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The Upper Midwest Weighs Its Hopes for 'Black Gold' Wealth

Oil Strikes in Williston Basin Indicate Further Successful Explorations . . . Growth in Refinery Capacity Has Begun—Based Currently on Canadian Oil

WHEN an oil well was brought in near Tioga, North Dakota, early this year, followed by a second strike in Manitoba and a third near Richey, Montana, many Upper Midwest persons allowed themselves to entertain their first active hopes that new wealth might become theirs—either directly or indirectly—from the earth's "black gold."

Geologists have known for years that the "Williston Basin", in which these strikes were made, was a potential oil source, but not until drills found rich crude in this trio of exploratory wells was there any tangible evidence that the area might actually become productive.

Perhaps equally significant, though somewhat less heralded, have been recent refinery developments. A refinery was erected at Superior, Wisconsin, to handle a part of the crude oil a new pipeline is bringing from Canada, and at St. Paul Park, Minnesota, the Northwestern Refining company announced plans to expand its 8,000 barrel-a-day capacity to 30,000 barrels.

These events sparked a greater interest in oil all across the stretch of northern states comprising the Ninth Federal Reserve district—namely, Minnesota, Montana, the Dakotas, northwestern Wisconsin, and upper Michigan.

For those who will want to follow the developments closely, this Supplement to the Monthly Review is intended to provide a background against which to weigh their speculations. Besides appraising prospects for important crude oil supplies, this report considers the outlook for refinery expansion and, finally, economic implications of these developments.

EDITOR'S NOTE: This report on prospects for oil production and refinery development in the Upper Midwest, with consideration of the economic implications, is the result of studies made in the Department of Research of the Federal Reserve Bank of Minneapolis.

As the central banking institution for an area known as the Ninth Federal Reserve district, this bank is engaged continuously in collecting and disseminating information on economic trends in this district.

Since this study is a limited effort to provide a background to impending developments, it must be considered a preliminary one. Later investigations and observations will be benefitted by knowledge gained as these developments take form.

The author of this report is Clarence W. Nelson, assistant economist. In preparing it, he had the help and advice of several persons, whose names are listed on page 12. The bank, as publisher, wishes to absolve them of all responsibility for any errors of fact or interpretation in this manuscript.

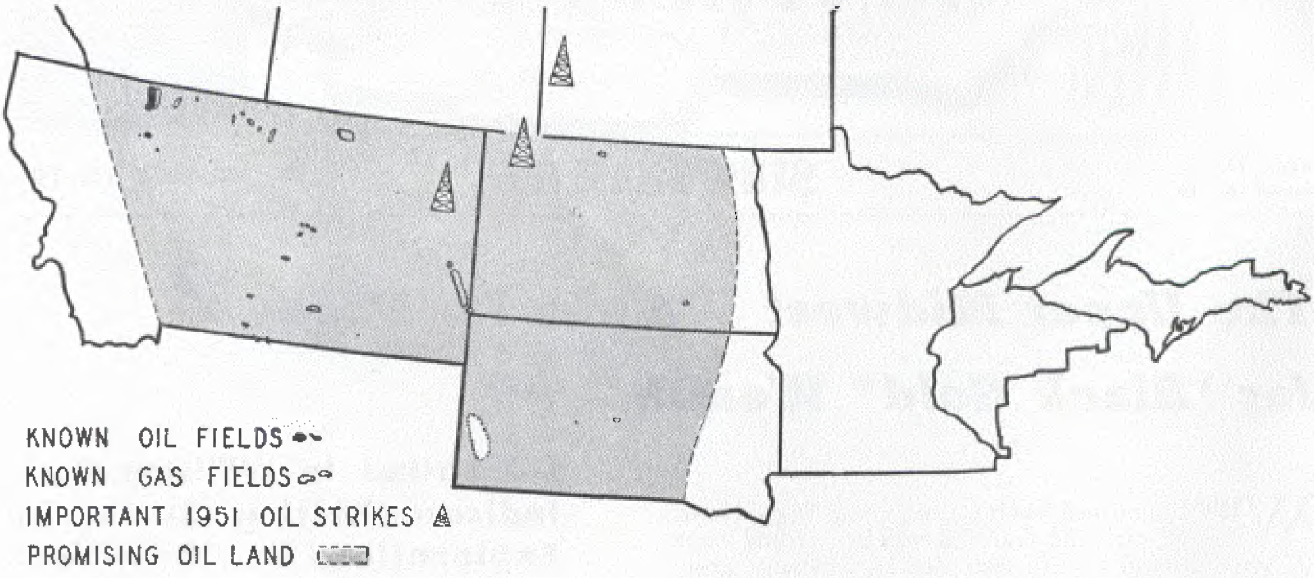
PART I OUTLOOK FOR THE 9th FEDERAL RESERVE DISTRICT AS OIL SOURCE

Crude Oil Sources Confined to Western Half of District

The eastern half of the Ninth Federal Reserve district has been pretty well written off as a petroleum source. In the three western states, however, the story is quite different. The shaded area of the Ninth district shown on **Chart 1** is, in general, considered "good hunting" for oil. The remainder of the Ninth district is not. Montana, of course, is already an oil state, but its annual production is relatively small, amounting to less than one-half of one per cent of the nation's output.

What makes this western area look so promising? The answer is tied up in the geology of how oil is formed and where it can be found.

CHART I — POTENTIAL OIL LAND IN THE NINTH FEDERAL RESERVE DISTRICT



NEW OIL discoveries are hoped for in a wide belt of land—considered geologically favorable—in Montana and the Dakotas. Source: Oil and Gas Journal

Geologic Layers Determine Where Oil Is to Be Found

Imagine cutting down through the earth across the Ninth district and lifting out a slice. The slice shows several distinct geologic layers — like a cake. Cut a similar slice almost anywhere on earth and many of the same layers will show up. Geologists have named these layers to represent the geological period during which they were formed. Certain layers are known to be potential oil bearers and, when identified, provide a clue to the presence of oil.

These layers accumulated through the earth's history from bottom to top — like layers of surfacing on a road. They were piled up (and partly worn down) during the ages-long struggle when continents wrestled their way up from the ocean floor.

Each layer was packed, heated, and pressured by countless tons of accumulated material on top of it. Some bore the remains of dead plants and animals that had washed into the ancient seas and merged with sea-bottom ooze; others were largely inorganic sand and silt laid down by the eroding forces of wind and water.

Under heat and pressure the decaying materials that made up these layers gradually changed. Some of the matter was transformed into tiny droplets of oil that began a slow migration upward through the porous structures about them.

A cross section view of these layers is shown in **Chart 2.** The bottom layer, you will note, is given the name "Cambrian." There are other layers below this in the earth, but the Cambrian layer (formed about a billion years ago) is the earliest or deepest layer in which we find remains of living organisms.*

Cambrian, for practical purposes, is the lowest layer that interests oilmen. Pre-Cambrian layers are made up of "igneous" rock (cooled from a molten state) and, like granite, are impenetrable to oil. No oil that we know of formed prior to this period.

Presence of Sedimentary Rock Gives Clue to Oil Supplies

Some of the higher layers, on the other hand, have been consistent sources of petroleum throughout the continent. Made up of "sedimentary" rock, they contain the fossil remains of pre-historic life. Among these layers are the oil-rich zones sought by drillers.

Great oil fields in Oklahoma are located in the Ordovician (second from the bottom) layer. More recent discoveries at the Leduc oil field in Alberta tap the Devonian layer. The Devonian reef is believed to underlie many mid-continent states, extending from rich Canadian fields on the north to the Oklahoma-Texas region on the south.

The depth of these layers varies considerably with the location. For example, in western Canada the Devonian layer runs about 6,500 feet underground. If the Amerada well in North Dakota is actually drawing oil from Devonian reef, the layer's depth at that location must be better than 10,000 feet. Shell Oil company's well near Richey, Montana, is believed to be tapping the Mississippian-Madison layer at about 7,200 feet.

The layers in **Chart 2** slope generally upward from a low spot near west central Dakota toward the east, and the pre-Cambrian layers actually come to the surface in Minnesota.* The depression in the west central part of North Dakota is the "Williston Basin," a bowl-like

* Fossil remains found in the layers above the Cambrian help "date" them.

* St. Cloud's granite quarries, for example.

structure of the underground layers whose sloping sides extend into Canada, Montana, and South Dakota to underlie some 100,000 square miles of surface lands.

The extent of the Williston basin is shown more clearly in **Chart 3.** This is a contour map, looking down from above. It shows contours of the Cretaceous layer by lines that connect all points the same height above or below sea level. The shaded area of the map is the heart of the Williston basin, and it is here that the arching layers form the basin's low point.

Closely spaced contours in western South Dakota show the steep rising slope of the Cretaceous layer at the Black Hills. Here the upper layers, including the layer on which this map was contoured, have been eroded away until the pre-Cambrian granite juts out. Mt. Rushmore is formed of this granite.

The dotted line on the map running north and south near the eastern Dakota border indicates the line where the pre-Cambrian granite is just 1,000 feet below the surface. In the crossed sections to the east of this line — the Sioux uplift in South Dakota and a great section of central Minnesota — the pre-Cambrian igneous rock is exposed or has only the thin covering of soil left behind by glaciers.

A well sunk in these areas is apt to "hit bottom" at very shallow depth and with few intervening layers. This is why the eastern half of the Ninth Federal Reserve district is not considered good oil country. East of the dotted line the usual oil-producing layers are either very thin or entirely absent.

Finding Pools Is the Problem

While the general location and depth of sedimentary rock layers likely to yield oil is well known, pinpointing oil pockets within these layers is pretty much of a needle-in-a-haystack affair. Oil gathers in localized pools that lie spread under a large area, and it is these pools that drillers must tap to get oil in commercial quantities.

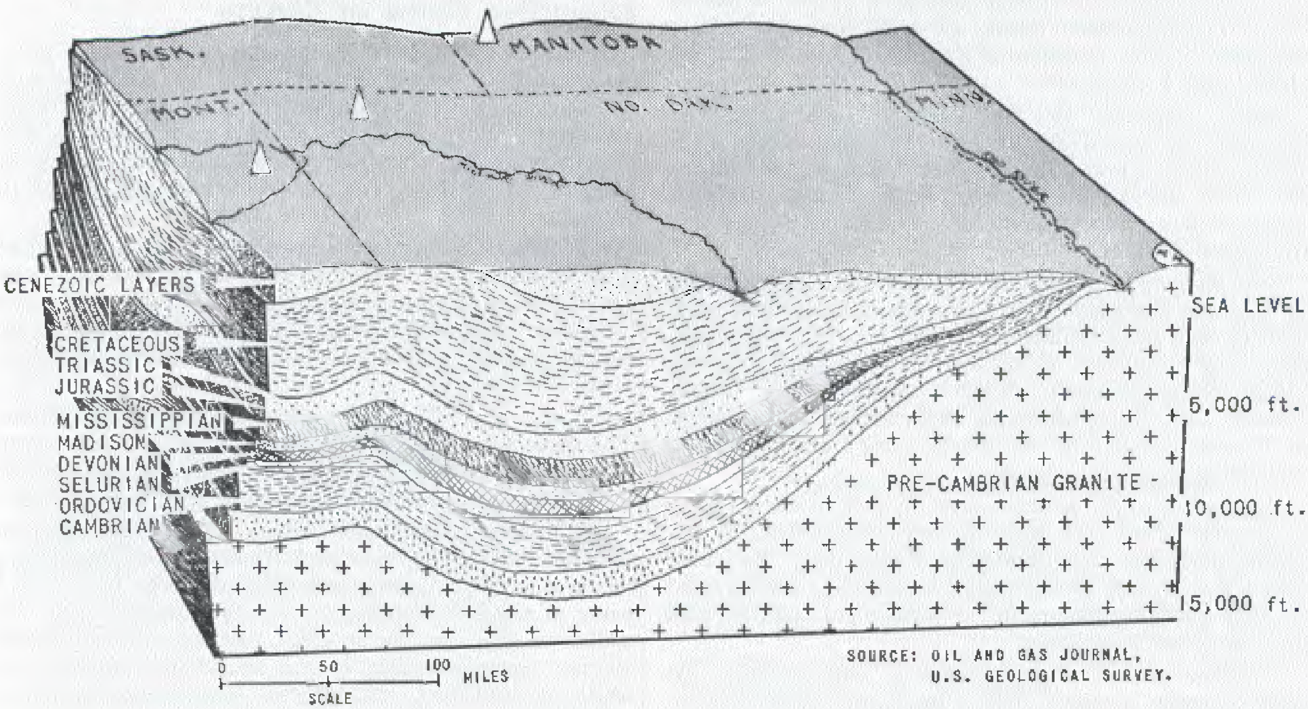
Actually, the layers under the earth's surface are not as smooth as diagrammed in **Chart 2,** but are full of irregular folds and ripples, breaks and ridges. As oil seeps upward through the porous limestone and moves along the sloping undersurface of a layer of impenetrable slate above it, the folds and ripples act to catch and concentrate oil in pools. The underground structures that do this job are called "traps."

One of the important types of traps encountered in oil prospecting is shaped much like an inverted bowl and is called an "anticline." Two large anticlines flanking the Williston basin are shown on **Chart 3.** The Nesson anticline is a long nose-like projection into the basin from the north. Amerada's well is drilled astride this anticline.

The Cedar Creek anticline (sometimes called the Baker-Glendive anticline) in eastern Montana is already a source of natural gas that supplies several western Dakota towns. Shell Oil's important oil strike was near the north end of this anticline.

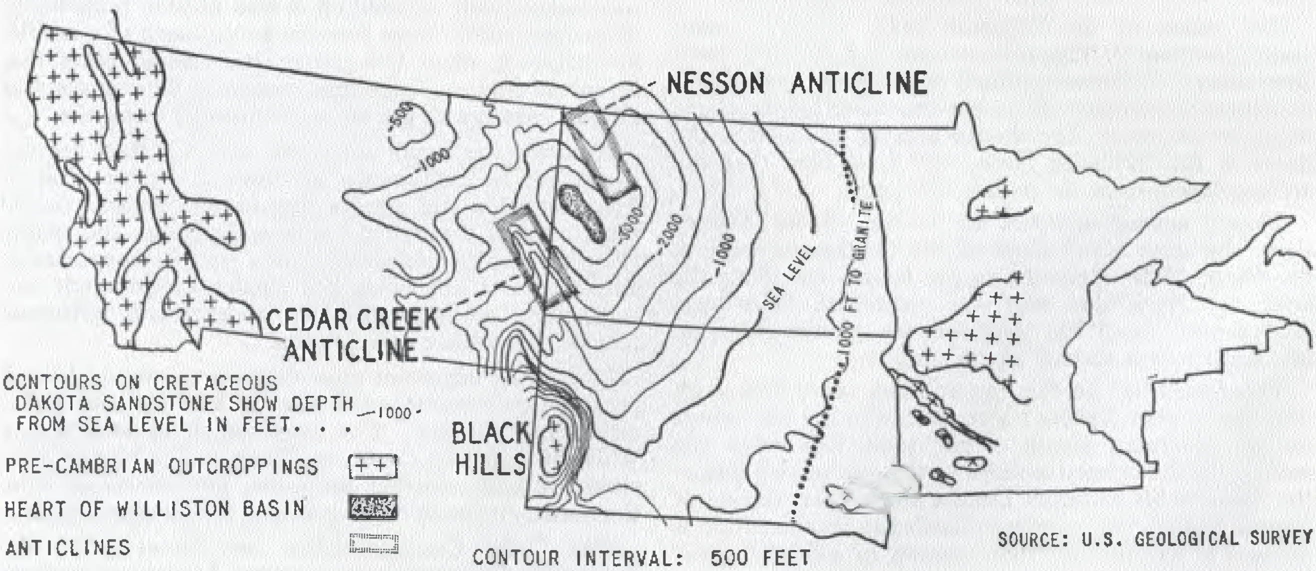
A cross section view of a typical anticline is illustrated by **Chart 4.** This inverted-bowl formation may be anything from a few hundred yards to several miles across.

CHART II — GEOLOGIC FORMATIONS UNDERLYING THE NINTH DISTRICT*



SEDIMENTARY rock layers of the Williston basin—abundant and deep, though scarcely explored—are the basis of hopes that commercial oil supplies will be found in the district. (*Vertical scale on this idealized diagram is exaggerated.)

CHART III — GEOLOGICAL MAP SHOWING WILLISTON BASIN CONTOURS



MOST of the Ninth district's sedimentary deposits belong to the Williston basin trend. Both east and west, granite outcroppings mark the absence of oil-bearing rock.

Typically the layers of sand containing the oil deposits are sandwiched between layers of slate. The heavier water pushes the oil and gas into the curved dome of the anticline.

Exploration Techniques Make Terrain Give Up Secrets

An anticline is one of the underground features looked for in exploration of a likely area such as the Williston basin. To exploration crews, an anticline is sometimes indicated by the contours of the earth's surface and by visible rock formations.

More frequently the underground features are "mapped" by sound. A charge of dynamite is blown off at the surface, and a network of microphones records the sound waves bouncing back from the different rock layers underground. Anticlines are indicated by the way the sound is reflected.

Two years of this "seismic" exploration were expended in choosing the spot where Amerada sunk its successful wildcat well near Williston. At the end of April 1951, there was a total of 18 seismic crews operating in the Ninth district — two in North Dakota, three in South Dakota, and 13 in Montana. An average seismic crew of 15 men and one or two trucks costs from $15,000 to $20,000 a month to operate.

In addition to the seismic crews, in each of the Dakotas a "gravity" crew was scouting the terrain, using a different technique for underground mapping. To these crews, the curving rock layers of an anticline are detected by ever-so-slight changes in the earth's gravitational pull on a sensitive instrument.

Another method of exploration is "core drilling." At chosen depths, a special drill is used to core out a cylindrical piece of rock about four inches in diameter. The core is then studied to find out what layer it came from. After cores have been taken from several locations over a wide area, the slopes and curves of the underground layers can be plotted.

Hitting New Oil Finds Is Expensive Game of Chance

There are two general classes of oil wells — the "wildcat" and the development well. The development well is drilled to increase production from an oil field already established. Since it merely punches a hole into a pool of oil already known, about three out of four such wells produce oil. Out of 221 development wells drilled in Montana in 1950, 151 were successful.

A wildcat well is much more of a gamble, drilled as it is where no underground pool of oil has yet been established. Both the Shell and the Amerada wells were "wildcats." But while these struck oil, most wildcats do not. Of the 64 full-fledged wildcat attempts in the Ninth district during 1950, only three found oil.

Of the dry holes, 15 were drilled in the Dakotas. The three successful wildcats were in Montana. So even with careful exploration prior to drilling, hitting new oil finds is an expensive game of chance.

Oil hunting is not new in the Dakotas. The Nesson anticline, where the successful Amerada well was drilled this spring, was charted during World War I by a field party of the U.S. Geological Survey. The first well was drilled on this anticline in 1926, just six miles southwest of the Amerada strike. It was abandoned as dry at a depth of 4,700 feet, although gas was detected at about 4,300 feet.

In 1938, the California Company drilled to 10,281 feet just a few hundred yards from the 1926 well. It was finally plugged and abandoned with no more indication of oil than a slight odor from the cores cut near the bottom of the hole. The Amerada well, which is six miles northeast, produced oil at about 11,650 feet.

But six miles can make a world of difference in oil geology. The prolific Redwater field in Alberta is only four miles wide by fourteen miles long. A well drilled just six miles out from the center of this field could miss Canada's largest source of oil by four full miles.

This year, attention centers on the Williston basin, where many of Montana's 76 proposed exploratory wells and all of the Dakota's 13 wildcats are to be drilled. Canada's part of the basin may get 60 to 70 wildcat starts this year.

Rotary Drill Is the Favored Deep-Well Technique

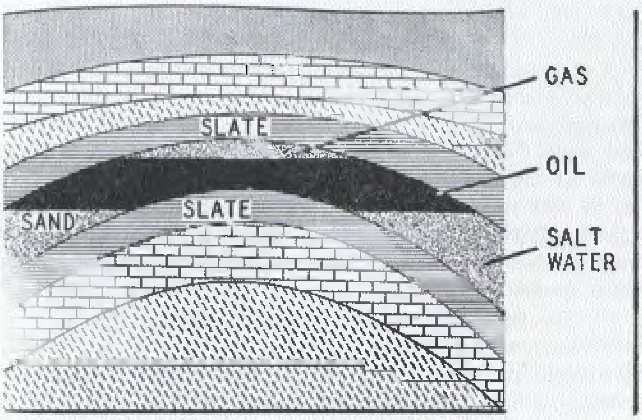
Drilling begins after the "most probable" spot is found. Some wells are drilled by the cable-tool method, in which a weighted cutting tool is suspended on a cable and alternately raised and dropped to chip and hammer its way down through the layers of earth and rock.

But most modern deep wells use a rotary drill technique. In this method, one of a variety of drill bits is fastened to the end of a long string of pipes and the whole assembly is rotated from above. As the bit (which may be anything from a few inches to nearly a foot across) grinds into the earth, a special lubricating mud is pumped down through the pipe to carry back to the surface the particles of rock chipped away by the drill.

The walls of the hole are lined with steel casings which are lowered into the well and cemented in place. For deep wells the casings are usually telescoped; 8-inch, 6-inch, and 4-inch casings may be used in one well.

When the casing is all cemented in place, the well is tested at what seem to be its most promising levels. To test, the casing at a particular interval is perforated by a pistol-like device — a service which may cost the driller close to $1,000.

CHART IV — CROSS-SECTION OF TYPICAL ANTICLINE



GAS AND SALT water which occupy the same reservoir rock as the oil are important in driving oil to the surface.

On the Amerada well, for example, the first test was made between 11,706 and 11,720 feet. When this recovered only a small quantity of mud and oil-water mixture, a second test was made within the 30-foot interval just above it. The second test resulted in a small flow of "sour" gas (gas containing noticeable traces of sulphur). The third test, made on the next higher 30-foot interval (11,630 to 11,660 feet), broke through with a strong flow of oil.

Real Value of Oil Strikes Depends on Variety of Factors

Initial oil strikes in the Williston basin are just the beginning of an important series of events. Development of new fields takes time and costs are high; many factors that will determine the real value of this oil source are not yet known. Early reports on the Amerada well give us a few facts to go on, but the details are sketchy. What are these factors that "make a difference" in the economic production of oil?

Deeper Wells Mean Greater Cost

An 11,700 foot well, such as the Amerada, is comparatively deep. If the rest of the Dakotas' oil lies this deep, it means more cost — more cost for exploration and more cost for oil production. The average cost of wells drilled from 7,000 to 9,000 feet deep is about $12 a foot. Those between 9,000 and 12,000 feet run about $18 a foot, while deeper wells from 12,000 to 14,000 feet cost over $20 per foot.

So the deeper the well the more cost per foot to drill and, judging from these fairly recent figures, Dakota wells might reach up to $200,000 in drilling costs.

Wells have been drilled deeper than 20,000 feet, and there is oil production from as deep as 15,000 feet. However, the average new well drilled in the United States is about 3,600 feet. Since most of Montana's oil is produced from Cretaceous or Mississippian layers at depths of less than 4,000 feet, the average depth of new Ninth district wells is relatively shallow — about 2,300 feet during 1950.

In the Dakotas, it appears that the wells must be drilled deep. Many Texas wells are deep, too. Canada, on the north end of the mid-continent oil belt, seems to require less drilling. The Redwater field in Alberta, Canada's largest, comes from a rock formation only about 3,100 feet underground. The Virden well reported oil at 2,400 feet. It is interesting to note that the first oil in Pennsylvania was struck at 69 feet.

"Thickness" of Zone Is Important

"Thickness" of the producing zone is another feature of oil fields that influences their importance. It is much too early to determine the actual thickness of the pools supplying oil in the Williston area, but at least the interval between 11,630 and 11,660 feet in the Amerada well was producing initially and a second flow occurred between 10,490 and 10,530 feet.

The Leduc field, Canada's big 1947 discovery, flows from an interval that averages 30 feet in thickness at a depth of about 5,000 feet. But one field in Alberta, called the "Golden Spike," flows from a zone nearly 550 feet thick.

Gravity, Base Set Crude Prices

Crude oil quality is an important factor that may help to offset the cost resulting from the greater depth at which the North Dakota well is producing. The most common measure of crude oil quality is given by its API gravity. Oil from the Amerada well was initially reported to be about 53° gravity oil, which is very high.

The API (American Petroleum Institute) measure of gravity puts oil on a scale of degrees between zero and 100°— the higher the number, the lighter the oil. Gasoline runs around 60°-70° API, while water is 10° API. Heavy crude oil might have a gravity around 20°.

In general, the lighter the oil, the higher the price, because lighter oils yield more gasoline. Since gasoline is the major petroleum product in demand in our economy, it is the determining factor in the price of crude oil. If subsequent strikes yield the same high gravity crude oil as the Amerada, it will be a factor offsetting more expensive deep-well production in the Dakotas. Oil from the shallower well at Richey, Montana, was reported to be 38° gravity.

The quality of the oil depends on other factors, too. Some oils have an asphalt base, while others have a paraffin base. The paraffin base oils are considered more valuable because of prominent quantities of lubricating oil hydrocarbons.

The particular qualities shown by the oil after refining make some crudes more valuable. For example, crude oil from the Pennsylvania-New York area sold for an average of $4.25 a barrel during July 1951, while oil from Texas and other mid-continent states sold for only about $2.75. The reason for this lies in the superior lubricating and wearing qualities of the oils refined from Pennsylvania crude.

The presence of sulphur or other foreign substances may add to refining costs and thus affect the price refineries will pay for crude oil.

Pressure Essential to Recovery

Pressure is another important aspect. Oil may be subject to pressures up to several thousand pounds per square inch from the weight of the rock layers which overlie it. It is this pressure that forces the oil up through the well and, in a few isolated cases, causes the spectacular "gushers" that may blow casing and fluids right out of the well hole. But this same pressure, when harnessed, does the work of moving the oil out of the ground.

Even when a well gets too old to "dribble," some normal pressure must be present in order for artificial recovery methods to operate successfully. Pressure in the Amerada well reached a maximum of 400 pounds per square inch at the twelfth hour of an 18-hour test and then declined to 200 pounds per square inch at the end. This pressure is not especially high for an 11,000-foot well.

To start production from the well, the steel casing that lines the bottom of the well is perforated. Since the pressure inside the steel casing is much less than the pressure in the surrounding rock, the oil is squeezed from the porous rock through the casing perforations to its escape route to the surface. This porous oil-bearing rock, by the way, usually has the appearance of solid stone. It takes a considerable push from the salt water and gas sharing the same reservoir to move oil from any extensive area surrounding the well.

Rock Structure Governs Oil Flow

Obviously, structure of the conducting rock will have quite an effect on the volume of flow and also on the sustained rate of flow. Some kinds of reservoir rock, with the same pressure acting on them, have a tighter hold on the oil they have soaked up, and it takes a proportionately bigger effort to recover a share of their oil.

Frequently, it is necessary to rupture the structure of surrounding rock to get an easy flow of oil to the well. This is sometimes done by detonating a charge of TNT at the level of the oil bearing rock. In the case of the Williston strike, several thousand gallons of acid were pumped into the surrounding rock to "eat" some of it away and enlarge the pore openings of the rock.

Getting a steady oil flow can involve many problems even after a good strike has been made, as is indicated by this Associated Press dispatch just two weeks after Shell Oil brought in its strike near Richey, Montana:

> RICHEY, MONT.—(AP) The Shell Oil Co. will try to prod back to life the eastern Montana oil well that started out with a gush and then subsided to a trickle.
>
> Shell officials said Saturday their company's Northern Pacific No. 1, which they reported flowed at a rate of 4,000 barrels a day during one test after it was brought in July 13, will be acidized and fitted with a new drill pipe. The oil flow ceased this week during another test.
>
> . . . the company will core-drill ahead in preparation for further tests.

Gas-to-Oil Ratio Significant

At the Williston well, it was reported that gas flowed along with the oil at rates of from 2 to 5 million cubic feet daily. It was also stated at the initial test that the "gas-to-oil" ratio was about 15,000 cubic feet per barrel. This means that, for every barrel of oil produced at the well opening, 15,000 cubic feet of gas was also produced — a high ratio.

When the gas-to-oil ratio is very high, it may be both less economical and more difficult to produce oil. Much of the reservoir rock may be taken up by highly compressed gas. This normally helps to push the oil towards the well. But a high gas-to-oil ratio may indicate that some of the gas is not pushing, but rather by-passing oil on its way to the well, making it an inefficient oil producer. In some situations, when there is little oil in the rock, it may be more economical to use the well to produce gas instead of oil.

In the Amerada well, a second oil-producing interval was discovered between 10,490 and 10,530 feet(over a thousand feet up from the initial flow). The 300 barrel-a-day flow of the second test was almost the same as the first, but its gas-to-oil ratio was only 1,000 cubic feet per barrel — considerably less than that of the initial test. Under present conditions, it would be more practical to produce oil from the upper interval in spite of its lower (39°) gravity crude oil.

Normally, if there is oil in the reservoir rock, it will take priority, since there is more money in oil. Most of the gas that comes from oil wells is not "dry" gas (such as is found in big pockets underground in some areas of the country), but is "well-head" gas that comes out of the oil as it rises to the surface.

Under the tremendous pressures in the reservoir rock, much gas is compressed into solution in the oil — like the gas in soda pop. As the oil rises to the surface and its pressure drops, gas is released from the oil until at the surface the oil has lost part of its original volume. The gas has now mushroomed to several hundred times the volume of the oil.

In calculating underground reserves, this "shrinkage" must be taken into account. To get a barrel of oil at the surface, it may take as much as a barrel and a half underground. For higher gravity oils, this shrinkage factor is even more important.

Many Factors Influence Profitability of Oil Finds

The output of an individual well usually rises to a peak during the first few years after discovery and then drops off over a long period of years to a trickle. The peak in some outstanding wells may be as high as several thousand barrels a day. But the potential flow of a well — its output when "opened up" — is seldom exploited in actual production.

Running a well full blast reduces the total amount of oil that can ultimately be recovered. Therefore, wherever sound conservation is practiced, a well is never operated above its "maximum efficient rate." For this reason, reports that "Amerada has a potential flow of 350 barrels a day" or that "Shell's initial potential flow is 4,000 barrels a day" do not indicate how much oil is going to flow under production conditions. A few hundred barrels a day might be the practical production limit.

This aspect of oil production logically leads to the question of conservation, which will be treated in Part III. In general, it takes many wells to make an oil field and the average daily output of any one well is relatively low.

All the factors just discussed — depth of oil, size of reservoir, gravity and other measures of quality, efficiency of production, ease of access, pressure, and the presence of gas — influence the profitability of exploiting new oil discoveries.

As the Ninth district awaits news of further developments in the Williston basin, the strictly "oil" aspects of reports will find their importance in the light of the above factors. Once the existence of large proven reserves has been established, the "economics" of oil will come into play.

In summary, the outlook for discovery of important crude oil and natural gas supplies in the Williston basin sector of the district is promising. Oil has been found in the area this year for the first time. More strikes will undoubtedly follow the stepped-up pace of exploration. The strikes themselves may take many months to evaluate, but the general atmosphere is favorable.

PART II OUTLOOK FOR 9th DISTRICT AS A REFINING CENTER

Dominant Pattern of Oil Flow from Texas to Industrial North

The prospects for refinery development in the Ninth district can be better understood within the framework of the nation's well-to-market petroleum structure. This structure is shown in **Chart 5,** a map of the continent picturing the generalized flow of crude petroleum and finished products.

Before they can be consumed, petroleum products go through these distinct steps: (1) crude oil is taken from the well, (2) shipped to refineries, (3) processed into usable items such as gasoline and fuel oil, and then (4) shipped to the market outlet.

Over half of the nation's crude oil is produced in the Texas-Oklahoma-Louisiana area, where a good deal of the refinery capacity is located. The dominant pattern of flow — both crude oil and finished products — is from the Texas area to the industrial north. Crude oil moves by pipeline and by ocean tanker to northern refineries, and refined products move through additional pipelines.

California, also a large producer, is primarily concerned with supplying its own needs and those of the Pacific northwest.

Most oil used in the Ninth district arrives through pipelines as finished products from refineries in Oklahoma, Kansas, or Illinois. Pipelines by reason of lower cost are the preferred means of transportation, carrying four out of five barrels of the nation's oil.

Two existing pipelines of interest to the Ninth district are indicated on **Chart 5.** One gathers crude oil from Montana, Wyoming, and Colorado, shipping it to refineries in the Kansas City area and points eastward. The other is the recently completed pipeline from the Alberta oil fields through northern Minnesota to Superior, Wisconsin, where its 70,000 barrel-a-day capacity has begun delivering oil to lake tankers headed for Ontario refineries.

This, in brief, is the "strategic" framework within which decisions about Ninth district oil will be made.

Source of Oil, Market for Products Determine Growth of Refining

Crude oil as it comes from the ground is not suited to modern needs — it will neither fuel an engine nor lubricate a bearing. The function of a refinery is to convert the crude oil into useful petroleum products — gasoline, kerosene, light and heavy fuel oils, lubricating oils, and lesser hydrocarbons. Modern refining equipment is complex, but basically the crude oil is heated and a series of products distilled off. In 1949, the average refinery yield from a barrel of crude oil (42 gallons) was:

- 18 gallons of gasoline
- 2 gallons of kerosene
- 7 gallons of distillate (lighter fuel oil)
- 9 gallons of residual fuel oils (heavier, cheaper grade fuels)

The remaining 6 gallons were either miscellaneous products, such as lubricating oils, or loss through evaporation or waste. This yield varies considerably, depending on the type of refining equipment used and the quality of the crude oil processed.

On the basis of June 1951 prices*, however, this particular output from a barrel of crude oil would bring a refinery about $3.10. Had crude oil been purchased at the prevailing price of $2.60 a barrel, an operating margin of 50c a barrel would be left to cover operating costs and investment, and to provide the necessary profit.

This, sketchily, is the cost-price economics of the refinery enterprise. Both the source of oil and the market for refined products must be present. Through their effect on prices and costs, they determine to what extent refineries will actually develop.

Williston Basin Oil May or May Not Affect Development of Refineries

Decisions about what will be done with the Williston basin oil must await evaluation of the factors previously mentioned. However, there are certain broad alternatives that will confront the individuals and groups making and influencing the eventual decisions — assuming a large source of oil is proved.

Piping the Oil East

Oil might be piped through existing trunk pipelines to the east to be refined there with existing refining capacity. A line might run south to connect the Williston basin with the Wyoming-Kansas route†, or north to the Canadian crude line to the Great Lakes. This would mean little change in present distribution channels.

Small refineries (less than 5,000 barrels a day) that partly meet local needs are bound to spring up in the vicinity of oil sources and pipelines where small quantities of oil may economically be purchased, processed, and sold. But this would not result in any generalized, large scale development of refinery capacity within the district sufficient to serve the district's needs.

Feeding Local Refineries

A second alternative would be the establishment of large scale refinery capacity in the district which would then meet most of the district's requirements. Refining centers might be established in the immediate oil producing areas — near the Williston basin — and the finished products piped or shipped to the major consuming areas.

More likely, the refining capacity would develop farther east at points near the Twin Cities or the Duluth-Superior area, because these centers are the major consumers in the district and have more well-established shipping and marketing channels, such as railroads, truck lines, and lake and river shipping.

Relative consumption of petroleum products in 1949 for the states shown in **Chart 6** gives some idea of the concentration of the district's petroleum market in the east.

Refineries have a whole series of products to market. Heavier low grade fuel oils, which sell at a considerably lower price than the other products, would find their best market where heavy industry and marine transportation equipment are located. This would be another factor tending to encourage the location of large refining capacity near the Twin Cities and Duluth-Superior areas rather than farther west.

Minnesota's present consumption of residual oils is low because it doesn't pay to ship them in from refining areas, while Montana's consumption of this class of products is higher because local refineries make the product available at a low price.

Probably the greatest potential market for all grades of petroleum products is centered in the east where adjacent areas of Wisconsin and Iowa would fall into the marketing area.

Decisions to build refinery capacity in the district would not be unanimous among oil companies. Companies with substantial capital invested in existing refineries and distribution channels would undoubtedly prefer to move Williston basin oil to their present refineries and ship the finished products back to the area as they do now.

Canadian Oil Major Influence Behind Expansion in Refining

Probably the major force in Ninth district refinery expansion will be Canadian oil. With or without Dakota oil, there are certain features that ordinarily make Canadian oil significant to the Ninth district. The Minneapolis area is a natural market outlet for Alberta oil—that is, it would be more economical to supply this area from Alberta and use Texas-Oklahoma oil through present channels to supply part of eastern Canada's oil needs.

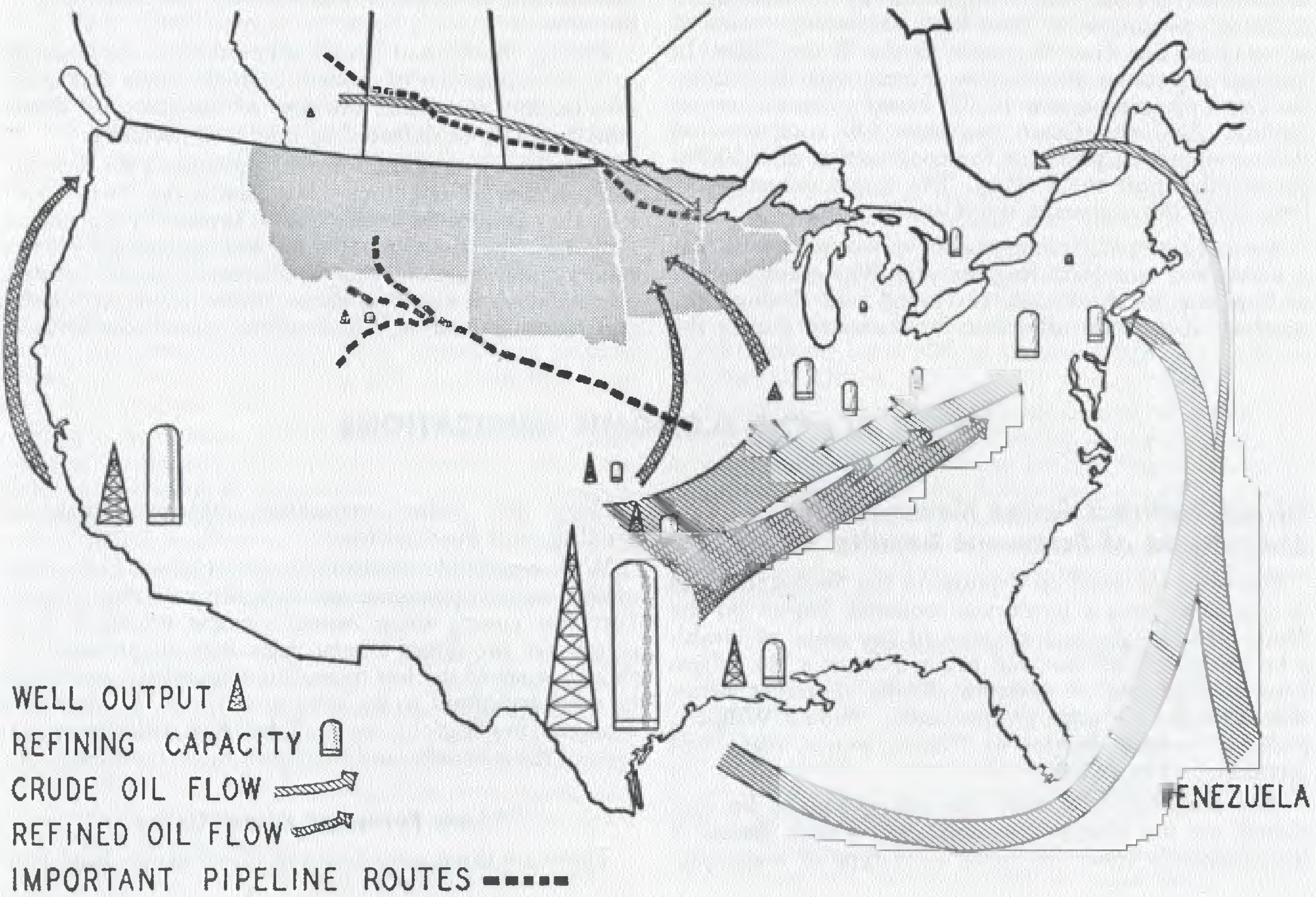
Three factors taken together would seem to give impetus to refinery construction: (1) the logistic advantage of Alberta crude in the Minneapolis area, (2) the area's potential consumption of nearly 200,000 barrels daily, and (3) its present lack of refining capacity. A flow of Williston basin oil would strengthen this tendency.

The State of Minnesota, with these conditions in mind, passed legislation during 1951 designed to stimulate refinery development. Refinery property, both real and personal, will henceforth be assessed for purposes of taxation at a reduced rate. There will be no tax loss,

* Representative Midwest refinery prices at the end of June 1951: gasoline, 11c a gallon; kerosene, 9c; distillate, 8c; and residual fuel oil, 4c.

† North Dakota and Montana have both been named among potential sources of oil for the Platte river pipeline under construction during 1951 that will parallel the existing Wyoming-Kansas line.

CHART V — STRATEGIC PATTERN OF CRUDE OIL AND PETROLEUM PRODUCT FLOW IN U.S.*



since refinery expansions and additions are a source of new tax income not previously existing.

Possibility of Tariff

Two possible restraining factors to the use of Canadian oil are occasionally cited. The first of these is restrictions on imports by the U.S. The 1951 tariff duty on the importation of Canadian crude oil amounts to 21c a barrel, with some minor amounts getting by at half that rate.

Arrangements for duty-free oil imports from western Canada, to be balanced by U. S. oil exports to eastern Canada, are due for discussion in the House Ways and Means committee. But there is agitation in Congress, particularly from the coal industry, for higher tariff rates.

A bill was introduced in the 82nd Congress proposing an increase in the tariff on fuel oil to $1.05 a barrel, and a substantial increase in the existing tariff on other petroleum products. Since it costs around 60c a barrel to ship finished products by pipeline from Tulsa refineries to Minneapolis, it can be seen that importing Canadian crude would become increasingly uneconomical as tariffs are raised.

Potential Export Restrictions

A second factor operating against use of dominion oil is the potential restriction on exports from Canada.

THE NINTH district lies outside the major petroleum distribution channels, which primarily find Texas oil being piped to the nation's industrial heart.

* Nine-tenths of the nation's oil production and refining capacity is depicted by symbols on the map. Heights of wells are proportional to average daily production during 1950, while height of refining towers is proportional to daily crude oil capacity at that time for the states shown.

The provincial governments, quite logically concerned about the exploitation of resources within their own borders, have established agencies such as the Alberta Petroleum and Natural Gas Conservation board charged with the responsibility of regulating petroleum. Concern by these bodies is particularly evident over the question of exporting natural gas. But crude oil exports, should demand rise to the point where reserves do not seem adequate to meet Alberta's own future needs, will undoubtedly undergo some restrictions.

Evidence Points to Ninth District Becoming a Refining Center

The evidence suggests, however, that those who make decisions in the oil industry have largely discounted these two influences. Here are the facts:

First, refinery construction is being undertaken and contemplated. At Superior, a 5,000 barrel-a-day refinery was purchased from the Carter Oil company in Montana and moved in to process Canadian oil. The addition of a 22,000 barrel-a-day unit announced by Northwestern Refining company at St. Paul Park also brought hints of a crude oil line from Superior to the Twin Cities. In August, it became known that International Refineries, Inc., was planning a new 11,500 barrel-a-day refinery at Duluth. And the Great Northern Oil company has defense-approved plans for the construction of a 30,000 barrel-a-day unit in St. Paul. The major influence behind these developments was Canadian oil.

Secondly, the Canadian pipeline comes to a port that is closed five months during the year. The costly storage at Superior, or the drastic cut in oil sent through the pipeline that would otherwise be necessary during the winter months, makes it probable that some of the through-put of this line was intended for marketing in this area.

Finally, the United States is becoming — increasingly so — a net importer of crude oil, which means that measures tending to restrict the flow of Canadian oil would most probably be defeated by economic necessity.

In summary, the Ninth district's prospects for development as a refining center—particularly the Twin Cities and the Duluth-Superior area — appear to be sound. Although the shortage of steel will undoubtedly delay refinery construction, this development seems assured. Some Canadian crude oil seems already destined for this area. And Dakota oil, if it develops, would also be used.

PART III THE ECONOMIC IMPLICATIONS

Direct, Indirect Gains Measure Magnitude of Economic Results

Discovery of large oil deposits in the Williston Basin is certain to have a significant economic impact on the Ninth district. As an indication of the scope of wealth a booming new oil area can bring, Alberta's 1¼ billion barrels of proved oil reserves already represent better than $3 billion in underground assets. Should Williston basin oil actually develop as a major source, many will certainly feel its effects.

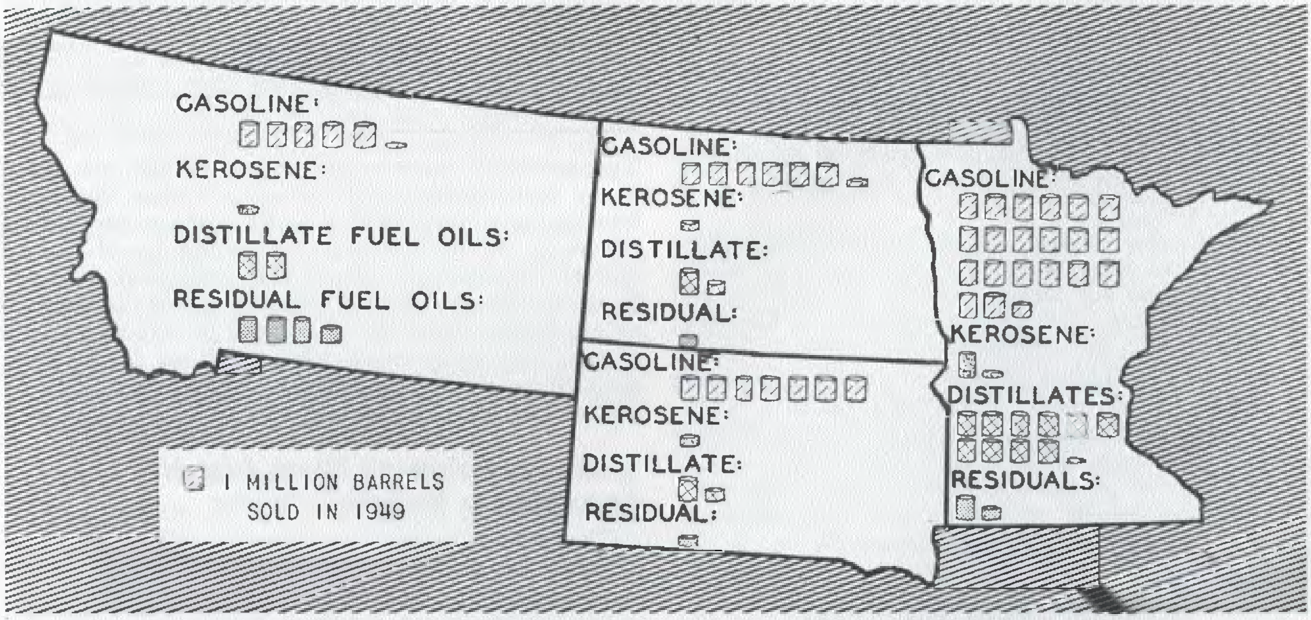
The economic effects of new oil, it should be cautioned, are not always favorable. Along with discovery has frequently come "oil fever"— a type of boom psychology that fosters speculation, overinvestment, instability, and financial loss.

With reasonable foresight, however, the development of this valuable resource can bring far-reaching benefits. Foremost among these benefits in the minds of most people are the direct money gains that oil promises, although some of the less immediate effects may eventually be more important to the area as a whole. In reviewing economic implications, we shall deal first with the magnitude of these benefits and then with their duration.

Three Forms of Direct Gains

There are three main forms of direct gains: lease pay-

CHART VI — SALES OF PETROLEUM PRODUCTS IN NINTH DISTRICT DURING 1949



MARKET concentration in the larger metropolitan centers will help decide refinery location. Better than 55% of the value of 1949 petroleum sales shown on the chart were in Minnesota.

Source: American Petroleum institute; U. S. Bureau of Mines.

ments, royalty payments, and taxes on production.

Lease Payments: Payments for leases may be made for some time before there is actual oil production in a particular area, and they usually cease when oil is struck. The lease itself can take many forms, but ordinarily it grants the oil company the right to explore and drill for oil for a period of about three to five years. In return, the landowner is paid an initial bonus and an annual rental.

Bonus and rental payments are customarily 10c an acre, but in "hot" areas bonuses may be several hundred dollars an acre with rentals of $5 or $6 an acre — as has been the case in the Williston basin. Several million acres in the Williston basin have been leased since the Leduc discovery in Canada in 1947. This income has reached millions of dollars, and there is still no proof that large oil reserves actually exist.

Royalty Payments: Under the usual terms of a lease, when oil production begins the landowner is paid one-eighth of the value of oil produced. It is this one-eighth interest that is customarily referred to as the "mineral rights" of the landowner. And these mineral rights, in turn, may be legally split up into small fractions and sold. There has been much speculative buying of such rights in the Williston basin.

Royalty payments can reach sizeable proportions. Should the Williston basin attain Alberta's 1950 production level, about $10 million would be paid annually in royalties. Not all of this would be paid locally, since large shares of mineral rights are not held by local individuals. Some will be paid to brokers, speculators, and other outside interests who have purchased mineral rights in the Williston basin.

Some will go to the federal government. In Montana during 1950, about $3 million was paid in royalties on oil production valued at $24 million. Close to 40 percent of this went to the federal government for royalties on public lands and Indian lands.

Some lending institutions have retained 50 percent of the one-eighth mineral rights on land taken over during the depression and subsequently offered for resale.

Railroads, too, have extensive land holdings. Shell Oil company's strike near Richey, Montana, was on land leased from the Northern Pacific railroad. The strike occasioned a rather sharp jump in the price of stock in the railroad, which had received more than one-half million dollars from oil royalties during 1950.

Taxes on Production: Most of the states tax the removal of oil and gas from land within their borders, and, like royalties, these payments vary directly with the total amount of production. In Montana, crude oil taken from the ground is taxed at a rate of 2 percent of gross value plus an additional one-fourth cent for each barrel produced. On 1950 production, this amounted to around $420,000. Such tax income, unlike royalties, goes entirely to the producing state.

Nature of Indirect Gains

Immediate Results: Additional gains, of course, have been felt by every community in the Williston basin. The influx of individuals with money to spend — leasemen, company officials, exploration crews, drilling crews, brokers, speculators, and newsmen — causes local business to swell. Most of this "new money" will move on as initial activity subsides, but it adds to the boom atmosphere.

Long-term Results: More permanent developments, which will not occur until oil sources are proven, are more difficult to assess. There is a connection, however, between large crude oil and natural gas supplies and the development of certain types of industries.

The petro-chemical industry turns petroleum into a host of chemicals, plastics, and synthetic materials. Growth of the chemical industry in Texas can be traced to the readily available crude oil that is its raw material and to the availability of natural gas as a low-cost fuel. For similar reasons, the Celanese Corporation of America is now building a $50 million chemical plant in the prairie province of Alberta.

Natural gas, if available in large quantities in the Williston basin, could possibly furnish a low-cost fuel for processing lignite and taconite, both of which are found in larger quantities in this district than anywhere else in the country. The part Williston oil would have in stimulating refinery growth has been discussed, but the effects of large supplies of oil on other industries would obviously be favorable too.

Oil Development Problems

New oil development also carries with it dangers of overexpansion and excess. The "oil fever" stage of the development cannot always be kept in hand. Businesses and municipalities that overexpand in the expectation of an oil boom may find themselves saddled with debt they cannot justify or repay.

Conservatism on the part of local communities before oil is proven and the application of conservation principles after oil is in production will contribute more to the solution of unsound expansion than anything else.

Extent of Deposits and Conservation Spell Duration of Economic Results

The economic effect of oil production is measured not only by the rate at which oil income is received, but also by its duration. After oil is producing, the next important question is: "How long is this going to last?"

The long-term wealth that Williston basin oil represents to the district depends on three factors: (1) the amount of oil actually present in the ground, (2) efficiency of the recovery methods, and (3) stability of the market on which the oil is sold.

No one can do anything about the first of these factors, but sound conservation measures can favorably influence the workings of the second and third.

Extent of Oil Deposits

"Reserves" are the amount of oil actually in the ground, and "known reserves" are that portion so far proven. Calculating oil reserves in the Williston basin is an engineering problem that can be done fairly accurately. However, it will take considerable drilling and measurement for each new strike.

Reserves in Montana's biggest field — the Cut Bank field — were estimated to be 33 million barrels at the beginning of 1951. Since its discovery in 1931, a total of 70 million barrels has been recovered from the field, while its production during 1950 was around 3 million barrels. Should production continue at present rates, the field will have been exhausted over a 30-year period ending in the early 1960's.

Once recoverable reserves have been estimated for a given field, it does not necessarily mean that the end will come as soon as that figure is exhausted. For many fields, there is successive expansion through the discovery of additional supplies out on the flanks of the field or at different levels in the ground below. Exploration in the oil industry is a continuing business. Other, newer fields may be found near-by that will continue to benefit the locality in the face of decline of the older fields.

Efficiency of Oil Recovery

Underground oil represents nobody's wealth, however, unless it can be brought to the surface and used. And the recovery methods used influence greatly the amount of oil that will be gotten out of the ground. When oil is recovered too rapidly — as typified by the gusher-style production of earlier years — underground damage occurs that cuts down the ultimate ability of the well to produce oil.

Some of the oil in the ground is never recovered. It is estimated that under modern methods about one barrel in five is still left in the ground after the last possible barrel has been pumped out. But this is a great improvement over the wasteful oil production of earlier days when an estimated three out of five barrels were permanently left in the ground. Producing oil too fast reduces total recovery.

The oil-producing states administer conservation laws directed at eliminating waste, motivated by the facts that (1) oil is a vital and irreplaceable resource and (2) it can be wasted through improper production and handling methods. Co-ordination and exchange of ideas between states on matters of conservation is accomplished through the Interstate Oil Compact commission, a voluntary organization chartered by Congress to which most oil-producing states belong.

One of the important conservation measures an oil state might adopt limits the rate at which a well may flow to its "maximum efficient rate" of production. Another measure prohibits "flaring" gas — that is, allowing it to escape or burning gas to avoid handling it.

Some states set a maximum allowable gas-to-oil ratio, with credit given for re-injecting the gas into underground layers. In modern oil fields, some gas is wasted, but more and more is being put to work by pumping the gas back down into the producing sands to maintain the pressure that is responsible for oil flow.

Additional measures provide for unit operation of oil fields and set forth requirements about waste disposal, pollution of underground fresh-water supplies, spacing of wells, and plugging of abandoned wells. All these conservation measures share the common purpose of ensuring maximum benefit from the state's oil resources.

Condition of Oil Market

The third factor affecting the economic return from oil is the price the oil sells for when it finally is brought to the surface. The dime-a-barrel markets such as have occurred after oil gluts of the past can be disastrous to oil-dependent communities and to the institutions financing them. For this reason, conservation measures aimed at eliminating the above-ground waste resulting from overproduction are highly important to the oil area.

"Proration" is the chief measure for combating instability. Proration, administered under the state conservation laws, attempts to distribute equitably among the producers of the state the probable market need for that state's crude oil. Both the Bureau of Mines and the American Petroleum Institute make estimates of the probable market demand for each state or producing district. The states can then use these figures to allot each field its proportionate share.

Proration when carefully followed keeps above-ground stocks to a safe working level, minimizing the loss through handling, evaporation, and fire. Proration has a stabilizing effect on the price of crude oil without obstructing its response to long-term supply and demand factors.

The resulting stability is in pleasant contrast to the violent fluctuations in prices that could otherwise follow oil discoveries and the dumping of large new supplies of oil on the market. Without this stability, a sound development of both oil and the community are not likely — a moral quite well illustrated throughout the history of oil production.

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