Mines Branch Information Circular IC-121

PRESENT STATUS OF UNDERGROUND STORAGE OF NATURAL GAS IN SOUTHERN ONTARIO AND QUEBEC

by

R. P. Charbonnier*

SYNOPSIS

Following the completion of the Trans-Canada gas pipeline in 1958, the consumption of natural gas is expected to grow very rapidly in southern Ontario and Quebec -- in a trend similar to that which has occurred in the eastern United States in recent years.

The United States data show the importance of underground storage of natural gas as a solution to irregular consumption problems and winter peak demand periods. The situation in Canada is likely to be very similar.

In the present study various aspects of underground gas storage are considered, including an example of evaluation of market requirements in southern Ontario, a survey of the design and operation of partly depleted fields and aquifer reservoirs, and some cost data.

The present facilities and future possibilities of gas storage in southern Ontario and Quebec are also studied, and show the desirability of further investigations of the storage gas pool possibilities in that area.

---

*Head, Petroleum Reservoir Engineering Section, Fuels and Mining Practice Division, Mines Branch, Department of Mines and Technical Surveys, Ottawa, Canada.

CONTENTS

TABLES

INTRODUCTION

The rapid growth of the natural gas industry in the United States in recent years has been possible only because tremendous volumes of gas have been stored underground near the delivery ends of the long distance pipelines. Through the existence of this storage and the use of interruptible industrial gas sales the pipelines have been enabled to operate regularly at load factors close to capacity. The gas fields produce more satisfactorily at fairly uniform flow rates and the consumers are protected in times of peak demand.

It is to be expected that as the market for natural gas develops in southern Ontario and Quebec, the required storage facilities will have to grow in a trend similar to that observed in the United States in recent years. For the protection and welfare of the public and in the best interests of the Canadian industry, the storage requirements must be carefully considered and fulfilled before the markets are extensively developed.

In this study, a brief summary of the importance of underground storage of natural gas in the United States is first given since the general conditions of growth of the gas industry are expected to be fairly similar in Canada.

As the planning of storage reservoir capacity and deliverability must be based on the expected market requirements, a hypothetical example of the estimation of market requirements in southern Ontario is described, and that study is followed by a survey of the design and operation of the three types of reservoirs used for gas storage, namely partly depleted gas pools, partly depleted oil fields, and water-bearing strata (aquifer reservoirs). The cost of underground gas storage is also briefly considered.

Finally, the present facilities and the future possibilities of underground gas storage in southern Ontario and Quebec are studied, with a view to drawing attention to the necessity of planning a suitable programme of preparation of storage gas pools in this area.

UNITED STATES STATISTICS(1)

At the end of 1958, the proven gas reserves of the United States were estimated at 254 trillion cu ft and the marketed production in 1958 was 10.9 trillion cu ft, while the home and commercial sales increased by 8 per cent to the detriment of the interruptible consumers, which is the usual trend of natural gas markets. The total storage capacity was 2.7 trillion cu ft at the end of 1958, provided by 205 pools in 19 states. With 8,237 active wells, these reservoirs provided a maximum day output of nearly 10 billion cu ft. In 1958 the maximum gas in storage (excluding native gas) was over 1.5 trillion cu ft, with an annual input to storage of nearly 700 billion cu ft and an annual output from storage of almost 500 billion cu ft.

The recent growth in underground gas storage capacity in the United States may be seen from Table 1.

About 70 per cent of the gas stored in the United States is located in four states: Pennsylvania, Ohio, West Virginia and Michigan.

In 1957 the types of reservoirs were reported as follows: 9 aquifers and 190 partly depleted fields, comprised of 175 dry gas, 13 oil and gas, and 2 oil pools.

TABLE 1

Underground Gas Storage Capacity in the United States, 1944-57[1]

Year	Number of Pools	Number of States	Estimated Total Reservoir Capacity, in billions of cu ft (MMMcf)
1944	50	11	135
1949	80	11	497
1951	142	15	916
1953	167	17	1,735
1955	178	18	2,096
1957	199	19	2,603

The native gas in storage reservoirs in 1958 was estimated at nearly 400 billion cu ft, and the ultimate capacity was estimated at 1.3 trillion cu ft for the "cushion" gas and 1.1 trillion cu ft for the "working" gas. At the end of 1958, "cushion" gas and "working" gas volumes were about equal to 700 billion cu ft each, i.e., 50 per cent of the total stored gas.

Rock pressures usually ranged from 100 to 3,000 psig. Approximately 5 per cent of the wells were used for pressure control and 10 per cent were under observation. About 80 per cent were generally used for both input and output. Usually the date of maximum gas in storage is about the end of October.

The data given above show the importance of underground storage of natural gas in the United States, and it is expected that the general trends are likely to be similar in the growth of the Canadian gas industry.

The planning of storage reservoir capacity and deliverability must be based on the expected market requirements, and an example of their evaluation will now be described.

MARKET REQUIREMENTS IN SOUTHERN ONTARIO

For obvious reasons, the trend is to operate all facilities at the highest load factors possible -- especially the long-distance gas pipeline, which require very large investments. This is most easily accomplished by offering off-peak interruptible sales at low rates, but the gross revenue per cu ft of gas is thereby considerably reduced.

The space-heating load varies with the weather and is usually[2] characterized by the "degree-day deficiency" (DDD), which is the sum of the differences between the mean daily temperatures and the base temperature (65°F) for all days when such temperature was below 65°F, as recorded in the local weather bureau. In southern Ontario, where the greatest growth of the gas market is expected, the annual degree-day deficiency may be estimated between 6,000 and 8,000. However, experience has shown that, to be prepared for exceptionally cold years, a safety margin of about 20 per cent should be added, thus giving estimates of 7,500 to 9,500 DDD.

It should be noted that peak demands are far more serious in their effects late in the winter than earlier, because storage gas is then considerably depleted and less pressure is available.

The patterns of hourly variation in temperature and of wind velocity are also important factors of gas consumption.

A favourable factor is the summer air - conditioning load, which is growing rapidly.

In Table 2 are given estimates of the order of magnitude of the usual ranges of consumption factors per customer in Canada.

TABLE 2

Consumption Factors per Customer in Canada (Estimated, 1960)

Class of Sale	Consumption Factor per Customer
Residential exclusive of space-heating	20-40 Mcf/year
Commercial " "	80-200 "
Residential space-heating	0.02-0.04 Mcf/DDD
Commercial " "	0.05-0.15 Mcf/DDD

Table 3 shows some estimates of the usual ranges of load factors in Canada.

TABLE 3

Load Factors in Canada (Estimated, 1960)

Class of Sale	Load Factor (in per cent)
Residential or commercial exclusive of space heating	70-85
Residential or commercial space heating	15-45
Industrial - firm load	50-75
Company use	85-100

The load factor for space heating may be calculated as the ratio of the actual average annual DDD to the value it would have if all days were as cold as the average peak day. For instance, in Windsor, between 1941 and 1952, the peak days averaged 5°F, corresponding to 60 degree-days, and the average annual DDD was about 6,400. The load factor for space heating was therefore: $\frac{6400}{60x365}$ x 100 or about 29 per cent.

The total sales and peak day sendout may be estimated, as shown in Table 4, for a hypothetical market in the Windsor area. The table shows totals of 25,000 residential and 2,500 commercial customers and, for space-heating saturations of respectively 48 and 40 per cent, there would be 12,000 and 1,000 customers in these classes. The table assumes consumption and load factors from the data previously given to arrive at a maximum per day demand of 29 MMcf. As it would be rarely that all classes of sale would impose maximum demands simultaneously, and then only for very brief periods, a "diversity factor" should be applied, which experience indicates is usually between 0.7 and one. Assuming a diversity factor of 0.9, the peak day send-out would be $29 \times 0.9 = 26.1$ MMcf and against this peak demand the average per day load of 12.7 MMcf shown by the table would represent an overall load factor of 12.7/26.1 or about 50 per cent.

TABLE 4

Hypothetical Market Requirements for Gas in the Windsor Area
(Estimated, 1960)

	A	B	C	D=AB D=ABC	E=D/365	F	G=E/F
Class of Sale	Number of customers	Consumption Factor Mcf	Annual DDD degree days	Annual Sales MMcf	Average per day MMcf	Load Factor %	Maximum per day MMcf
Residential	25,000	30		750	2.0	80	2.5
Commercial.....	2,500	100		250	0.7	80	0.9
Residential space heating..	12,000	0.025	6,400	1,920	5.3	29	18.2
Commercial space heating..	1,000	0.075	6,400	480	1.3	29	4.5
Industrial firm load				600	1.6	65	2.5
Industrial Interruptible load				500	1.4		
Company use, etc.				150	0.4	100	0.4
Total				4,650	12.7		29.0

In order to operate at 100 per cent load factor, the transmission pipelines supplying the market considered in Table 4 should have a capacity of about 12.7 MMcf/day. The space-heating part of this market corresponds to a yearly average deficiency of 6,400/365 or 17.5 degree days. But the weather records for the Windsor area show a total of about 2,470 degree days observed in excess of the yearly average of 17.5 DD. These additional requirements account for 2,470/6,400 or 38.6 per cent of the annual space-heating load. This excess over average load would need a minimum working gas storage of 38.6 per cent of the annual residential and commercial space-heating requirements shown in Table 4 as 1,920 plus 480 i.e. 2,400 MMcf of gas. These storage facilities, which amount to 926 MMcf of working gas, should have a maximum daily deliverability of at least 26.1 minus 12.7 MMcf or about 13.4 MMcf. It should be noted that the maximum hourly deliverability, usually expressed as a percentage of the maximum daily deliverability, may be as high as 6 or 7 per cent, and peak shaving facilities must be provided accordingly.

In practice, storage reservoirs have to be considerably larger than required for the average winter, to provide for unusually high demand and insufficient supply. Gas storage facilities designed for winter conditions are usually acceptable for summer injections, except in some cases of high pressure storage, when compression facilities may be the limiting factors.

DESIGN OF STORAGE RESERVOIRS

Generally, the best type of storage is the adaptation of partially depleted gas or oil fields, if any suitable such reservoir is located reasonably olose to the markets from an economic viewpoint.

The first step in the development of storage in a depleted field is the gathering and study of all geological and engineering data available — such as scout tickets, well logs, well plugging reports, production and pressure histories, and core data — in order to estimate the capacity of the reservoir. In addition, performance tests, such as back pressure tests, will help to evaluate the probable deliverability and hence the number of wells required. Regarding the tightness of the reservoir, the records of casing, cement and well plugging are most important; redrilling and plugging of old wells, new casings and new completions are often required.

If these initial studies are favourable, the rights to use the formation for gas storage must be acquired by leases or warranty deeds, etc.

Some new wells should be drilled for various purposes, e.g., delimitation wells, to define the field limits; observation wells (about 4 per cent of all storage wells), to detect possible leaks and check water level changes; additional wells, for peak-day deliverability (usually located at the top of the reservoir); and drainage wells around the periphery of the pool, to decrease the excessive pressure gradients which may occur.

The main difference between operation of a storage reservoir and a gas field is that the rate of withdrawal may be much higher from storage, causing drops in reservoir pressure of as high as 30 psi/day. For a well-head pressure of 600 psia in an 8-inch casing, the maximum flow rate to avoid entraining of formation particles in the gas stream is about 35 MMcf/day[2].

Well pipelines are usually oversized, for protection against freeze-off caused by hydrate formation. In fact, dehydration of the gas withdrawn from storage reservoirs is often required, because even dry gas injected in water-bearing strata collects water. Dehydration is most often obtained by the liquid (glycol) or solid-absorbent processes, either before or after compression, depending on various conditions.

In view of the wide range of compression ratios, pressures and loads, the compressors should offer a variety of possible power and capacity combinations.

OPERATION OF STORAGE RESERVOIRS

Storage in Depleted Gas Fields

In reservoirs with bottom or edge water drive, the changes in reservoir volume may be estimated by the unsteady-state flow equations and methods of Van Everdingen and Hurst[3].

In a reservoir with only gas expansion drive, the range of pressures determines the capacity. To select a suitable range, back pressure tests[4] should be studied, and back pressure curves should be prepared as convenient illustrations of the well-known equation for single-phase gas wells:

$$Q = C\left(P_f^2 - P_s^2\right)^n \qquad \text{(1)}$$

where Q = flow rate at 14.7 psia and 60°F. in Mcf/day,

C = performance coefficient,

P_f = closed formation pressure, in psia,

P_s = flowing sand face pressure, in psia, and

n = reciprocal of back pressure curve slope.

"Flow after flow" or "isochronal" tests are also often used to determine the constants n and C, especially for slow stabilizing wells.

The minimum or base pressure can then be chosen after consideration of the compression costs, the cushion gas investment, and the rate of deterioration in field performance when the pressure is lowered.

The maximum storage pressure may be limited by the allowable working pressure of the available equipment, or by the common practice of not exceeding the field discovery pressure. In shallow fields, hydrate formation may be the limiting factor. Consideration must be given to the formation breakdown factor, which indicates the pressure per foot of depth at which the formation would be fractured, ranging from 0.45 to 1.45 psi/ft, and usually above one psi/ft.

Cycling around the discovery pressure is often the best policy. Open-flow tests are wasteful, and may cause caving and water coning. Instead, stabilized back pressure curves are used to estimate the ability of a well to receive or produce gas. Periodic testing is necessary, often annually. The curve slope seems to be a characteristic of the well, and certain modifications of the curves will show the need for remedial procedures, such as blowing to clean cavings; installing liners to prevent cavings; chemical treatments; under-reaming; and perforations.

The maximum withdrawal rates are mainly limited by water encroachment at high pressure differentials as determined by experience. For instance, pressure "draw down" may be limited to a maximum of 50 to 60 psi for field pressures of 500 to 700 psi, the exact figures depending on local conditions. In the absence of bottom or edge water, the transmission pipeline pressure or the installed power of the compressors may be the limiting factor.

Charts relating the withdrawal rates, the compressor station inlet pressures and the observation well pressures can be established to predict one of these variables with various assumptions on the others.

Gas dispatching is based on the weather records and on forecasts and estimates of the various hourly demands. The hourly loads can thus be predicted and the storage reservoir properly operated. Each well should be inspected frequently — daily, in most cases. Pressures should be checked with deadweight gauges.

Inventories of stored gas should be taken in the spring and fall, when the market requirements are closely met by the transmission pipeline. From shut-in pressures isopiestic maps can be drawn, and, with isopachous maps and other data, a weighted average pressure for the reservoir can be calculated. With the measurement of the volume of injected gas, the reservoir volume can be determined. Gas migration and leaks may thus be detected.

Losses due to leakage from the pipe equipment may be estimated at about 0.2 cf/year/psi/sq ft of pipe surface.

Gas migration may also be detected by gas analysis procedures, such as mass-spectrometry and gas-chromatography.

Storage in Depleted Oil Fields

Field history and performance must first be studied and the oil reservoir mechanism determined. The available space can be calculated from the total production of oil and gas, and from material balance calculations. The pressure range used will be based on pressure history of the field, and the maximum is often close to the initial pressure. The secondary oil recovered from the gas helps to reduce the cost of the storage project, and may be very profitable in some cases, but the time-table for storage may be affected by the secondary recovery schedules. Using the same wells for both injection and withdrawal may cause troublesome emulsions.

The volume (V) of gas, to replace oil produced, in Mcf is:

$$V = 0.199 \frac{\Delta N \ P \ B_o}{Tz} \qquad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (2)$$

where ΔN = oil produced, bbl,

P = reservoir pressure, psia,

B_o = formation volume factor

T = reservoir temperature, °R, and

z = gas compressibility factor.

Some injected gas may also go into solution.

With a good cap rock, pressures can be higher than the usual discovery pressure caused by the hydraulic gradient of earth pressure, but pressures exceeding 0.6 psi/ft of depth should be avoided. If water is present, it is usually considered that water movements will be minimum with a pressure cycle in which the average of the highest and lowest pressures would be equal to the discovery pressure. It must be noted that working gas may amount to only 40 to 70 per cent of the total gas in the field.

The gas capacity of a water-drive oil field depends on the possibilities of removing the water by gas pressure. Edge water wells are often quite effective to facilitate this displacement.

The gas flow capacity of oil wells in the case of laminar flow may be expressed as follows:

$$Q = 0.099 \frac{Q_o \, B\mu_o \, (P_1^2 - P_2^2)_g}{z \, T\mu_g \, (P_1 - P_2)_o} \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (3)$$

where Q = gas flow rate, Mcf/day,

B = formation volume factor,

μ_o = oil viscosity, centipoises,

μ_g = gas viscosity, centipoises

P_1 = reservoir pressure, psia,

P_2 = flowing bottom-hole pressure psia,

subscript o applies for oil,

subscript g applies for gas,

z = average gas compressibility factor, and

T = reservoir temperature, °R.

Storage in Aquifers

Suitable anticlinal structures must first be found by geology, by core and slim-hole drilling, and, especially by geophysical methods. The permeability of the cap rock should be lower than 10^{-5} millidarcy, to avoid water displacement. The tightness of the cap rock must be checked by gas injection tests. Limited seepage may be acceptable, and the leaking gas may be collected and recycled from a shallower zone.

To initiate the flow of gas into the reservoir, pressures from 100 to 300 psi above the water pressure may be required. After the flow has started, the maximum gas injection rate at a given gas bubble pressure is based on the aquifer behaviour in the unsteady state. The solutions of Van Everdingen and Hurst[3] may be used to express the water movement q from the gas bubble, in cu ft, as follows:

$$q = 6.28\, \phi\, C_W R_g^2 h (\bar{P}_g - P_f) Q_t \qquad \text{.........} \quad (4)$$

where ϕ = fractional porosity,

C_W = compressibility of water including formation, (volumes)/(volume) (psi),

R_g = gas bubble radius, ft,

h = formation thickness, ft,

P_g = pressure on gas bubble, psia,

P_f = initial water pressure, psia,

Q_t = fluid influx, function of t_D, tabulated by Van Everdingen and Hurst(3) and Chatas(5)

t_D = dimensionless time = $0.0063 \dfrac{Kt}{\phi\mu\, C_W\, R_g^2}$,

K = permeability, millidarcys,

t = time, days, and

μ = water viscosity, centipoises.

In the case where the pressure is not constant, but the rate of water flow is constant, the cumulative pressure increase at the field radius may be expressed as follows:(3)

$$\bar{P}_g - P_f = 25.2 \frac{q\mu\, P_t}{Kh}, \qquad \text{.........} \quad (5)$$

with the same notations as before, but where:

q = water flow rate, cu ft/day, and

P_t = pressure change, function of t_D, tabulated by Van Everdingen and Hurst(3) and Chatas(5).

If neither the pressure nor the flow rate is constant, the principle of superposition may be used to group together a series of different flow rates.

Cost of Underground Storage

Acquisition costs vary a great deal, depending on local conditions. Development costs include drilling costs, which may vary from $5 to $100 per foot for actual drilling, casing, cementing, logging, coring, and testing. Wellhead structures may cost $5,000 each. Gathering system costs should not exceed $10,000 per well. Expenditures for an old well may be higher than for a new one.

Cushion gas, which occupies about the same volume as working gas, costs from 25 to 50 cents per Mcf (close to the interruptible sales price). Capital costs of compressor stations may be from $250 to $300 per horsepower.

Transmission line installation may cost 50 to 60 cents per inch of diameter per foot of length. Gas-treating costs vary to a great extent.

The total investment cost, usually given per Mcf of working capacity, may be estimated to range from 40 cents to $1 per Mcf.

The operating cost seems to be about 5 cents per Mcf delivered, i.e. about 1 cent per Mcf of total sales, since less than 25 per cent of total sales usually comes from storage.

Other methods of peak shaving are much more expensive. Low-pressure steel holders cost hundreds of dollars per Mcf. High-pressure pipe batteries cost tens of dollars per Mcf. Low-temperature liquefaction and storage may cost $5 to $10 per Mcf, but could be greatly reduced for large capacities. Mined caverns cost $4 to $5 per Mcf, and caverns dissolved from salt about half as much.

Investment costs for manufactured oil gas may vary from $170 to $270 per Mcf. Natural gas substitutes from propane may cost

$1.10 per Mcf, to which must be added depreciation costs for the propane plants.

GAS STORAGE IN SOUTHWESTERN ONTARIO

A number of gas and oil fields in southwestern Ontario are now used (others are available) for storage of natural gas to help solve the peak shaving problems that occur in the operation of the Ontario markets of Trans-Canada Pipe Lines Limited(6) and to improve the load factors of the distribution pipelines. For economic reasons, most of the storage fields now in use in the world are located within 200 miles from the markets they supply. As all the available storage fields in western Ontario are located in the extreme southwestern region -- with one small exception -- it is quite probable that their usefulness will be limited mainly to the market areas of the Union Gas Company of Canada Ltd.(7) and the Consumers' Gas Company's central zone(8).

Towards the end of 1959, the gas storage pools in operation had a total capacity of about 35 billion cu ft, the cushion gas pressures varying from 200 to 550 psig. The volume of gas in storage in these pools was about 30 billion cu ft, including a gas cushion of approximately 15 billion cu ft, compared with a total working storage capacity of 20 billion cu ft.

Maximum pressures at capacity would range from 500 to 900 psig. With 4 to 8 wells for each gas field of a few billion c.f. capacity, the total daily deliverability would vary from 250 MMcf at cushion pressures to 550 MMcf at maximum pressures, against an 80 per cent back pressure.

These storage facilities have proved quite adequate, as the available working storage is superior to the winter excess of the demand over the receipts from the pipeline suppliers and the producing fields in southwestern Ontario; at the same time the deliverabilities have been sufficient during the peak periods.

Early in 1960, the total storage capacity was being increased by about 9 billion cu ft, including a gas cushion of about 3 billion cu ft, and therefore a working storage capacity of 6 billion cu ft. The daily deliverability is expected to be increased by 100 MMcf at maximum pressure and 25 MMcf at cushion pressure (80 per cent back pressure).

Additional storage facilities, in the order of 20 to 25 billion cu ft, are expected to be required by the middle 1960's and can be provided easily by a number of gas pools under preparation, which have a total capacity of 90 billion cu ft, including a gas cushion of 42 billion cu ft, and therefore a working storage capacity of about 48 billion cu ft. With 46 wells, these pools could provide an additional daily deliverability of about 640 MMcf at maximum pressure and about 245 MMcf at cushion pressure, against an 80 per cent back pressure.

There are also some currently producing oil fields that could be used for storage later. Although the injection of gas could help in the production of oil, all gas withdrawals would have to depend to a great extent on the most efficient recovery of the oil, and that is not very attractive from the viewpoint of adequate storage operations. However, these supplementary fields would have an estimated working storage capacity of about 10 billion cu ft, with approximately equal cushion, and therefore could have some usefulness within strict limits.

Although their characteristics are not as favourable, a few other gas pools offer possibilities of storage if required; they would have a total working storage capacity of about 10 billion cu ft.

As a last resort, some sour gas pools could provide approximately 13 billion cu ft of working storage capacity, and some gas fields of indefinite extension (under lakes or with other disadvantages of leaks or excessive cushion) could offer over a hundred billion cu ft of working storage capacity.

A comparison of the needs for storage in southwestern Ontario with the availability of possible storage facilities (within 200 miles from the main market areas) indicates that, over a period of at least the next decade, the expected winter withdrawals and peak day requirements from storage can be adequately met by the development of presently known reservoirs in the area.

GAS STORAGE IN SOUTHEASTERN ONTARIO AND THE ST. LAWRENCE LOWLANDS OF QUEBEC

At present there are no partly depleted gas or oil fields that could be used for gas storage in these areas, nor do there seem to be any old mines, salt structures, or excavations that might be suitable. Therefore, the only possibility of providing gas storage seems to be in the selection of natural formations for operation as aquifer storage fields. Unfortunately, few wells have been drilled in southeastern Ontario and southern Quebec. In those areas, some suitable structures may eventually be found, in water-bearing strata in the Upper Potsdam sandstone (Upper Cambrian) under Beekmantown March calcareous sandstones and dolomites at a depth of about 1,000 feet; e.g. in the vicinity of the McCrimmon No. 1 well, Caledonia township, Prescott county about 45 miles east of Ottawa. Showings of gas and water have been noted in some other wells, such as the Carlsbad Springs well, Cumberland township, Russell county, and the Nestle Jackson No. 1 well, Winchester township, Dundas county; also in Chazy sandstones and in the more coarse and porous sections of the Trenton[12] formations.

However, the possibilities for underground storage of gas are more attractive in the St. Lawrence Lowlands of Quebec, which are also nearer the fast-growing gas markets of the Montreal area[9]. In that area, the Chazy, and possibly the Black River, formations seem to be the most promising for gas storage, although the possibilities of the region are not yet well known, inasmuch as only about 40 per cent of the 158 wells drilled there have penetrated below 1,000 feet and rock samples are available for less than one-third of all the wells. Porosities and permeabilities at suitable depths appear to be rather low, and the only core analysis on record shows 1.2 per cent porosity. Well records have recently been published[11]. A great number of faults have been reported and many of the formations are not likely to be suitable for gas storage[12]. The Potsdam is often highly jointed and so is the Utica. The Beekmantown formation may contain many active aquifers and the Trenton is generally quite dense. The Chazy and the Black River together with the Lorraine may offer the best possibilities for gas storage if sufficient porosity and permeability can be found in relatively undisturbed areas.

It must be emphasized that the available geological and well data are still very limited concerning the St. Lawrence Lowlands. However, it seems that the most promising structures, based on present knowledge, would be in the vicinity of the following wells:

Well No. 516 (Mallet No. 1), in Terrebonne county, although a dry hole, showed a number of gas horizons between 1,000 and 2,000 feet, and the area could be suitable for gas storage, depending on the seal in an adjacent fault.

Wells Nos. 72 and 73 (Okalta-Oilmont Nos. 1 and 2), in Laval county, indicated a number of gas and water intervals below 1,000 feet, but are adjacent to a major fault.

Well No. 120 (Quebec Fuel No. 3), in Vercheres county, produced gas from the 1,860-foot level at 250 Mcf/day with a closed-in pressure of 240 psi. This well was completed in 1910, is relatively close to Montreal, and indicates some possibilities for the area, although the neighbouring wells have been rather disappointing.

Well No. 520 (Roy, J.A., and Fortin, J.), in Nicolet county, showed water and gas between 900 and 1,000 feet of depth, but is close to the St. Germain complex and much farther from Montreal than the wells previously mentioned.

Wells Nos. 2, 3, 4, 5 and 6 (Bald Mountain Batiscan Nos. 1, 2, 3, 4 and 5), in Champlain county, about 100 miles from Montreal, have shown numerous gas and water horizons. Well No. 2, completed in 1957, had a reported flow of 3.5 MMcf/day, with a closed-in pressure of 1,000 psi.

Well No. 11 (Bald Mountain No. 1, Louiseville), in Maskinongé county, completed in 1957, produced at 850 Mcf/day with a closed-in pressure of 384 psi. Although this well is rather shallow (819 feet) and the neighbouring Well No. 12 was not so encouraging, Louiseville is closer to Montreal than is Batiscan and there seem to be definite possibilities, especially in the

Beekmantown horizon.

In summary, it may be stated that there are a number of structures in the St. Lawrence Lowlands which may offer suitable aquifer storage of natural gas. However, the available data are very limited at present and much geophysical, drilling and core-analysis work is required to ascertain the possibilities of any of the favourable areas or to discover new suitable locations in the regions where the conditions appear promising in spite of too shallow drilling.

TYPICAL CONDITIONS OF ARTIFICIAL UNDERGROUND STORAGE OF GAS

The relatively poor choice of suitable gas storage structures in the Ottawa-Montreal area is such that even very small shallow reservoirs should be considered; in fact, some storage pools have been useful with less than 400 million cu ft capacity and with pressures cycling between 50 and 150 psig.

However, with pools of such rather small dimensions and low pressures, a great number of reservoirs would be required and the economics of that solution to peak shaving problems are not likely to be very favourable, especially since a high deliverability is usually desirable.

For the selection of structures suitable for gas storage in the St. Lawrence Lowlands, it may be helpful to consider some typical conditions[10] found in the few successful aquifer storage reservoirs that have been created under similar circumstances in the world (United States, France and Germany). These structures are generally anticlines at depths of 1000 to 2500 ft. The reservoirs are usually in sands, 100 to 150 ft thick, that are covered by an impervious cap rock (at least 20 ft thick) consisting of limestones, dolomites, shales or clayish rocks with permeabilities lower than 10^{-5} to 10^{-7} millidarcys. The permeability of the reservoir varies between 30 md and 15 darcys, and the porosity between 8 and 40 per cent. The original rock pressure is in the order of 500 to 900 psi and has been raised in some storage fields up to 0.65 psi/ft depth. The total storage capacity of each of these reservoirs may range from 5 to 80 billion cu ft. The maximum deliverability per day is usually in the order of 1 per cent of the total capacity, although it is obviously variable to a large extent, depending on local conditions.

The preparation of an aquifer gas storage field generally takes two to five years because of the lengthy preliminary studies of possible structures, geophysical surveys, core-drilling programmes, and injection tests. In addition, the final filling injection of the pool must be gradual, to avoid excessive pressures and unnecessary gas layers. In order to have only one gas bubble, the second and following wells receive injections only after the gas zone has reached them.

CONCLUSION

Underground storage facilities for natural gas are an essential part of the gas industry. In view of the large capital investment and relatively long and careful development they require, it appears very important to give, as early as possible, proper consideration to the provision of adequate storage capacity and deliverability for the new and fast-growing natural gas industry in southeastern Ontario and in the St. Lawrence Lowlands of Quebec. Although no geological structure has as yet been found very attractive in that area, several formations have been indicated which offer definite possibilities for gas storage, especially if their permeability can be artificially improved by the modern stimulation techniques.

REFERENCES

1. "The Underground Storage of Gas in the United States, December 31, 1958"; Report ON-59-1, American Gas Association, New York, May 18, 1959.

2. Katz, D.L. et al., Handbook of Natural Gas Engineering (McGraw-Hill, New York, 1959), p. 655 et seq.

3. Van Everdingen, A.F., and Hurst, W., "The Application of the Laplace Transformation to Flow Problems in Reservoirs". Trans. AIME 186, 305 (1949).

4. Rawlins, E.L. and Schellhardt, M.A., "Back-Pressure Data on Natural Gas Wells, and Their Application to Production Practices". U.S. Bureau of Mines Monograph 7, 1936.

5. Chatas, A.T., "A Practical Treatment of Nonsteady-State Flow Problems in Reservoir Systems". Petrol. Engr., 25 (5), B 42; 25 (6), B 38; 25 (9), B 44 (1953).

6. "Submission on Gas Storage", by Trans-Canada Pipe Lines Limited to the Royal Commission on Energy, Ottawa, July 1958.

7. Submission to the Royal Commission on Energy, Ottawa, by Union Gas Company of Canada, Ltd., July 1958.

8. Submission to the Royal Commission on Energy, Ottawa, by the Consumers' Gas Company Ltd., July 1958.

9. Submission to the Royal Commission on Energy, Ottawa, by Quebec Natural Gas Corporation, July 1958.

10. Clarac, E., Monicard, R., and Richard, I., "Techniques Employees pour l'Etude et la Realisation de Stockages Souterrains de Gaz dans des Regions Aquiferes". Fifth World Petroleum Congress, New York, Section VIII, Paper 9, 1959. See also the bibliography of the paper.

11. De Blois, R., "Data on Wells Drilled for Gas and Petroleum in the St. Lawrence Lowlands Area". Department of Mines, Quebec, 1959.

12. Private Communications from the Geological Survey of Canada (Caley, J.F., Sanford, B.N., and Howie, R.D.), 1960.

SELECTED BIBLIOGRAPHY ON UNDERGROUND GAS STORAGE

(1) "Bibliography on Underground Gas Storage", American Gas Association, New York, October 27, 1952, and two supplements each following year.

(2) "Comparaison de l'interet du stockage souterrain et de l'effacement des consommateurs industriels". N.Y. Cojan, Revue de l'Institut Francais du Petrole, Nov. 1959, pp. 1575-89.

(3) Proceedings, Research Conference on Underground Storage of Natural Gas, U. of Michigan, July 17, 1959. Notes prepared for the Intensive Course preceeding this Conference.

(4) "The Unsteady-State Behaviour of Linear Gas-Storage Reservoirs". J.E. Warren, Petroleum Engineer, Nov. 1956, pp. B60-85.

(5) "Le Stockage Souterrain de gaz a Beynes". L. Richard and P. Bouraly, Revue de l'Institut Francais du Petrole, July-Aug. 1959, pp. 977-1007.

(6) "Stockage souterrain de gaz a Lussagnet". L. Socrate, Revue de l'Institut Francais du Petrole, Jan. 1959, pp. 72-79.

(7) "Underground Storage - a key to natural gas problems". L.T. Bissey, Mineral Industries, Pennsylvania State University, University Park, Pa., May 1959, pp. 1-6.

(8) "Le role du stockage souterrain dans l'economie du transport ou de l'utilisation du gaz et le developpement de l'industrie gaziere". R. Delsol, World Power Conference, Montreal, Sept. 1958, paper 123F/4, 15 pp.

(9) "Design of Gas Storage Fields". D.L. Katz, J.A. Vary, and J.R. Elenbaas, Journal of Petroleum Technology, March 1959, pp. 44-8.

(10) "Facteurs techniques influant sur la rentabilite des stockages souterrains de gaz en couche aquifere". R. Fort, Revue de l'Institut Francais du Petrole, Feb. 1958, pp. 119-30".

(11) "Effect of Unsteady-State Aquifer Motion on the Size of an Adjacent Gas Storage Reservoir". D.L. Katz, M.R. Tek and K.H. Coats, Journal of Petroleum Technology, Feb. 1959, 5 pp.

(12) "Underground Storage of Gas in France". R. Delsol, 7th International Gas Conference, Rome, 1958, 14 pp.

RPC:(PKS):DL