STATE OF ILLINOIS

DEPARTMENT OF REGISTRATION AND EDUCATION

UNDERGROUND STORAGE OF NATURAL GAS IN ILLINOIS—1973

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ILLINOIS PETROLEUM 101

ILLINOIS STATE GEOLOGICAL SURVEY

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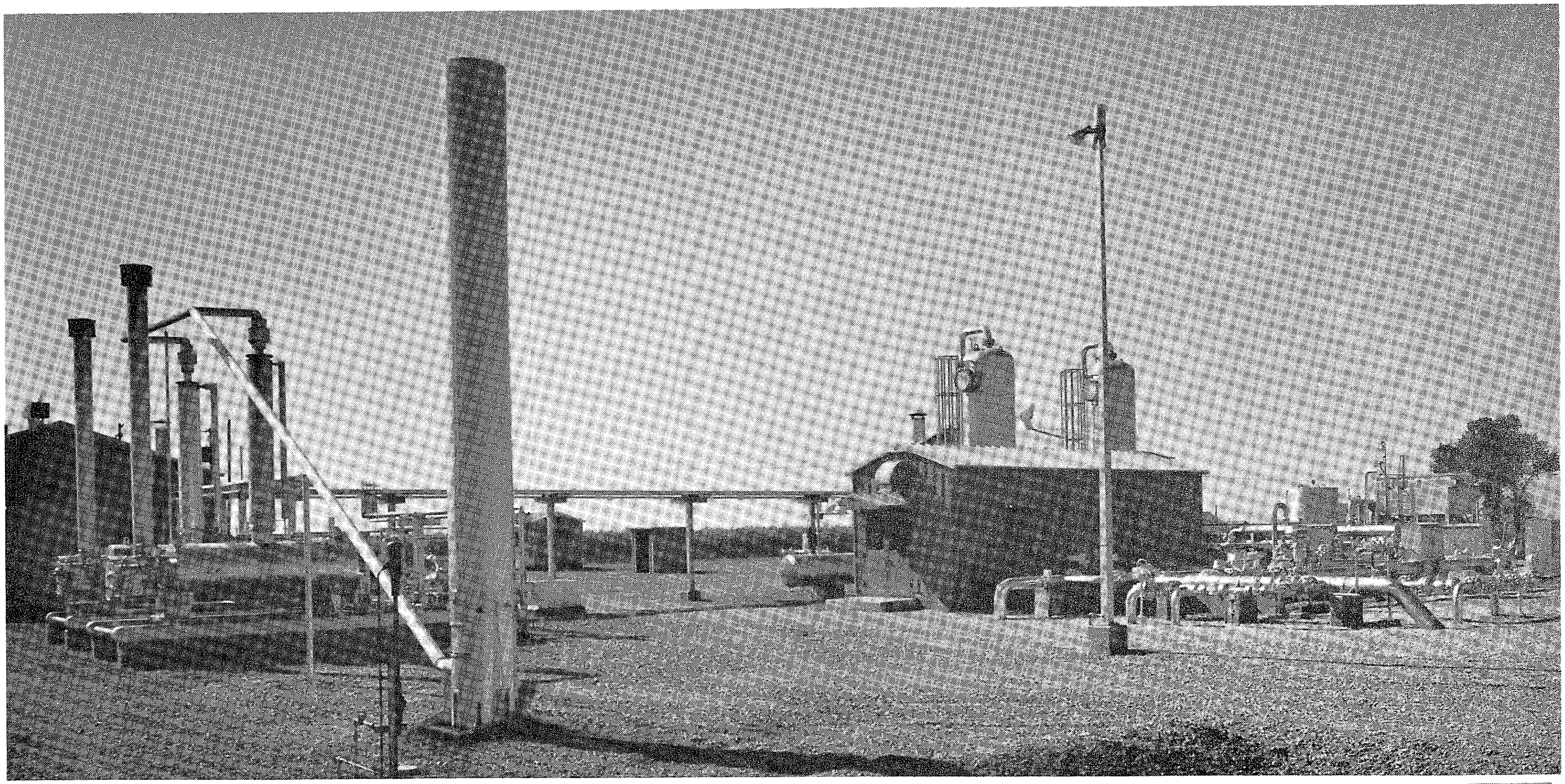
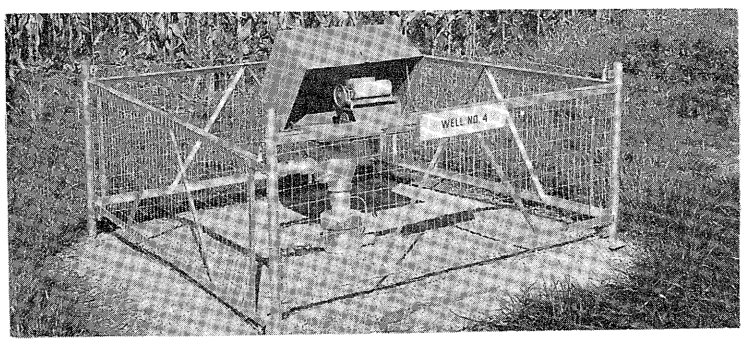
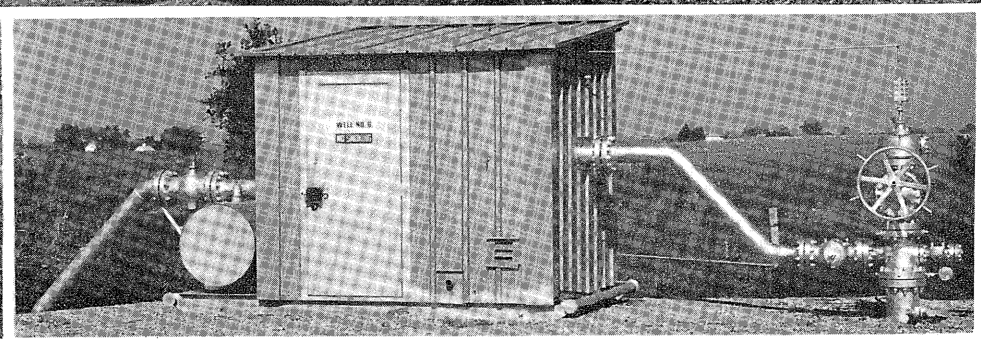
URBANA, IL 61801







Shanghai gas storage project (Illinois Power Co.). Above: plant for handling and treating gas. Lower left: observation well. Lower right: injection-withdrawal well.

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ABSTRACT

Natural gas is stored in underground reservoirs at 37 locations in Illinois. These reservoirs contain more than 580 billion cubic feet of gas, about one-third of which is working gas and two-thirds is cushion gas. Potential usable capacity of these reservoirs is estimated to be 1.2 trillion cubic feet. At 11 of the storage projects, gas is stored in depleted, or partially depleted, gas reservoirs; one depleted oil reservoir is used for storage; in the remaining projects, gas is stored in aquifers that originally contained no hydrocarbons in commercial quantities. At four locations, two reservoirs at different depths are in various stages of exploration, testing, or development for storage. Two projects have been abandoned.

Rocks of all systems from Cambrian to Pennsylvanian are used for storage of gas in Illinois. Most of the storage volume, however, is in sandstone aquifers of Cambrian and Ordovician age.

This report includes a brief discussion of some of the technology associated with the underground storage of natural gas. Also included is information on the geologic setting and the history of development of each project.

INTRODUCTION

This report was prepared: (1) to give a brief introduction to the subject of underground storage of natural gas, and (2) to present basic information about Illinois natural gas storage projects that are in operation or under development.

Illinois gas storage was the subject of two previous reviews (Bell, 1961; Buschbach and Bond, 1967). The present report updates the data given in these earlier studies. For convenience, some of the background material presented by Buschbach and Bond (1967) is repeated here in revised form.

In many places, liquefied petroleum gas (LPG) is stored underground in caverns; this LPG may be ethane, propane, or butane (Van Den Berg and Lawry, 1973, table 6). In some places, liquefied natural gas (LNG) is stored, usually in tanks above ground; for example, Peoples Gas Light & Coke Company has a storage facility for 2 billion cubic feet of gas in the form of LNG at its Manlove field near Mahomet, Illinois. Our report is primarily concerned with the underground storage of natural gas in the gaseous state.

Acknowledgments

This report would not have been possible without the help of many people in the gas storage industry. In particular, information about the operations of individual companies was supplied by the following men: Robert Ryan - Central Illinois Light Company; C. L. Greenwalt, Frank Logan, and J. E. Niemeyer - Central Illinois Public Service Company; R. L. Gower - Gas Utilities Company; C. V. Crow and K. W. Robertson - Illinois Power Company; L. L. Howard - Midwestern Gas Transmission Company; R. H. Fulton and Jack Thomas - Mississippi River Transmission Corporation; W. R. Clark and W. M. Rzerpczynski - Natural Gas Pipeline Company of America; Fred Hunter, Gerry Keen, Robert Magenheimer, C. G. Nelson, and Gordon Royce - Northern Illinois Gas Company; Russell Clausing, W. R. King, and Cecil Little - Panhandle Eastern Pipeline Company; K. R. Larson and S. J. Standlee - Peoples Gas Light & Coke Company. Merle Williams, geological consultant, also contributed valuable information about certain projects.

Figure 2, "Development of gas bubble in an aquifer," was taken from Katz et al. (1963). We are grateful to the publishers, the American Gas Association, for permission to use this illustration.

Why Gas Storage?

Space heating in homes and other buildings consumes large amounts of gas. Because of the seasonal fluctuation in the demand for gas for space heating, the total gas demand generally varies considerably from summer to winter.

One way to accommodate this fluctuating demand would be to build a pipeline from the gas fields large enough to supply the greatest amount of gas that would be needed in the middle of winter. In the summer, then, pipeline pressure could be reduced so that gas would flow at a fraction of the pipeline capacity. This, however, would be an inefficient use of an expensive facility. Instead, the pipeline companies usually have operated their pipelines at full capacity throughout the year; in summertime, they (or the gas distributing companies) have sold the excess gas at reduced prices to manufacturers and other industrial users. In the winter, when the gas was needed for heating, the industrial users switched to other fuels such as oil or coal.

To make better use of the pipelines throughout the year, the gas distributors have acquired more heating customers than the pipelines have been able to supply in the middle of winter. Then, any deficiency in gas supply has been filled by using gas that was stored above ground during summer months in "gas holders" at atmospheric pressure, or gas that was stored under high pressure in pipelines or cylinders, or a mixture of stored propane and air. (These expedients are often called "peak shaving" in the industry.)

None of these measures, however, has been very satisfactory. The pipeline companies have not made much money on the gas that they have sold to industry in the summer, and the gas distributing companies have not been able to store enough gas or propane to handle many customers. Thus, both the pipeline companies and the distributing companies have been under great economic pressure to develop ways to store large amounts of gas. In many cases underground gas storage has proved to be the answer to this problem.

The daily capacity for peak shaving in the United States is more than 43 billion cubic feet. It is available in these forms (Hale, 1971):

	Billion cubic feet
Underground storage	35.05
Propane (LPG) - air	4.06
LNG plants	3.50
Other sources	0.60

In Illinois, as in the United States as a whole, underground storage supplies most of the gas needed for peak shaving.

What Is Underground Gas Storage?

In a few places, such as Michigan, Mississippi, and Saskatchewan, gas is stored in underground caverns leached out of natural salt deposits. In one case, in Colorado, an abandoned coal mine has been used to store gas. More commonly, however, gas that is stored underground is injected into wells in porous sandstone or carbonate rock. In sandstone, the stored gas occupies pores, or void spaces, between the sand grains. In a typical sandstone used for gas storage, the pores are generally a few thousandths of an inch in size. In carbonate rocks, gas may occupy void spaces between grains of dolomite or in oolitic limestone. In some cases, as at Glasford, Illinois, much of the porosity is apparently due to fractures and openings caused by solution of the carbonates by natural chemical agents. In a typical storage rock, the pores make up about 15 to 25 percent of the total volume of the rock; that is, 75 to 85 percent is "solid" rock and 15 to 25 percent is void space available for storage of gas.

HISTORY OF UNDERGROUND GAS STORAGE

Gas was first successfully stored underground in Welland County, Ontario, Canada, in 1915. In the United States the first successful underground storage of natural gas was carried out in 1916 by the Iroquois Gas Company in the Zoar field, south of Buffalo, New York. In 1919, a much larger storage project was developed by the United Fuel Gas Company in the Menefee field of eastern Kentucky. Both of these projects were in depleted gas fields.

By 1936, the United States had 13 storage reservoirs, with a total capacity of 39 billion cubic feet. In the next year, the number of reservoirs rose to 22, with a capacity of 103 billion cubic feet. Growth was steady until 1950, when the number of reservoirs jumped from 80 to 125, with a capacity of 774 billion cubic feet. At the end of 1972, reservoirs numbered 348 in 26 states, with a capacity of 6.0 trillion cubic feet (Perkins, 1962; Vary et al., 1973).

In Illinois the first known experiments with underground gas storage were made by Superior Oil Company at New Harmony in 1941. Fifteen million cubic feet of gas was injected into a Pennsylvanian water sand. When the well was opened, some gas flowed back, but salt water shut off the flow and the experiment was abandoned. The first practical use of underground gas storage in Illinois was made by Mississippi River Fuel Corporation at Waterloo in 1950. In 1952, Natural Gas Pipeline Company of America and Panhandle Eastern Pipeline Company started their large projects at Herscher and Waverly, respectively. Since then, the number of projects and their capacity have grown continuously (fig. 1).

Illinois has a greater total reservoir capacity for underground storage than any other state. However, Pennsylvania has the greatest amount of working gas, followed closely by Michigan; Illinois, Ohio, and West Virginia each have about one-half to two-thirds as much working gas as Pennsylvania or Michigan (Vary et al., 1973).

GAS STORAGE ECONOMICS

In a study of 181 United States storage fields, Coats (1966) showed that fixed charges

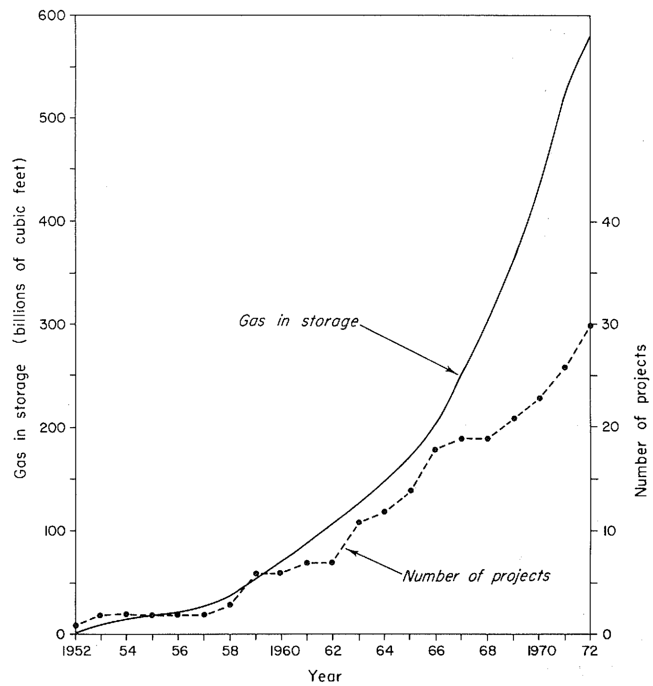

Fig. 1 - Number of operating underground natural gas storage projects and amount of storage gas in Illinois, 1952-1972.

accounted for 80 percent of total storage costs. These fixed charges included depreciation, return on investment, and taxes. About one-third of the total investment was for "cushion" gas—gas that cannot be withdrawn for practical reasons during the normal operation of the storage project (see page 12). A considerable part of this cushion gas is considered nonrecoverable and should be depreciated. The depreciated investment for all 181 fields was 92¢ per thousand cubic feet (Mcf) handled or 27¢ per Mcf in storage at the end of the year. For 11 aquifer storage reservoirs, investment was $1.26 per Mcf handled or 41.3¢ per Mcf inventory. The investment per Mcf per day delivery capacity was $46.50 for all 181 fields and $66 for the 11 aquifer storage reservoirs.

Coats also showed that the average cost of aquifer storage was about 24¢ per Mcf withdrawn and about 16¢ for storage in depleted dry gas fields. The difference results partly from the fact that aquifer storage requires exploratory testing and development to establish the presence of a structure with a satisfactory caprock. Also, aquifer storage sometimes is plagued by leakage problems that must be overcome by reinjecting gas, withdrawing water, or other costly expedients. Furthermore, dry gas storage generally requires less expenditure for new wells. Sometimes storage gas taken from a depleted gas reservoir requires no dehydration. Finally, the depleted gas reservoir itself may supply a considerable amount of the cushion gas, at reduced cost.

A study by the Federal Power Commission (FPC) (1971) of the operations of 31 pipeline companies showed that the cost of storing gas averaged 16¢ per Mcf of gas injected and withdrawn. The fixed costs (return on investment, taxes, depreciation) were about three times the operating and maintenance costs. Most of the storage covered in the FPC report was non-aquifer storage. Since Illinois storage is predominantly in aquifers, the average cost of storage in Illinois is considerably greater than the figure given by the FPC.

Schwalm (1971) gives these estimates of the cost of providing a peak shaving capacity of 3 billion cubic feet per season, with a deliverability of 100 million cubic feet per day:

	Average investment per Mcf	Average operating cost per Mcf	Total cost: Cost of supplying 3 billion cu. ft. per year	Total cost: Cost per Mcf
Dry gas field storage (non-aquifer gas reservoir)	$1.23	$0.05	$1,453,500	$0.48
Aquifer storage	1.49	0.08	1,660,500	0.55

As Schwalm points out, economics is only one factor to be considered in meeting peak shaving demands. Depleted gas fields may not be available for storage. Aquifer storage may not be feasible because the necessary geologic conditions do not exist where they are needed; or aquifer storage may be precluded because of dense population. Use of alternate sources of energy, such as LNG or LPG, may be affected by the scarcity or the unpredictability of supply of these alternate fuels. All of these factors influence any decision about the use of underground gas storage.

Following are the approximate amounts that have been invested or projected in some typical Illinois gas storage projects (from data in the files of the Illinois State Geological Survey):

		Thousands of dollars
I.	Large aquifers, 75 to 100 billion cu. ft. capacity	30,000 to 55,000
II.	Small aquifer, 10 billion cu. ft. capacity	4,600
III.	Small depleted gas reservoir, 2.5 billion cu. ft. capacity	1,100
IV.	Very small gas reservoir, 50 million cu. ft. capacity	
	Actual cost of lease	80
	(Estimated cost if wells had to be drilled and completed and gathering lines laid)	(200 to 280)

ENGINEERING OF GAS STORAGE PROJECTS

Many complex problems arise when a gas storage project is planned. These problems generally must be handled by experienced engineers and geologists. Anyone who wishes to make a serious study of the subject should consult the literature on gas storage, in particular the comprehensive monographs by Katz and his associates (1963, 1968). The following gives a brief introduction to some of the engineering aspects of gas storage.

Nature of Underground Gas Storage Reservoirs

To store natural gas underground, the following are needed: (1) rock layers with sufficient permeability and porosity to accept and hold the gas, (2) an impermeable caprock overlying the storage rock to prevent upward migration of gas, and (3) a geologic trap to keep the gas from moving in a horizontal direction. This trap may be a closed anticline, caused by gentle upward arching of the strata; a stratigraphic trap caused by updip gradation of the reservoir rock from sandstone to shale; or a trap caused by faulting that sealed the updip side of the reservoir by emplacing an impermeable bed adjacent to the reservoir. Exploration for an underground gas storage site is discussed by Buschbach (1965).

The porous storage rock in a geologic trap under the caprock is called a reservoir. This reservoir may have been filled originally with oil or gas and thus may be a depleted oil or gas reservoir. On the other hand, the reservoir may have been filled originally with water; in this case, it is called a natural aquifer. The water in an aquifer may be fresh or salty; in Illinois, however, freshwater aquifers usually are not used for gas storage because they are too valuable as sources of water for human consumption.

Illinois has far greater aquifer storage capacity than any other state (Vary et al., 1973, p. 15). More than 90 percent of underground gas storage in Illinois is in aquifers; some gas is also stored in small abandoned or partially depleted gas reservoirs. One depleted oil reservoir is used for gas storage in Illinois.

In a few cases, gas is stored in a reservoir associated with an oil producing structure; for example, at St. Jacob, Illinois, oil is produced from the Galena (Trenton) Limestone Group and gas is stored several hundred feet below, in the St. Peter Sandstone.

A variety of traps are used to store gas in Illinois. The Herscher Dome is an example of a structural trap, and Tilden is a stratigraphic trap. Trapping at Troy Grove is partially the result of faulting. Hookdale is a combination structural and stratigraphic trap. In some cases, the reservoir not only has a tight caprock but is bounded on all sides and on the bottom by relatively impervious rock. The reservoir in the Cypress Sandstone at Cooks Mills is a sand lens of this type. Such a reservoir behaves like a closed container. In predicting its behavior, the engineer needs to consider only the compression and expansion of the storage gas as it is injected and withdrawn.

Illinois gas storage projects show great diversity with respect to lithology, original fluid, and type of trap (tables 1, 2, and 3). However, over 90 percent of the storage capacity is in reservoirs in Ordovician and Cambrian sandstone aquifers; therefore, we will concentrate our discussion on that type of reservoir.

In many ways, a gas storage reservoir behaves like a reservoir that produces gas naturally. Therefore, gas storage engineers and geologists have been able to borrow much of the technology used in the gas producing industry. On the other hand, when gas is withdrawn from storage, parts of the reservoir may resemble an oil reservoir subjected to certain primary and secondary recovery processes. Therefore, the gas storage industry has also used techniques that were developed by oil recovery engineers (Katz et al., 1959; Craft and Hawkins, 1959).

Although gas storage reservoirs and natural oil and gas reservoirs are similar in some respects, they differ in many ways. In a storage reservoir, the injection rates and deliverabilities of wells generally must be considerably higher than those that might be used in some gas production or secondary recovery operations. In a storage reservoir, the engineer must not inject at too high a pressure or he may fracture the caprock. This is not a problem in gas production, although it may be one in secondary oil recovery. During the initial injection of storage gas, because of the high flow rate, the gas fingers and channels as a result of permeability variations. Because of the high flow rate in a storage reservoir, gravity and capillary effects are less pronounced than in many oil and gas reservoirs, at least in the early stages of injection of storage gas. Finally, the volume of storage gas changes very rapidly during the injection and withdrawal parts of the storage cycle; in comparison, the volume of gas in a gas producing reservoir during the life of the reservoir changes much more slowly. For this reason, the movement of water in the outer boundary of the storage reservoir is generally more rapid and more complex than it is in the outer boundary of a gas producing reservoir.

Because of the differences between storage reservoirs and oil and gas reservoirs, gas storage engineers have greatly extended the techniques and concepts of petroleum reservoir engineering.

Behavior of Fluids in Storage Aquifers—Development of the Storage "Bubble"

When gas flows through a porous, water-saturated rock, it does not displace all of the water from the pores of the rock. Even after a large volume of gas has been injected, the rock still contains a "residual water saturation." This residual water saturation varies from about 15 to 30 percent of the pore space in typical aquifers; it must be taken into account when an estimate is made of the amount of gas in a given volume of aquifer rock. As relatively dry gas is cycled into and out of the aquifer, the water in the rock around the well evaporates. As the rock dries out, it develops a greater capacity for gas; the permeability of the rock to the gas also increases, resulting in higher injection and withdrawal rates in the operating wells.

Let us consider an ideal aquifer that has the same permeability throughout. Further, let us assume that the reservoir is isotropic—that is, it has the same permeability in all directions. One would expect that when gas was injected into a well in such an aquifer, the gas would

TABLE 1 - ACTIVE UNDERGROUND NATURAL GAS

Project	Company	County Township Range	Operational dates (initial) Devel-opment	Stor-age	With-drawal	Number of wells Oper-ating	Obser-vation	Other	Geologic data Stratigraphic unit	Lithol-ogy	Trap	Native fluid
Ancona	Northern Illinois Gas Co.	La Salle & Livingston 29, 30N-2, 3E	1961	1963	1965	94	37	131	Mt. Simon	sand	anti-cline	water
Ashmore	Central Illinois Public Service	Coles & Clark 12N-10, 11E, 14W	1960	1963	1963	42	10	15	Spoon Salem	sand lime	dome	gas
Brocton	Peoples Gas Light & Coke Co.	Douglas & Edgar 14, 15N-13, 14W	(testing, 1973)			0	5	—	Lingle Grand Tower	lime dolo-mite	dome	water
Centralia East	Illinois Power Co.	Marion 1N-1E	1960	1964	1966	17	4	—	Pennsylvanian	sand	strati-graphic	gas
Cooks Mills	Natural Gas Pipe-line Co.	Coles & Douglas 14N-7, 8E	1956	1959	1959	24	5	4	Cypress Spar Mountain ("Rosiclare")	sand	lens	gas
Corinth	Central Illinois Public Service	Williamson 8S-4E	1972	1972	1972	2	—	—	Hardinsburg	sand	—	gas
Crab Orchard	Central Illinois Public Service	Williamson 9S-4E	1972	1972	1972	2	—	—	Hardinsburg	sand	—	gas
Crescent City St.P.	Northern Illinois Gas Co.	Iroquois 26, 27N-13W	1959	1967	(operations temporarily ceased)				St. Peter	sand	anti-cline	water
Crescent City Mt.S.			(in exploration, 1973)			3	9	—	Mt. Simon	sand	dome	water
Eden	Illinois Power Co.	Randolph 5S-5W	1970	1971	1971	12	2	10	Cypress	sand	strati-graphic	gas
Elbridge	Midwestern Gas Transmission Co.	Edgar 12, 13N-11W	1961	1965	1966	12	7	—	Grand Tower	lime	drape over reef	water
Freeburg	Illinois Power Co.	St. Clair 1, 2S-7W	1958	1959	1959	83	7	—	Cypress	sand	strati-graphic	gas
Gillespie-Benld	Illinois Power Co.	Macoupin 8N-6W	1958	1958	1959	7	0	—	Pennsylvanian	sand	strati-graphic	gas
Glasford	Central Illinois Light Co.	Peoria 7N-6E	1960	1964	1964	35	13	—	Niagaran	dolo-mite	dome	water
Herscher Gvl.	Natural Gas Pipe-line Co.	Kankakee 30N-10E	1952	1953	1953	60	58	85	Galesville	sand	anti-cline	water
Herscher Mt.S.			1957	1957	1958	56	17	—	Mt. Simon***		anti-cline	water
Herscher-Northwest	Natural Gas Pipe-line Co.	Kankakee 30, 31N-9E	1968	1969	1970	16	13	1	Mt. Simon***	sand	anti-cline	water
Hillsboro	Illinois Power Co.	Montgomery 9, 10N-3W	1972	(testing, 1973)		2	6	—	St. Peter	sand	dome	water
Hookdale	Illinois Power Co.	Bond 4N-2W	1962	1963	1963	10	4	—	Yankeetown ("Benoist")	sand	strati-graphic & struc-tural	gas
Hudson	Northern Illinois Gas Co.	McLean 24, 25N-2, 3E	1970	1971	1971	17	7	—	Mt. Simon	sand	dome	water
Hume	Peoples Gas Light & Coke Co.	Edgar 16N-13, 14W	(testing, 1973)			0	9	—	Lingle Grand Tower	lime dolo-mite	dome	water
Lake Bloomington	Northern Illinois Gas Co.	McLean 25, 26N-2, 3E	1971	1971	1972	27	13	40	Mt. Simon	sand	anti-cline	water
Lexington	Northern Illinois Gas Co.	McLean 25N-3, 4E	1971	1971	1972	11	5	16	Mt. Simon	sand	dome	water
Lincoln	Central Illinois Light Co.	Logan 19N-3W	1971	1974	1974	17	15	—	Silurian	dolo-mite	dome	water
Loudon	Natural Gas Pipe-line Co.	Fayette 7, 8, 9N-3E	1967	1967	1969	53	70	21	Grand Tower	lime	anti-cline	oil
Manlove (Mahomet)	Peoples Gas Light & Coke Co.	Champaign 21N-7E	1960	1964	1966	90	12	—	Mt. Simon	sand	anti-cline	water
Nevins	Midwestern Gas Transmission Co.	Edgar 12, 13N-11W	1961	1965	1966	14	7	—	Grand Tower	lime	drape over reef	water
Pecatonica	Northern Illinois Gas Co.	Winnebago 27N-10E	1967	1969	1970	14	15	—	Eau Claire	sand	dome	water
Pontiac	Northern Illinois Gas Co.	Livingston 27, 28N-6E	1966	1968	1969	40	14	54	Mt. Simon	sand	dome	water
Richwoods	Gas Utilities Co.	Crawford 6N-11W	1966	1966	1966	4	2	0	Pennsylvanian	sand	—	gas
St. Jacob	Mississippi River Transmission Corp.	Madison 3N-6W	1963	1963	1965	10	4	—	St. Peter	sand	dome	water
Sciota	Central Illinois Public Service	McDonough 6, 7N-3, 4W	(testing, 1973)			3	8	—	Mt. Simon	sand	dome	water
Shanghai	Illinois Power Co.	Warren & Mercer 12, 13N-1W	1970	1971	1971	9	9	—	Galesville	sand	dome	water
State Line	Midwestern Gas Transmission Co.	Clark, Ill., † & Vigo, Ind. 12N-10W	1961	1963	1964	9	6	—	Grand Tower	lime	drape over reef	water
Tilden	Illinois Power Co.	St. Clair & Washington 3S-5, 6W	1957	1961	1961	45	15	—	Cypress	sand	strati-graphic	gas
Troy Grove	Northern Illinois Gas Co.	La Salle 34, 35N-1E	1957	1958	1959	96	27	123	Eau Claire Mt. Simon	sand	dome	water
Tuscola	Panhandle Eastern Pipeline Co.	Douglas & Champaign 16, 17N-8E	(testing, 1973)			5	10	9	Mt. Simon	sand	dome	water
Waterloo	Mississippi River Transmission Corp.	Monroe 1, 2S-10W	1950	1951	1951	(abandoned, 1973)			Ordovician	sand & dolo-mite	dome	water
Waverly St.P.	Panhandle Eastern Pipeline Co.	Morgan 13N-8W	1952	1954	1962	50	19	22	St. Peter	sand	dome	water
Waverly Gvl.			1969	1969	1970	10	3	—	Galesville	sand	dome	water

*Million cubic feet.
**Current storage; ultimate capacity not available.
***Includes Elmhurst Member of overlying Eau Claire Formation.
†15 percent in Illinois; 85 percent in Indiana.

STORAGE PROJECTS IN ILLINOIS—January 1, 1974

Reservoir data						Capacities (MMcf)*				Withdrawals (MMcf)		
Area in acres		Depth (feet)	Thickness or closure (feet)	Average porosity (%)	Average permeability (millidarcys)	Potential, cushion and working	Dec. 31, 1973		Max. vol. in storage 1973 (MMcf)	Peak daily, 1973	Total, 1973	Project
Storage	Closure						Working	Cushion				
—	12,840	2,154	290	12.3	114	130,000	44,070	79,549	120,265	451	17,936	Ancona
—	1,600	400	4-80	15.0	up to 3,000	3,575	1,308	1,991	3,500	31	690	Ashmore
—	30,000	672	210	12.2	—	70,000	0	0	0	0	0	Brocton
463	—	812	49	18.2	200	672	236	416	672	13	176	Centralia East
—	1,500	1,600	40	16.0	67	4,500**	2,652	1,567	4,458	73	1,007	Cooks Mills
20	—	2,125	28	—	—	250	159	72	241	4	60	Corinth
20	—	2,200	19	—	—	176	99	67	109	3	55	Crab Orchard
—	16,725	1,200	150	14.5	138	50,000	—	—	—	—	—	St.P. Crescent City
—	—	—	—	—	—	100,000	—	—	—	—	—	Mt.S. Crescent City
—	1,000	875	18	20.6	168	2,493	530	868	1,406	6	124	Eden
—	1,691	1,925	145	17.5	18	7,950	907	6,030	7,127	17	1,074	Elbridge
4,222	—	350	47	21.5	216	6,836	2,087	4,636	6,956	37	812	Freeburg
113	—	510	28	16.0	326	151	31	116	150	1	8	Gillespie-Benld
—	3,200	800	120	12.0	426	12,525	5,583	6,262	12,525	108	3,618	Glasford
6,750	8,000	1,750	100	18.0	467	50,000	14,996	23,283	39,636	812	16,703	Gvl. Herscher
7,500	8,000	2,450	80	12.0	185	67,000	25,939	30,704	61,003	193	12,597	Mt.S. Herscher
—	3,000	2,200	58	15.0	82	17,000	3,463	8,703	12,851	44	2,177	Herscher-Northwest
4,000		3,150	100	16.0	250	38,000	0	499	499	0	0	Hillsboro
414	—	1,125	28	20.3	458	1,061	712	285	1,057	29	551	Hookdale
	13,200	3,800	160	11.0	45	100,000	1,841	7,386	9,209	20	133	Hudson
—	6,500	670	120	10±	—	4,000	0	0	0	0	0	Hume
	10,600	3,525	97	11.0	45	100,000	6,793	23,355	31,138	92	3,845	Lake Bloomington
	14,300					100,000	706	3,656	4,570	14	213	Lexington
	3,000	1,300	85	12.0	250	15,000	2,796	3,800	6,909	24	315	Lincoln
2,610		3,050	65	15.0	—	75,000	15,838	26,506	45,850	289	15,377	Loudon
—	13,370	3,950	116	11.0	15	100,000?	21,555	70,589	94,119	260	2,927	Manlove (Mahomet)
—	1,650	1,975	105	16.5	25	7,200	1,226	5,510	6,956	20	1,234	Nevins
—	2,600	800	38	18.6	556	3,000	1,077	1,615	2,692	18	689	Pecatonica
3,500	—	3,000	100	10.0	25	40,000	10,311	17,939	29,530	142	4,422	Pontiac
—	—	700	—	—	—	100	79	15	79	1	23	Richwoods
550	650	2,860	100	14.0	400+	5,600	1,800	3,800	5,600	70	1,846	St. Jacob
—	2,500	2,600	70	12.0	39	12,000	0	327	327	0	0	Sciota
	1,850	2,000	95	15.2	246	11,000	2,293	6,007	8,629	57	1,787	Shanghai
—	496	1,860	91	17.3	47	5,200	855	3,750	4,774	15	945	State Line
1,287	—	800	33	20.8	183	3,090	1,136	1,820	3,063	56	1,219	Tilden
—	9,600	1,420	100	17.0	150	72,000	26,850	32,334	71,803	868	37,263	Troy Grove
—	—	4,000	—	—	—	60,000	0	1,429	1,430	0	0	Tuscola
100	300	1,650	100	vuggy	—	450			(abandoned)			Waterloo
1,500	7,000	1,800	115	18.0	1,220	150,000	7,441	14,814	24,123	209	8,259	St.P. Waverly
—	—	3,500	68	—	—	127,000	1,458	17,695	19,169	36	1,418	Gvl. Waverly

TABLE 2 - INACTIVE OR ABANDONED RESERVOIRS THAT HAVE BEEN TESTED WITHIN ACTIVE UNDERGROUND NATURAL GAS STORAGE PROJECTS IN ILLINOIS - January 1, 1973

Project	Company	County Township Range	Dates: Testing	Dates: Abandoned	Geologic data: Stratigraphic unit	Geologic data: Lithology	Geologic data: Trap	Geologic data: Native fluid	Reservoir data: Area of closure (acres)	Reservoir data: Depth (feet)	Reservoir data: Thickness or closure (feet)	Reservoir data: Average porosity (%)	Reservoir data: Average permeability (millidarcys)	Status
Crescent City	Northern Illinois Gas Co.	Iroquois 26, 27N 13W	1967		St. Peter	sand	dome	water	16,725	1,200	150	14.5	138	inactive
Manlove (formerly Mahomet)	Peoples Gas Light & Coke Co.	Champaign 21N 7E	1961-1963	1963	St. Peter	sand	dome	water	13,370	1,625	153	17.9	388	abandoned
			1963-1964	1964	Galesville	sand	dome	water	13,370	3,132	24	12.9	78	abandoned
Pontiac	Northern Illinois Gas Co.	Livingston 27, 28N 6E	1970*		St. Peter	sand	dome	water	3,500	1,060	100	15.0	155	inactive
Sciota	Central Illinois Public Service	McDonough 6, 7N 3, 4W	1971-1972		Galena	lime	dome	water	2,500	670	70			abandoned

*Tested with inert combustion gas

TABLE 3 - ABANDONED UNDERGROUND NATURAL GAS STORAGE PROJECTS IN ILLINOIS - January 1, 1973

Project	Company	County Township Range	Dates: Testing	Dates: Abandoned	Geologic data: Stratigraphic unit	Geologic data: Lithology	Geologic data: Trap	Geologic data: Native fluid	Reservoir data: Area of closure (acres)	Reservoir data: Depth (feet)	Reservoir data: Thickness or closure (feet)	Reservoir data: Average porosity (%)	Reservoir data: Average permeability (millidarcys)
Brookville	Natural Gas Pipeline Co.	Ogle 23, 24N 7E	1964-1966	1966	Mt. Simon	sand	dome	water	6,200	1,050	138	18.7	1,062
Leaf River	Northern Illinois Gas Co.	Ogle 25N 9E	1968-1969*	1971	Eau Claire	sand	anticline	water	2,000	810	80	20.0	640

*Tested with inert combustion gas.

displace water uniformly in all directions and form a "bubble" with a circular interface between the gas and the water. In practice, however, no aquifer has such ideal uniform properties. Generally, the permeability of the rock varies with depth; also, the horizontal permeability is usually greater than the vertical permeability. The result is that gas that is first injected into such an aquifer preferentially flows into the zones of higher permeability. Later, gas rises into the rock above these permeable zones, while water trickles down into them because of gravity. Gradually, the entire space around the well becomes filled with gas to some degree to form a bubble with more or less uniform saturations of gas and water (fig. 2). This may take many months, depending on the permeability and inhomogeneity of the aquifer.

Even after a uniformly saturated bubble has been formed, it will not necessarily have a flat bottom. Katz et al. (1963, p. 131) show that the bottom side of the bubble should be concave

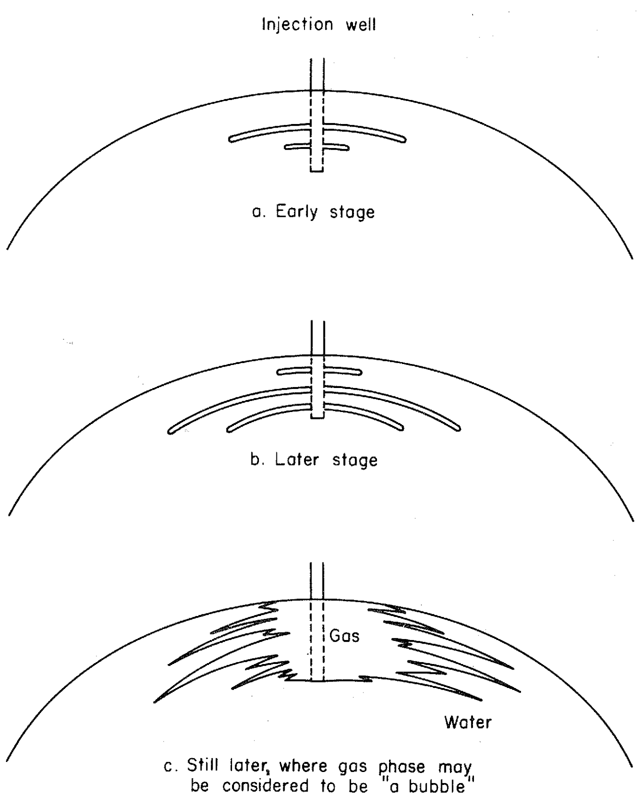

Fig. 2 - Development of gas bubble in an aquifer (Katz et al., 1963, p. 130; published with permission of the American Gas Association).

downward during gas injection and concave upward during gas withdrawal. Chaumet, Croissant, and Colonna (1966) found that in an actual reservoir, even after 8 years of operation, the bottom side of the bubble was still quite irregular in shape. These effects can seriously reduce the usable storage capacity of a given structure in an aquifer.

The storage engineer must develop a bubble large enough to satisfy his needs for the highest "peak" load that he can anticipate in a heating season. The simplest way to do this would be to start injecting gas into the aquifer, as described above, and to continue injection until the bubble was big enough. This, however, would create a problem, because gas is usually available from the supply pipeline only during the summer, when demand is low. Furthermore, the engineer must often withdraw gas long before the bubble has reached the desired size; therefore, the bubble is usually developed through a series of injection and withdrawal periods. Each year more gas is injected than is withdrawn, until the bubble finally reaches the required size. This may take 2 to 5 years, or longer.

Figure 3 shows how the pressure in the reservoir varies as the bubble is developed. When gas is injected into an aquifer, water is displaced from the pores of the rock around the injection well. Where does this water go? If the storage formation crops out nearby (or if it is in communication with other formations that crop out nearby), some of the water can be forced to the surface. On the other hand, if the storage formation extends for many miles underground, which is usually the case, the net effect is merely to compress the water and the rock around the storage bubble as gas is injected. In a typical storage aquifer, roughly half of the space for the injected gas is created by the compression of the solid rock matrix and half is created by the compression of the water in the pores of the rock. Near the storage bubble the fluid pressure in the pores of the rock is the same as it is within the bubble. As the distance from the storage bubble increases, the pressure in the water-saturated rock and the density of the rock decrease. At a distance of several miles, the density and the pressure are practically unchanged, even at the end of the normal injection season.

At the beginning of the gas withdrawal season, this process is reversed. The pressure within the storage bubble is reduced, permitting water to flow back into the bubble. The energy

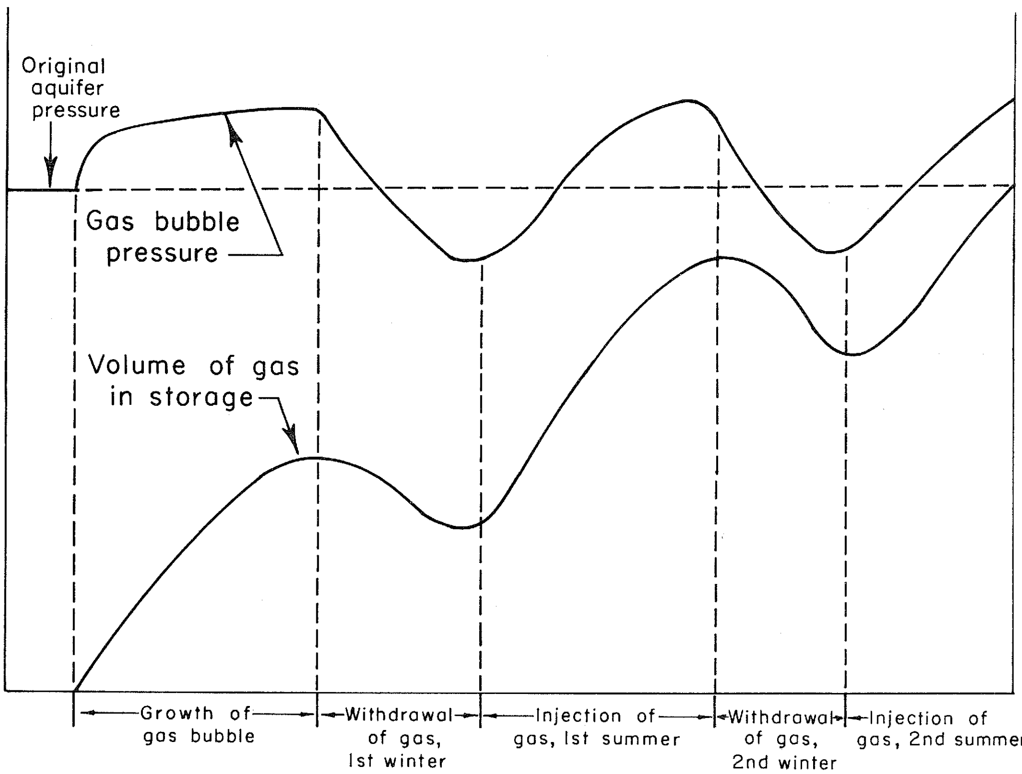

Fig. 3 - Changes in gas bubble pressure during development and operation of an aquifer storage project (gas bubble pressure curve adapted from Katz et al., 1963, p. 13, with permission of the American Gas Association).

for this flow of water is produced by the expansion of the water-saturated rock around the bubble. Thus, the rock around the storage bubble acts like a large elastic reservoir. During the injection period, the rock is compressed, making room for more gas in the storage bubble. Then, during the withdrawal period, it expands, providing the energy to drive water into the bubble and displace some of the gas from it.

Petroleum production engineers encounter similar conditions when they try to predict the behavior of an oil or gas producing deposit in an aquifer. Van Everdingen and Hurst (1949) have presented methods for solving this problem. Katz et al. (1963) have shown how the Van Everdingen and Hurst method can be applied to specific problems in gas storage in aquifers. For example, suppose we know the following: initial pressure, thickness of reservoir, bubble radius, permeability of storage rock, and porosity of storage rock. The storage bubble grows at a constant rate, e_w; that is, water is displaced at the rate e_w. It is assumed that the aquifer is very large in comparison to the storage bubble. How will the reservoir pressure change with time as gas is injected? This can be found in the following manner. First, the "dimensionless time," t_D, is calculated:

$$t_D = \frac{6.33 \times 10^{-3}\ kt}{\mu \phi c r_b^2} \qquad (1)$$

where

k = permeability, millidarcys
t = time, days
μ = viscosity of water, centipoises
ϕ = porosity, fraction
r_b = bubble radius, feet
c = composite compressibility of the water-saturated porous formation, $\frac{\text{volume}}{\text{volume x pounds per square inch (psi)}}$.

Then, from Appendix A of Katz et al. (1963), the value of the "dimensionless pressure," P_t, is found that corresponds to this value of t_D. Finally, the reservoir pressure, p, is calculated from:

$$p = p_o - \frac{25.15 e_w \mu}{kh} P_t \qquad (2)$$

where

p_o = initial reservoir pressure, pounds per square inch absolute (psia)
h = thickness of aquifer, feet
(e_w is given a negative sign if water moves away from the storage bubble; it is given a positive sign if water moves toward the bubble).

On the other hand, suppose we have a bubble of known thickness and radius. We propose to inject gas into the bubble while maintaining the pressure in the bubble at a pressure, p, greater than the pressure, p_o, in the aquifer. We wish to calculate how much water will be displaced during a given period of gas injection. First, we calculate this cumulative water efflux, W_e, in terms of Q_t, "dimensionless water efflux," by substituting the known values of ϕ, c, r_b, h, p_o, and p in this equation:

$$W_e = 6.283 \phi c r_b^2 h (p - p_o) Q_t. \qquad (3)$$

Next, we calculate the dimensionless time, t_D, from equation (1). Then, from Appendix B of Katz et al. (1963), we find the value of Q_t that corresponds to this value of t_D. Finally, we insert this value of Q_t in equation (3) to give W_e, the volume of water that is displaced. This procedure enables us to estimate how the bubble will grow as gas is injected into the reservoir.

If the aquifer is enclosed (for example, a sand lens surrounded by shale), it is called a "limited" aquifer; the treatment of the problem is the same, but different values of Q_t are used.

In the calculations outlined above, the assumption is made that within the gas bubble only gas flows and that outside the bubble only water flows. This assumption does not cause any serious errors after a large bubble has been developed; but in the early stages of development of the bubble, this is an overly simplified picture.

Actually, as gas displaces water from the aquifer, both gas and water flow through the rock in the same direction. In any given part of the rock, the flow of gas depends on the gas saturation—the greater the gas saturation, the higher the flow rate of gas. Likewise, the greater the water saturation, the higher the flow rate of water.

In choosing the upper limit of pressure in the storage bubble (p_{max}), consideration is given to the pressure per foot of depth and to the difference between the initial aquifer pressure and the bubble pressure (see p. 12). The lower limit (p_{min}) during the gas withdrawal period depends on the economics of compressing gas that is withdrawn and the storage capacity that is required. If p_{min} is set at too high a value, the working capacity may be too small. On the other hand, if p_{min} is too low, the cost of compressing the gas for delivery to the pipeline may be too great.

Calculation of the storage capacity for given values of p_{max} and p_{min} would be a simple matter if water at the outer edge of the bubble did not move during the period of gas withdrawal. The amount of water movement can be estimated by the method outlined above for estimating the rate of growth of a storage bubble. Experience shows that in a typical withdrawal season about 10 to 20 percent of the bubble volume is filled by water that flows inward as gas is withdrawn.

Let us assume that of the rock filled with gas at the start of withdrawal, 10 percent becomes flushed with water during the withdrawal season. This supplies a volume of gas equal to one-tenth of the total amount of gas that was in the storage bubble at the beginning of the withdrawal season. (A small amount of gas is trapped in the rock when it is flushed with water; this usually is so small that it can be neglected.) In addition, in nine-tenths of the original bubble, the pressure is reduced from p_{max} to p_{min}. The volume of gas supplied by this pressure reduction can easily be calculated by means of standard formulas involving the known temperature, pressure, and compressibility of the gas.

Reservoir Capacity

The gas content of a reservoir can be calculated from the following equation (Katz et al., 1959, p. 456):

$$Q = 43,560 A h \phi (1 - S) \frac{P T_b}{P_b T z} \qquad (4)$$

where

Q = gas in place, cubic feet, measured at P_b and T_b

- A = areal extent, acres
- h = thickness, feet
- ϕ = fractional porosity
- S = fractional saturation of pore space with water (for Illinois aquifers, S is usually about 0.15 to 0.30)
- P = reservoir pressure, psia
- P_b = measurement pressure base, psia
- T = reservoir temperature, °R
- T_b = measurement temperature base, °R
- z = compressibility factor for gas

The thickness, h, is often considered to be the number of feet of closure on the storage structure, that is, the difference between the elevation of the top of the structure and that of the last closing contour on the structure. Sometimes only the top part of the structure is to be filled with gas; in this case, h is the thickness that is to be utilized for storage.

In some reservoirs the amount of effective closure can be changed because of differences in hydrodynamic potential, due to flow of water from one side of the reservoir to another, which causes a tilting of the bottom of the storage bubble. For example, the volume of available storage capacity in the Eau Claire reservoir at Pecatonica is increased considerably because a favorable potential gradient exists there (Burnett, 1967).

In the application of equation (4), the reservoir is assumed to be of uniform thickness, h. If the structure of the reservoir does not permit this assumption, the gross volume of the gas-filled rock is determined by planimetering the isopach map; the sum of the number of acre feet is inserted in the above equation in place of the volume factor, Ah. The quantity, Q, which is obtained in this manner, is the total amount of gas in the reservoir. Experience shows that in developed storage projects usually about half of this gas is available for use in meeting peak load needs ("working gas"). The other half is known as "cushion gas."

Although the cushion gas is not available during the normal cycling of the reservoir, this does not mean that all of the cushion gas will be lost when the storage reservoir is eventually abandoned. Katz and Coats (1968, p. 464) show that the gas lost at abandonment of an aquifer includes: (1) the low-pressure gas cap at the top of the aquifer (this permits gas to be produced without too much interference from advancing water), (2) gas trapped in the sand below the gas-water contact at abandonment, and (3) gas dissolved in the water in and below the original storage bubble. In a typical case, the gas that would be lost at abandonment was estimated to be 35 percent of the maximum inventory. This value will vary, of course, from one storage aquifer to another. Computer studies by Knapp, Henderson, and Coats (1968) indicate that about 24 to 82 percent of the cushion gas can be lost at abandonment, depending upon the heterogeneity of the reservoir.

After the reservoir has been filled with gas and cycled once or twice, a working plot of gas volume versus observation well pressure can be drawn. Often changes in this working curve can be used to infer changes in the behavior of the reservoir.

Well Performance and Injection Pressures

Water pumping tests can be made on a well that penetrates the storage aquifer; from the results of these tests, the effective permeability of the reservoir rock can be calculated. Then, by standard reservoir engineering methods, the performance curve of a gas injection (or producing) well can be predicted. Or, if the permeability of the aquifer is known from core analyses, the performance curve of a well can be calculated. This enables one to estimate the number of operating wells that will be needed for the anticipated peak production rate.

The higher the injection pressure, the greater the rate at which the storage bubble is developed. However, if gas is injected at too high a pressure, the caprock may be fractured. Experience with hydraulic fracturing of oil and gas producing wells to increase production of these wells shows that sand-face pressures from about 0.7 to 1.0 psi per foot of depth are required to cause fracturing. In gas storage aquifers, injection pressures of approximately 0.55 psi per foot are often used, but pressures as high as 0.7 psi per foot have been used.

Besides pressure per foot of depth, the difference between the injection pressure and the initial fluid pressure in the aquifer must also be considered. In the early stages of the development of the bubble, this difference is usually held at about 100 psi. If no leakage occurs, the pressure difference is then increased to 200 psi or more. Selection of both the pressure per foot of depth and the pressure difference depends on the judgment of the storage engineer.

Caprocks

As pointed out above, if gas is to be stored in a porous reservoir, the reservoir must be overlain by a caprock that is relatively impervious to gas. In theory, this caprock need not have an extremely low permeability if it has a sufficiently high threshold pressure (Ibrahim, Tek, and Katz, 1970). (Threshold pressure is the pressure required to force gas into the pores of the water-wet rock.) In practice, the caprocks that are considered for storage purposes generally have extremely low permeabilities (10^{-4} to 10^{-6} millidarcys) as well as high threshold pressures (several hundred psi).

Laboratory measurements of permeability and threshold pressure can give the engineer some assurance that the caprock will be sufficiently tight, but usually these measurements cannot detect fractures in the caprock through which gas might leak, so a number of other criteria are often used (Bays, 1964; Witherspoon, Mueller, and Donovan, 1962; Witherspoon and Neuman, 1966). Measurements of the static water level are taken in wells drilled into porous zones above and below the caprock; a difference in head may give an indication that the caprock is tight. Also, samples of the formation waters above and below the caprock are analyzed; a difference in the composition of the waters may indicate that the caprock contains no conduits for leakage.

Those who use such water-level measurements and water analyses to evaluate the tightness of the caprock argue that differences in water level and in chemical composition prove that the caprock contains no fractures; otherwise, the hydraulic heads would have equalized and the waters above and below the caprock would have come to the same composition as a result of flow of water through such fractures. This argument is based on the assumption that present conditions have existed many years. However, in northern Illinois many of the observed vertical head differences are probably largely the result of modern pumpage from upper aquifers (Bond, 1972, p. 43). Therefore, even though fractures exist through which water flows, the water may not have been flowing long enough to cause the hydraulic heads and water compositions above and below the caprock to equalize. In such cases, differences in water level and in water composition may tell little about the tightness of the caprock. In fact, some storage reservoirs whose caprocks should have been tight, according to the water-level and water-composition criteria, actually have leaked when gas was injected.

Various kinds of pumping tests have been devised to gain information about the in situ permeability of the caprock. Hantush (1956) shows how, as water is pumped from one well in an aquifer, drawdown measurements in other wells in the aquifer can be used to give an estimate of the caprock permeability. Katz et al. (1963, p. 123) show how the slope of the drawdown curve for a well in the aquifer can be used to obtain an estimate of the permeability of the caprock. If such estimates are significantly greater than the matrix permeability, as determined by analysis of core samples from the caprock, we have definite evidence that the caprock is fractured. These methods detect large fractures, but they are not sensitive enough to detect borderline cases that could permit a troublesome amount of leakage. In the final analysis, one must rely on some kind of observation in the porous zones overlying the caprock.

Witherspoon et al. (1967) give a comprehensive discussion of such pumping tests. Generally the static water level in an observation well in the caprock is measured while water is pumped from a well in the aquifer. The observed water levels are corrected to take into account the effects of changes in the barometric pressure. The calculation procedure can be summarized as follows:

1. Determine Δh (drawdown in the aquifer) at a radial distance from the pumping well equal to r, where r is the distance from the pumping well to the caprock observation well.

2. From this Δh and $\Delta h'$ (observed drawdown in the caprock observation well), calculate $\frac{\Delta h'}{\Delta h}$.

3. Calculate the dimensionless time, t_D.

$$t_D = \frac{6.331 \times 10^{-3}\, k t}{\phi \mu c r^2}$$

(Here the quantities k, t, ϕ, μ, and c are the same as in equation (1) above.)

4. Use this calculated value of t_D to choose the appropriate chart (Witherspoon et al., 1967, figs. 3-9 to 3-12, p. 74-77). For the calculated value of $\frac{\Delta h'}{\Delta h}$, read the parameter γ from the chart.

5. Calculate k' from:

$$k' = \frac{\gamma \phi' \mu' c' \times 10^4}{t}$$

where k' = permeability of caprock

γ = value of γ read from chart

ϕ' = porosity of caprock

μ' = viscosity of water in caprock, centipoises

c' = caprock compressibility, psi^{-1}

t = pumping time, days

As in the Hantush method, if the calculated value of k' is significantly greater than the matrix permeability determined by core analysis, the caprock is probably fractured in the region under test. Of course, if a sizable response is observed quickly in the observation well (for example, a change of several feet in a few hours), we have definite evidence of fracturing and no calculations are required.

In the use of pumping tests to detect leakage, usually the density of the water in the storage aquifer is assumed to be the same as the density of the water in the observation well (Witherspoon et al., 1967). This assumption causes no problem if the vertical distance between the aquifer and the observation well is small and the densities of the waters do not differ greatly. However, if the observation well is several hundred feet above the storage aquifer and if the densities of the waters in the aquifer and in the observation well differ substantially, the sensitivity of the pump test is reduced and the radius of investigation over which conduits for leakage can be detected is decreased (Bond and Cartwright, 1970).

The criteria described above can at best give only indications about the possibilities for leakage from a reservoir. The acid test of the tightness of a caprock is to inject gas into the reservoir and then watch for changes in the observation wells in and above the caprock—either a rise in water level or the actual appearance of leaking gas.

Even if leakage does occur when gas is injected into a storage reservoir, various corrective measures can be taken to minimize the problem. For example, at Herscher, where some leakage occurs, water is pumped from the periphery of the Galesville reservoir and is injected into the Potosi above; this relieves the pressure in the Galesville while pressurizing the aquifers above the storage reservoir. Also at Herscher, gas that leaks from the Galesville to the St. Peter and the Galena is withdrawn from vent wells and is recycled into the Galesville. At Troy Grove, gas migrates upward from the Mt. Simon to sands in the lower part of the Eau Claire; to prevent excessive pressure buildup in the Eau Claire, some of this gas is either produced for consumption or is recycled into the Mt. Simon. At Waverly, gas leaks from the St. Peter upward to the Galena; this leakage gas is collected in the Galena and is either produced or is recycled to the St. Peter.

Thus, modern technology can solve many of the problems that might be caused by leakage of gas through a caprock. Illinois companies have been pioneers in the development of this technology.

LAWS AND REGULATIONS CONCERNING UNDERGROUND GAS STORAGE

Pipeline companies and other companies subject to the regulations of the Federal Power Commission must satisfy the requirements of that commission with respect to any proposed underground gas storage project (Code Fed. Reg., 1973). Public utilities operating in Illinois are subject to the Public Utilities Act (Ill. Revised Statutes, 1965, chapt. 111 - 2/3). Under Section 55 of this act, the Illinois Commerce Commission is directed to issue an order authorizing a new facility (such as an underground gas storage project) after it has found that the new facility is necessary.

In addition, gas storage companies that operate in Illinois are subject to certain rules and regulations of the Illinois Department of Mines and Minerals and of the Illinois Environmental Protection Agency. Each well that is drilled requires a permit from the Department of Mines and Minerals. The Illinois State Mining Board is authorized to make rules and regulations to prevent the pollution of freshwater supplies by oil, gas, or salt water (Ill. Revised Statutes, 1965, chapt. 104, secs. 62-88; Illinois Dept. Mines and Minerals, Division of Oil and Gas, 1969). Furthermore, a storage company may need to furnish evidence to the Illinois Environmental Protection Agency that a proposed storage project will not result in the pollution of potable waters (Ill. Rev. Stats., 1965, chapt. 19, secs. 145-1 to 145-18; 1970, chapt. 111 1/2, secs. 1001 et seq.).

With respect to water pollution, each gas storage project is a separate problem. However, some broad guidelines may be helpful to one who is considering the possibility of underground storage. As a general rule, a given aquifer cannot be used for gas storage if it is a potential freshwater source. The principal aquifers used for gas storage in Illinois are the St. Peter, the Galesville, and the Mt. Simon Sandstones; in northern Illinois these aquifers are the main sources of fresh ground water. Generally the salinity within each aquifer increases southward; figure 4 shows the southern limits of the use of these sandstones as sources of potable water. Of course, no sharp dividing line exists between waters that are definitely fresh and those that are definitely salty, and under some circumstances, waters containing several thousand parts per million of solids may be considered usable. The Illinois Sanitary Water Board (now part of the Illinois Environmental Protection Agency) has defined fresh water as "water of 10,000 mg/l or less total dissolved solids" (Akers, 1968). The Environmental Protection Agency might require that such waters be protected against pollution; this could prevent the storage of gas in formations where these waters occur, or it could affect the casing program for storage wells in deeper formations.

The Natural Gas Storage Act (Ill. Revised Statutes, 1965, chapt. 104, secs. 104-112) gives storage companies the right to use private property for gas storage purposes in the manner provided for by the law of eminent domain. According to the act, before the right of condemnation can be exercised, the corporation must receive an order from the Illinois Commerce Commission approving the proposed storage project. Furthermore, the Commerce Commission cannot issue such an order unless it finds that the proposed storage (1) will be confined to strata lying more than 500 feet below the surface; (2) will not injure any water resources; and (3) will involve no condemnation of any interest in any geological stratum within the area of the proposed storage containing oil, gas, or coal in commercial quantities (paraphrased and condensed from parts of the Natural Gas Storage Act; for further details, consult the Illinois Revised Statutes and the files of the Illinois Commerce Commission since 1951).

Thus, a company that has difficulty in acquiring storage rights from the owners of the mineral rights in a given storage area must meet the provisions of the Natural Gas Storage Act if it wishes to exercise the right of eminent domain. However, a company that already has leases that

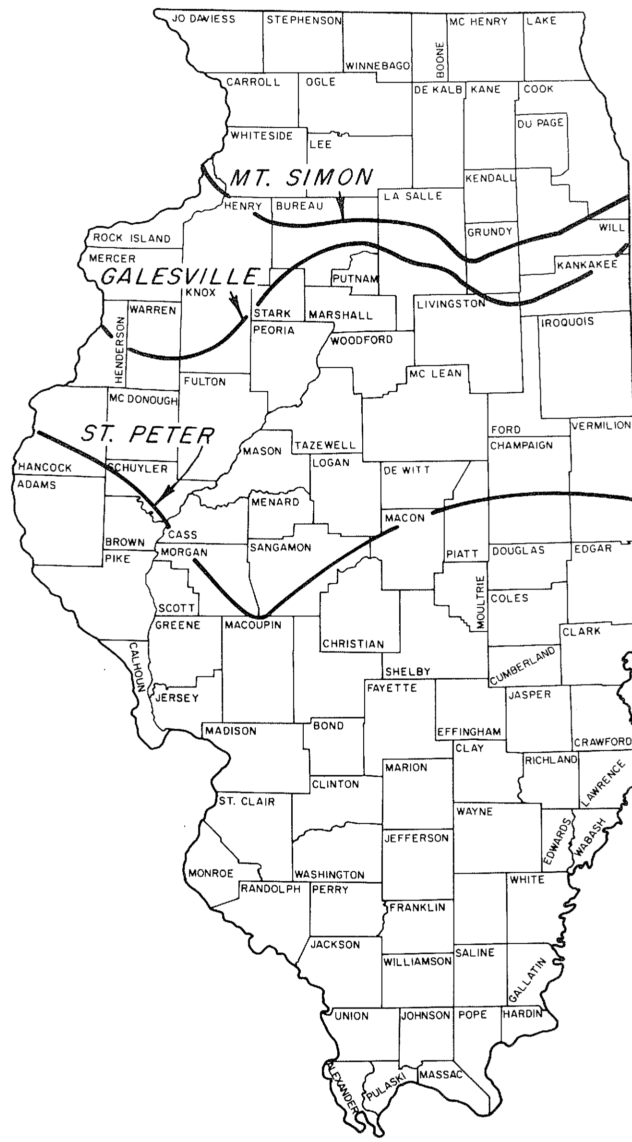

Fig. 4 - Southern limits of use of the Mt. Simon, Galesville, and St. Peter Sandstones as sources of potable water (adapted from Bergstrom, 1968, p. 5).

permit it to store gas may not need to exercise the right of eminent domain, and thus it may not have to satisfy the depth requirement of the Storage Act. For example, a depleted gas reservoir such as Freeburg can be used for storage even though its depth (350 feet) is less than the 500 feet specified in the Natural Gas Storage Act.

To summarize, in Illinois, a given gas storage project may have to satisfy the requirements of the Federal Power Commission, the

Illinois State Mining Board, the Illinois Environmental Protection Agency, and the Illinois Commerce Commission, depending upon the circumstances.

FUTURE OF UNDERGROUND GAS STORAGE IN ILLINOIS

Many of Illinois' underground gas storage projects will continue to be enlarged, through the drilling and completion of more injection-withdrawal wells and through the injection of larger and larger volumes of gas. Projects which are just being started will be expanded and will become fully operational. Probably the capacity of some facilities will be increased by the use of reservoirs that exist above or below the reservoirs that are now used for storage. Several large prospective storage reservoirs are in various stages of exploration or testing; some of these, no doubt, will be developed soon. Furthermore, pipeline companies and gas distributing companies are expected to continue to explore for new reservoirs in which to store gas. Of course, the rate of growth of underground storage will be dependent upon the amount of gas available.

With regard to type of reservoir, most of the new storage in Illinois, like most of the present storage, will be in Cambrian-Ordovician aquifers. However, as suitable structures in aquifers become difficult to find, some depleted oil reservoirs are expected to be used for storage. As the price of crude oil increases substantially, the move toward storage projects in depleted oil reservoirs, engineered for maximum oil recovery, should be accelerated. Also, more small depleted or shut-in gas reservoirs will be utilized, especially those that are strategically located near distribution pipelines or small cities.

The available supply of gas will not be large enough to satisfy both the demand for gas for residential purposes and the demand for gas to replace polluting fuels in industry. We cannot predict how the available supply will be apportioned between these two competing demands. However, a member of the Federal Power Commission has said that "end-use controls" on gas are inescapable (Oil and Gas Journal, 1972). A policy statement of the FPC has proposed that residential and small commercial customers be given priority over other customers in applications to the FPC for new service (Oil and Gas Journal, 1973). Furthermore, some interstate pipeline companies and distribution companies, under pressure from the FPC, have already attempted to curtail the use of gas for power generation and other "interruptible" uses. If the FPC does force the gas distributing companies to restrict the sale of gas for industrial and power-generating usage so that more residential customers can be served, more underground storage will be needed.

The need for gas storage may be increased because of the manufacture of synthetic gas. Within the next few years several facilities for the generation of synthetic gas (SNG) from petroleum liquids will be constructed and put into operation in Illinois, if satisfactory sources of feedstocks can be found. Within the next 10 to 20 years, a coal gasification industry will be built up in Illinois. As these synthetic-gas industries are developed, gas storage reservoirs will be needed to serve as surge tanks to supply gas in case the gasification plants are shut down and to take care of seasonal variations in the demand for gas.

Synthetic gas could be stored in aquifers or in depleted gas or oil reservoirs, or it could be liquefied and stored as LNG. Known natural gas reservoirs in Illinois could hold only a small fraction of the synthetic gas that is likely to be stored. Many depleted oil reservoirs in Illinois lie near potential sources of coal for gasification, so these reservoirs are strategically located for storage of gas derived from coal; such storage has the added advantage that it should result in the production of valuable oil. The high cost of synthetic cushion gas, especially for aquifer reservoirs, could make underground storage less attractive economically than LNG storage.

Some of the waste by-products from the manufacture of gas, particularly carbon dioxide (CO_2), have potential uses in gas storage operations. For example, CO_2, in the form of carbonic acid, could be used to increase the permeability of a gas storage reservoir. Gardner, Downie, and Wyllie (1962) have proposed the use of an inert gas as a cheap cushion gas; we suggest that by-product CO_2 might be a suitable gas for this usage.

Illinois now has a greater reservoir capacity for underground gas storage than any other state (Vary et al., 1973). Within a few years it could have a larger volume of gas actually in storage than any other state. Underground storage of gas will continue to be a growing and important segment of the Illinois economy for many years.

SUMMARY OF ACTIVE GAS STORAGE PROJECTS IN ILLINOIS

At the end of 1972, 30 underground gas storage projects were operating in Illinois. These projects, plus seven others that are in various stages of testing and development, are discussed here. A summary of pertinent data is presented in table 1. At several of these projects, reservoirs other than those currently used for storage have been tested but are currently inactive or abandoned. These inactive or abandoned reservoirs are discussed in the descriptions of each project, and the information is summarized in table 2. Two projects have been tested and abandoned. They are discussed in the next section of this report, and data from them are summarized in table 3.

Information about each project was obtained from current statistics and structure maps that were furnished by the operating companies. Also freely used in the preparation of this report was testimony presented to the Illinois Commerce Commission during hearings on petitions for certification to store gas at each project. The testimony contains much valuable information that is available to the public from the files of the Illinois Commerce Commission at Springfield, Illinois.

Most storage projects in Illinois are located near the major centers of population, such as Chicago and St. Louis, or are relatively near the main pipeline systems (fig. 5).

Rocks of all systems from Cambrian to Pennsylvanian are used for gas storage in Illinois (figs. 6 and 7), but most of the storage volume is in aquifers of Cambrian and Ordovician age. In 11 projects gas is stored in depleted or partially depleted gas reservoirs, and in 1 project it is stored in a depleted oil reservoir. In all of the rest of the projects, the gas storage reservoirs are aquifers.

The Mt. Simon, Galesville, and St. Peter Sandstones are the aquifers most commonly used for gas storage in northern and central Illinois. The Mt. Simon is a thick basal sandstone overlain by shale and siltstone of the Eau Claire Formation. The Galesville is a porous and permeable sandstone that varies from a feather edge to about 100 feet in thickness in northern Illinois. It is absent in the southern part of the state. Overlying the Galesville is the Ironton Sandstone, which contains several beds of dolomite, and the Franconia Formation, which contains sandstone, shale, and dolomite. The St. Peter is a permeable sandstone of varied thickness. It crops out in northern Illinois and dips southward under younger strata. Overlying the St. Peter are thin beds of shale and sandstone of the Glenwood Formation in the north, and dolomite, shale, sandstone, and anhydrite of the Joachim Formation in the south. The Platteville Limestone Group overlies the Glenwood or Joachim.

At the top of the Ordovician System is the Maquoketa Shale Group, which is widespread and relatively impermeable. In many areas, the Maquoketa is considered an ultimate caprock in the event of any upward migration of gas stored in underlying formations.

The gas storage capacity of Illinois aquifers in presently developed projects is far greater than the aquifer storage in any other state.

Ancona (formerly Ancona-Garfield) Project

Operator: Northern Illinois Gas Company
Location: Near Ancona, 7 miles southwest of Streator, T. 29 and 30 N., R. 2 and 3 E., Livingston and La Salle Counties

Gas for the Ancona project is purchased from Natural Gas Pipeline Company of America. A 24-inch pipeline connects the project to the Natural Gas Pipeline Company of America trunkline at Mazon, Illinois. The gas is consumed in the suburban Chicago area.

Structure drilling in the area began in 1958, and 123 structure tests have been drilled to the Galena Dolomite Group or deeper. A gravity survey was run to help delineate the structure. Gas was first injected in 1963 and the project became operational in 1965 (table 4).

TABLE 4 — INJECTION AND WITHDRAWAL HISTORY OF ANCONA PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory (end of year)	Peak daily withdrawal
1963	105	0	105	0
1964	1,976	0	2,080	0
1965	4,857	39	6,899	22
1966	9,237	360	14,431	77
1967	8,300	4,100	20,500	105
1968	17,514	4,911	32,961	105
1969	26,549	10,258	51,113	153
1970	21,220	9,644	75,310	315
1971	38,900	27,000	103,700	450
1972	38,929	41,007	101,564	471

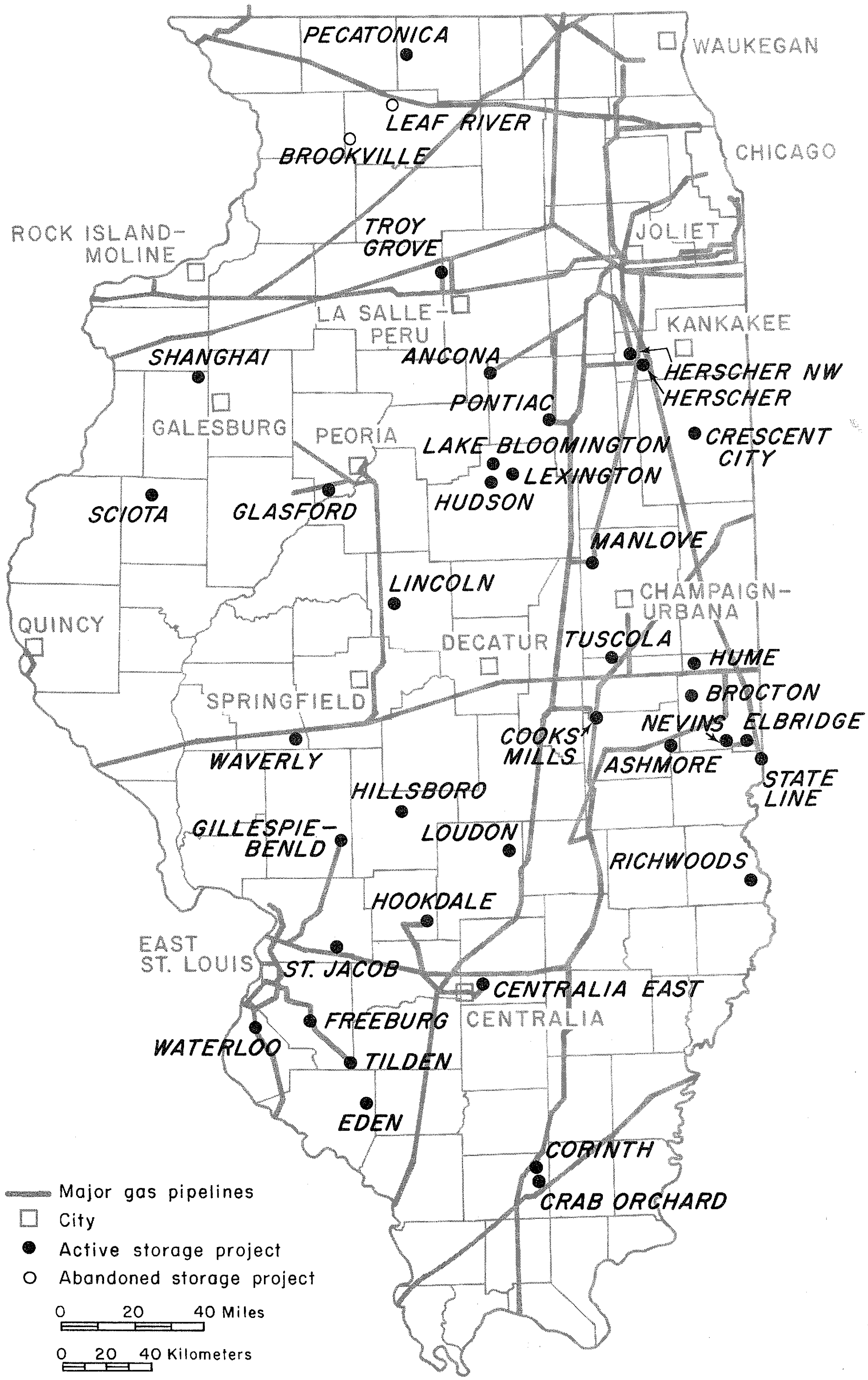

Fig. 5 - Underground gas storage projects and major gas transmission lines in Illinois.

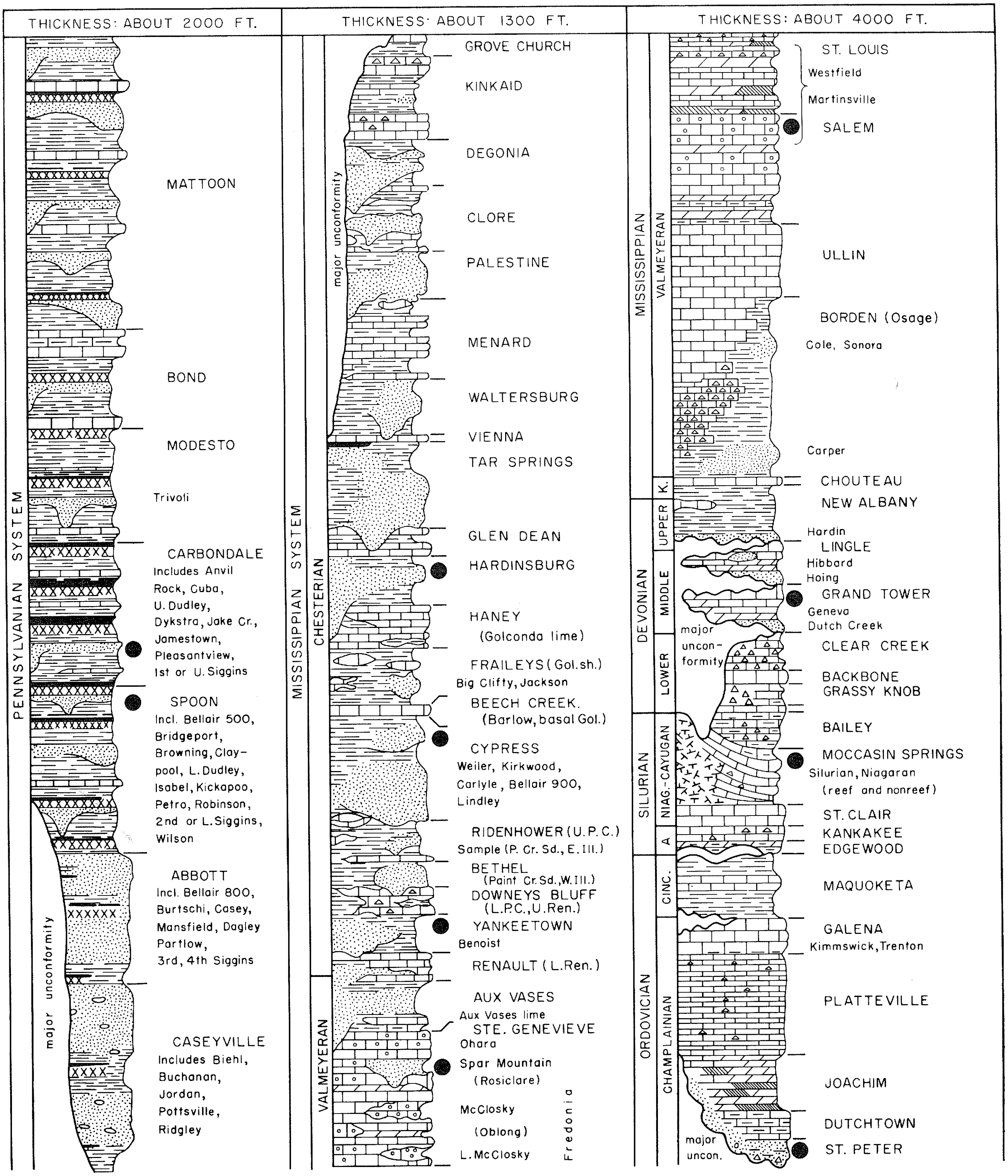

Fig. 6 - Generalized geologic column of southern Illinois above the St. Peter Sandstone. Black dots indicate gas storage zones (variable vertical scale; stratigraphy modified from D. H. Swann).

SYSTEM	SERIES	STAGE	MEGAGROUP	GROUP	FORMATION	GRAPHIC COLUMN	THICKNESS (FEET)	LITHOLOGY
ORDOVICIAN	CINCINNATIAN	RICH.		MAQUOKETA	Neda		0–15	Shale, red, hematitic, oolitic
					Brainard		0–100	Shale, dolomitic, greenish gray
					Ft. Atkinson		5–50	Dolomite and limestone, coarse-grained; shale, green
		MA. / ED.			Scales		90–100	Shale, dolomitic, brownish gray
	CHAMPLAINIAN	TRENTONIAN	OTTAWA	GALENA	Wise Lake - Dunleith		170–210	Dolomite, buff, medium-grained
					Guttenberg		0–15	Dolomite, buff, red speckled
		BLACKRIVERAN		PLATTEVILLE	Nachusa		0–50	Dolomite and limestone, buff
					Grand Detour		20–40	Dolomite and limestone, gray mottling
					Mifflin		20–50	Dolomite and limestone, orange speckled
					Pecatonica		20–50	Dolomite, brown, fine-grained
				ANCELL	Glenwood		0–80	Sandstone and dolomite
					St. Peter ●		100–600	Sandstone, fine-grained; rubble at base (Kress Member)
	CANADIAN		KNOX	PRAIRIE DU CHIEN	Shakopee		0–67	Dolomite, sandy
					New Richmond		0–35	Sandstone, dolomitic
					Oneota ●		190–250	Dolomite, slightly sandy; oolitic chert
					Gunter		0–15	Sandstone, dolomitic
CAMBRIAN	CROIXAN	TREMPEALEAUAN			Eminence		50–150	Dolomite, sandy; oolitic chert
					Potosi		90–220	Dolomite, slightly sandy at top and base, light gray to light brown; drusy quartz
		FRANCONIAN			Franconia *Davis Mbr.*		50–200	Sandstone, dolomite and shale; glauconitic
					Ironton		80–130	Sandstone, medium-grained; dolomitic in part
					Galesville ●		10–100	Sandstone, fine-grained
		DRESBACHIAN			*Proviso Mbr.* Eau Claire ● *Lombard Mbr.* ● *Elmhurst Mbr.* ●		370–575	Siltstone, shale, dolomite, sandstone, glauconite
			POTSDAM		Mt Simon ●		1200-2900	Sandstone, fine- to coarse-grained

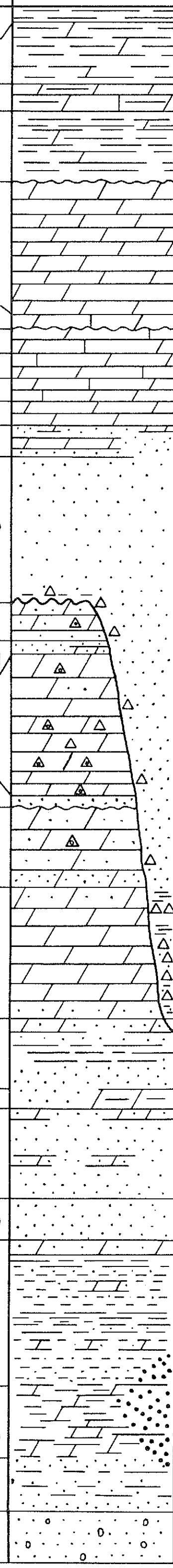

Fig. 7 - Generalized columnar section of Cambrian and Ordovician strata in northeastern Illinois (after Buschbach, 1964). Black dots indicate gas storage zones. Abbreviations: Ed. - Edenian; Ma. - Maysvillian; Rich. - Richmondian.

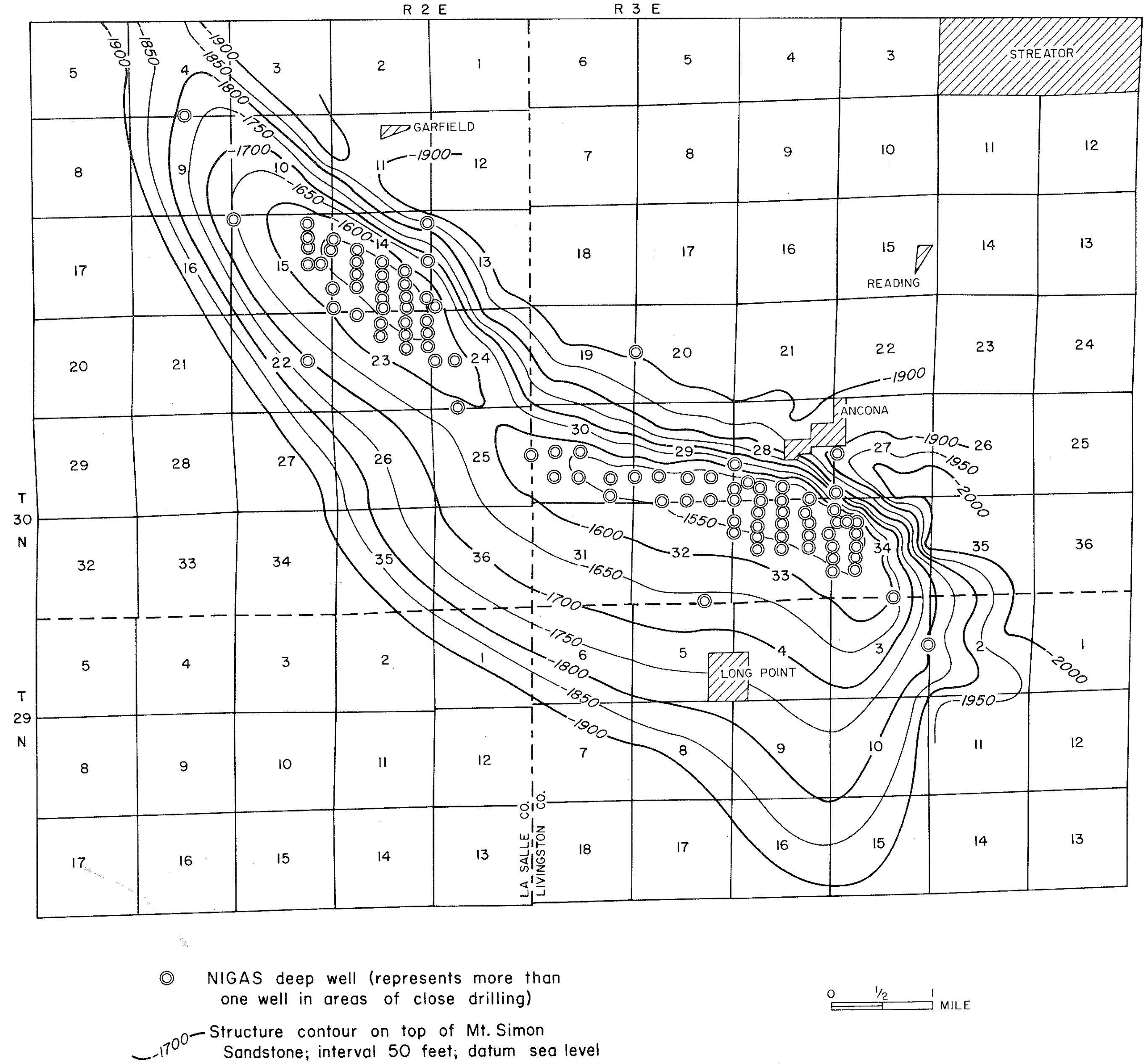

Fig. 8 - Top of Mt. Simon Sandstone at Ancona, Livingston and La Salle Counties (Northern Illinois Gas Co.).

The Ancona structure is an asymmetrical anticline, 10 miles long and 4 miles wide, that trends northwest (fig. 8). At the crest of the structure are two domes, separated from each other by a shallow saddle.

The storage reservoir is in the Mt. Simon Sandstone, an aquifer with an average porosity of 12.3 percent and an average permeability of 114 millidarcys. The caprock is the Eau Claire Formation, which is 400 feet thick. The upper 250 feet of the Eau Claire consists of shaly and dolomitic sandstones and siltstones; the lower 150 feet consists chiefly of dense, grayish green shale with thin silty and sandy beds at the base.

The Ancona structure has 290 feet of closure on top of the Mt. Simon Sandstone. (Closure is the difference in elevation between the highest point on the dome or anticline and the lowest structural contour that completely surrounds it.) The southeastern dome, near Ancona, has 96 feet of closure, and the northwestern dome, near Garfield, has 89 feet. When injection of gas exceeded the limits of the two domal peaks, the gas commingled through the saddle area, forming a single storage reservoir.

The reservoir is 2,154 feet deep and covers about 12,840 acres. Ultimate capacity of the project has been estimated as high as 130 billion cubic feet, about a third of which is working gas.

The Ancona project has 85 injection and withdrawal wells and 26 observation wells. In each operational well, 7-inch casing was cemented through the storage zone and perforated. The normal injection pressure is 1,160 pounds per square inch gauge (psig).

Before gas was injected, water was pumped from the Mt. Simon while the water levels were observed in wells completed in the overlying Galesville and St. Peter Sandstones. The results of the pumping tests showed that there was no significant communication between these sandstones and the Mt. Simon, indicating that the Eau Claire caprock was tight.

Ashmore Project

Operator: Central Illinois Public Service Company
Location: 8 miles east of Charleston, T. 12 N., R. 10 and 11 E., 14 W., Coles and Clark Counties

Gas for the Ashmore project comes from Panhandle Eastern Pipeline Company and Trunkline Gas Company by way of Central Illinois Public Service Company's distribution lines and an 8-inch feeder line to the project. The gas is consumed in east-central Illinois.

This reservoir originally contained gas that was discovered in 1957. Since then, 43 gas wells have been completed (Meents, 1965, p. 2). Ten of these wells were completed in the northern area, where the small volume of gas produced is used for individual households. The southern part of the field contains 33 gas wells, 23 of which are now being used for injection and withdrawal of storage gas.

Gas is stored in sandstone of the Spoon Formation (Pennsylvanian) and in the underlying Salem Limestone (Mississippian). No attempt is made to record separately the injection or production data from the two units. The Pennsylvanian gas sand is 4 to 80 feet thick in the area, generally thickening off structure. Average porosity of the sandstone is 15 percent and average permeability is 144 millidarcys. The Salem Limestone has an average porosity of 15 percent, and its permeability is up to 3,000 millidarcys. The caprock is several hundred feet of shale and coal of Pennsylvanian age.

The Ashmore structure is an elongate dome. It trends north-south and has closure of 87 feet on top of the gas sand and 144 feet on top of the Salem Limestone and Borden Siltstone (Meents, 1965, p. 13). The dome is about 4 miles long and 2 miles wide (fig. 9) and covers 1,600 acres within the closure. Depth of the reservoir is 350 to 446 feet. Ultimate capacity of the reservoir is estimated to be 3.6 billion cubic feet.

Most wells have 4 1/2-inch production casing set in the top of the Pennsylvanian gas sand, and the wells are completed as open holes. In a few instances, casing has been set through the Salem porosity, with the casing perforated by four shots per foot. No tubing or siphon strings are used.

Normal injection pressure is 145 psig. Open-flow potential of the wells ranges from 200 to 7,200 Mcf per day with an average of 800. The Ashmore structure was developed for gas storage in 1960 and became operational in 1963. The amounts of gas injected and withdrawn are shown in table 5.

TABLE 5 — INJECTION AND WITHDRAWAL HISTORY OF ASHMORE PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory* (end of year)	Peak daily withdrawal
1963	311	58	253	11
1964	458	115	596	10
1965	489	234	851	12
1966	388	310	929	14
1967	311	450	787	16
1968	619	411	995	20
1969	731	445	1,281	17
1970	990	768	1,504	27
1971	710	673	1,546	36
1972	590	1,037	1,035	40

*Working gas.

Brocton Project

Operator: Peoples Gas Light & Coke Company
Location: T. 14 and 15 N., R. 13 and 14 W., Edgar and Douglas Counties

The Brocton reservoir is in the process of being tested. Gas for the initial testing will be supplied by Panhandle Eastern Pipeline Company,

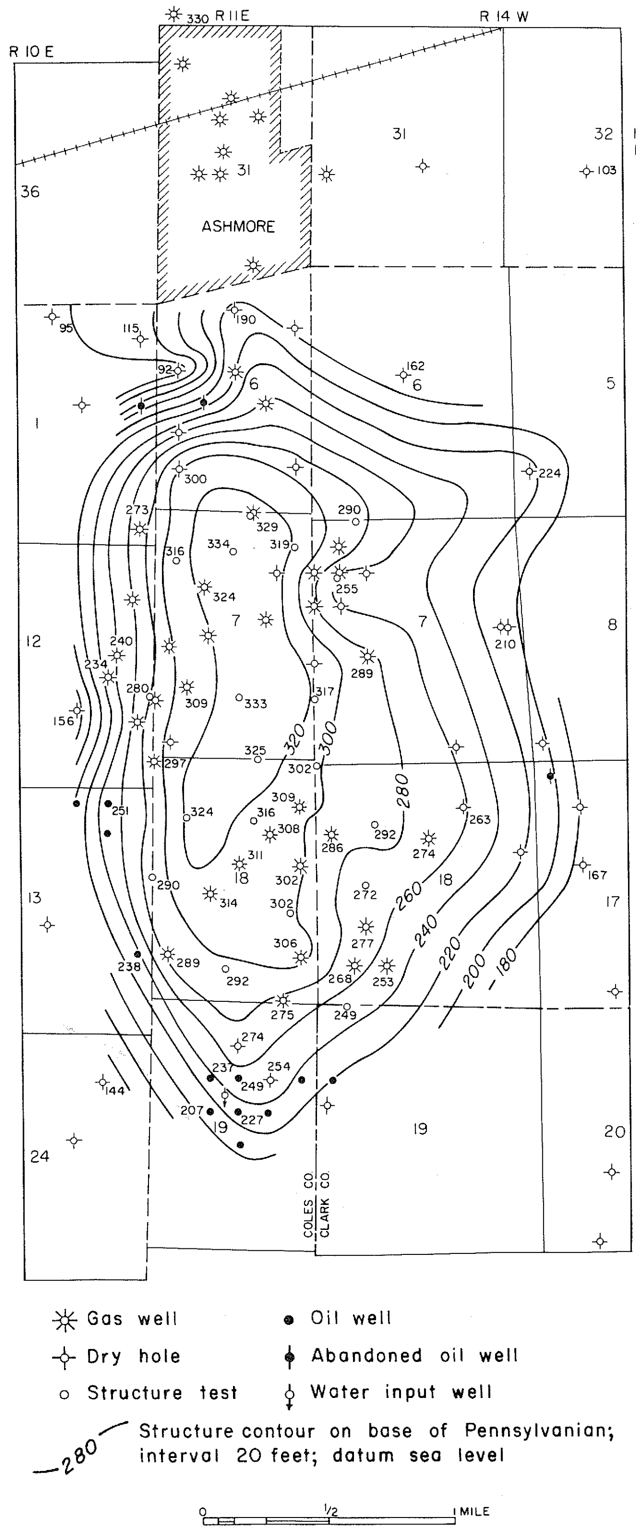

Fig. 9 - Top of Mississippian (Salem Limestone or Borden Siltstone) at Ashmore, Coles and Clark Counties (Meents, 1965).

through an exchange agreement among Panhandle, Peoples Gas Light and Coke Company, and Midwestern Gas Transmission Company. An 8-inch line, 6.68 miles long, will connect the Brocton field with the existing Panhandle pipeline. If the Brocton project proves feasible, other pipelines will be constructed to transport gas from Brocton to Peoples' Manlove (Mahomet) project; from there it will be delivered through existing pipelines to the Chicago area for consumption.

A map drawn by L. A. Mylius (1927, plate XX) showed that a dome existed in the Brocton area. In 1959 representatives of the Union Hill Gas Company studied records on file at the Illinois State Geological Survey and further delineated the structure. Following that study, Union Hill drilled six structure tests and three deeper stratigraphic tests to the St. Peter Sandstone in the area. For various reasons further testing and development were discontinued at that time.

During exploration for St. Peter storage reservoirs at Brocton, carbonates of Devonian age were found to possess some of the properties required in a gas storage reservoir. In 1970 a deep test located at the top of the structure was drilled by Peoples Gas Light & Coke Company; it showed that storage in the St. Peter probably would not be practical but that the Devonian could serve as a storage reservoir.

The New Albany Shale Group appears to be a satisfactory caprock. When water was withdrawn from the Devonian during pumping tests, no change was seen in water levels in observation wells in the overlying Mississippian strata. Differences in static water levels of the Mississippian and Devonian wells, as well as differences in the chemical content of the interstitial waters, also gave evidence that the New Albany caprock was impermeable.

Gas is to be stored at a depth of 672 feet in a northwest-southeast-trending anticline. The reservoir, in the Middle Devonian, consists of 60 feet of Lingle, a dense limestone, and 150 feet of Grand Tower, a porous, vuggy dolomite. The overall average porosity of the storage rock is 12.2 percent. The rock is water-saturated; the interstitial water contains 12,000 to 17,000 mg/l total dissolved solids.

The Brocton Anticline has about 220 feet of closure and it covers 32,000 acres within the last closing contour (fig. 10). The ultimate capacity of the reservoir is estimated to be 70 billion cubic feet.

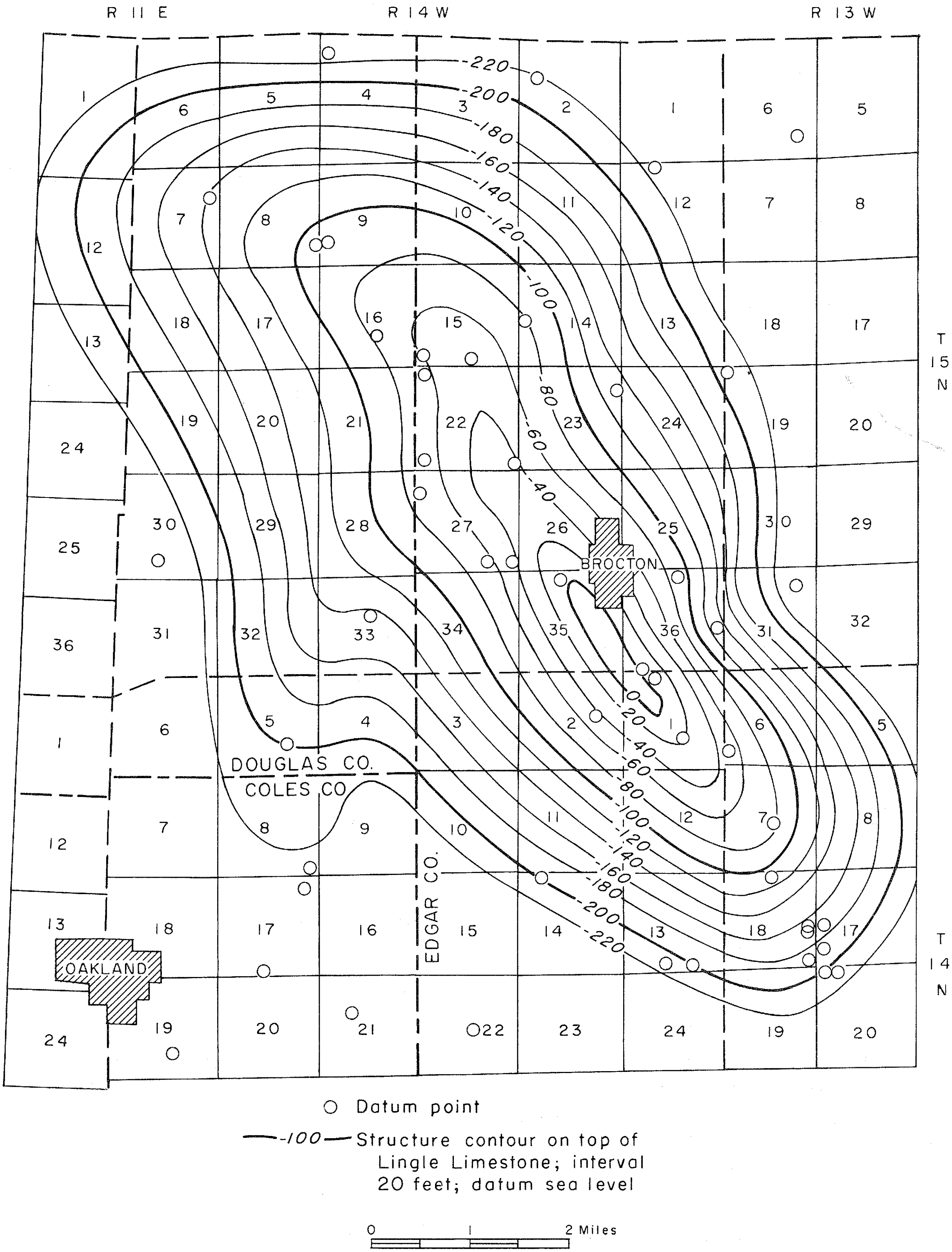

Fig. 10 - Top of Lingle Limestone at Brocton, Edgar and Douglas Counties (Peoples Gas Light and Coke Co.).

As of January 1, 1973, five observation wells had been drilled and completed in the Devonian. The wells were cased through the reservoir and perforated with four shots per foot opposite the porous zones. The injection pressure is not to exceed 400 psig.

Centralia East Project

Operator: Illinois Power Company
Location: 1 mile east of Centralia, T. 1 N., R. 1 E., Marion County

Gas for the Centralia project is purchased from Natural Gas Pipeline Company of America and is delivered to the field through Illinois Power Company's distribution lines nearby. The gas is consumed in the Centralia-Mt. Vernon area.

The reservoir is in a former gas field that was discovered in 1958. Gas was produced from 1958 to 1964. Injection of storage gas commenced in 1964 with 272 MMcf injected that year and 61 MMcf injected in 1965. No withdrawals of injected gas were made in 1965, but the project became operational during the 1966-67 heating season (table 6).

TABLE 6 — INJECTION AND WITHDRAWAL HISTORY OF CENTRALIA EAST PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory* (end of year)	Peak daily withdrawal
1964	272	—	272	—
1965	61	—	332	—
1966	23	18	337	4.8
1967	232	269	75	18.0
1968	277	263	165	17.0
1969	191	159	226	14.0
1970	280	300	204	16.0
1971	273	271	207	16.0
1972	292	276	222	16.0

*Working gas.

The reservoir is a stratigraphic trap in a sandstone of Pennsylvanian age. The sandstone has a maximum thickness of 49 feet. It has an average porosity of 18.2 percent and an average permeability of 200 millidarcys. The reservoir is 812 feet below the surface and covers 463 acres (fig. 11). Shale of Pennsylvanian age serves as a caprock. The ultimate capacity of the project is estimated to be 663 million cubic feet of gas.

The project contains 17 injection and withdrawal wells and 4 observation wells. In all wells, 5 1/2-inch production casing was set 40 feet below the gas-water contact. The casing was perforated with four shots per foot at the gas sand.

Normal injection pressure is 250 to 350 psig. Open-flow potential of the wells ranges from 260 to 9,000 Mcf per day, with an average of 3,016.

Cooks Mills Project

Operator: Natural Gas Pipeline Company of America
Location: T. 14 N., R. 7 and 8 E., Coles and Douglas Counties

Gas for the Cooks Mills project comes from the Gulf Coast System line of Natural Gas Pipeline Company of America by way of 16 miles of 20-inch pipeline to Cooks Mills. The gas is consumed in the Chicago area.

The Cooks Mills Consolidated oil pool was discovered in 1941 (Whiting, 1959), but it was not fully developed until 1954. Oil and gas are produced from the Cypress and Aux Vases

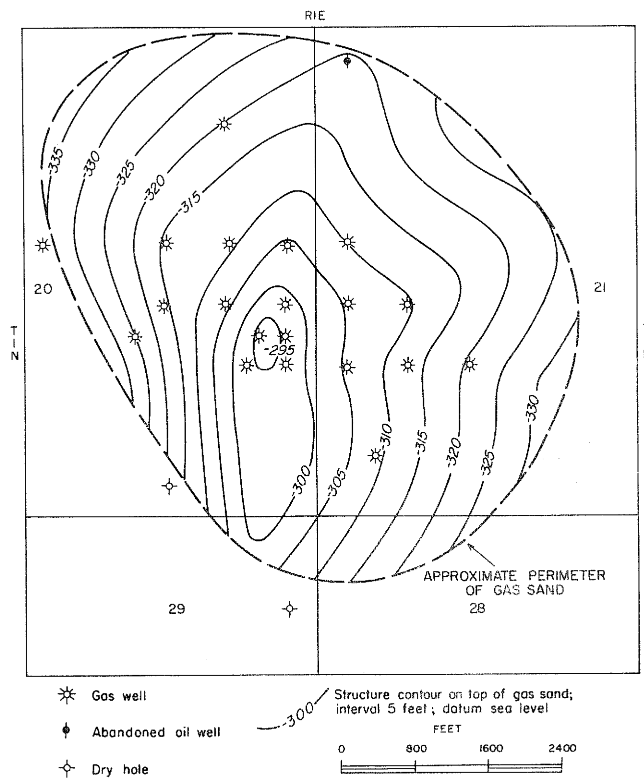

Fig. 11 - Top of Pennsylvanian gas sand at Centralia East, Marion County (Buschbach and Bond, 1967; original map by Illinois Power Co.).

Sandstones and the Spar Mountain ("Rosiclare") Sandstone Member of the Ste. Genevieve Formation, all of Mississippian age. In 1963, oil was discovered in the underlying Carper sand and in limestone and dolomite of Devonian age. The pool has produced 2,972,000 barrels of oil through the end of 1971 and is currently under waterflood. In one part of the field, several wells produced gas from the Cypress Sandstone. Natural Gas Pipeline Company of America purchased the gas in place and also the storage rights. Gas was first injected in 1959 (table 7), and the project became operational the same year.

TABLE 7 — INJECTION AND WITHDRAWAL HISTORY OF COOKS MILLS PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory (end of year)	Peak daily withdrawal
1958	—	—	1,769	—
1959	1,206	978	1,998	—
1960	427	304	2,120	32
1961	1,022	1,058	2,083	27
1962	1,142	1,016	2,210	31
1963	1,532	1,327	2,416	45
1964	2,495	1,412	3,499	45
1965	2,099	1,801	3,796	52
1966	2,386	2,392	3,790	56
1967	2,088	1,988	3,888	59
1968	1,351	1,178	4,058	60
1969	2,088	1,998	4,147	67
1970	2,901	2,704	4,343	83
1971	2,384	2,401	4,326	74
1972	2,200	2,201	4,324	80

Gas is stored in the Cypress Sandstone, which has an average porosity of 16 percent and an average permeability of 67 millidarcys. The trap is a combination of an anticline and a stratigraphic trap (fig. 12). The caprock is shale of Chesterian age. The reservoir is 1,600 feet deep, has 40 feet of closure, and covers 1,500 acres. Ultimate capacity of the reservoir is unknown, but it has contained as much as 4.5 billion cubic feet of gas.

Twenty-four wells are used for injection and withdrawal of gas and five for observation. Operational wells were drilled through the Cypress and were cased to total depth. The 5 1/2-inch production casing was perforated adjacent to the reservoir.

Normal injection pressure is 840 psig. No records are available on open-flow potential, but as much as 83 million cubic feet of gas has been withdrawn during one day (table 7).

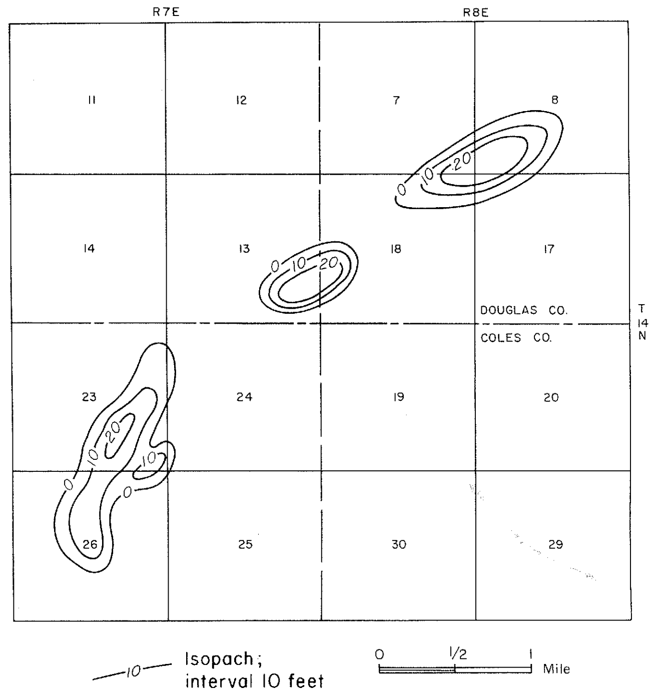

Fig. 12 - Thickness of Cypress net gas sand at Cooks Mills, Coles and Douglas Counties (Buschbach and Bond, 1967; original map by Natural Gas Pipeline Co. of America).

Corinth Project

Operator: Central Illinois Public Service Company
Location: T. 8 S., R. 4 E., Williamson County

Gas for this project comes from the distribution line of Central Illinois Public Service Company near Belle Gent. Gas originally in the reservoir serves as cushion gas. Gas withdrawn from storage is to be consumed in the Belle Gent area.

Gas is stored in a reservoir which produced 85 million cubic feet of gas in the period from September 1970 to June 1972. In that period the reservoir pressure dropped from its original value, 859 psig, to 625 psig.

Storage is in the Hardinsburg Sandstone, 26 to 28 feet thick, at a depth of 2,125 feet (fig. 13). The gas-water contact is at a depth of 2,139 to 2,143 feet. The surface area of the reservoir is about 20 acres. The porosity, permeability, and nature of the trap are not known. The estimated capacity of the reservoir under the original pressure is 250 million cubic feet.

The two injection-withdrawal wells were completed with 5 1/2-inch casing. One well has an open-hole completion, while the other is cased through and has 10 feet of perforations opposite the storage sand.

In November 1972 the field was converted to gas storage. Forty-seven million cubic feet of gas was injected in the period November 1 to December 31, 1972.

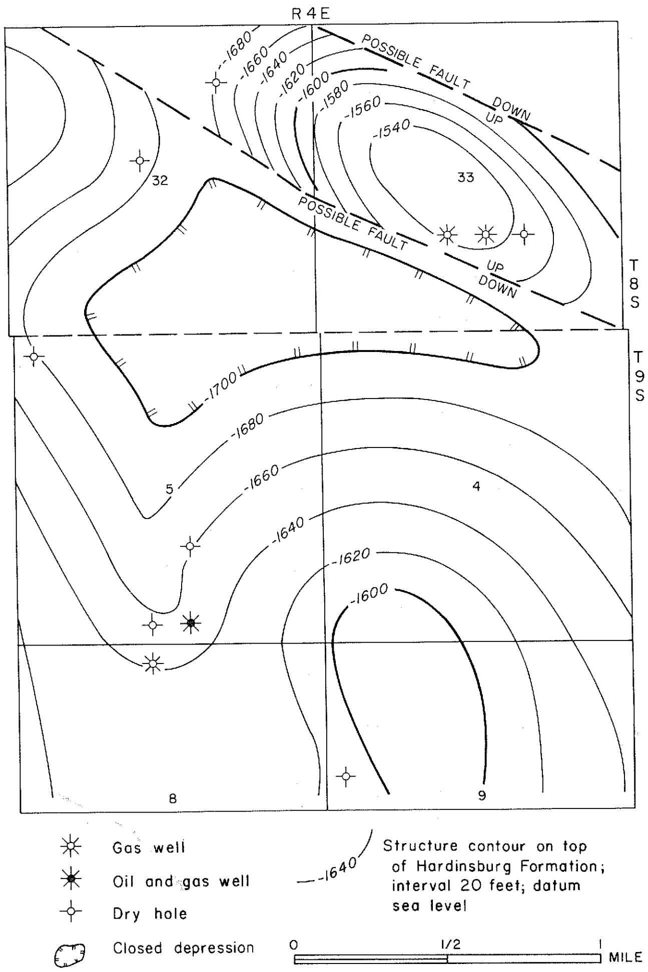

Fig. 13 - Top of Hardinsburg Formation at Corinth and Crab Orchard, Williamson County (Central Illinois Public Service Co.).

Crab Orchard Project

Operator: Central Illinois Public Service Company
Location: T. 9 S., R. 4 E., Williamson County

Gas for this project comes from the distribution line of Central Illinois Public Service Company in the vicinity of Belle Gent. Gas originally in the reservoir serves as cushion gas. Gas withdrawn from storage is to be consumed in the Belle Gent area .

Gas is stored in a reservoir which has produced gas with some oil. In the period from December 1970 to March 1972, two wells have produced 65 million cubic feet of gas; in the period from January 1971 to February 1972, 2,673 barrels of oil were produced. One of the wells has produced only gas; the other has produced gas and some oil. In July 1972 the reservoir pressure had declined from 950 psig, the original pressure, to 616 psig.

Storage is in the Hardinsburg Sandstone (19 feet thick) at a depth of slightly greater than 2,200 feet. The gas-oil contact is estimated to be at a depth of 2,230 feet (fig. 13). The surface area of the reservoir is about 20 acres. The porosity, permeability, and nature of the trap are not known. The estimated capacity of the reservoir under the original pressure is 173 million cubic feet.

The injection-withdrawal wells are completed with 5 1/2-inch casing, which has about 14 feet of perforated section opposite the storage sand.

In November 1972 the field was converted to gas storage. Thirty-seven million cubic feet of gas was injected in the period November 1 to December 31, 1972.

Crescent City Project

Operator: Northern Illinois Gas Company
Location: Between Crescent City and Watseka, T. 26 and 27 N., R. 13 W., Iroquois County

Gas for the Crescent City project is supplied by Midwestern Gas Transmission Company through a 6-inch supply main from their 30-inch pipeline. Currently, there is no pipeline from the project to the consuming area, suburban Chicago.

An oil test near Crescent City indicated a structural high that was mapped as a dome by the Illinois State Geological Survey (Meents, 1954).

The Crescent City Dome was delineated in 1959 by structure drilling and gravity surveys. A total of 78 structure tests have been drilled to the Fort Atkinson Limestone (middle Maquoketa) or deeper. The development of the field was delayed by litigation with some landowners. Test injection of gas began in 1967 (table 8).

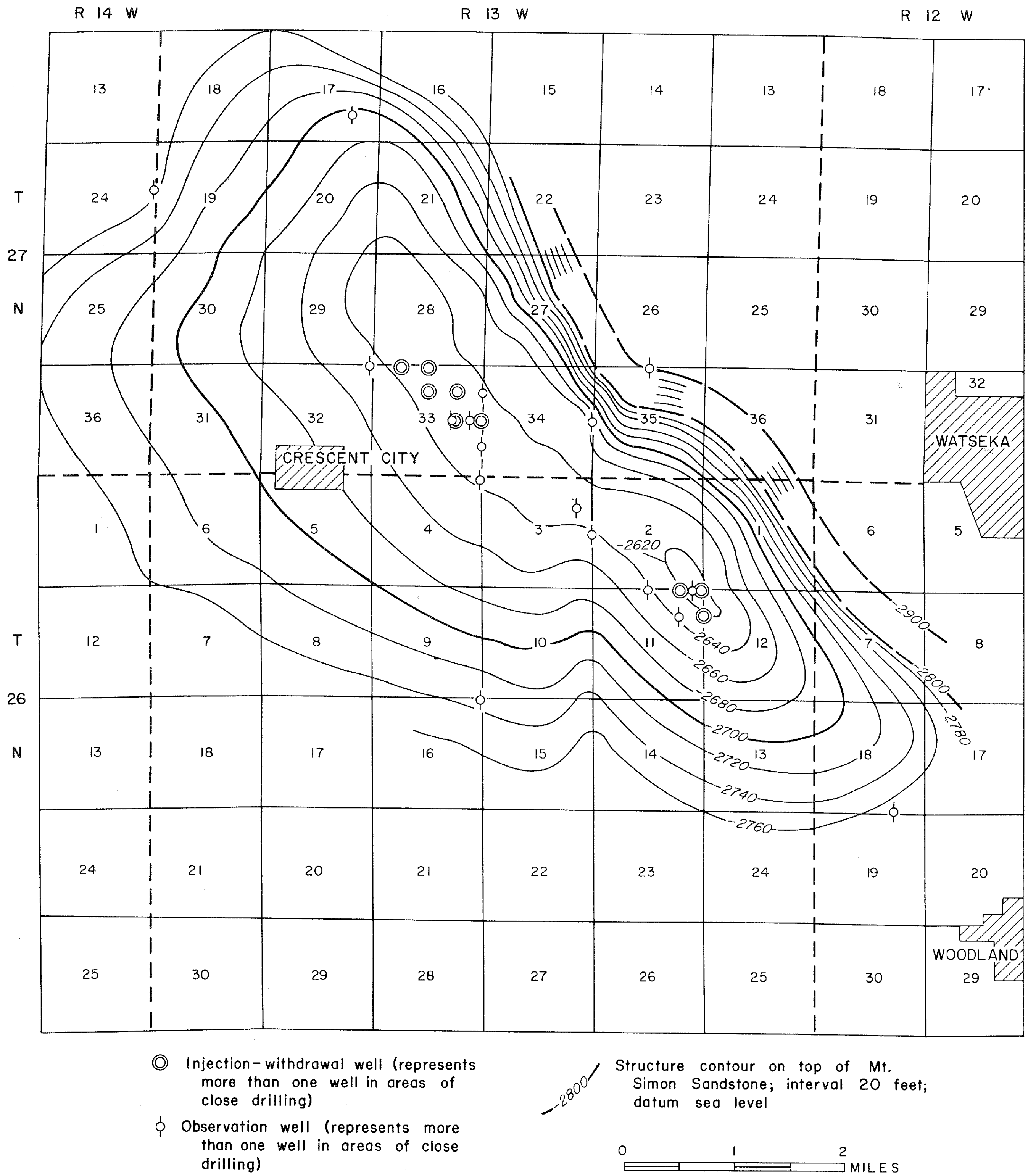

Fig. 14 - Top of Mt. Simon Sandstone at Crescent City, Iroquois County (Northern Illinois Gas Co.).

TABLE 8 — INJECTION AND WITHDRAWAL HISTORY OF CRESCENT CITY PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory (end of year)	Peak daily withdrawal
		St. Peter Sandstone		
1967	92	0	92	0
1968	249	0	340	0
1969	726	0	1,086	0
1970	1,003	28	2,089	5
1971	0	47	2,044	0.5

The trap is an asymmetrical anticline that trends northwest (fig. 14). The reservoir is in the St. Peter Sandstone, an aquifer with 14.5 percent porosity and an average permeability of 138 millidarcys. The reservoir is 1,200 feet below surface and covers 16,725 acres within the area leased. The ultimate capacity of the Crescent City project is estimated to be 50 billion cubic feet. The caprock is 400 feet of limestone and dolomite assigned to the Platteville and Galena Groups. The lower part of the Platteville contains beds of very fine grained limestone. Observation wells in the overlying Galena will be used to monitor and collect any leakage gas. Overlying the Galena is the Maquoketa Shale Group, which is about 220 feet thick.

Twenty-eight wells have been completed for observation, injection, or withdrawal. The operational wells have been cased through the reservoir with 7-inch production casing which has been perforated adjacent to the reservoir.

The Galesville and Mt. Simon Sandstones, beneath the St. Peter, were considered as potential reservoirs for gas storage. Several deep wells were drilled and cored to the Mt. Simon Sandstone.

Operations in the St. Peter at the Crescent City project have ceased at the present time.

Eden Project

Operator: Illinois Power Company
Location: T. 5 S., R. 5 W., Randolph County

Gas for the Eden project is supplied by Natural Gas Pipeline Company of America and the Mississippi River Transmission Corporation through existing facilities of Illinois Power Company in the Sparta area and a 6-inch pipeline to the project. Gas withdrawn from the Eden project is used in the Sparta area.

The Eden project is a former gas field in the Cypress Sandstone of Mississippian age. A previously drilled and abandoned hole was recompleted as a gas well in 1961. Between that time and 1963 nine additional gas wells were completed. The field has been shut in except for production of a small volume of gas withdrawn from two wells for domestic purposes. The original reservoir pressure was 384 psi. In 1969 the Illinois Power Company negotiated an option to acquire gas storage rights in the field.

The Eden reservoir is sandstone of the Cypress Formation in two stratigraphic traps which are about half a mile apart (fig. 15). Each trap is defined by a gas-water contact down structural dip to the east and by a sandstone pinchout at all other sides. The caprock is shale of the Cypress Formation. The average thickness of pay sand is 18 feet. The average porosity of the sandstone is 20.6 percent, and the average permeability is 168 millidarcys. The reservoir is 875 feet below surface, and the field underlies about 1,000 acres. The ultimate capacity of the reservoir is 2.5 billion cubic feet at its initial pressure of 384 psi. The southern trap of the field will be developed first.

The Eden project has 12 injection-withdrawal wells and 7 observation wells. The operating wells were completed with 4 1/2-inch production casing, which was cemented through the Cypress Sandstone and perforated opposite the gas sand. Casing 8 5/8 inches in diameter was set from the ground surface through a Pennsylvanian coal that overlies the reservoir. Three of the storage wells penetrate strippable coal deposits, and underground mining or stripping of coal has previously been carried out within the boundaries of the Eden project. It is anticipated that the storage of gas and the production of coal can be carried out without inconvenience to either operation.

Storage gas was first injected at Eden in 1971 and the project became operational in the same year (table 9). Extrapolated open-flow potentials of the production wells vary from about 1,000 to 7,300 Mcf per day.

TABLE 9 — INJECTION AND WITHDRAWAL HISTORY OF EDEN PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory (end of year)	Peak daily withdrawal
1970	0	0	1,362	0
1971	64	13	1,412	5
1972	105	194	1,323	6.5

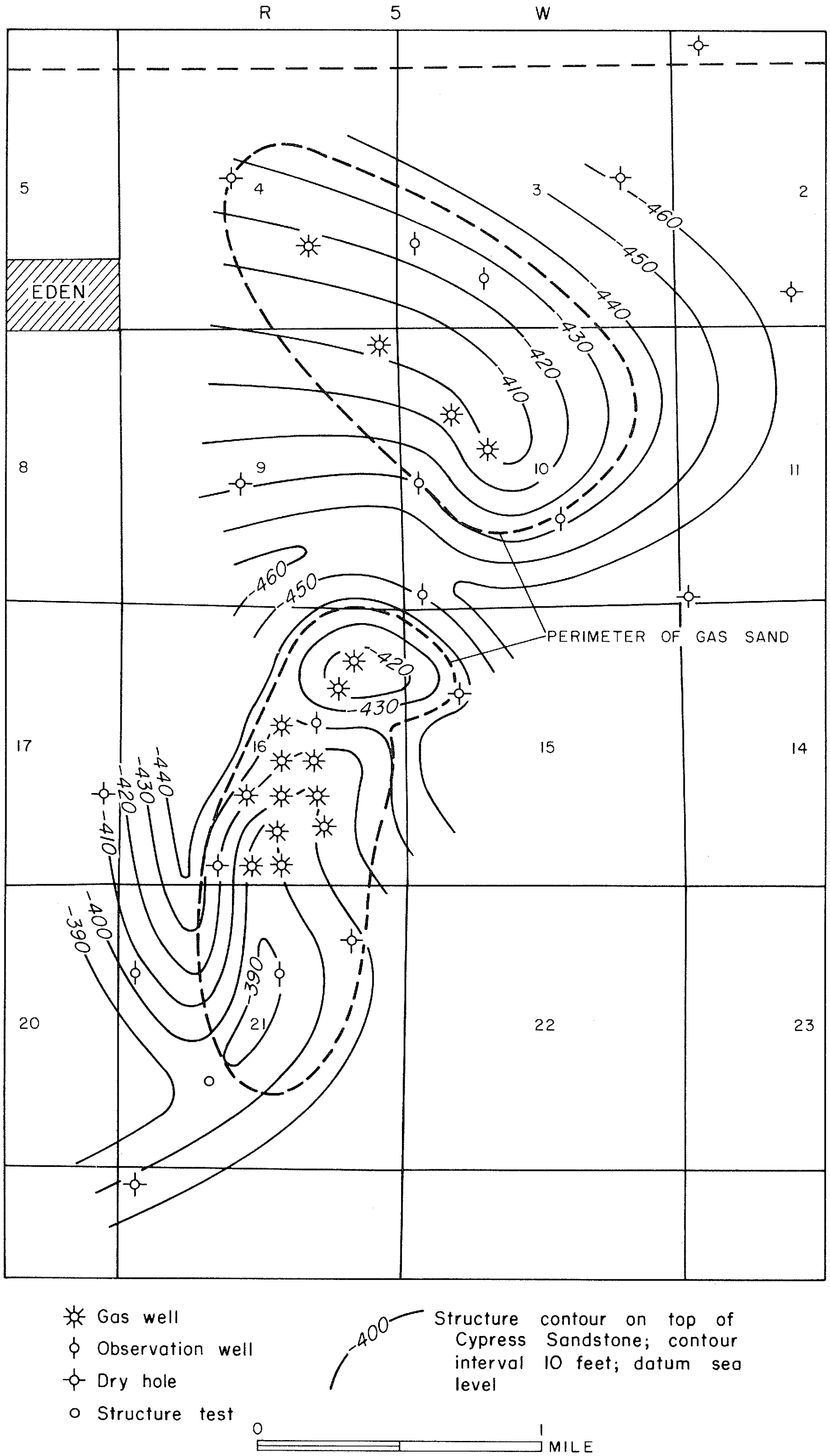

Fig. 15 - Top of Cypress Sandstone at Eden, Randolph County (Illinois Power Co.).

Elbridge Project

Operator: Midwestern Gas Transmission Company
Location: T. 12 and 13 N., R. 11 W., Edgar County

Gas for the Elbridge project comes from Midwestern Gas Transmission Company's 30-inch line through 10- to 16-inch feeder lines. At times of withdrawal, the gas is returned to the same pipelines. Elbridge is a former oil field that was discovered in 1949. About 1.5 million barrels of oil have been produced from this pool, chiefly from the Mississippian Ste. Genevieve Limestone.

Gas is stored in porous dolomite and dolomitic limestone beds of the Grand Tower Formation, an aquifer. No gas is stored in the oil producing formations. The dome-shaped structural trap was formed by the draping of Devonian and younger strata over a Silurian reef. The caprock is 90 feet of shale of the New Albany Group directly overlying the dolomite and limestone. Observation wells in the porous Carper sand, which overlies the New Albany, are utilized to monitor any gas leakage from the reservoir upward through the caprock.

The Elbridge Dome has 145 feet of closure on top of the Grand Tower and covers 1,691 acres (fig. 16). The reservoir has an average porosity of 17.5 percent and an average permeability of 18 millidarcys. It is 1,925 feet deep. The ultimate capacity of the Elbridge project is estimated to be about 8 billion cubic feet.

Elbridge has 12 injection and withdrawal wells and 7 observation wells. The operational wells have 4 1/2-inch casing that is set and cemented 30 feet into the storage formation. The casings are perforated with four shots per foot opposite the top 25 feet of porosity. Packers are run on 2 3/8-inch tubing and set about 50 feet above the perforations. Gas is injected and withdrawn through the 2 3/8-inch tubing.

TABLE 10 — INJECTION AND WITHDRAWAL HISTORY OF ELBRIDGE PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory (end of year)	Peak daily withdrawal
1965	425	0	425	—
1966	2,375	81	2,719	11
1967	2,583	465	4,834	31
1968	860	1,041	4,625	18
1969	1,182	695	5,112	12
1970	1,475	811	5,754	16
1971	2,013	1,142	6,626	29
1972	1,381	1,188	6,819	16

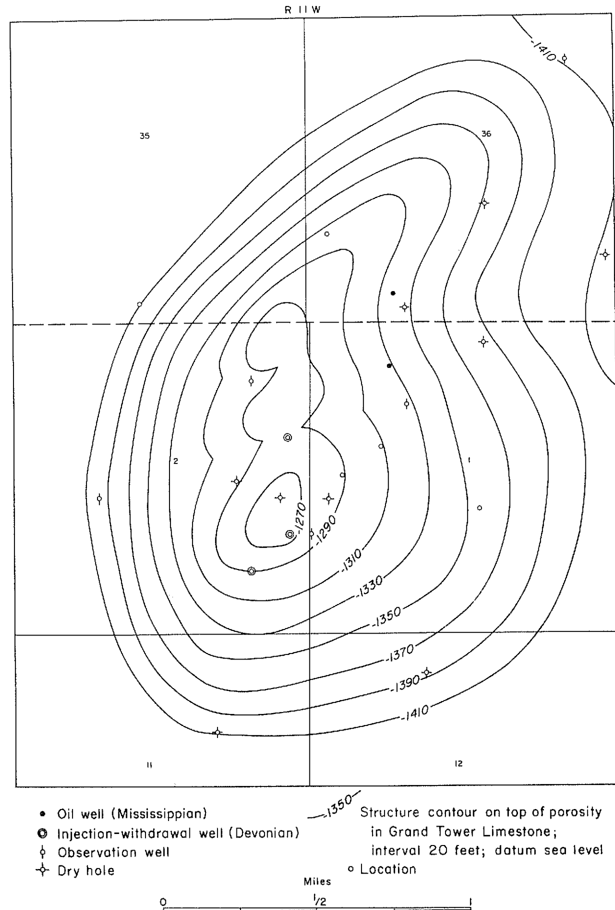

Fig. 16 - Top of porosity in Grand Tower Limestone at Elbridge, Edgar County (Buschbach and Bond, 1967; original map by Midwestern Gas Transmission Co.).

Normal injection pressure is 1,100 psig. Open-flow potentials of the wells range from 600 to 7,400 Mcf per day and average 3,900 Mcf. Gas injection at Elbridge began in 1965 and the project became operational in 1966 (table 10).

Freeburg Project

Operator: Illinois Power Company
Location: 2 miles south of Freeburg, T. 1 and 2 S., R. 7 W., St. Clair County

Gas for the Freeburg project is purchased from the Mississippi River Transmission Corporation and is delivered to the project through Illinois Power Company's distribution lines. The gas is consumed in the East St. Louis area.

The reservoir is in a former gas field, discovered in 1956 (Meents, 1959) and acquired for use as a storage field in 1958. The reservoir is a monoclinal stratigraphic trap in the Cypress Sandstone. The Cypress dips to the south and east and grades to shale to the north and west. The sandstone has an average porosity of 21.5 percent and an average permeability of 216 millidarcys. The reservoir has a maximum thickness of 47 feet. The reservoir is 300 to 400 feet below the surface and covers 4,222 acres (fig. 17). The caprock is 16 to 28 feet of shale directly overlying the sandstone reservoir.

Injections and withdrawals of storage gas were first made in 1959. At the end of 1972, the reservoir contained 1.86 billion cubic feet of working gas (table 11) and 4.64 billion cubic feet of cushion gas. The project has 83 injection and withdrawal wells and 7 observation wells. In all wells, 5 1/2-inch casing was set to the top of the Cypress and the wells were completed open-hole with cable tools.

TABLE 11 — INJECTION AND WITHDRAWAL HISTORY OF FREEBURG PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory* (end of year)	Peak daily withdrawal
1959	170	181	1,798	19
1960	494	462	1,760	23
1961	534	473	1,821	30
1962	1,085	1,059	1,869	42
1963	301	620	1,541	39
1964	720	632	1,604	40
1965	1,664	1,580	1,686	37
1966	1,463	1,551	1,871	38
1967	1,664	1,937	1,326	38
1968	2,007	1,976	1,357	39
1969	1,825	1,451	1,729	35
1970	1,918	1,527	2,119	38
1971	1,044	945	2,217	42
1972	988	1,343	1,862	45

*Working gas.

Normal injection pressure is 150 to 180 psig. Open-flow potential of the wells ranges from 60 to 4,600 Mcf per day, with an average of 1,989.

Gillespie-Benld Project

Operator: Illinois Power Company
Location: 2 miles east of Gillespie, T. 8 N., R. 6 W., Macoupin County

Gas for the Gillespie-Benld project is purchased from the Mississippi River Transmission Corporation and is delivered through an Illinois Power Company distribution line. The gas is consumed in Gillespie, Benld, and nearby communities.

This reservoir is a former gas field, discovered in 1923 and abandoned in 1935 after it had produced 136 million cubic feet of gas. Storage gas was first injected at Gillespie-Benld in 1958 and withdrawals began in 1959 (table 12).

TABLE 12 — INJECTION AND WITHDRAWAL HISTORY OF GILLESPIE-BENLD PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory (end of year)	Peak daily withdrawal
1958	101	0	115	0
1959	44	10	147	1
1960	37	30	148	4
1961	74	61	146	4
1962	59	47	146	4
1963	8	8	146	1
1964	8	6	147	2
1965	3	2	147	0.1
1966	13	14	147	4
1967	34	34	145	4
1968	48	53	139	7
1969	19	22	141	4
1970	52	46	146	5
1971	24	23	147	5
1972	34	32	150	5

The reservoir is a stratigraphic trap consisting of a sandstone lens of Pennsylvanian age. The sandstone ranges from a feather edge to 28 feet in thickness. It has an average porosity of 16 percent and an average permeability of 326 millidarcys. The reservoir is 500 to 550 feet deep and covers 113 acres (fig. 18). The sandstone reservoir is enclosed and capped by shales of Pennsylvanian age.

Seven wells are used for injection and withdrawal. Old gas wells were cleaned and filled with crushed stone to the top of the gas reservoir. New wells were drilled to the top of the reservoir, where 4 1/2- or 5 1/2-inch production casing was set. The new wells were then completed open-hole into the reservoir with cable tools.

Normal injection pressure is 145 to 180 psig. Open-flow potential of wells ranges from 83 to 5,100 Mcf per day, with an average of 2,350.

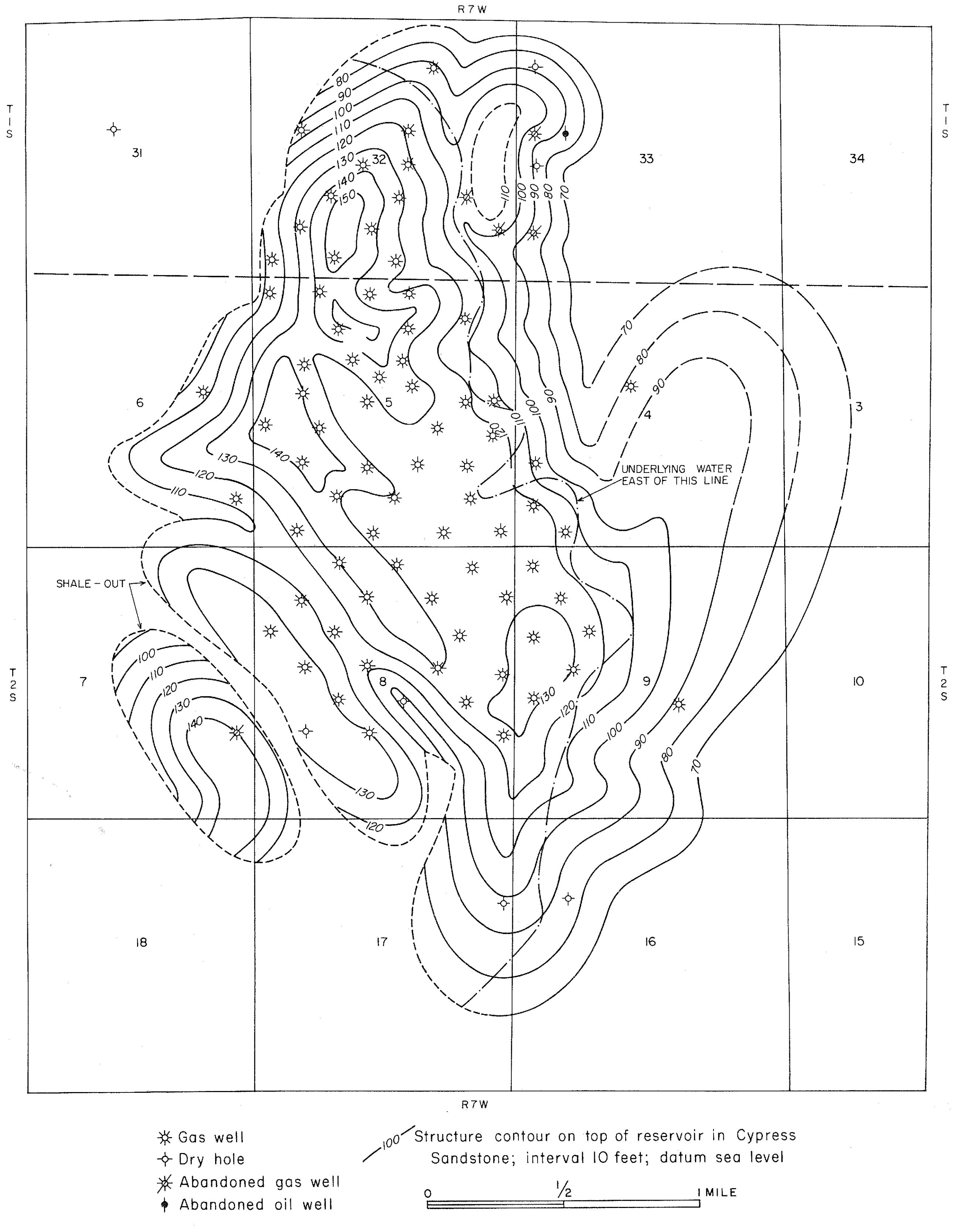

Fig. 17 - Top of reservoir in Cypress Sandstone at Freeburg, St. Clair County (Buschbach and Bond, 1967; original map by Illinois Power Co.).

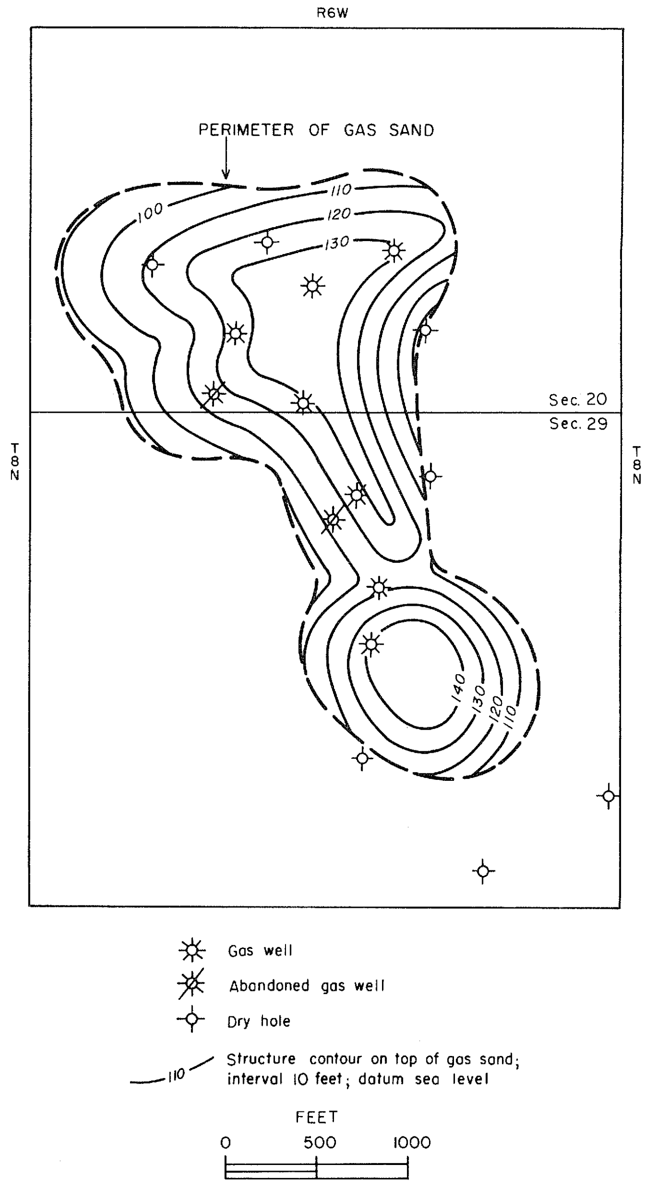

Fig. 18 - Top of Pennsylvanian gas sand at Gillespie-Benld, Macoupin County (Buschbach and Bond, 1967; original map by Illinois Power Co.).

Glasford Project

Operator: Central Illinois Light Company
Location: 12 miles southwest of Peoria, 3 miles northeast of Glasford, T. 7 N., R. 6 E., Peoria County

Gas for the Glasford project comes from Panhandle Eastern Pipeline Company through a 24-inch line and an 8-inch line. The gas is consumed in the Peoria market.

Studies of Pennsylvanian rocks in outcrops and coal test borings indicated a structural high northeast of Glasford. The structure was mapped as a dome by the Illinois State Geological Survey (Wanless, 1957).

Field mapping, gravity surveying, and structure drilling delineated the Glasford structure as a circular dome with a diameter of about 2 1/2 miles. A deep well was drilled and cored at the crest of the dome. It penetrated a normal appearing, though slightly thinned, sequence of Paleozoic strata down to the Ordovician Maquoketa Shale Group. The Maquoketa is about 100 feet thicker than it is in wells nearby, and beneath it is a jumble of blocks set at all angles in a matrix of fine breccia. The structure is classed as an explosion structure and has been interpreted as an astrobleme, the result of a meteorite or comet collision with the earth (Buschbach and Ryan, 1963).

Gas is being stored above the disturbed rocks, in gently arched beds of vuggy dolomite of the Niagaran Series (Silurian). The trap is a structural dome. The top of the Niagaran Series has 120 feet of closure; there are about 3,200 acres included within the last closing contour (fig. 19).

The reservoir, an aquifer, is slightly more than 100 feet thick. It has an average porosity of 12 percent and an average permeability of 426 millidarcys. The reservoir is 800 feet below the surface and has an estimated capacity of 12.3 billion cubic feet.

Overlying the reservoir is 40 feet of fine-grained dolomite of Devonian age, which is overlain by more than 200 feet of shale assigned to the New Albany Group. The New Albany serves as the ultimate caprock. Water was pumped from the Silurian reservoir while the water level was observed in the overlying Burlington Limestone (Mississippian); no change in the water level was observed, an indication that the caprock was tight.

Wells were completed by drilling 450 feet of 8 5/8-inch hole to the middle of the Burlington Limestone, then decreasing to a 5 1/2-inch hole down into the Devonian at a depth of about 750 feet. The storage zone was reached by drilling with cable tools to total depth. Fourteen observation wells monitor gas movement in the field.

Normal injection pressure is 350 psig. Open-flow potential of wells ranged from 4 to 25

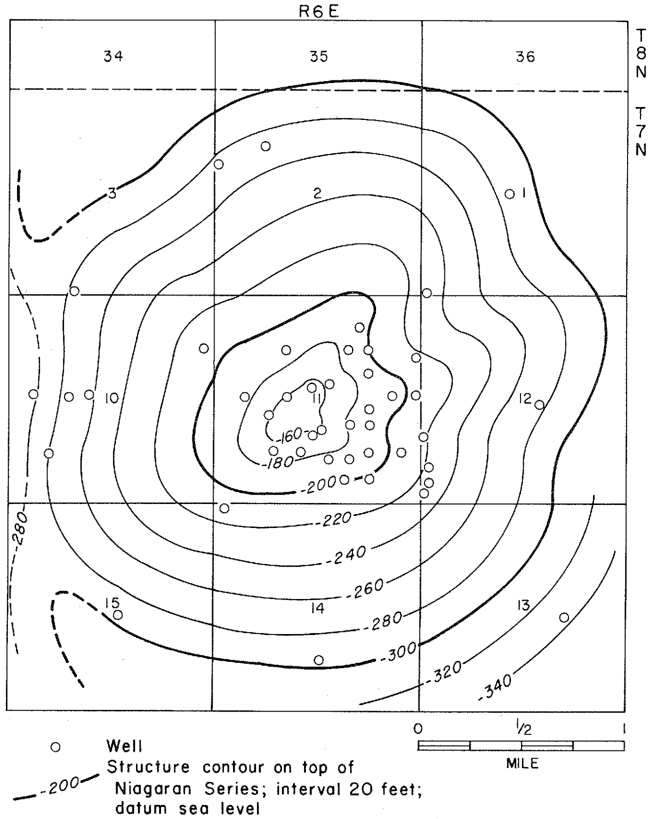

Fig. 19 - Top of Niagaran Series at Glasford, Peoria County (Central Illinois Light Co.).

MMcf per day, with an average of 8. Treatment of the wells with acid resulted in considerably enhanced deliverabilities for some of the 28 operational wells.

Gas was first injected at Glasford in 1964, with only minor withdrawals in 1964 and 1965 (table 13).

TABLE 13 - INJECTION AND WITHDRAWAL HISTORY OF GLASFORD PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory (end of year)	Peak daily withdrawal
1965	1,745	55	2,963	—
1966	611	574	3,000	30
1967	1,153	752	3,401	58
1968	2,258	1,270	4,500	80
1969	3,181	2,206	4,500	83
1970	5,420	2,211	8,500	105
1971	5,802	3,090	11,038	134
1972	4,821	6,400	9,459	142

Herscher Project

Operator: Natural Gas Pipeline Company of America
Location: Half a mile south of the village of Herscher, T. 30 N., R. 10 E., Kankakee County

Gas for the Herscher project comes from the Gulf Coast System line of the Natural Gas Pipeline Company of America by way of a 30-inch pipeline between Dwight and Herscher. The gas is consumed in Chicago and vicinity.

The Herscher Anticline was indicated on a structure map of the St. Peter Sandstone drawn by D. J. Fisher (in Athy, 1928, p. 75). Several small oil wells had been drilled to the Galena (Trenton) Group in the early 1900's, but all were abandoned in less than a year. In 1952, Natural Gas Storage Company of Illinois drilled more than 100 Galena structure tests to delineate the anticline. Four deep tests were drilled and cored to the Galesville Sandstone to determine the presence of a suitable reservoir and caprock.

Injection of gas into the Galesville Sandstone commenced in April 1953. During the last week in July 1953, four months after gas injection was started, one of the shallow water wells at Herscher began to bubble gas (Natural Gas Storage Co. of Illinois, 1957). Within a week, 33 water wells in the vicinity became active with gas. Gas injection was stopped, and a search for the cause of leakage was undertaken. To date, the cause has not been determined with certainty.

Early in 1956, efforts were made to utilize the Galesville reservoir to its maximum limit with safety. Wells were drilled into the reservoir to remove water from the periphery of the bubble, thereby facilitating injection of gas without significant pressure change. Water from the peripheral wells in the Galesville was injected into the Potosi Dolomite; this had the effect of pressurizing the formations above the reservoir. Thus, by careful regulation of differential pressures, and by recycling gas from vent wells in the Galena and St. Peter, the Galesville Sandstone at Herscher has become a successful storage reservoir.

Test drilling was done in 1957 to determine the feasibility of deeper gas storage to supplement the Galesville reservoir. The information obtained indicated that the Mt. Simon Sandstone had the requirements of a good storage zone. Gas was injected into the Mt. Simon late in 1957 and withdrawals began in 1958 (table 14). No leakage of gas from the Mt. Simon has been observed.

TABLE 14 — INJECTION AND WITHDRAWAL HISTORY OF HERSCHER PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory (end of year)	Peak daily withdrawal
Galesville Sandstone				
1953	11,885	99	11,984	61
1954	6,178	340	17,822	158
1955	4,338	1,865	20,295	368
1956	6,491	1,539	25,247	415
1957	7,041	2,997	29,291	291
1958	9,124	8,529	29,887	411
1959	9,698	6,051	33,534	430
1960	7,826	7,166	34,195	473
1961	7,561	7,160	34,596	495
1962	12,381	11,547	35,430	634
1963	16,185	17,693	33,922	702
1964	16,809	11,956	38,776	705
1965	18,149	15,488	41,436	771
1966	16,064	16,336	41,163	1,054
1967	16,144	17,559	39,549	791
1968	17,422	17,911	39,024	858
1969	18,342	17,333	40,062	907
1970	18,787	18,890	39,930	986
1971	17,643	18,208	39,364	803
1972	20,664	21,892	38,137	930
Mt. Simon Sandstone				
1957	22	0	22	0
1958	3,750	88	3,684	25
1959	6,034	364	9,354	52
1960	7,456	734	16,076	65
1961	7,636	1,626	22,087	81
1962	8,678	4,293	26,472	97
1963	10,856	4,147	33,181	97
1964	10,325	7,976	35,529	142
1965	11,759	3,797	43,492	145
1966	11,293	8,300	47,894	148
1967	11,697	8,136	51,455	193
1968	11,418	14,357	48,517	148
1969	11,985	9,575	51,034	154
1970	12,961	10,696	53,356	218
1971	13,255	13,647	52,964	205
1972	14,515	13,730	53,748	149

The Herscher structure is an asymmetrical, doubly plunging anticline that trends generally north-south. Both the Galesville and Mt. Simon reservoirs are aquifers. The Galesville Sandstone has an average porosity of 18 percent and an average permeability of 467 millidarcys. The Mt. Simon Sandstone has an average porosity of 12 percent and an average permeability of 185 millidarcys. The Galesville is 80 to 100 feet thick in the area, and its caprock is 125 feet of sandstone and dolomite of the Ironton Formation. The Mt. Simon is more than 2,500 feet thick (Buschbach, 1964), but gas is stored only in its uppermost part and in the Elmhurst Sandstone Member of the overlying Eau Claire Formation. Caprock for this reservoir is 200 feet of shale and dolomite assigned to the Lombard Member of the Eau Claire.

The Galesville is 1,750 feet deep and the Mt. Simon is 2,450 feet deep. Closure totals almost 200 feet on the Galena, a little more than 100 feet on top of the Galesville, and 80 feet on top of the Mt. Simon (fig. 20). Closure is lost with depth because of northward thinning (convergence) of most beds. The storage area covers about 8,000 acres. The ultimate capacity of the Galesville reservoir is estimated to be 50 billion cubic feet. The capacity of the Mt. Simon is about 67 billion cubic feet.

In the Herscher project, 116 wells are used for injection and withdrawal of gas and 75 are used for observation. A total of 85 wells are used for other purposes, such as recycling leakage gas, withdrawing water from the Galesville at the periphery of the bubble, or injecting that water into the Potosi Dolomite near the crest of the structure.

Some of the Galesville wells are completed open-hole, and some have been cased and perforated. All of the Mt. Simon wells are cased through the upper part of the formation and perforated.

Normal injection pressures are 680 psig for the Galesville and 1,180 psig for the Mt. Simon.

Open-flow potential of the wells is not available, but the peak daily withdrawal from the Galesville has exceeded 1 billion cubic feet.

Herscher-Northwest Project

Operator: Natural Gas Pipeline Company of America

Location: T. 31 N., R. 9 and 10 E., Kankakee County

Gas for the Herscher-Northwest project comes from the Gulf Coast System line of Natural Gas Pipeline Company of America (NGPLA). The gas is supplied by a pipeline between Herscher-Northwest and the 36-inch pipeline between the original Herscher project and the Natural Gas Pipeline Company-Chicago District facilities at Joliet. The gas is consumed in Chicago and vicinity.

In 1959 a detailed subsurface exploration program conducted by NGPLA and its former subsidiary, Natural Gas Storage Company of Illinois, confirmed the presence of a domal structure northwest of the original Herscher storage project. From 1959 through 1965 a total of 48 test wells

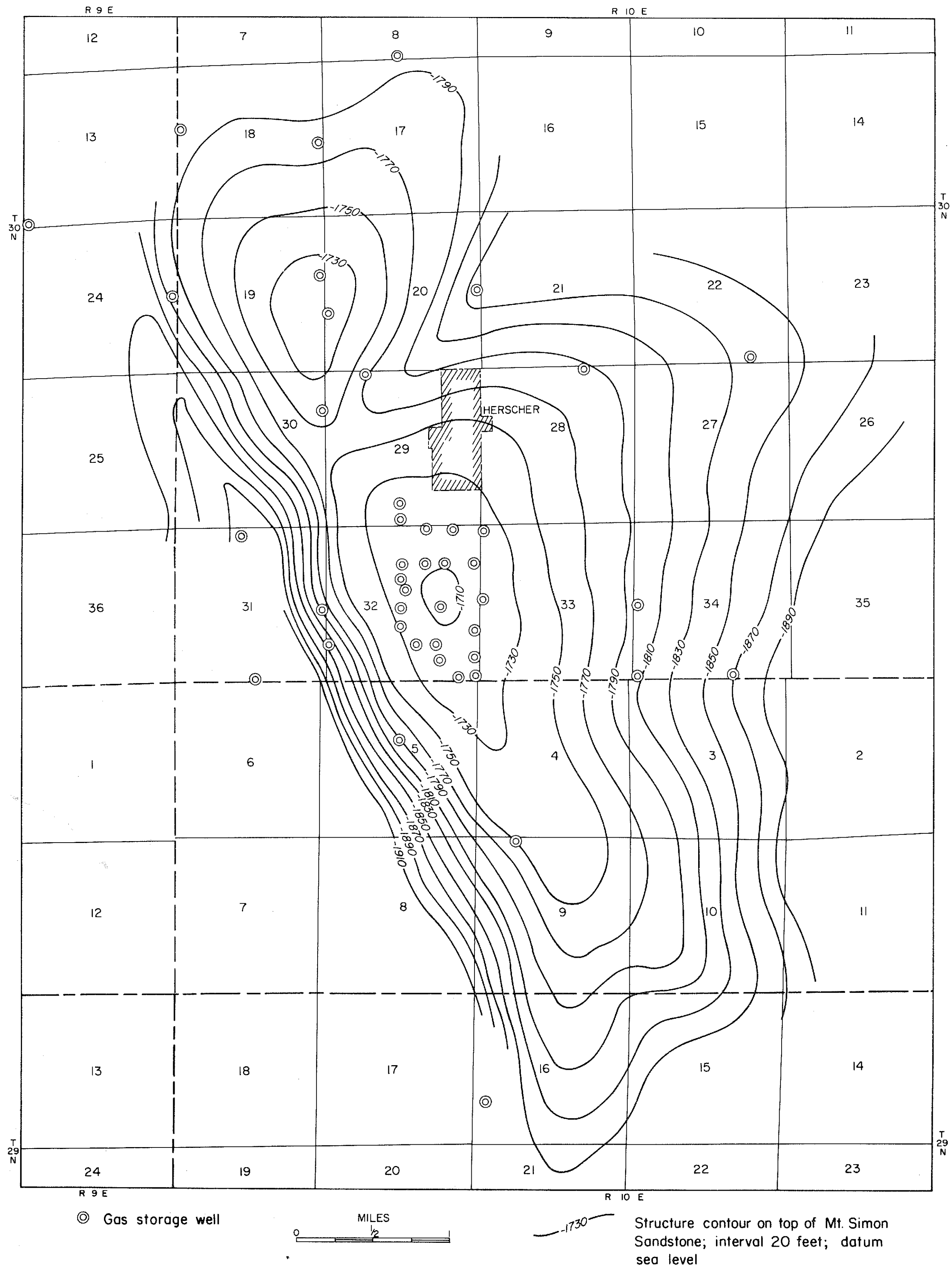

Fig. 20 - Top of Mt. Simon Sandstone at Herscher, Kankakee County (Buschbach and Bond, 1967; original map by Natural Gas Pipeline Co. of America).

were drilled in the area. Of these wells, 32 were structure tests drilled to the Galena or into the overlying Maquoketa Shale Group, 3 were drilled through the Prairie du Chien Group into the underlying Cambrian carbonates, 1 was drilled to the Galesville, and 10 penetrated the upper few hundred feet of the Mt. Simon Sandstone. Two oil tests were drilled and abandoned in the area by independent operators.

Water was pumped from the Mt. Simon Sandstone while water levels were recorded in observation wells completed in strata above the caprock. The pumping tests indicated that there was no communication between the Mt. Simon and the overlying Galesville Sandstone.

The Herscher-Northwest structure is a doubly plunging anticline that trends slightly west of north (fig. 21). It is slightly asymmetrical, with distinctly steeper west and southwest flanks. The structure has 58 feet of closure on top of the Mt. Simon.

The reservoir is in the Mt. Simon Sandstone, an aquifer with an average porosity of 15 percent and an average permeability of 82 millidarcys. Some gas is also stored in the overlying Elmhurst Sandstone Member of the Eau Claire Formation. The Elmhurst is only 12 feet thick and consists of sandstone with a few interbeds of shale. The caprock is 161 feet of shale, dolomite, and siltstone assigned to the Lombard Member of the Eau Claire. The reservoir is 2,200 feet deep and covers more than 3,000 acres. The ultimate capacity of the project is estimated to be 17 billion cubic feet of gas.

The injection-withdrawal wells were cased with 5 1/2-inch casing into the Mt. Simon. The casing was perforated adjacent to the reservoir. Gas was first injected at Herscher-Northwest in 1968, and the project became operational in 1970 (table 15). There are at present 14 injection-withdrawal wells, 12 observation wells, and 1 water recycling well.

TABLE 15 — INJECTION AND WITHDRAWAL HISTORY OF HERSCHER-NORTHWEST PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory (end of year)	Peak daily withdrawal
1968	1,441	—	1,441	—
1969	2,496	—	3,937	—
1970	1,899	61	5,743	14
1971	3,275	405	8,613	29
1972	3,551	1,669	10,496	34

Hillsboro Project

Operator: Illinois Power Company
Location: T. 9 and 10 N., R. 3 W., Montgomery County

Gas for the Hillsboro project comes from the Natural Gas Pipeline Company of America. The gas is transported from existing pipelines of the Illinois Power Company's distribution system through a 12-inch pipeline to the Hillsboro field. Gas withdrawn will be used primarily in the Hillsboro-Granite City area.

In 1960 a review of information in the files of the Illinois State Geological Survey by the Illinois Power Company indicated the possible presence of a structure suitable for storage of gas in the Hillsboro area. Seven structure tests were drilled to the Ste. Genevieve Limestone in 1969. During 1970, the St. Peter Sandstone was tested by the deepening of an existing well and the drilling of another well to the St. Peter. In 1971 a deep well was drilled to the Eau Claire Formation. No Galesville Sandstone was encountered, and the well was plugged back to the St. Peter. Water pump tests were conducted in 1970 and 1971. Water was withdrawn from the St. Peter at rates high enough to indicate that the sandstone had adequate porosity and permeability to serve as a reservoir for gas storage. During the pumping of water from the St. Peter Sandstone, observation wells showed a small response in the overlying Joachim Formation but no response in the shallower Silurian-Devonian strata.

The Hillsboro structure is a dome with about 100 feet of closure on the top of the St. Peter (fig. 22). The storage reservoir is the St. Peter Sandstone, an aquifer with an average porosity of 16 percent and an average permeability of 250 millidarcys. The St. Peter is 100 to 160 feet thick in the area and is about 3,150 feet below the surface. The reservoir underlies 4,000 acres within the last closed contour. Although current plans are to store about 5.7 billion cubic feet, the storage may be expanded in the future. The ultimate capacity of the project is calculated to be more than 30 billion cubic feet.

The principal caprock is the Joachim Formation, a unit of limestone, dolomite, sandstone, and shale which is 150 feet thick and immediately overlies the St. Peter. Overlying the Joachim is 360 feet of limestone assigned to the Platteville and Galena Groups. Overlying the Galena is a secondary caprock, which consists of 210 feet of shale assigned to the Maquoketa Group.

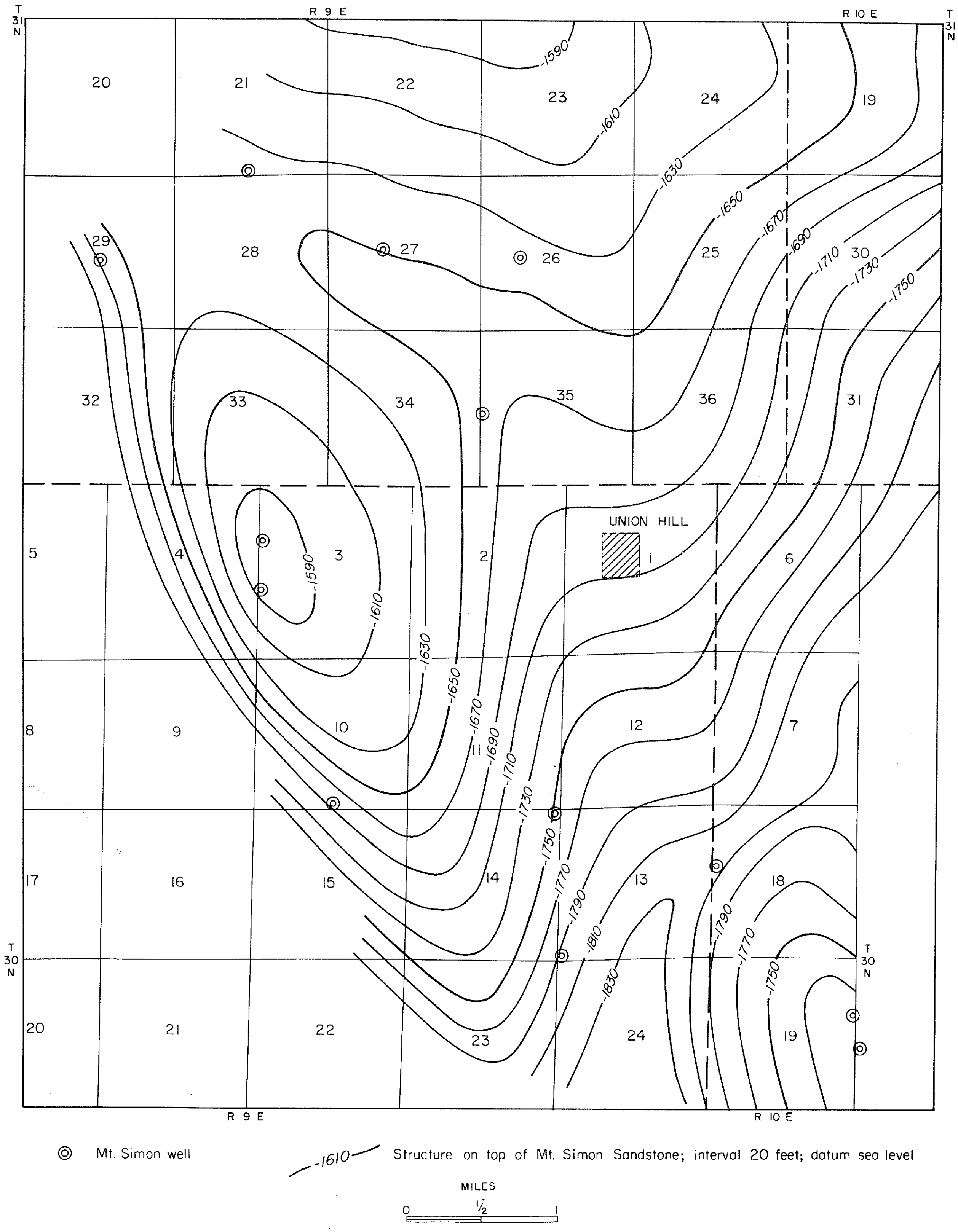

Fig. 21 - Top of Mt. Simon Sandstone at Herscher-Northwest, Kankakee County (Buschbach and Bond, 1967; original map by Natural Gas Pipeline Co. of America).

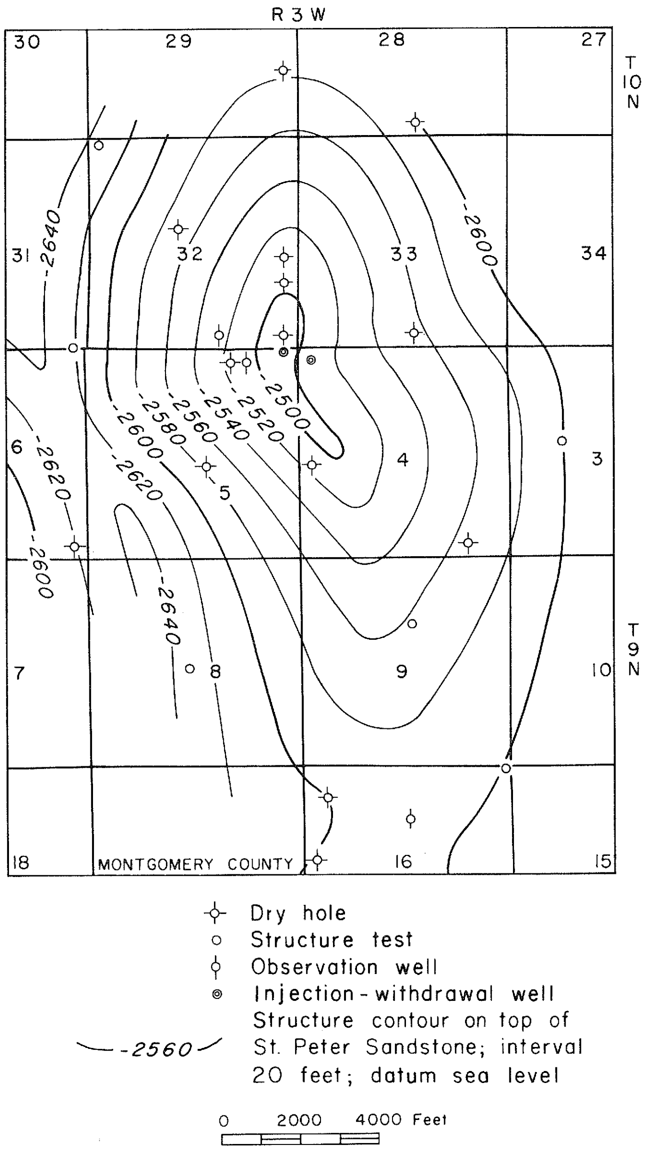

Fig. 22 - Top of St. Peter Sandstone at Hillsboro, Montgomery County (Illinois Power Co.).

The Hillsboro project has eight wells. Three of the wells are completed in the St. Peter Sandstone. These wells were cased through the St. Peter with 5 1/2-inch production casing, which was perforated adjacent to the reservoir. The maximum injection pressure is expected to be 150 psig above hydrostatic pressure.

Hookdale Project

Operator: Illinois Power Company
Location: 7 miles south and 2 miles east of Greenville, T. 4 N., R. 2 W., Bond County

Gas for the Hookdale project comes from Natural Gas Pipeline Company of America through the nearby 12-inch distribution lines of Illinois Power Company and an 8-inch line to the project. The gas is consumed in the area east of East St. Louis.

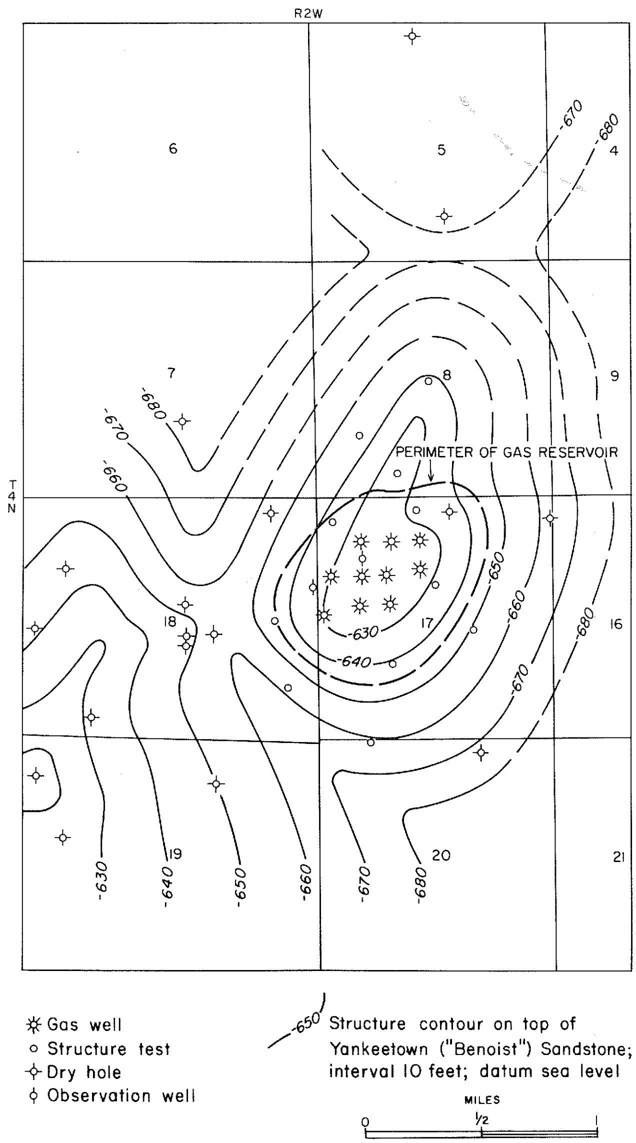

Fig. 23 - Top of Yankeetown ("Benoist") Sandstone at Hookdale, Bond County (Buschbach and Bond, 1967; original map by Illinois Power Co.).

This reservoir is a former gas field, discovered in 1961. It was acquired and developed for gas storage in 1962 and 1963, with injections and withdrawals beginning in 1963. The reservoir is a combination structural and stratigraphic trap in the Yankeetown ("Benoist") Sandstone of Mississippian age. The sandstone has an average porosity of 20.3 percent and an average permeability of 458 millidarcys. It is 1,125 feet deep. The reservoir has 28 feet of closure and covers 414 acres (fig. 23). The caprock consists of shale of Mississippian age.

At the end of 1972, the reservoir contained 902 million cubic feet of gas (table 16). Ten wells are used for injection and withdrawal of gas, and four wells are used for observation. Wells were drilled to about 40 feet below the gas-water contact. Production casing, 4 1/2 or 5 1/2 inches in diameter, was cemented from total depth to surface and perforated opposite the producing zone with four shots per foot.

TABLE 16 — INJECTION AND WITHDRAWAL HISTORY OF HOOKDALE PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory* (end of year)	Peak daily withdrawal
1963	83	109	46	29
1964	638	610	513	23
1965	596	596	513	26
1966	629	756	512	30
1967	793	818	357	25
1968	633	524	466	21
1969	621	551	534	24
1970	643	524	650	30
1971	695	579	765	32
1972	812	960	617	34

*Working gas.

Normal injection pressure is 300 to 450 psig. Open-flow potential of the wells ranges from 2.5 to 32 MMcf per day with an average of 13.8 MMcf per day.

Hudson Project

Operator: Northern Illinois Gas Company
Location: T. 24 and 25 N., R. 2 and 3 E., McLean County

Gas for the Hudson project is purchased from the Natural Gas Pipeline Company of America. The gas is transported through a 10-inch main which services the City of Normal and through a 12-inch main to the Hudson compression station. A market line transports gas withdrawn from Hudson to the Lake Bloomington market line; this gas is used in the suburban Chicago area.

The Hudson structure was located by a series of test holes drilled to the Springfield (No. 5) Coal Member (Pennsylvanian). The structure was further defined by the drilling of 34 additional structure tests to the Devonian or deeper. To determine the suitability of caprock and reservoir, a total of 10 deep holes were drilled. Nine of the wells reached the Mt. Simon Sandstone and one well was drilled into the Eau Claire.

The Hudson structure is a dome with 160 feet of closure on top of the Mt. Simon Sandstone (fig. 24). The storage reservoir is the Mt. Simon Sandstone, an aquifer with an average porosity of 11 percent and an average horizontal permeability of 45 millidarcys. The Mt. Simon is estimated to be 2,000 feet thick in the area, but only the upper 160 feet will be used as a storage reservoir. The reservoir is about 3,800 feet below the surface, and the leased area covers 13,200 acres. The ultimate capacity of the reservoir is calculated to be 235 billion cubic feet, but only 100 billion cubic feet of this capacity will be used in the foreseeable future. The latter figure will be carried in our tables as the ultimate capacity of this project until decisions are made by the operator to utilize more of the capacity.

The caprock is the Eau Claire Formation, which is 450 feet thick. It consists of siltstone and shaly sandstone at the top; shale, dolomite, and thin sandstone layers in the middle; and about 45 feet of fine-grained, shaly sandstone at the base. Water pumping tests gave no evidence of communication across the Eau Claire caprock when water was pumped from the Mt. Simon. The tests were interpreted to indicate that at least some beds in the Eau Claire are essentially impermeable.

The Hudson project has 12 wells completed for injection and withdrawal, and 7 wells completed as observation wells. The injection-withdrawal wells have been cased through the upper part of the Mt. Simon with 5 1/2-inch production casing which was perforated adjacent to the reservoir. The maximum bottom-hole pressure anticipated during injection of gas is 2,050 psia. Injection began on an experimental basis in 1970, and full-scale injection started in 1971 (table 17).

TABLE 17 — INJECTION AND WITHDRAWAL HISTORY OF HUDSON PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory (end of year)	Peak daily withdrawal
1970	118	0	118	0
1971	2,211	119	2,329	16
1972	4,080	33	6,237	16

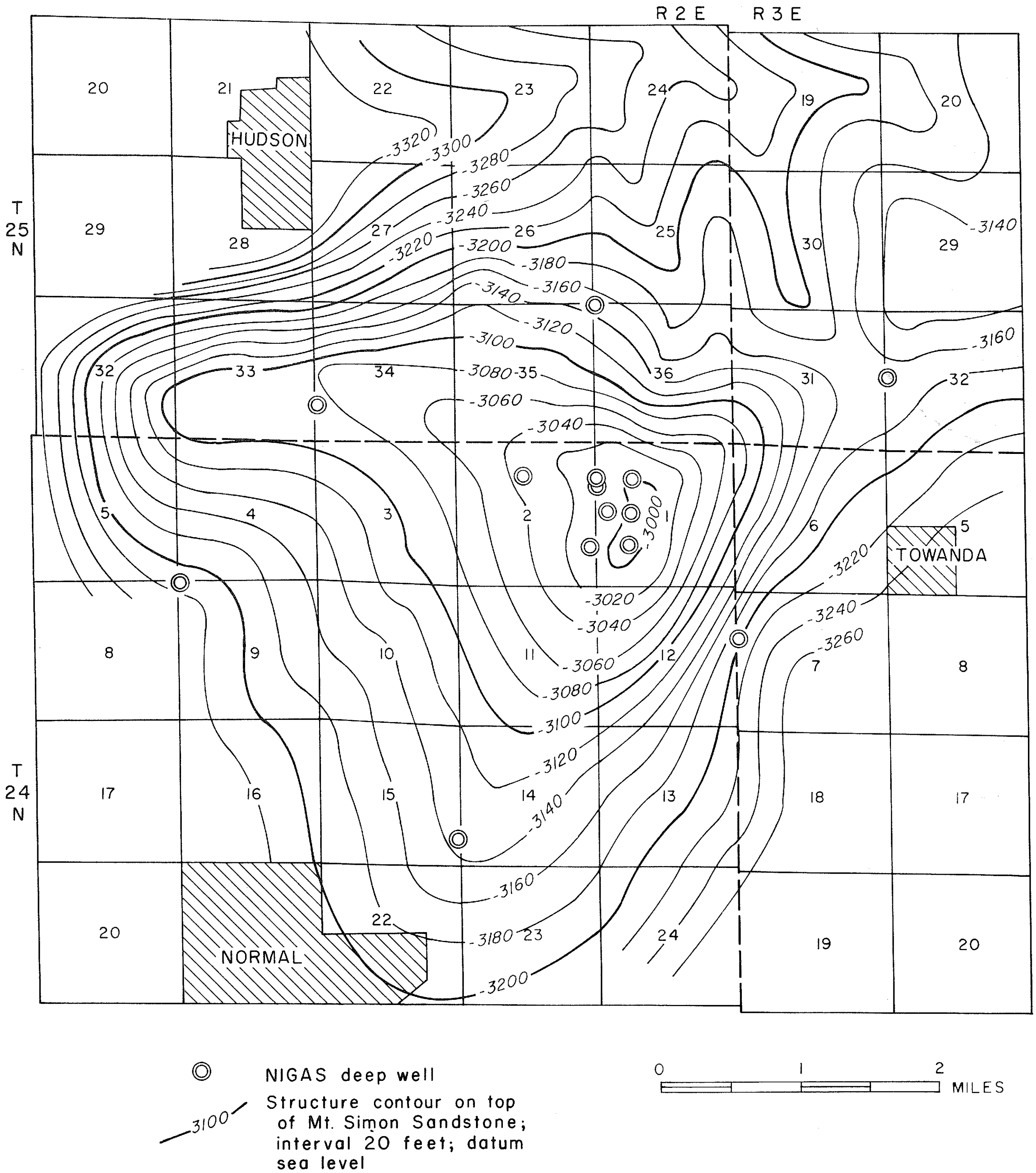

Fig. 24 - Top of Mt. Simon Sandstone at Hudson, McLean County (Northern Illinois Gas Co.).

Experimental withdrawals began in 1971, and the project was declared operational at the end of that year.

Hume Project

Operator: Peoples Gas Light and Coke Company
Location: T. 16 N., R. 13 and 14 W., Edgar County

The Hume project is in the process of being tested. During the testing of the reservoir, as much as 10 million cubic feet of gas per day will be supplied by Panhandle Eastern Pipeline Company, through an exchange agreement among Panhandle, Peoples Gas Light and Coke Company, and Midwestern Gas Transmission Company. The gas will be taken from a point on Panhandle's transmission line 2 miles west of the village of Hume, through 4 1/2 miles of 8-inch line to the Hume storage field. If the project proves to be feasible, a transmission line will be constructed from Hume to the transmission system of either Midwestern Gas Transmission Company or the Natural Gas Pipeline Company of America. Gas from the Hume project will ultimately be consumed in the Chicago area.

The presence of an anticline near the town of Hume was established in 1971 by subsurface geologic investigations and by the drilling of several structure tests. Twenty-three structure tests were drilled to delineate the structure, and nine other holes were drilled to test the potential reservoirs and caprocks. Two of these latter holes reached the St. Peter Sandstone, five penetrated the Devonian, one reached the Mississippian, and one reached the Pennsylvanian. All nine wells were cased and used in water pump tests.

In the pumping tests, water was withdrawn from the proposed Devonian reservoir. No response was seen in water levels of the observation wells that had been completed in Mississippian and Pennsylvanian strata above the New Albany caprock. This lack of response indicated that the caprock is essentially impervious.

The Hume structure is an asymmetrical anticline with 120 feet of closure on top of the Middle Devonian carbonates (fig. 25). There are about 6,500 acres included within the last closing contour.

The reservoir is 650 feet deep and consists of 130 feet of Grand Tower, a dolomite with an average porosity of 15 percent, and 50 feet of Lingle, a limestone with an average porosity of

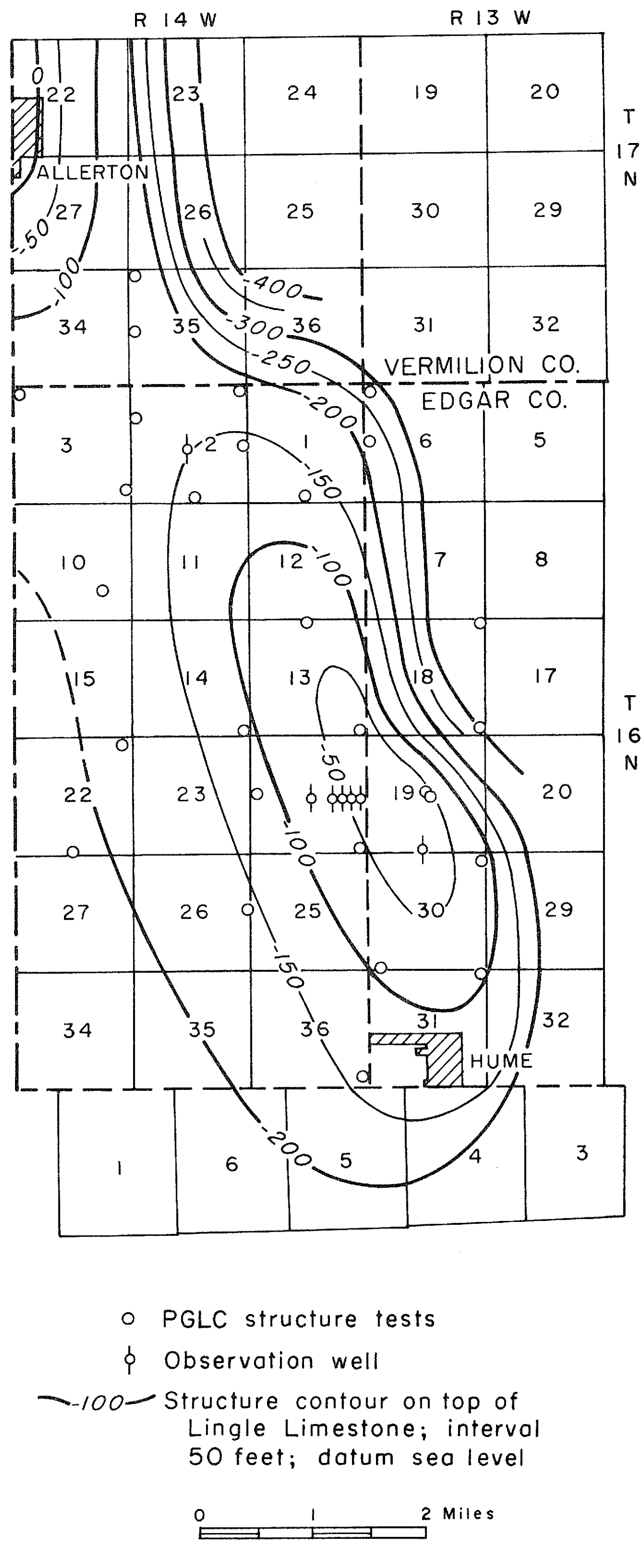

Fig. 25 - Top of Lingle Limestone at Hume, Edgar County (Peoples Gas Light and Coke Co.).

6 percent. Slight shows of non-commercial oil were detected in the reservoir rock; however, the reservoir is essentially water-saturated and is considered an aquifer. The ultimate capacity of the reservoir is estimated to be 4 billion cubic feet.

By the end of 1972, nine wells had been drilled and completed in the Devonian strata at Hume. The wells are cased through the reservoir and the casing is perforated opposite the storage zone. The injection pressure is not to exceed 400 psig.

Lake Bloomington Project

Operator: Northern Illinois Gas Company
Location: T. 25 and 26 N., R. 2 and 3 E., McLean County

Gas for the Lake Bloomington project comes from the Natural Gas Pipeline Company of America's pipeline by way of a 10-inch pipeline which services the City of Normal, and through a 12-inch pipeline to the Lake Bloomington field. Gas withdrawn from this project is sent through a market line from Lake Bloomington to Northern Illinois Gas Company's Pontiac storage project and on to the suburban Chicago area.

The Lake Bloomington structure was located by a series of test holes drilled to the Springfield (No. 5) Coal Member (Pennsylvanian). The structure was further delineated by the drilling of 52 structure tests to the Devonian strata or deeper. To determine the suitability of the caprock and reservoir, a total of 12 deep holes were drilled into the Mt. Simon and Eau Claire Formations.

The Lake Bloomington structure is a north-south-trending anticline about 4 1/2 miles long and 2 3/4 miles wide. It has about 100 feet of closure on top of the Mt. Simon (fig. 26).

The storage reservoir is in the Mt. Simon Sandstone, an aquifer with an average porosity of 11 percent and an average permeability of 45 millidarcys. The reservoir is 3,525 feet deep. The leased area of this project covers about 10,600 acres. The ultimate capacity of the structure is estimated to be 100 billion cubic feet, about 45 percent of which will be working gas.

The caprock is the Eau Claire Formation, which is 450 feet thick. The upper 300 feet of Eau Claire consists of shaly and dolomitic siltstone and fine-grained sandstone; the lower 150 feet is chiefly dense shale, interbedded with dolomite and fine-grained sandstone. Core analyses of the Eau Claire and water swabbing tests from the Mt. Simon were interpreted to indicate that the Eau Claire caprock is essentially impermeable.

The Lake Bloomington project has 23 wells completed for injection and withdrawal and 12 wells completed for observation. The operational wells are cased to total depth with 5 1/2-inch production casing, which has been perforated opposite the storage zone. The maximum bottom-hole pressure anticipated during injection is 1,980 psia, or about 400 psia above native pressure of the upper part of the Mt. Simon. Injection of gas into the reservoir began in 1969, and withdrawals were made in 1970 (table 18). The project became operational in 1972.

TABLE 18 — INJECTION AND WITHDRAWAL HISTORY OF LAKE BLOOMINGTON PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory (end of year)	Peak daily withdrawal
1969	565	0	565	0
1970	3,767	127	4,205	10
1971	9,689	0	13,894	0
1972	11,226	1,726	23,491	94

Lexington Project

Operator: Northern Illinois Gas Company
Location: About 2 miles west of Lexington, T. 25 N., R. 3 and 4 E., McLean County

Gas for the Lexington project comes from Natural Gas Pipeline Company of America and is delivered to the Northern Illinois Gas Company at its Pontiac station. From Pontiac the gas is transported to Northern Illinois Gas Company's Lake Bloomington field through a 36-inch pipeline. A 6-inch pipeline from the Lexington field connects with the 36-inch main at a point 4 miles north of Lexington. A market line for withdrawn gas joins the market line of the Lake Bloomington project which delivers gas to Pontiac and on to the suburban Chicago area.

The Lexington Dome was located by a series of test holes drilled to the Springfield (No. 5) Coal Member (Pennsylvanian). The structure was further delineated by the drilling of 27 structure tests to the Devonian or deeper. To determine the suitability of the caprock and reservoir, a total of eight deep holes were drilled. Seven of the wells reached the Mt. Simon

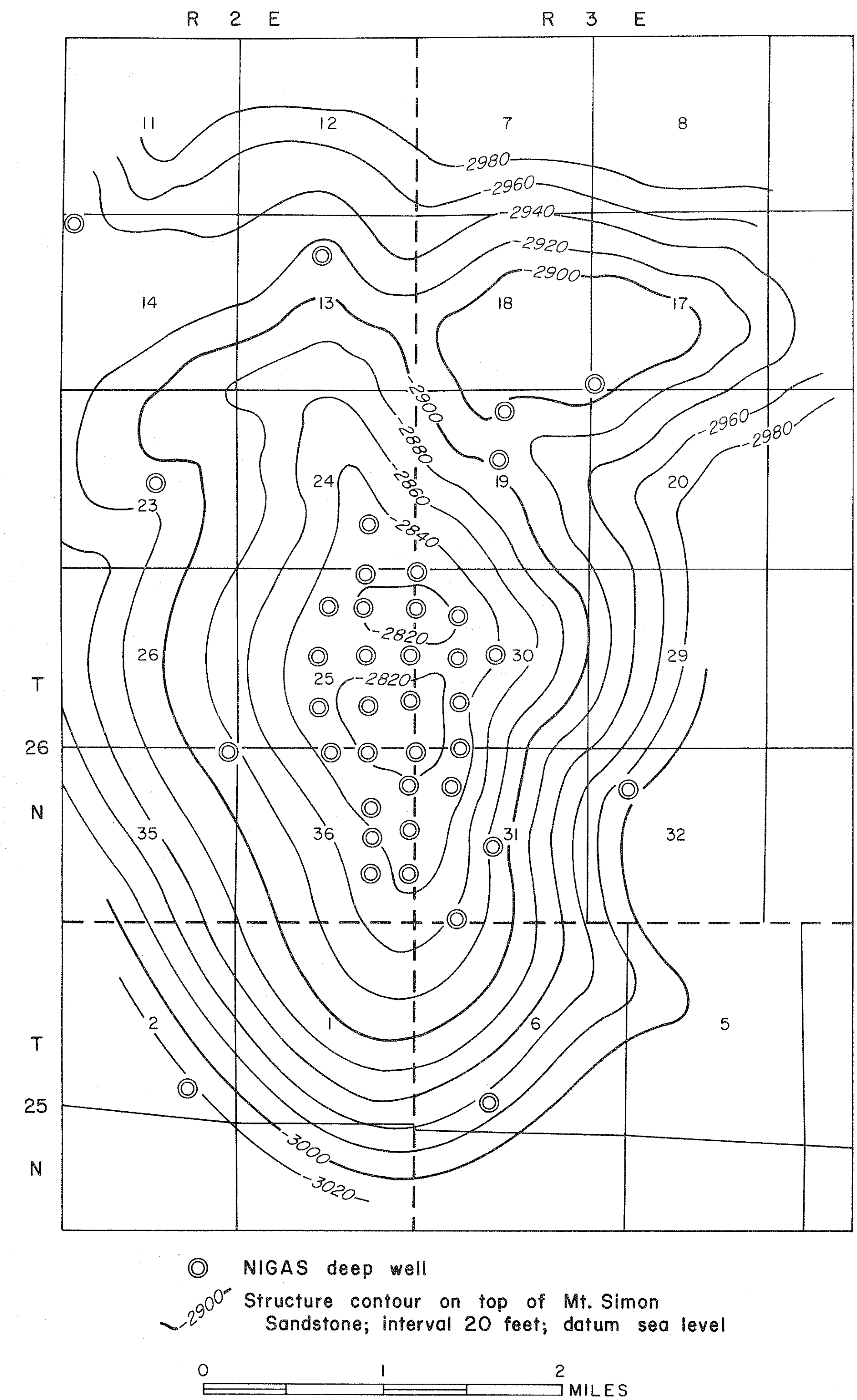

Fig. 26 - Top of Mt. Simon Sandstone at Lake Bloomington, McLean County (Northern Illinois Gas Co.).

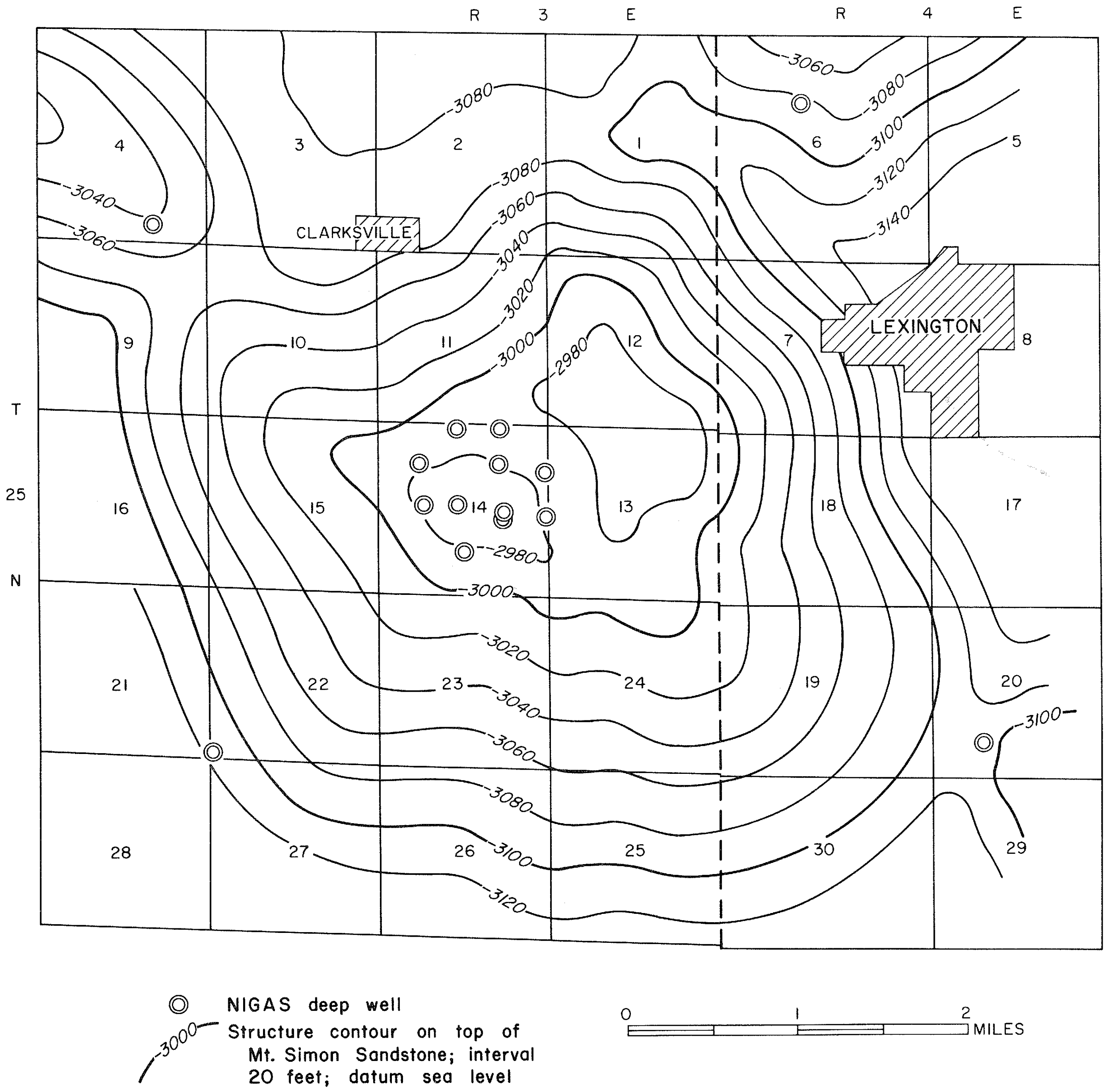

Fig. 27 - Top of Mt. Simon Sandstone at Lexington, McLean County (Northern Illinois Gas Co.).

Sandstone, and one well reached the Eau Claire but was completed in the Galesville Sandstone.

The Lexington structure is a rather symmetrical dome with about 100 feet of closure (fig. 27). The reservoir is the Mt. Simon Sandstone, an aquifer with an average porosity of 11 percent and an average horizontal permeability of 37 millidarcys. The Mt. Simon is estimated to be 2,000 feet thick, but only the upper 100 feet will be used for storage. The reservoir is 3,700 feet below the surface, and the leased area covers 14,300 acres. The ultimate capacity of the structure is about 200 billion cubic feet; however, it is anticipated that only about 100 billion cubic feet of this capacity will be used in the foreseeable future.

The caprock is the Eau Claire Formation, which is 470 feet thick. It is divided into three members. An upper unit, the Proviso Member, consists of about 295 feet of fine-grained dolomitic sandstone and siltstone with interbedded shales. A middle unit, the Lombard Member, is about 130 feet thick and consists of slightly silty grayish green shale with some thin dolomite and sandstone interbeds. The lower unit, the Elmhurst Member, is about 45 feet thick and is composed of shaly sandstone.

Water swabbing tests gave no evidence of communication across the Eau Claire caprock when water was being swabbed from the Mt. Simon.

The Lexington project has eight wells completed for injection and withdrawal, and five wells completed as observation wells. The operational wells have been cased through the upper part of the Mt. Simon with 5 1/2-inch production casing, which was perforated adjacent to the reservoir. The maximum injection pressure (bottom-hole) anticipated is 2,025 psia. Injection tests began in 1971, and the project became operational late in 1972 (table 19).

TABLE 19 — INJECTION AND WITHDRAWAL HISTORY OF LEXINGTON PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory (end of year)	Peak daily withdrawal
1971	329	0	329	0
1972	1,956	73	2,286	14

Lincoln Project

Operator: Central Illinois Light Company
Location: 4 miles west-southwest of Lincoln, T. 19 N., R. 3 W., Logan County

Gas for the Lincoln project comes from Panhandle Eastern Pipeline Company's main, through an 18-inch feeder line to the project. The gas will be consumed in the Lincoln-Peoria area.

Prior to 1967, 10 oil and gas test wells had been drilled within a 4-mile radius of the crest of the Lincoln Dome. The dome was shown on maps by the Illinois State Geological Survey (Whiting and Stevenson, 1965). In 1967, Northern Illinois Gas Company drilled and cored three wells through the Silurian strata on the structure. In 1971 Central Illinois Light Company acquired storage rights in the Lincoln reservoir. They drilled a total of 22 structure tests for delineation of the dome, and they drilled 5 wells for injection, withdrawal, and observation.

The Lincoln structure is a slightly asymmetrical dome almost 2 miles wide and 3 miles long with about 85 feet of closure on top of the Silurian (fig. 28). The reservoir is dolomite of Silurian age, an aquifer that had some showing of heavy oil; the oil could not be commercially produced. The Silurian strata consist of dense to vuggy, partly fractured dolomite that is about 250 feet thick. The average porosity of the carbonate is 12 percent and the average permeability is 250 millidarcys. The reservoir is 1,300 feet deep and

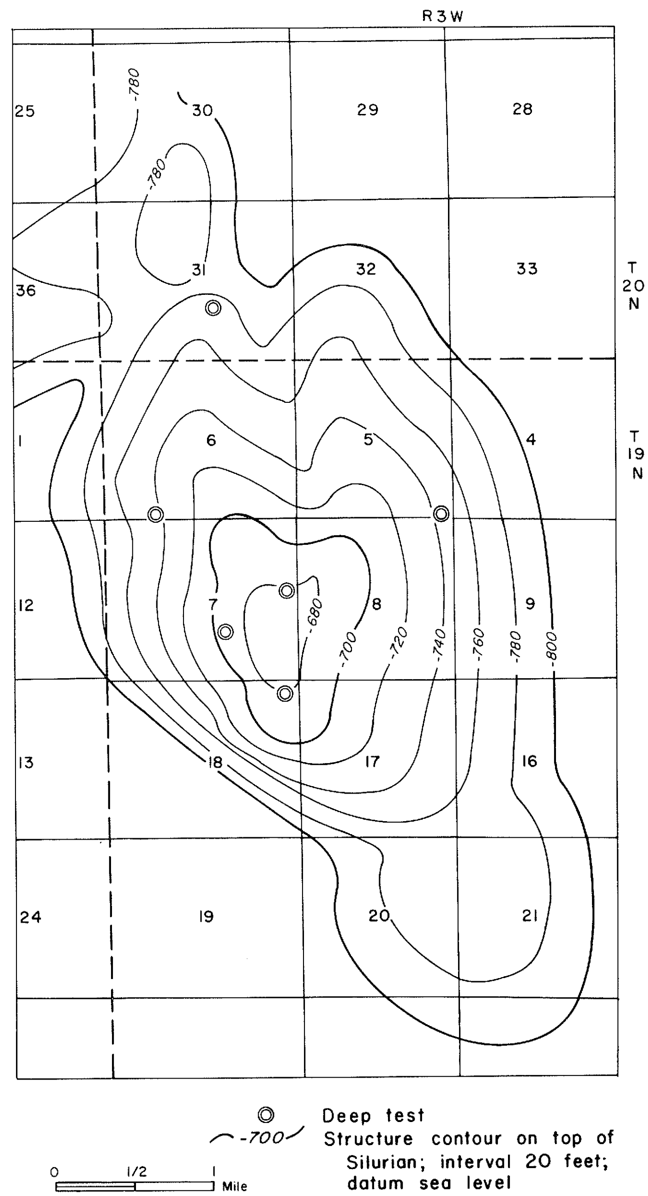

Fig. 28 - Top of Silurian at Lincoln, Logan County (Central Illinois Light Co.).

covers about 3,000 acres within the closing contours. The ultimate capacity of the project is estimated to be 17 billion cubic feet of gas.

The caprock is slightly more than 200 feet of shale assigned to the New Albany Group. The shale immediately overlies the Silurian strata. Pumping tests from the Silurian indicated that the overlying New Albany was a satisfactory caprock. Similar tests performed on the deeper St. Peter Sandstone at Lincoln suggested that the Joachim Formation, immediately overlying the St. Peter, might not be a satisfactory caprock.

Eight injection-withdrawal wells and 14 observation wells have been completed. The operational wells have been cased through the reservoir and perforated. However, a new well will use an open-hole completion for comparison of performances.

The Lincoln project is in early stages of testing and development (table 20).

TABLE 20 — INJECTION AND WITHDRAWAL HISTORY OF LINCOLN PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory (end of year)	Peak daily withdrawal
1971	209	0	209	0
1972	1,943	0	2,150	0

Loudon Project

Operator: Natural Gas Pipeline Company of America
Location: T. 7, 8, and 9 N., R. 3 E., Fayette County

The Loudon project is the only former oil reservoir used for gas storage in Illinois. Gas for the project comes from Natural Gas' main supply line from the Gulf Coast to Chicago by way of 4 miles of 30-inch pipeline between Loudon and the transmission line.

The Loudon field was discovered in 1937. It has produced about 350 million barrels of oil from strata of Mississippian, Devonian, and Ordovician age. Oil production from Mississippian rocks continues to this date; it results chiefly from waterflood operations. About 100 wells to the Devonian Grand Tower were recompleted with new casing after Natural Gas Pipeline Company acquired the storage rights at Loudon.

The Loudon structure is an anticline, 14 miles long and more than 4 miles wide, that trends northeast-southwest. The anticline has 146 feet of closure on top of the Grand Tower (fig. 29). About 24,000 acres are included within the closing contours; however, only 2,610 acres at the crest of the anticline will be used for storage.

The reservoir is the Grand Tower, a dolomite that is 65 feet thick and has an average porosity of 15 percent. The reservoir is 3,050 feet below the surface. It originally contained oil; 19.5 million barrels were produced before storage operations began. About 200,000 barrels of oil have been produced since the first injection of gas.

Overlying the Grand Tower is the Cedar Valley, a dense limestone that is 85 feet thick. Above the Cedar Valley is the ultimate caprock, a little more than 100 feet of shale assigned to the New Albany Group.

There are 50 injection-withdrawal wells and 73 observation wells completed at the Loudon project. There are also 21 wells completed for other purposes such as water recycling. The wells were completed by casing through the Grand Tower, cementing the casing, and perforating it opposite the porous zones.

Injection of gas began in 1967, and test withdrawals were made in 1968 (table 21). The Loudon project became operational in 1969.

TABLE 21 — INJECTION AND WITHDRAWAL HISTORY OF LOUDON PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory (end of year)	Peak daily withdrawal
1967	3,190	0	3,190	0
1968	9,521	990	11,767	63
1969	8,096	4,031	15,832	107
1970	15,955	5,392	26,384	151
1971	17,398	11,355	32,427	230
1972	19,509	13,643	38,292	296

Manlove (formerly Mahomet) Project

Operator: Peoples Gas Light and Coke Company
Location: 5 miles north of Mahomet, T. 21 N., R. 7 E., Champaign County

Gas for the Manlove (formerly Mahomet) project is supplied by Natural Gas Pipeline Company of America through 7 miles of 30-inch pipeline. The gas is consumed in Chicago.

During a detailed exploration program along the La Salle Anticline, the Union Hill Gas Storage Company, a subsidiary of Peoples Gas Light and Coke Company, confirmed the presence of a domal structure in the northwestern corner of Champaign County. A total of 24 structure tests

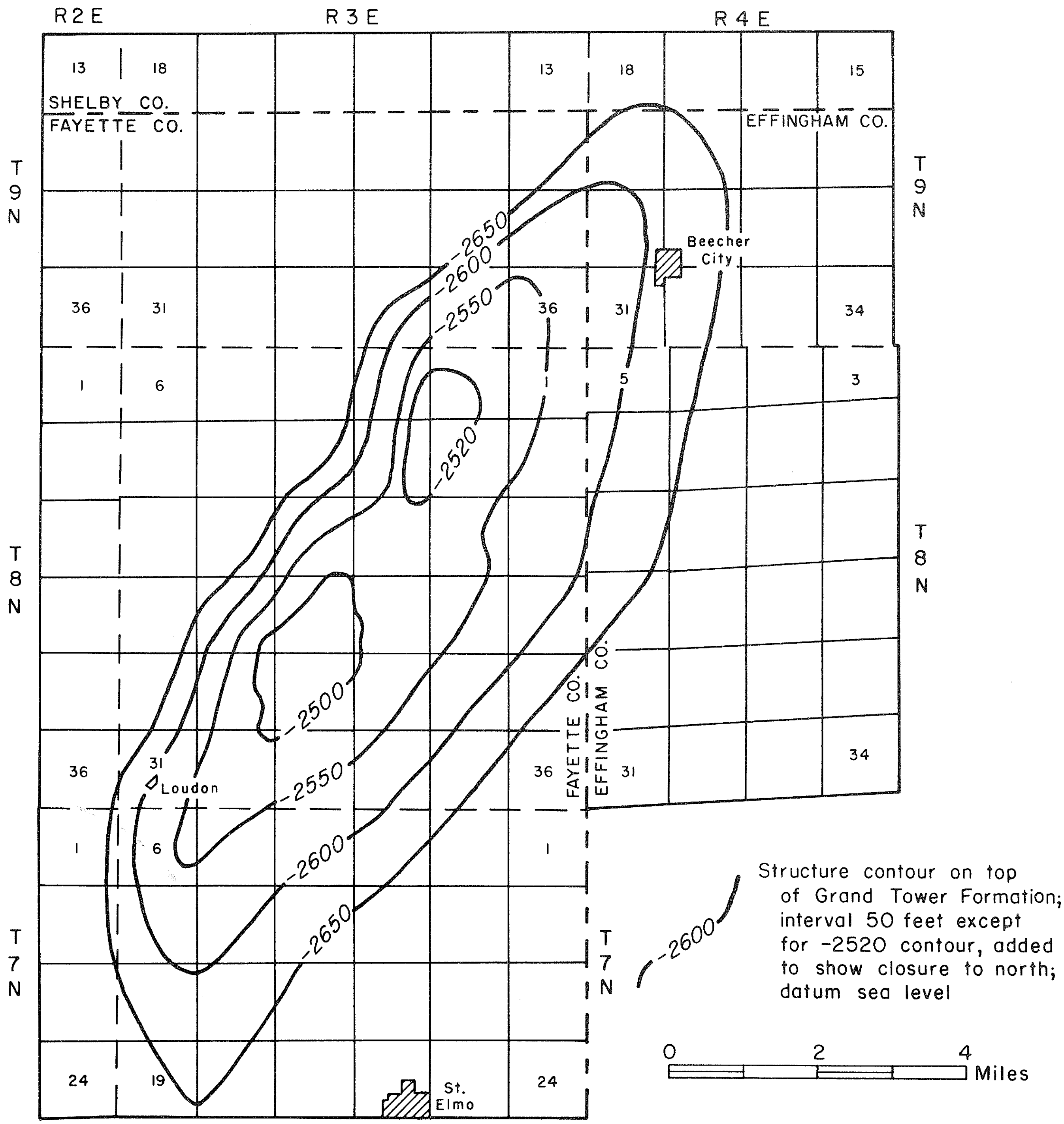

Fig. 29 - Top of Grand Tower Formation at Loudon, Fayette County (Natural Gas Pipeline Co. of America).

were drilled to the top of the Galena Group in 1959 and 1960. Injection into the St. Peter Sandstone began in 1961 (table 2). In early August 1961, gas was discovered migrating from the St. Peter to the glacial drift south of the crest of the structure. Gas injection into the St. Peter was discontinued on August 21, 1961.

Shallow vent wells were drilled in the area of leakage to prevent the accumulation of gas. Test holes were drilled within the bubble area in an attempt to locate the source of leakage. The cement around the casing on each injection well was tested, and tracers were injected into selected wells to determine areas of leakage. All of the tests were inconclusive; the location and nature of the leakage have not been determined.

In 1963, gas containing propylene as a tracer was injected into the Galesville Sandstone. After one month of injection, it was apparent that the gas was migrating upward into the St. Peter Sandstone. At about the same time, water analyses and pumping tests indicated a lack of communication between the Mt. Simon Sandstone and strata overlying the Eau Claire caprock. The Mt. Simon, therefore, was chosen as the ultimate reservoir.

The trap is an anticline, 7 miles long and 6 miles wide, that trends north-south (fig. 30). The reservoir is in the Mt. Simon Sandstone, an aquifer with an average porosity of 11 percent and an average permeability of 15 millidarcys. The caprock is 100 feet of shaly beds in the overlying Eau Claire Formation.

The structure has more than 120 feet of closure on top of the Mt. Simon. The reservoir is 3,950 feet deep and covers 23,000 acres within the last closing contour. The ultimate capacity of the reservoir is more than 100 billion cubic feet.

Seventy-six wells are used for injection and withdrawal from the Mt. Simon at Mahomet and 12 for observation. In the operational wells, 7-inch casing was set and cemented 500 feet into the Mt. Simon. The casing was perforated opposite the storage zone. Injection pressure is 1,650 psig. Injection of gas into the Mt. Simon began in 1964, and the underground storage project became operational in 1966 (table 22).

The underground storage capacity at Manlove is supplemented by a facility for liquefying natural gas and storing the liquefied natural gas (LNG). This facility has a storage capacity for 24 million gallons of LNG, equivalent to 2 billion cubic feet of gas measured in the gaseous state at standard temperature and pressure. The plant can liquefy gas at the rate of 10 million cubic feet per day, and it can vaporize LNG to produce gas at the rate of 300 million cubic feet per day.

TABLE 22 — INJECTION AND WITHDRAWAL HISTORY OF MANLOVE (MAHOMET) PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory (end of year)	Peak daily withdrawal
1964	440	0	440	0
1965	3,158	0	3,598	0
1966	8,945	178	12,249	22
1967	10,727	1,242	21,710	51
1968	12,585	2,255	32,035	200
1969	12,980	3,254	41,760	145
1970	16,141	6,534	51,652	223
1971	18,716	4,329	65,392	297
1972	21,122	16,403	70,111	354

Nevins Project

Operator: Midwestern Gas Transmission Company
Location: T. 12 and 13 N., R. 11 W., Edgar County

Gas for the Nevins project comes from Midwestern Gas Transmission Company's 30-inch line through the Elbridge storage project. A 10-inch feeder line connects the Nevins project to the Elbridge project. The line serves for both injection and withdrawal of gas.

The Nevins Dome was discovered during exploration for oil. Structure tests were drilled in 1961 and 1962, and injection of gas began in 1965. The first withdrawals were made in 1966 (table 23).

TABLE 23 — INJECTION AND WITHDRAWAL HISTORY OF NEVINS PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory (end of year)	Peak daily withdrawal
1965	1,682	0	1,682	—
1966	1,452	210	2,924	10
1967	2,942	663	5,203	26
1968	1,421	1,590	5,071	27
1969	1,332	1,113	5,281	21
1970	1,816	1,038	6,058	20
1971	1,737	1,482	6,313	29
1972	1,566	1,420	6,459	20

Gas is stored in porous dolomite and dolomitic limestone beds of the Grand Tower Formation. The trap is a structural dome caused by draping of Devonian and younger strata over a Silurian reef (fig. 31). Similar structures are present at the Elbridge and State Line storage projects. The caprock is 90 feet of shale of the New Albany

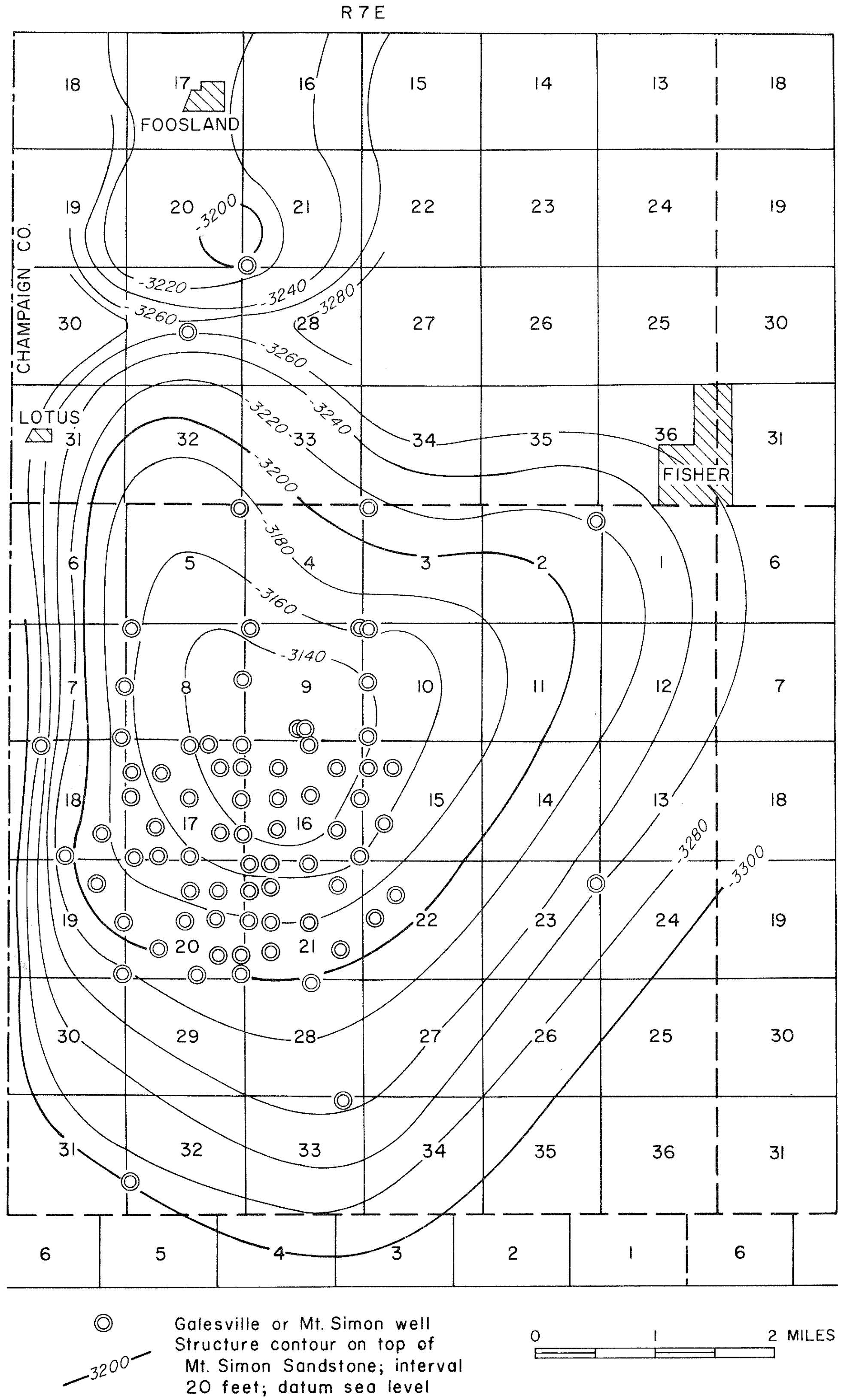

Fig. 30 - Top of Mt. Simon Sandstone at Manlove (Mahomet), Champaign County (Peoples Gas Light and Coke Co.).

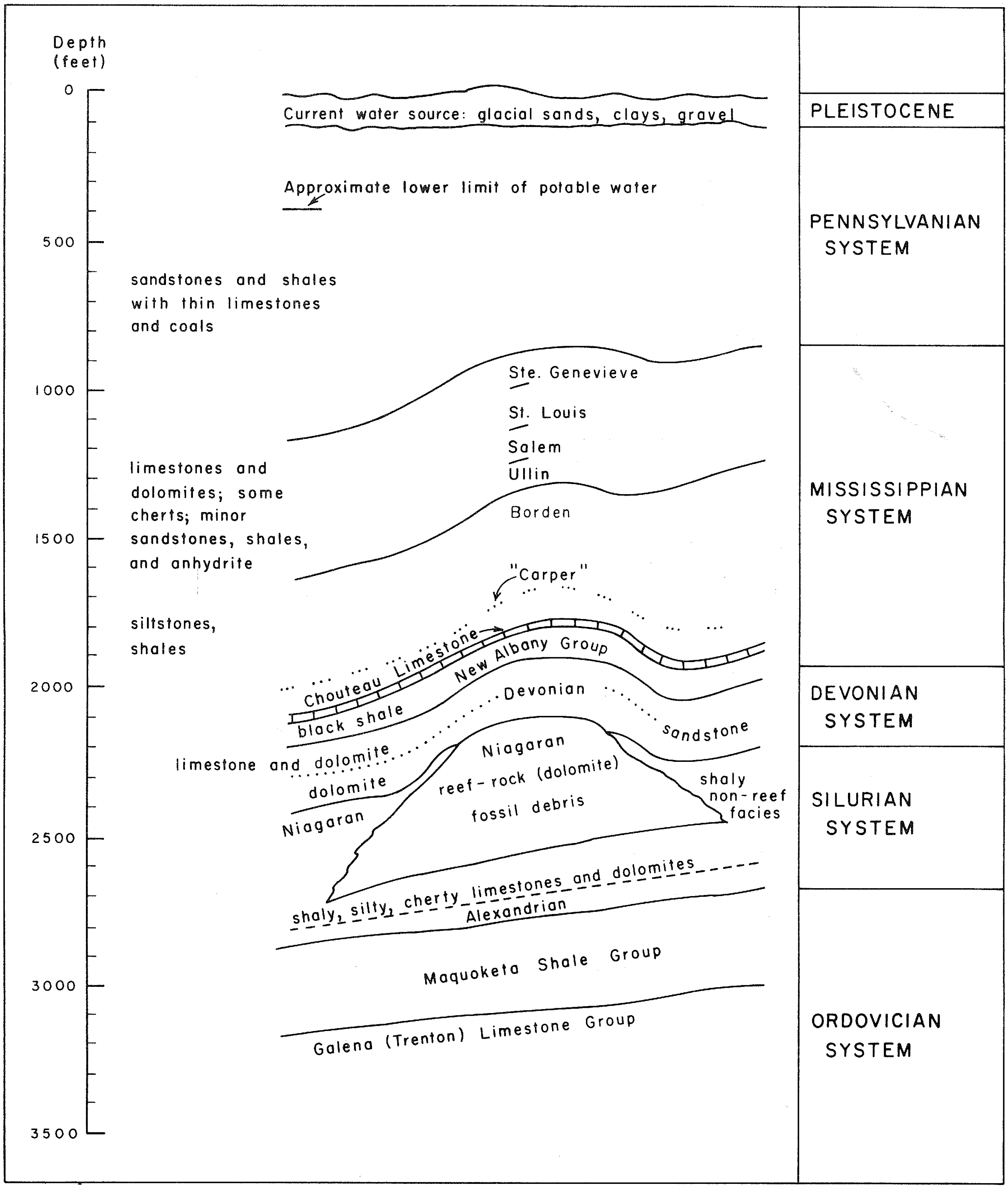

Fig. 31 - Generalized cross section showing draping of strata over a Silurian reef at Nevins, Edgar County (after a drawing prepared by E. N. Wilson for testimony presented to Illinois Commerce Commission, Docket No. 48793).

Group, which overlies the dolomite and limestone reservoir.

The Nevins Dome has 105 feet of closure on top of the Grand Tower and covers 1,650 acres (fig. 32). The reservoir, an aquifer, has an average porosity of 16.5 percent and an average permeability of 25 millidarcys. It is 1,975 feet deep. The ultimate capacity of the Nevins project is estimated to be 6.7 billion cubic feet of gas.

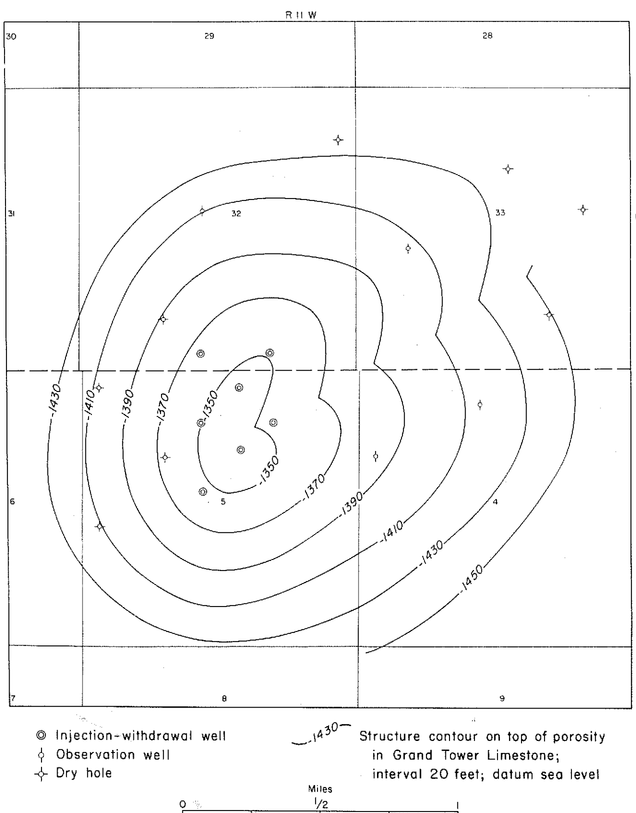

Fig. 32 - Top of porosity in Grand Tower Limestone at Nevins, Edgar County (Buschbach and Bond, 1967; original map by Midwestern Gas Transmission Co.).

Nevins has 14 injection and withdrawal wells and 7 observation wells. The operational wells have 4 1/2-inch casing set and cemented 30 feet into the storage formation. The casings are perforated with four shots per foot opposite the top 25 feet of porosity. Packers are run on 2 3/8-inch tubing and are set about 50 feet above the perforations. Gas is injected and withdrawn through the 2 3/8-inch tubing.

Normal injection pressure is 1,100 psig. Open-flow potentials of the wells range from 8.5 to 28 MMcf per day and average 15.2.

Pecatonica Project

Operator: Northern Illinois Gas Company
Location: T. 26 and 27 N., R. 10 E., Winnebago County

Gas for the Pecatonica project comes from Natural Gas Pipeline Company of America through 12-inch and 16-inch mains between Rockford and Freeport. Gas withdrawn from this project is used in the Rockford-Freeport area.

In 1965 Earth Science Laboratories, Cincinnati, Ohio, was retained by Central Illinois Electric and Gas Company to search for underground gas storage sites. The Pecatonica structure was first detected as a surface feature that influenced stream drainage in the area. It was investigated by the geophysical logging of 35 existing water wells. The structure was further delineated by the drilling of 78 structure tests, most of which reached the Glenwood Formation. In 1970 the Pecatonica project was transferred from the Central Illinois Electric and Gas Company to Northern Illinois Gas Company.

The Pecatonica structure is a northwest-southeast-trending anticline with about 38 feet of closure on top of the Glenwood and about 30 feet of closure on top of the reservoir (fig. 33). The structure covers 2,600 acres, but the leased area covers 6,400 acres.

The reservoir is a sandstone unit, 80 feet thick, in the Proviso Member of the Eau Claire Formation. The bed of sandstone, an aquifer, has been called "Lightsville sand" by Earth Science Laboratories and by Northern Illinois Gas Company. The reservoir has an average porosity of 18.6 percent and an average permeability of 556 millidarcys. It is about 800 feet below the surface. The estimated ultimate capacity of the reservoir is 3.0 billion cubic feet of gas.

The caprock is the upper part of the Proviso Member of the Eau Claire Formation. It consists of 63 feet of interlaminated siltstone, sandstone, and shale, which is overlain by 17 feet of shale. Water was swabbed from the "Lightsville sand," and water levels were observed in the "Lightsville" and in some porous beds of sandstone above the caprock. Results of the swabbing tests indicated that the "Lightsville" had good permeability and that there was no communication between the reservoir and the porous strata above the caprock.

Static water level measurements indicate that water is flowing from the spillpoint at the northwest end of the Pecatonica structure toward the southeast. This flow results in a tilted

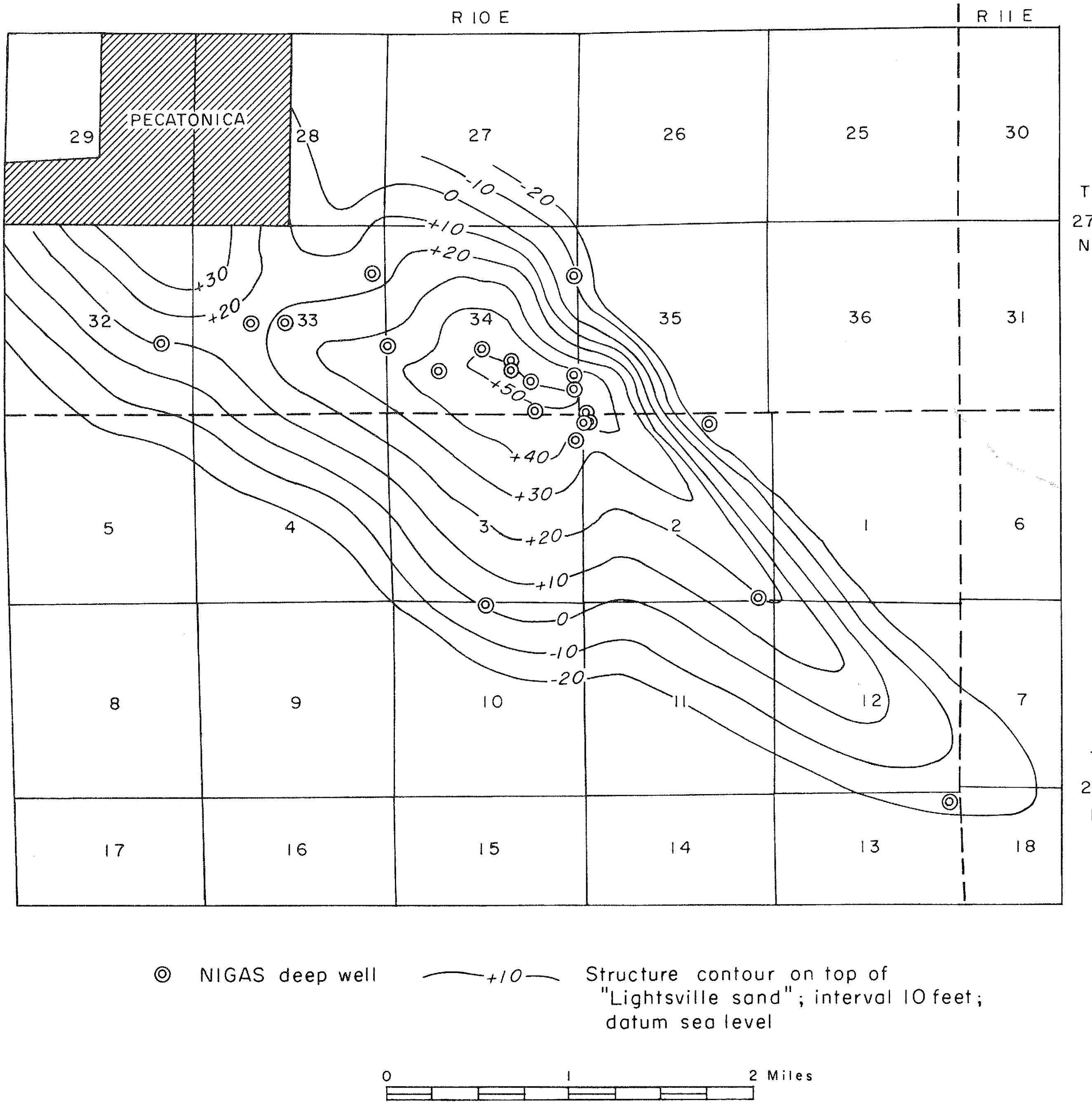

Fig. 33 - Top of "Lightsville sand" (Eau Claire Formation) at Pecatonica, Winnebago County (Northern Illinois Gas Co.).

gas-water interface, which adds to the effective closure and thereby increases the capacity of the reservoir (Burnett, 1967).

There are 7 injection-withdrawal wells and 15 observation wells completed on the structure. The operating wells were completed by setting 4 1/2-inch casing to total depth, cementing the casing, and perforating it adjacent to the reservoir. A 10-foot zone in the upper part of the reservoir was perforated with four shots per foot.

Maximum bottom-hole pressure will be 335 psia.

Injection of gas into the reservoir began in 1967, withdrawals in 1970 (table 24).

TABLE 24 — INJECTION AND WITHDRAWAL HISTORY OF PECATONICA PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory (end of year)	Peak daily withdrawal
1967	222	0	222	0
1968	612	0	821	0
1969	496	0	1,317	0
1970	673	174	1,910	14
1971	479	171	2,217	14
1972	538	96	2,660	15

Pontiac Project

Operator: Northern Illinois Gas Company
Location: Approximately 5 miles southeast of Pontiac, T. 27 and 28 N., R. 6 E., Livingston County

Gas for the Pontiac project comes from the trunkline of Natural Gas Pipeline Company of America through a 12-inch pipeline to the storage project. The gas is used in suburban Chicago areas.

Preliminary geologic exploration in the Pontiac area began in 1963. Northern Illinois Gas Company drilled 86 structure tests and 10 deep wells below the Ironton Sandstone to determine structural configuration and suitability for gas storage. Most of the structure tests were drilled to the Fort Atkinson (middle Maquoketa); however, 25 wells in the area reached the top of the Galena Group. Three experimental seismic profiles were run across the structure to aid structural mapping and to evaluate seismic methods for future exploration. The results were in agreement with the other information about the structure.

The trap is an anticline, 3 miles wide and 5 miles long, that trends north-south (fig. 34). The reservoir is in the Mt. Simon Sandstone, an aquifer with an average porosity of 10 percent and an average permeability of 25 millidarcys. The Mt. Simon is estimated to be more than 2,000 feet thick, but only the upper 465 feet has been tested for storage purposes.

The caprock, the Lombard Member of the Eau Claire Formation, consists of 125 feet of shale and thin dolomite lenses. Between the Mt. Simon reservoir and the Lombard Member is the Elmhurst Member of the Eau Claire, 50 feet of shaly and silty sandstone. Any gas that might migrate into the Elmhurst would be trapped by the overlying shale and become part of the cushion gas inventory. Water was pumped from the Mt. Simon Sandstone while water levels were observed in wells completed in the Galesville Sandstone and in a porous zone within the upper part of the Eau Claire. The tests indicated that the caprock was impermeable.

The Pontiac structure has 100 feet of closure on top of the Mt. Simon. The reservoir is 3,000 feet deep and covers about 3,500 acres within the last closing contour. The leased area covers 10,690 acres. Ultimate capacity of the reservoir is estimated to be 40 billion cubic feet.

Forty wells are completed for injection and withdrawal, and 13 wells are completed for observation. The wells were completed by casing to a total depth with 5 1/2- or 7-inch production casing, which was perforated opposite the storage zone. Maximum injection pressure is expected to be 1,635 psia.

Gas was first injected in the Mt. Simon at Pontiac in 1966, and the project became operational in 1969 (table 25).

TABLE 25 — INJECTION AND WITHDRAWAL HISTORY OF PONTIAC PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory (end of year)	Peak daily withdrawal
1966	543	0	—	0
1967	2,500	10	3,600	3
1968	4,000	24	7,573	3
1969	6,408	1,976	11,999	54
1970	7,050	4,225	16,550	82
1971	10,400	3,280	22,743	82
1972	11,033	8,930	24,805	143

In 1970 inert gas was injected into the St. Peter Sandstone to test its potential as a storage reservoir. The test indicated that the St. Peter may not have a satisfactory caprock. At this time operations in the St. Peter have ceased (table 2).

Richwoods Project

Operator: Gas Utilities Company, Robinson, Illinois
Location: T. 6 N., R. 11 W., Crawford County

Gas for the Richwoods project is supplied by Texas Gas Transmission Corporation through a 2 1/2-inch supply line about 2 miles long. A 4-inch line carries the storage gas to Palestine, Illinois.

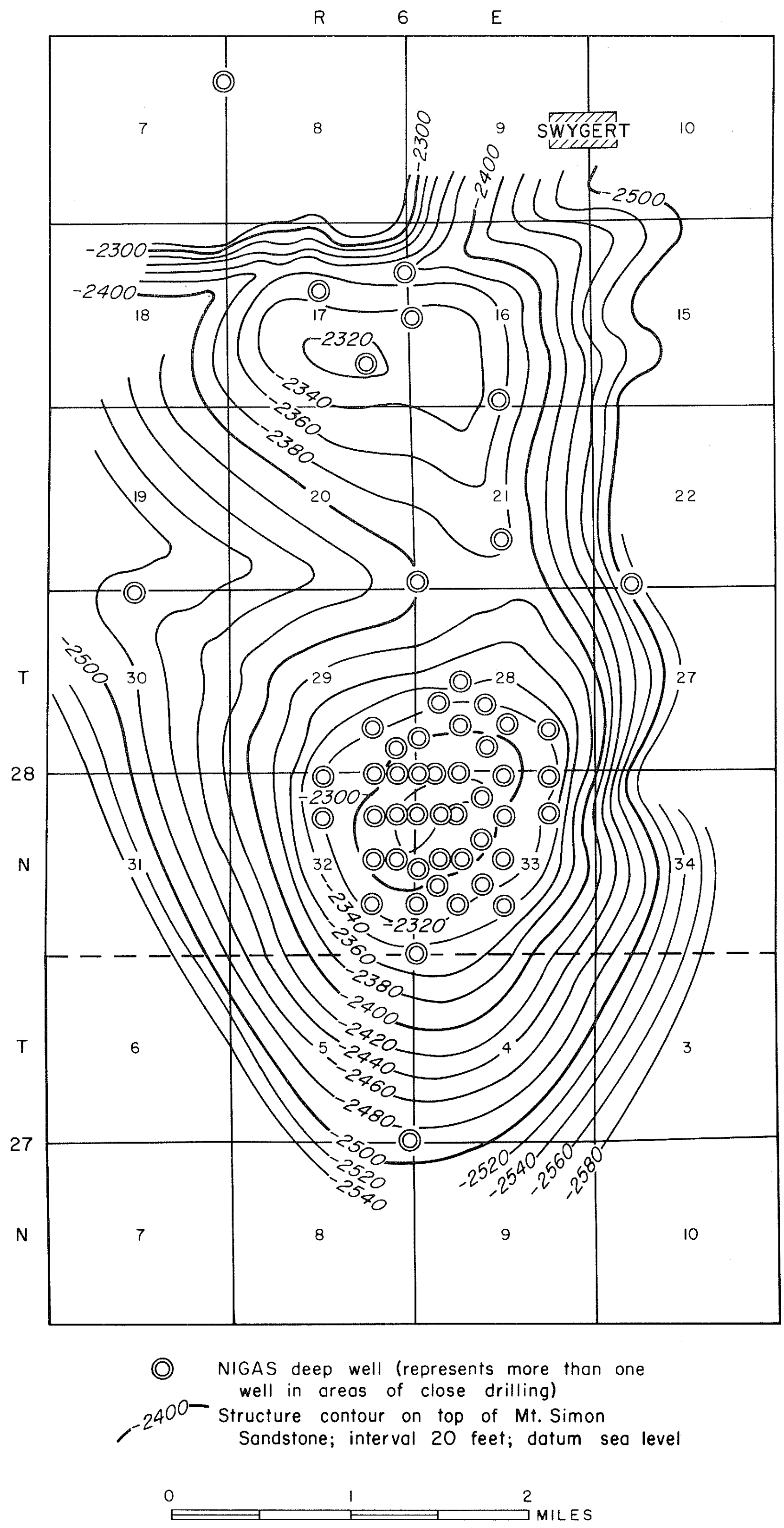

Fig. 34 - Top of Mt. Simon Sandstone at Pontiac, Livingston County (Northern Illinois Gas Co.).

The Richwoods project is a former gas field that produced 28 million cubic feet of gas before beginning to produce water. The gas was produced from a sandstone of Pennsylvanian age, which is about 700 feet below surface. In 1966, the one well that was in operation was reworked, and during that year 26 million cubic feet of gas was injected. Four million cubic feet of gas was vented to the atmosphere to test output capacity.

At the present time the project has three operating wells and one observation well. The ultimate capacity of the project is estimated to be 60 million cubic feet of gas; the maximum in storage has been 57 million cubic feet (table 26).

TABLE 26 — INJECTION AND WITHDRAWAL HISTORY OF RICHWOODS PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory (end of year)	Peak daily withdrawal
1966	26	4.8	—	.5
1967	24	15.6	34	1.0
1968	29	19	45	1.1
1969	23	21	47	1.0
1970	25	22	50	1.0
1971	19	16	52	1.0
1972	20	14	57	1.0

St. Jacob Project

Operator: Mississippi River Transmission Corporation

Location: St. Jacob, 6 miles east of Granite City, T. 3 N., R. 6 W., Madison County

Gas for the St. Jacob project is supplied by an 18-inch pipeline owned by Mississippi River Transmission Corporation. The gas is consumed in the St. Louis area.

The St. Jacob oil pool was discovered in 1942. Production is from the Galena (Trenton) Limestone Group. A total of 55 oil wells have been drilled on the structure, and the pool had produced 3,915,000 barrels of oil to the end of 1971. At that date, the Galena was being waterflooded and there were 29 producing wells. Production of oil from the Galena and storage of gas in the underlying St. Peter Sandstone have been carried out contemporaneously since 1963. Withdrawals of storage gas began in 1965 (table 27).

TABLE 27 — INJECTION AND WITHDRAWAL HISTORY OF ST. JACOB PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory (end of year)	Peak daily withdrawal
1963	400	0	400	0
1964	1,273	0	1,673	0
1965	2,063	932	3,300	30
1966	2,237	1,708	3,800	41
1967	2,133	1,673	4,302	47
1968	2,471	2,370	4,410	73
1969	2,594	2,217	4,777	71
1970	2,349	2,288	4,839	70
1971	2,529	1,783	5,600	59
1972	1,488	1,633	5,457	78

The St. Jacob structure is a double-domed anticline with 100 feet of closure on top of the St. Peter (fig. 35). Gas is stored in the north

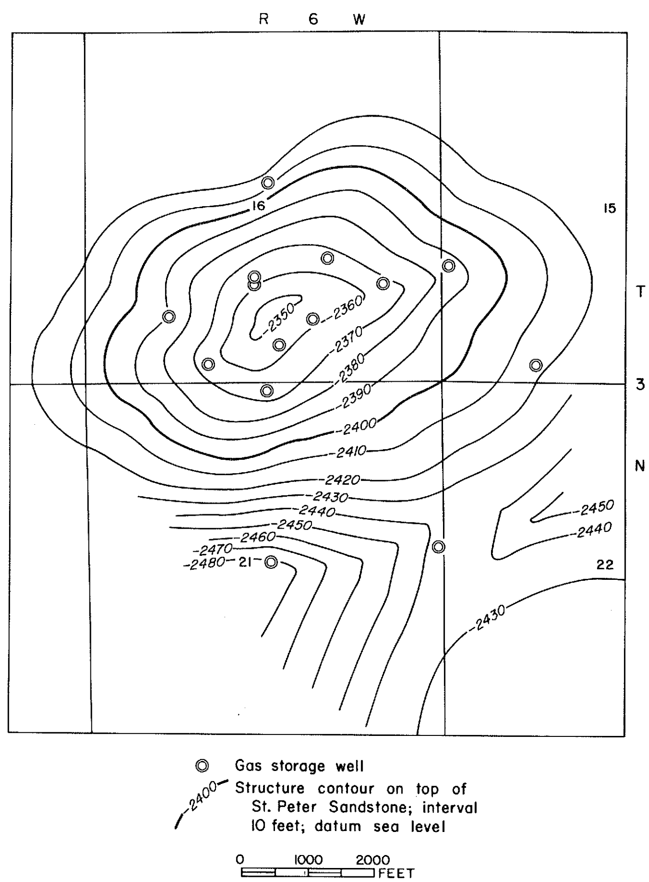

Fig. 35 - Top of St. Peter Sandstone at St. Jacob, Madison County (Mississippi River Transmission Corp.).

dome in the St. Peter Sandstone, an aquifer with an average porosity of 14 percent and an average permeability of more than 400 millidarcys. The reservoir is 2,860 feet deep, has a thickness of 100 feet, and covers 650 acres. Ultimate practical capacity of the reservoir has been estimated to be 5.6 billion cubic feet. The caprock is 400 feet of very fine grained limestone of the Platteville Group.

Ten wells are used for injection and withdrawal of gas, and four wells are used for observation in the north dome of the St. Jacob structure. Normal injection pressure is 1,260 psig. Maximum open-flow potential of all withdrawal wells is at least 41 MMcf per day. The production wells were cased to the top of the reservoir and completed open-hole. Surface pipe, 13 3/8 inches in diameter, was set to 320 feet, 8 5/8-inch intermediate string was set to 2,540 feet, and 5 1/2-inch production casing was set to approximately 2,860 feet.

Sciota Project

Operator: Central Illinois Public Service Company
Location: T. 6 and 7 N., R. 3 and 4 W., McDonough County

Gas for the Sciota project is supplied by Panhandle Eastern Pipeline Company. For the initial testing, the gas is being carried through 500 feet of 4-inch line. When the project becomes operational, a 12-inch main is to be constructed to carry gas to the project from an existing 8-inch main near Macomb, Illinois. Gas from the project will be used in the Macomb area.

Several oil tests were drilled in the Sciota area, and they indicated the presence of a structural high. In 1971, Central Illinois Public Service Company drilled 37 structure tests in the area; these tests revealed a structure that proved to have closure on the Galena (Trenton) Group and on the Mt. Simon Sandstone.

Pumping tests and the injection of gas indicated that the thin Maquoketa Shale Group (less than 30 feet thick over the structure) above the Galena was not sufficiently impermeable to permit the use of the Galena as a storage reservoir (table 2). This led to the testing and development of the Mt. Simon Sandstone as a reservoir. Drill-stem tests indicated that the Mt. Simon had suitable porosity and permeability. They also indicated that the caprock (Eau Claire Formation) would be tight.

The Sciota structure is an anticline with about 70 feet of closure on top of the Mt. Simon (fig. 36). The reservoir is in the Mt. Simon Sandstone, an aquifer with an average porosity of 12 percent and an average horizontal permeability of 39.2 millidarcys. It is about 2,600 feet deep and covers an area of 2,500 acres within the last closing contour. The estimated ultimate capacity of the Sciota project is 11.2 billion cubic feet.

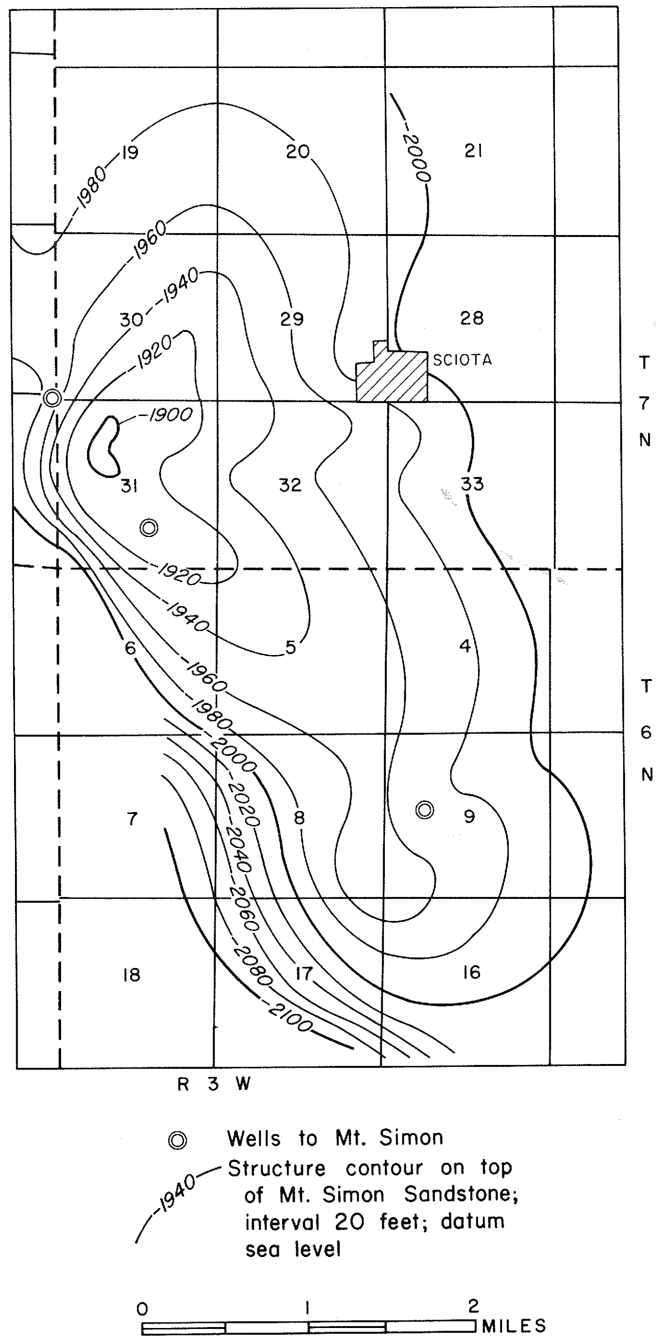

Fig. 36 - Top of Mt. Simon Sandstone at Sciota, McDonough County (Central Illinois Public Service Co.).

The caprock is the Eau Claire Formation, which is 290 feet thick. It consists of shaly and sandy dolomite with interbedded layers of shale.

Five wells have been drilled to the Mt. Simon. One well has been completed as a gas injection well for a pilot test. It is cased with

5 1/2-inch production casing, which is cemented 100 feet into the Mt. Simon. The casing opposite the upper 30 feet of the Mt. Simon is perforated. Injection pressure is not to exceed 1,330 psig.

At the end of 1972 about 20 million cubic feet of gas had been injected into the pilot well.

Shanghai Project

Operator: Illinois Power Company
Location: T. 12 and 13 N., R. 1 W., Warren and Mercer Counties

Gas for the Shanghai project is purchased from Panhandle Eastern Pipeline Company and Trunkline Gas Company, and it is delivered to the project through a 12-inch pipeline from Illinois Power Company's existing distribution lines near Galesburg. Gas withdrawn from the Shanghai project is used in the Galesburg area.

In 1966 a series of structure tests was drilled by Illinois Power Company on a structurally high coal bed east of Galesburg, but the structure on the coal was not indicative of the structure on deeper formations. A gravity survey in 1967 indicated three anomalies in the area. However, structure tests drilled on the gravity anomalies did not reveal any closed structures. Water well records on file at the Illinois State Geological Survey were searched and analyzed. These records directed attention to the Shanghai area. Structure test drilling to the Devonian strata began in 1967; the drilling confirmed the presence of a structural dome near Shanghai. In 1968 deep wells were drilled to determine the presence of a reservoir and caprock, and to confirm the presence of the structure on the deeper strata. Core analyses and water pump tests led to the conclusion that the lower part of the Franconia Formation should provide a satisfactory caprock and that vertical migration of gas from the underlying Ironton-Galesville Sandstone would not be a serious problem.

The Shanghai structure is a dome about 2 miles in diameter, which has 95 feet of closure on top of the Ironton-Galesville Sandstone (fig. 37). Closure on this structure increases downward, indicating some structural movement before Champlainian (middle Ordovician) time. The reservoir is the Ironton-Galesville Sandstone, an aquifer about 140 feet thick, with an average porosity of 15.2 percent and an average horizontal permeability of 246 millidarcys. The reservoir is 2,000 feet below the surface, and there are about 1,850

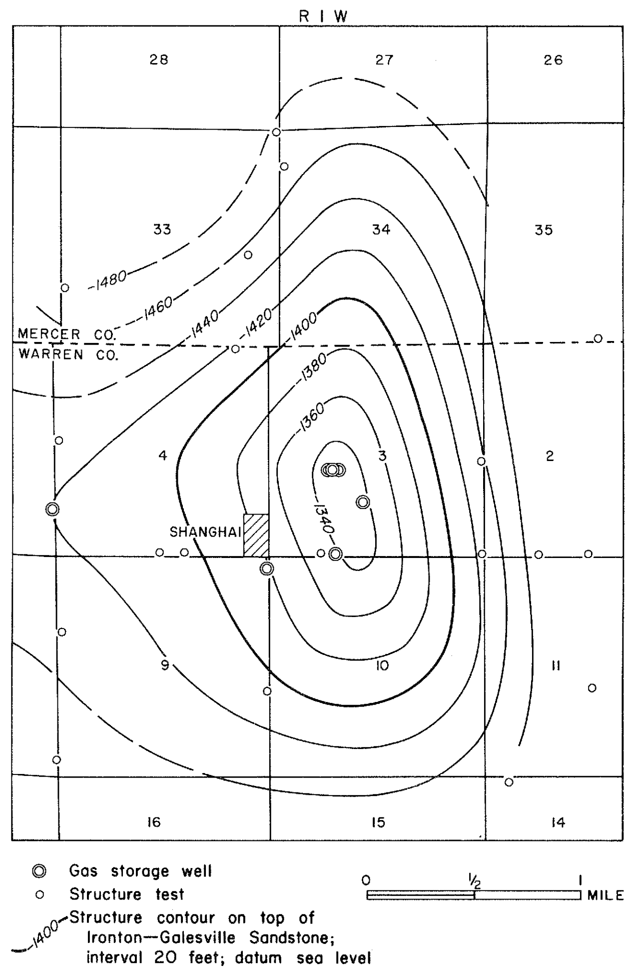

Fig. 37 - Top of Ironton-Galesville Sandstone at Shanghai, Warren and Mercer Counties (Illinois Power Co.).

acres included within the closure. The ultimate capacity of the project is calculated to be 11 billion cubic feet. In the first 5 years of operation (1971-1976), Illinois Power Company anticipates utilizing most of this capacity.

The caprock is the Davis Member of the Franconia Formation. It is 40 feet thick and consists mostly of dense dolomite and sandstone that is interbedded with shale in beds a few inches to a few feet thick.

The Shanghai project has nine wells completed for injection and withdrawal, and eight wells completed as observation wells. The injection-withdrawal wells were completed by cementing 4 1/2-inch or 5 1/2-inch production casing into the Ironton-Galesville and perforating the casing at the top of the reservoir. The maximum injection pressure anticipated is 965 psia. Gas was first injected in 1970 and the project became operational in 1971 (table 28).

TABLE 28 — INJECTION AND WITHDRAWAL HISTORY OF SHANGHAI PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory (end of year)	Peak daily withdrawal
1970	1,089	1.2	1,088	1
1971	3,354	59	4,386	20
1972	2,998	749	6,630	51

State Line Project

Operator: Midwestern Gas Transmission Company
Location: T. 12 N., R. 10 W., Clark County, Illinois, and Vigo County, Indiana

Gas for the State Line project comes from Midwestern Gas Transmission Company's 30-inch line through a 10-inch feeder line. The line serves for both injection and withdrawal of gas.

State Line is a former oil field; about 85 percent of its area is in Indiana and 15 percent is in Illinois. Gas was first injected into the State Line project in 1963, and minor withdrawals were made during the same year (table 29). The station site is in Indiana and the gas volumes are not separated by states. State Line is considered an Indiana storage project; therefore, its capacity is not included in the Illinois totals.

TABLE 29 — INJECTION AND WITHDRAWAL HISTORY OF STATE LINE PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory (end of year)	Peak daily withdrawal
1963	97	10	87	4
1964	764	74	777	11
1965	553	277	1,053	4
1966	1,015	653	1,415	13
1967	1,882	113	3,189	11
1968	873	852	3,210	13
1969	1,016	951	3,275	13
1970	1,765	1,510	4,109	12
1971	1,454	1,152	4,412	13
1972	1,160	1,024	4,548	14

Although oil is produced from limestone of Mississippian age at State Line, gas is stored in porous dolomite and dolomitic limestone beds of the underlying Grand Tower Formation (Middle Devonian). The trap is a structural dome caused by draping of Devonian and younger strata over a Silurian reef. Similar structures are present at the Elbridge and Nevins storage projects. Caprock is about 90 feet of shale of the New Albany Group overlying the dolomite and limestone reservoir.

The State Line Dome has 91 feet of closure on top of the Grand Tower and covers 496 acres (fig. 38). The reservoir is an aquifer with an average porosity of 17.3 percent and an average permeability of 147 millidarcys. It is 1,860 feet deep. The ultimate capacity of the project is estimated to be 4.7 billion cubic feet of gas. State Line has nine injection-withdrawal wells and six observation wells.

Normal injection pressure is 1,000 psig. Open-flow potentials of the operating wells range from 6.5 to 12 MMcf per day, and average 9.1.

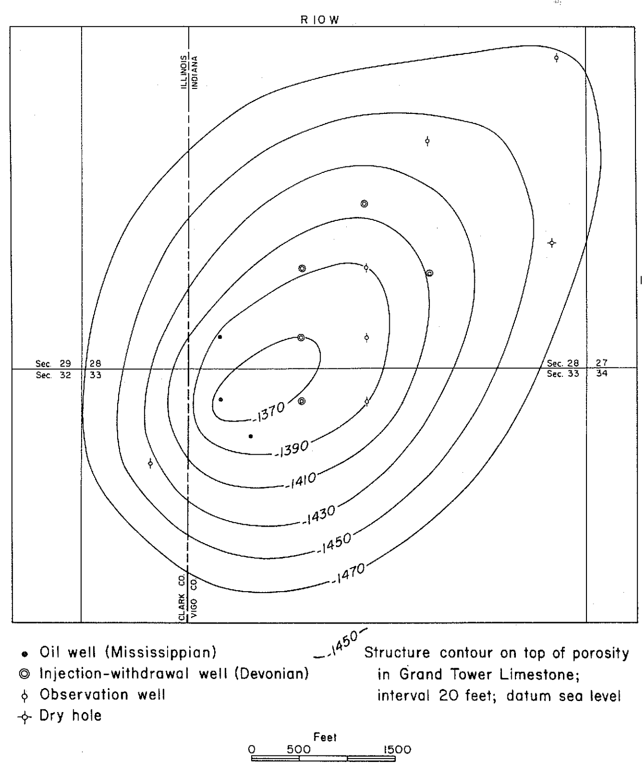

Fig. 38 - Top of porosity in Grand Tower Limestone at State Line, Clark County, Illinois, and Vigo County, Indiana (Buschbach and Bond, 1967; original map by Midwestern Gas Transmission Co.).

Tilden Project

Operator: Illinois Power Company
Location: 23 miles southeast of Belleville, T. 3 S., R. 5 and 6 W., St. Clair and Washington Counties

Gas for the Tilden project is purchased from Mississippi River Transmission Corporation and is delivered to the project through a nearby 16-inch distribution line of the Illinois Power Company. The gas is consumed in the East St. Louis area.

The reservoir is in a former gas field that was discovered in 1957. From 1957 to 1961, 21 core holes were drilled to determine the reservoir limits. Injection of storage gas began in 1961 (table 30). Gas is stored in the Cypress Sandstone of Mississippian age. The sandstone has an average porosity of 20.8 percent and an average permeability of 183 millidarcys. It has a maximum thickness of 33 feet.

TABLE 30 — INJECTION AND WITHDRAWAL HISTORY OF TILDEN PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory* (end of year)	Peak daily withdrawal
1961	327	330	810	24
1962	1,017	1,014	749	42
1963	708	857	560	41
1964	392	112	831	17
1965	313	267	868	20
1966	941	1,193	869	43
1967	1,079	1,233	450	42
1968	1,828	1,392	595	49
1969	1,690	1,404	844	43
1970	1,652	1,330	1,166	53
1971	1,121	962	1,320	47
1972	1,228	1,542	1,005	46

*Working gas.

The structure is a monoclinal stratigraphic trap, in which the Cypress Sandstone dips eastward and northeastward and grades to shale westward in the updip direction (fig. 39). The dips are apparently associated with an underlying Silurian reef at the western edge of the gas field. Oil was discovered in the reef in 1968, and the oil field is designated the Tilden North field.

The storage reservoir is 712 to 812 feet below the surface and covers 1,287 acres. The ultimate capacity of the project is estimated to be 3.1 billion cubic feet. In part of the reservoir the gas is underlain by water; in this part, where water production was anticipated, the wells were drilled and cased through the sandstone. The casings were perforated above the gas-water contact and 1-inch siphon strings were installed. In the rest of the reservoir, the gas column extends downward to the bottom of the reservoir; in this part, the wells were cased to the top of the Cypress Sandstone and completed open-hole into the reservoir. Casing 5 1/2 inches in diameter was used in all wells.

The project has 45 injection-withdrawal wells and 14 observation wells. Normal injection pressure is 250 to 360 psig. Open-flow potential of the wells ranges from 230 to 16,500 Mcf per day, with an average of 5,234.

Troy Grove Project

Operator: Northern Illinois Gas Company
Location: Midway between Mendota and La Salle, near Troy Grove, T. 34 and 35 N., R. 1 E., La Salle County

Gas for the Troy Grove project comes from the Amarillo trunkline of Natural Gas Pipeline Company of America by way of a 16-inch pipeline. The gas is used in the suburban Chicago area.

Basic geologic studies were carried out in 1957, and by 1958 Northern Illinois Gas Company had drilled 56 structure tests in the Troy Grove area. Currently, more than 200 test holes have been drilled to delineate the structure. Deep holes were drilled and cored to determine caprock qualities of the Eau Claire Formation and reservoir qualities of the upper part of the Mt. Simon Sandstone. One well reached the Precambrian after penetrating more than 2,000 feet of Mt. Simon.

The Troy Grove structure is an east-west elongated dome on the La Salle Anticlinal Belt. The structure is 5 miles long and 3 miles wide. It is intersected by four faults, one of which has 180 feet of vertical displacement (fig. 40). The primary reservoir is in the Mt. Simon Sandstone, an aquifer with an average porosity of 17 percent and an average permeability of 150 millidarcys. Gas has also been injected into sandstones in the lower part of the overlying Eau Claire Formation. Gas migrates between the Mt. Simon and the sandstones of the lower Eau Claire. Excessive pressure buildup in the uppermost sands of the Eau Claire has been controlled by withdrawing gas from these zones. The caprock is 180 feet of shale and siltstone in the upper part of the Eau Claire. Although the area is cut by faults, the caprock has prevented gas from migrating above the Eau Claire.

The Troy Grove structure has slightly over

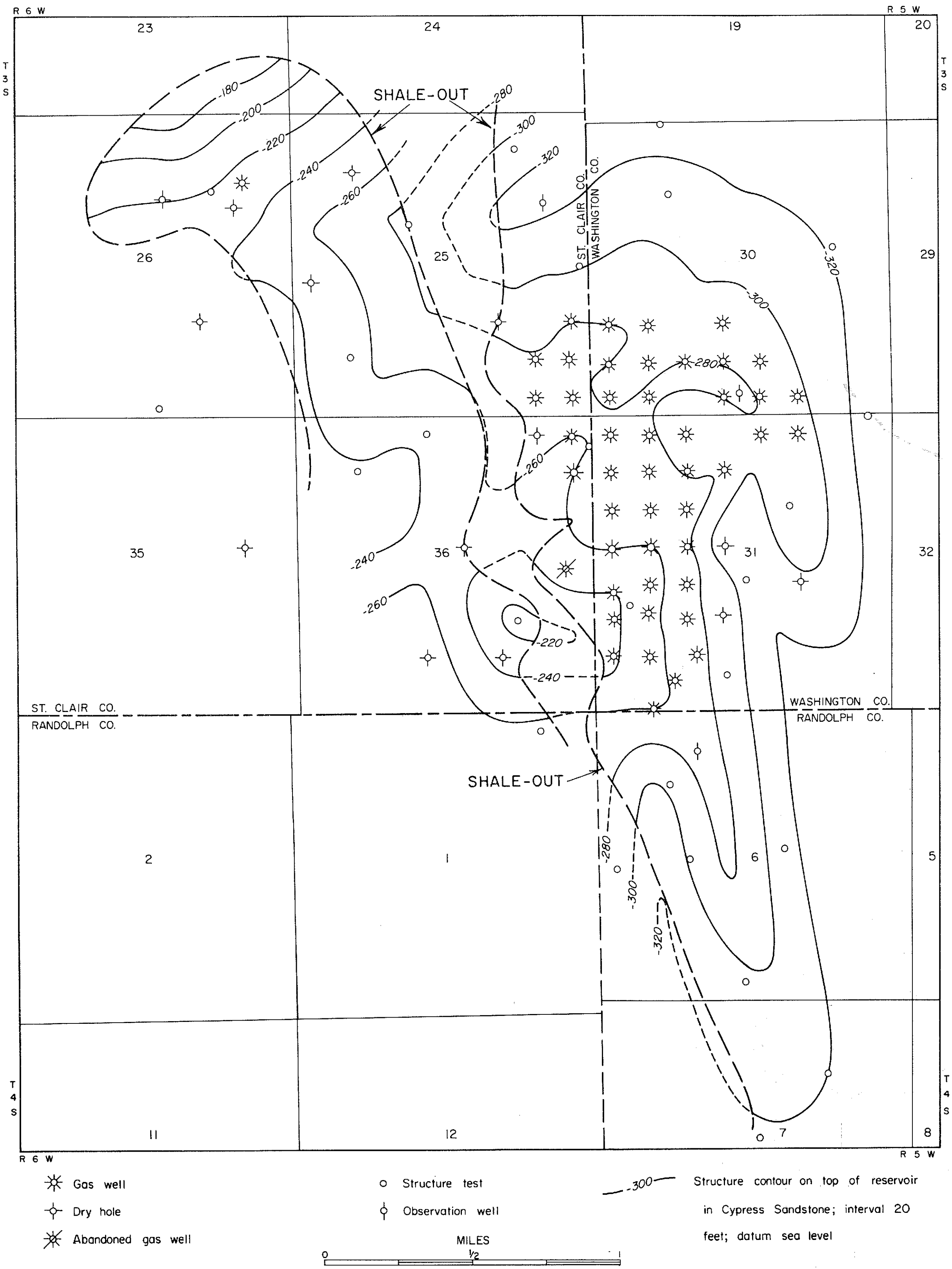

Fig. 39 - Top of reservoir in Cypress Sandstone at Tilden, St. Clair, Washington, and Randolph Counties. Shale-out lines indicate gradation of reservoir sand into shale (Buschbach and Bond, 1967; original map by Illinois Power Co.).

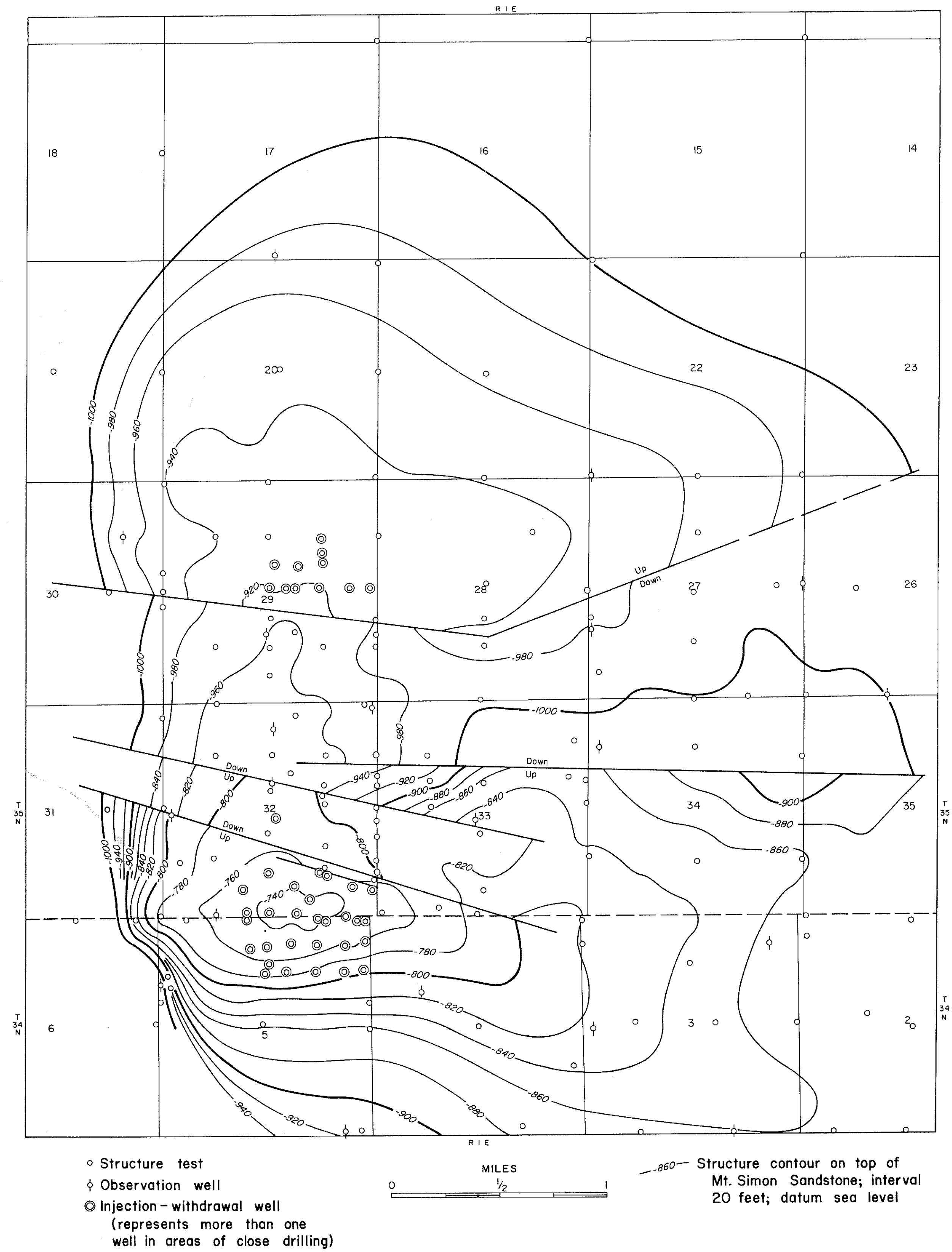

Fig. 40 - Top of Mt. Simon Sandstone at Troy Grove, La Salle County (Buschbach and Bond, 1967; original map by Northern Illinois Gas Co.).

100 feet of closure on top of the Mt. Simon Sandstone (fig. 40). The reservoir is about 1,420 feet below surface and covers 9,600 acres within the leased area. The capacity of the reservoir is estimated to be 70 billion cubic feet of gas. About 55 percent of the total is considered working gas.

Troy Grove has 96 injection-withdrawal wells and 27 observation wells. The operational wells were cased through the storage zone with 7-inch production casing. The casing was perforated adjacent to the reservoir. Gas was first injected in 1958 and the project was operational in 1959 (table 31). Normal injection pressure is 740 psig.

TABLE 31 — INJECTION AND WITHDRAWAL HISTORY OF TROY GROVE PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory (end of year)	Peak daily withdrawal
1958	707	0	707	0
1959	4,138	65	4,780	20
1960	6,930	528	11,182	50
1961	9,649	1,081	19,751	100
1962	12,670	3,042	29,408	250
1963	20,749	12,940	37,218	400
1964	16,070	8,372	44,916	500
1965	28,069	24,342	48,643	580
1966	26,700	22,762	46,447	650
1967	25,200	25,800	48,300	590
1968	28,766	24,736	53,170	706
1969	24,794	35,223	47,973	647
1970	30,300	27,295	54,077	887
1971	28,400	26,400	57,900	870
1972	36,777	32,109	62,515	792

Tuscola Project

Operator: Panhandle Eastern Pipeline Company
Location: T. 16 and 17 N., R. 8 E., Douglas and Champaign Counties

Gas for the Tuscola project comes through Panhandle Eastern Pipeline Company's main transmission line from the Mid-Continent region of Kansas, Oklahoma, and Texas. The gas will be used as part of Panhandle's system supply to its entire market.

Drill-hole data and geologic maps on file at the Illinois State Geological Survey indicated the presence of a large anticline in the Tuscola area. In the early 1960's the Illinois Power Company studied the records of water wells and oil tests in the area and outlined the location of the anticline. Oil was discovered in the Galena Group (Trenton) strata in the Tuscola area by R. D. Ernest in 1962. The discovery was near Hayes, north of Tuscola, in the No. 1 Schweighart well, Sec. 4, T. 16 N., R. 8 E., Douglas County (Bristol and Prescott, 1968, p. 2). In 1965 intensive development of the Hayes field was begun by M. H. Richardson. Forty-three wells were drilled into the Galena (Trenton). The field produced approximately 147,000 barrels of oil through 1971.

From 1962 to 1964 Illinois Power Company drilled shallow structure tests to the Hunton Megagroup, and they also drilled some deeper tests to determine the stratigraphy of the sediments to the base of the St. Peter Sandstone. By 1970 Panhandle Eastern Pipeline Company had acquired the oil production and the gas storage rights for the area. Panhandle drilled and cored to the Mt. Simon Sandstone to investigate it as a prospective gas storage reservoir; they began injecting gas into that reservoir in 1970 (table 32).

TABLE 32 — INJECTION AND WITHDRAWAL HISTORY OF TUSCOLA PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory (end of year)	Peak daily withdrawal
1970	119	0	119	0
1971	644	11	752	1
1972	0	52	698	4

The Tuscola structure is a large anticline that trends north-south (fig. 41). Although the structure has more than 700 feet of closure, current storage operations are planned for only the upper 110 feet of closure. The reservoir is in the Mt. Simon Sandstone, an aquifer with an average porosity of 8.5 percent and an average permeability of 22 millidarcys. The reservoir is about 4,000 feet deep. The ultimate capacity of the project is 60 billion cubic feet. The caprock is the Eau Claire Formation, which consists of 650 feet of siltstone, shale, sandstone, and carbonates.

The Tuscola project has 13 injection-withdrawal wells and 9 observation wells. The operational wells were drilled at least 600 feet into the Mt. Simon and cased to total depth. The casing was perforated adjacent to the intervals in which gas is to be injected.

Waterloo Project

Operator: Mississippi River Transmission Corporation
Location: 15 miles south of East St. Louis, T. 1 and 2 S., R. 10 W., Monroe County

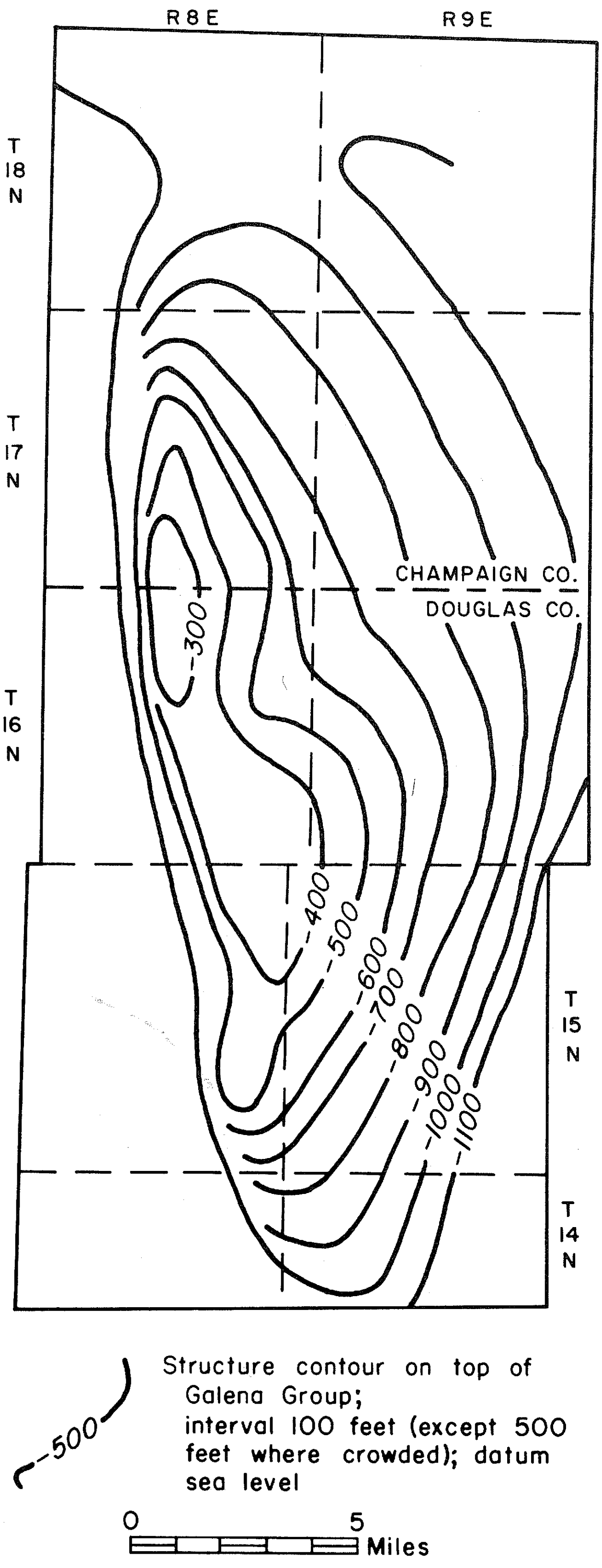

Fig. 41 - Top of Galena Group at Tuscola, Douglas and Champaign Counties (after Bristol and Buschbach, 1973).

Gas for the Waterloo project comes from a 22-inch line of the Mississippi River Transmission Corporation by way of a 6-inch pipeline. Because of its relatively small size, the reservoir has served chiefly as a surge tank to compensate for diurnal variations in demand for gas in the St. Louis area.

The Waterloo oil pool was discovered in 1920, abandoned in 1930, revived in 1939, and converted to gas storage in 1951. About 238,000 barrels of oil were produced from the Galena (Trenton) Limestone Group at a depth of about 410 feet.

The Waterloo structure is an anticline that trends generally north-south and has about 100 feet of closure on top of the Oneota Dolomite (fig. 42). Gas is stored in the St. Peter Sandstone and also in sandstones and vuggy dolomites of the New Richmond and Oneota Formations. The reservoirs are aquifers, 900 to 1,650 feet below surface. The storage area covers about 100 acres.

Six wells were used for injection and withdrawal of gas, and six were used for observation. The maximum amount of gas known to have been stored in the reservoir is 450 MMcf in 1959. As much as 21 MMcf was withdrawn in one day.

The Waterloo project is being abandoned.

Waverly Project

Operator: Panhandle Eastern Pipeline Company
Location: 1 mile southwest of Waverly, T. 13 N., R. 8 W., Morgan County

Gas for the Waverly project comes through Panhandle Eastern Pipeline Company's trunklines from the Anadarko Basin. The gas is consumed in Illinois, Indiana, Ohio, and Michigan.

A structure map of the Pennsylvanian strata in the vicinity of Jacksonville (Collingwood, 1923, fig. 2, p. 21) shows an anticlinal nose trending northeast in T. 12 N., R. 7 and 8 W. Later drilling found oil shows and gas in the Devonian strata and helped to delineate the structure of the Waverly Dome. In the early 1950's, Panhandle Eastern Pipeline Company acquired gas storage rights in the area, and in 1954 they began injecting gas into the St. Peter Sandstone. Withdrawals were begun on a small scale in 1961 (table 33). The project has been fully active since 1962.

While storing gas in the St. Peter, Panhandle drilled several test holes to the underlying

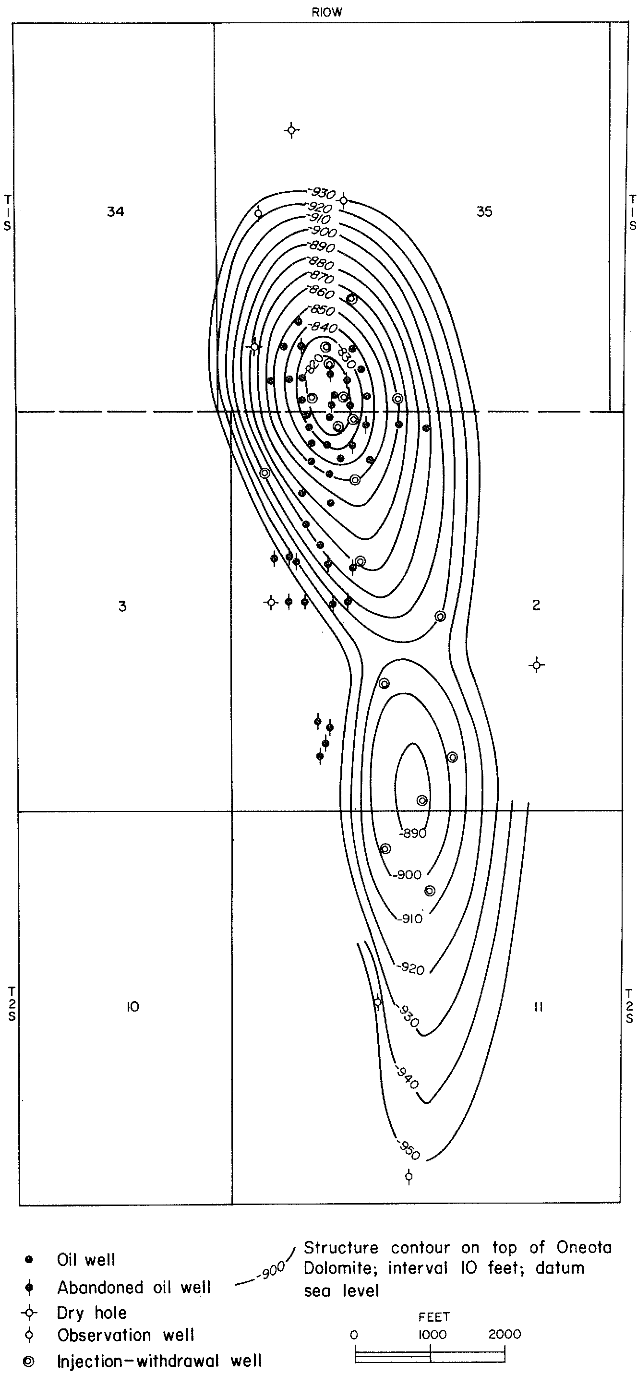

Fig. 42 - Top of Oneota Dolomite at Waterloo, Monroe County (Buschbach and Bond, 1967; original map by Mississippi River Transmission Corp.).

TABLE 33 — INJECTION AND WITHDRAWAL HISTORY OF WAVERLY PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory (end of year)	Peak daily withdrawal
		St. Peter		
1954-1960	10,708	—	—	—
1961	929	50	6,487	—
1962	2,666	834	8,319	71
1963	4,004	2,891	9,432	99
1964	5,838	3,553	11,201	154
1965	7,289	5,299	13,164	104
1966	8,250	6,636	18,000	142
1967	8,820	6,720	16,811	144
1968	9,557	7,916	18,453	172
1969	9,890	7,817	20,525	186
1970	10,754	8,289	22,989	208
1971	10,786	9,843	23,933	217
1972	8,815	11,040	21,708	214
		Ironton-Galesville		
1968	253	0.6	253	0.6
1969	2,086	135	2,203	28
1970	6,387	430	8,154	26
1971	6,822	1,194	13,782	28
1972	6,115	1,188	18,650	38

Ironton-Galesville and Mt. Simon Sandstones. The Ironton-Galesville was selected as a second storage reservoir, and gas was injected into it in 1968.

The Waverly structure is a dome with more than 100 feet of closure on top of the Galena (fig. 43) and 68 feet of closure on top of the Ironton-Galesville. About 7,000 acres are included within the closing contours.

The St. Peter reservoir is an aquifer with an average porosity of 18 percent and an average permeability of 1,220 millidarcys. The St. Peter is 1,800 feet below the surface, and it is 250 to 300 feet thick in the area. Its caprock is limestone, dolomite, and thin beds of shale of the Joachim Formation and the Platteville and Galena Groups, which total 380 feet in thickness. Overlying the Galena is a 200-foot section of shale assigned to the Maquoketa Group. Some gas migrates upward from the St. Peter into porous zones of the Galena. The leakage gas is recycled into the St. Peter or is produced.

The Ironton-Galesville reservoir, also an aquifer, has about 35 feet of friable, porous, fine- to medium-grained sandstone. It is 3,500 feet below the surface. Its caprock is shale, sandstone, siltstone, and dolomite of the Davis Member, which is at the base of the Franconia Formation. The Davis is about 70 feet thick.

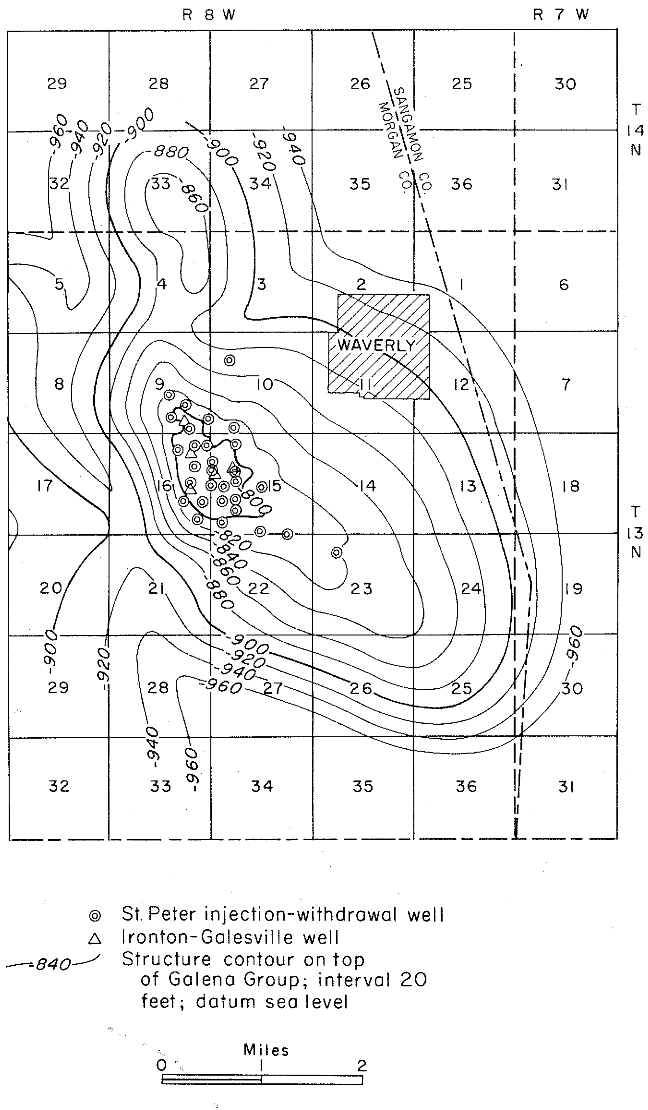

Fig. 43 - Top of Galena Group at Waverly, Morgan County (Panhandle Eastern Pipeline Co.).

The ultimate capacity of the St. Peter reservoir is estimated to be 150 billion cubic feet. The Ironton-Galesville is expected to hold 127 billion cubic feet. There are 50 injection-withdrawal wells completed in the St. Peter Sandstone and 9 completed in the Ironton-Galesville. Nineteen observation wells are completed in or above the St. Peter, and four are completed for observation in the Ironton-Galesville. The operational wells were cased through the reservoir, and the casing was perforated. Normal injection pressure into the St. Peter is 845 psig.

ABANDONED GAS STORAGE PROJECTS IN ILLINOIS

At the end of 1972 two underground gas storage projects in Illinois had been abandoned after testing because stored gas migrated upward from the reservoir. These projects are discussed here because their history offers important information for the entire gas storage industry. Finding suitable storage in aquifers is difficult, and the ultimate testing of aquifers can be done only by injecting gas. Therefore, we can expect to encounter, from time to time, a structure that appears to be worthy of testing but later proves unsatisfactory for gas storage.

The two abandoned projects, Brookville and Leaf River, are located in northern Illinois. Their proposed reservoirs were aquifers. In both projects the cause of leakage appeared to be related to faulting across the structure. Information about the projects is summarized in table 3.

Brookville Project

Operator: Natural Gas Pipeline Company of America
Location: T. 23 and 24 N., R. 7 E., Ogle County

In 1963 and 1964 water pump tests were performed at Brookville to test the soundness of caprock for a proposed Mt. Simon Sandstone storage reservoir. The tests were inconclusive; however, they did give some indication of communication between the Mt. Simon and porous zones above the proposed caprock. From November 1964 to July 1965, 894 million cubic feet of gas was injected into the Mt. Simon. Observations made in wells completed in zones above the caprock showed that communication existed between the Mt. Simon, the Eau Claire, the Galesville, and the Ironton. Furthermore, gas had migrated up to the Ironton Formation. Since there was no satisfactory caprock above the Ironton, the project was abandoned (table 3).

The proposed storage reservoir was in the Mt. Simon Sandstone, in an anticlinal structure that trends northwest-southeast, has 138 feet of closure, and covers a surface area of 6,200 acres. The reservoir sand, an aquifer, is 1,050 feet deep and it has an average porosity of 18.7 percent and an average permeability of 1,062 millidarcys. The proposed caprock was the overlying Eau Claire Formation, which is 234 feet thick. A

68-foot thick section of dense dolomite, the Lombard Member of the Eau Claire, overlies the Mt. Simon. This dolomite is overlain by 156 feet of interbedded siltstone and shale (Proviso Member), the upper 10 feet of which is chiefly shale. The potential capacity of the reservoir was estimated to be about 40 to 50 billion cubic feet.

Leaf River Project

Operator: Northern Illinois Gas Company
Location: T. 25 N., R. 9 and 10 E., Ogle County

In 1968 and 1969 the Leaf River reservoir was tested by the injection of 348 million cubic feet of inert gas. Subsequent rises in the water levels in observation wells completed in porous zones above the Eau Claire caprock indicated that the caprock was leaking. Therefore, the project was abandoned (table 3).

Storage had been proposed in a faulted anticline trending west-northwest and having about 80 feet of closure. At the location of the proposed storage project, the upper part of the Eau Claire Formation consists of about 20 feet of shale underlain by 55 feet of shaly siltstone. The siltstone grades downward into about 70 feet of fine-grained, water-saturated sandstone (called the "Lightsville" by Northern Illinois Gas Company), which was to have been the storage reservoir for the project. The "Lightsville" is 810 feet below the surface; it has an average porosity of 19.4 percent and an average permeability of 640 millidarcys. The area enclosed by the last closing contour is estimated to be about 1,400 acres.

Initial exploration work on the project was carried out in 1966. Water was pumped from a well in the "Lightsville" for 135 days at the rate of 100 gallons per minute. The results of the pump test indicated that the caprock had an effective permeability on the order of 10^{-4} millidarcys. Since this was considerably higher than the permeability of the caprock in known successful storage projects, the caprock was tested further by the injection of inert gas. Inert gas was chosen for two reasons: (1) in case of leakage, explosion hazards would be minimized, and (2) inert gas could be generated at a cost lower than the purchase cost of natural gas (Keen, 1968).

The inert gas that was used was the exhaust gas from an internal combustion engine. The exhaust from the engine was passed through a catalyst to remove potentially corrosive oxides of nitrogen. About 8 1/2 volumes of inert gas were produced for each volume of natural gas that was consumed (Keen, 1968; Wingerter, 1970).

Although the project was abandoned, the test demonstrated a method for testing caprock and determining well performance with an injection gas that was safe and inexpensive.

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