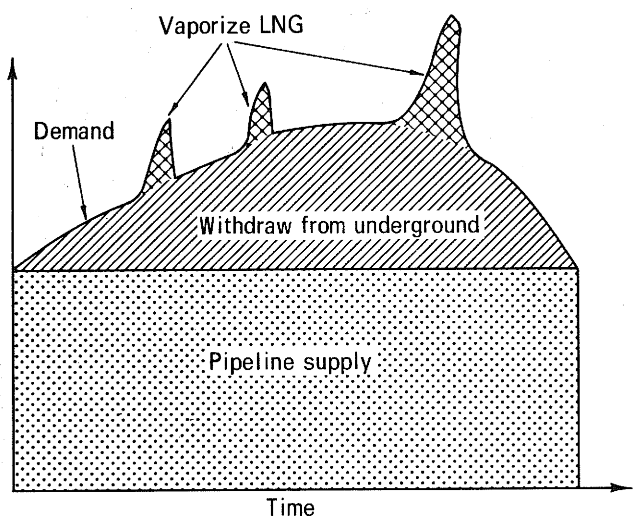


Fig. 23 - Complementary use of LNG and underground storage during withdrawal season.

For a number of years, oil-production engineers have known that considerable amounts of oil can be recovered incidental to the operation of a gas storage project in a partially depleted oil reservoir. Here, through the courtesy of Jack Elenbaas of Michigan Consolidated Gas Company (personal communication, 1973; see also Elenbaas, Buck, and Vary, 1967), I present a graph that shows the oil produced in the operation of their Loreed field (fig. 24). In the past, gas storage people have often considered this kind of produced oil to be more of a nuisance than an asset. But as the price of crude oil goes higher, more storage projects in depleted oil reservoirs are likely to be engineered for maximum oil production, and storage in depleted oil reservoirs is going to be much more attractive economically.

In a few years some large SNG plants will be going into operation. By SNG I mean "substitute natural gas," or, as some people call it, "synthetic natural gas." If the SNG that is produced just takes the place of pipeline gas that is lost, the storage picture may not change much. But if the SNG production is added onto current pipeline supply—and this appears likely in some places—much more storage will be needed. In any case, the normal growth of the seasonal winter demand for gas is going to create a need for more storage.

Looking down the road ten or twenty years or more, a large part of our gas is going to be supplied by gasification of coal, as well as by manufacture of SNG from naphtha. This could affect the gas storage picture in two ways. In the first place, the gas manufacturing plants will have to be operated year round if they are to be economically efficient. In places where no other gas is available, this could mean that you will have to manufacture and store most of your winter's requirement in the summer—a much larger portion than you store now. You will need huge surge tanks (that is, underground storage reservoirs) to hold a supply of gas in reserve to take care of emergencies that might be caused by labor problems or mechanical problems.

The manufacture of gas could also affect the storage picture and the energy picture in another way. When you make gas from naphtha or from coal, you make a lot of other things besides methane gas. For one thing, in some of these processes you produce more CO_2 than you do methane. This gives you an opportunity to do some creative, innovative thinking about uses for this by-product CO_2 (fig. 22). For one thing, you might use the CO_2 to increase the permeability of the rock in a gas storage reservoir, particularly a carbonate reservoir, because carbonic acid is a fairly good acidizing agent for carbonates. Even a sandstone can have a small percentage of material soluble in carbonic acid. In many reservoirs you should get sizable increases in injectivity and deliverability by injecting CO_2 or carbonated water.

Another potential use for CO_2 is as an oil recovery agent for secondary or tertiary oil recovery. This use is different from the use that I talked about earlier, that is, oil recovery incidental to gas storage, as at Loreed. Here I am talking about recovering CO_2 at the gas

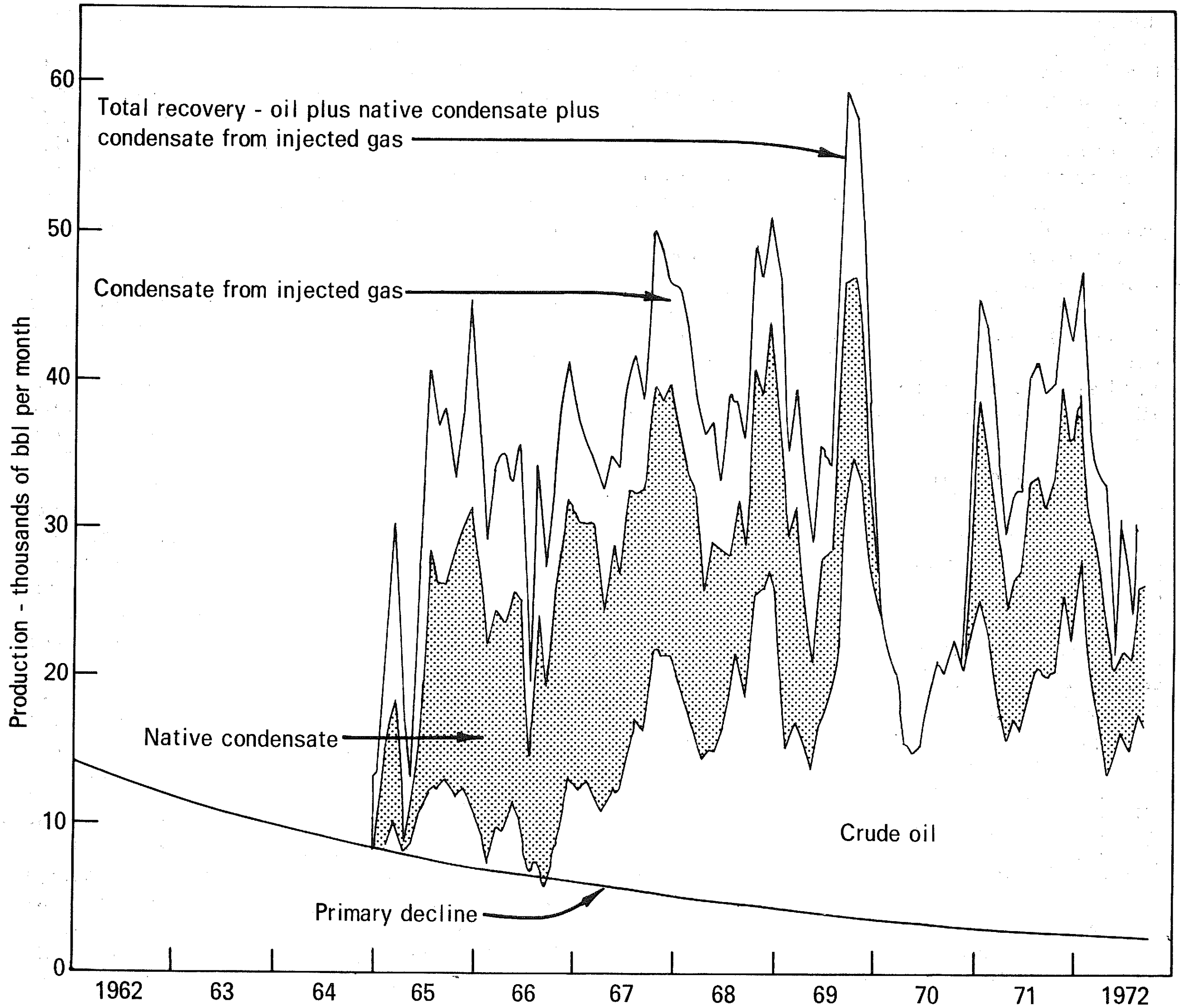
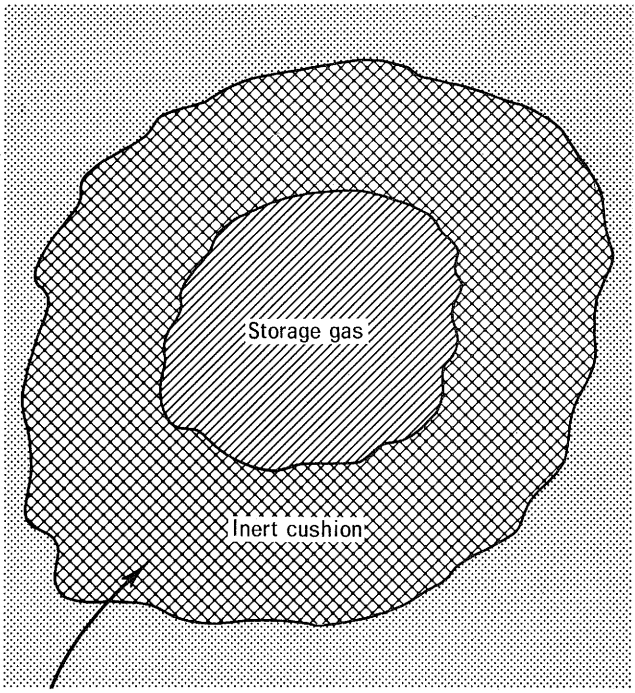


Fig. 24 - Loreed field - additional recovery obtained by gas injection operations. (Courtesy of Michigan Consolidated Gas Co.)

manufacturing plant and piping the CO_2 to some nearby oil reservoir where it will be injected. Laboratory tests and field tests have shown that under the proper conditions CO_2 can be an efficient, economical agent to increase the ultimate recovery of oil from a reservoir (Holm, 1959 and 1963). A huge CO_2-oil recovery project is now underway at the SACROC unit in Texas (Smith, 1971). As cheap CO_2 becomes available from gas manufacturing plants, and as the price of crude oil goes up, we can anticipate that more of these CO_2-oil recovery projects will go into operation.

Several years ago Gardner, Downie, and Wyllie (1962) at the Gulf Research and Development Company did some studies on the use of cheap inert gas as a cushion gas (fig. 25). Now that the price of natural gas and manufactured gas is going so high—and waste CO_2 is going to be available in huge quantities—maybe we should be thinking about ways of using this CO_2 as a cheap cushion gas.



CO_2 from coal gasification or SNG manufacture?

Fig. 25 - Use of cheap cushion gas.

SUMMARY

These are some of the ideas that I would like to leave with you:

- If you are going to use the observed differences in water composition and head (above and below a caprock) as criteria for the tightness of the caprock, remember that the head difference must have existed for "geologic time."
- In pumping tests to test the tightness of a caprock, variations in water density can affect the response to pumping and can limit the radius of investigation in the test.
- Entry of gas into a caprock is controlled by the head difference across the caprock, as well as by the threshold pressure.
- The threshold pressure of a crack in a caprock is equal to $\frac{2\gamma}{\Delta X}$, where γ is the surface tension of the water in the crack and ΔX is the width of the crack.
- Some anomalous behavior in aquifer storage is probably due to certain gravitational effects in variable-density aquifers.
- In a storage reservoir the water-gas interface can be tilted as a result of regional flow of water in the aquifer. The interface can also be tilted as a result of gravitational effects if the density of the water in the aquifer is variable. You can have a tilted interface with zero flow rate. (A tilted interface with zero flow rate is also possible under natural oil and gas deposits.)
- Perhaps hydrogen sulfide hydrate can be used as a blocking agent underground, preferably in relatively fresh-water aquifers.
- A greater number of depleted oil reservoirs are going to be used in gas storage projects, and these projects will be engineered for maximum oil recovery.
- By-product CO_2 (from gas manufacture) can be used (1) as an agent to increase injectivity and deliverability in gas storage reservoirs, (2) as a cheap cushion gas, or (3) as an oil recovery agent.

Gas storage technology will help us solve our energy distribution problems for many years to come. As long as we have gas to consume, gas storage is going to be needed.

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