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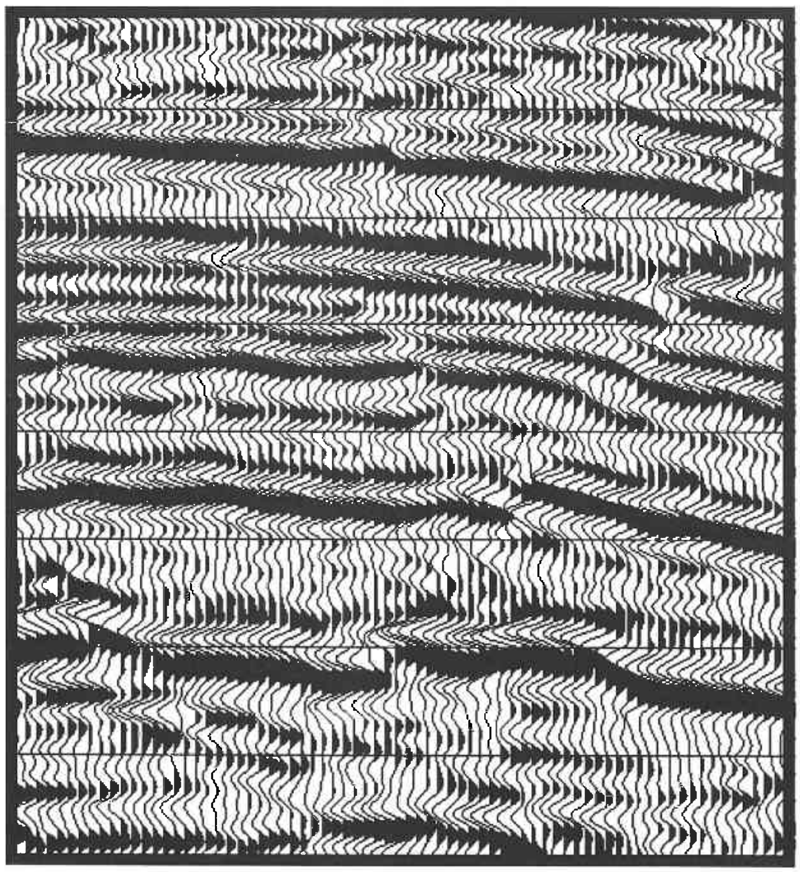
Two- and Three-Dimensional Seismic Methods:
Effective Application Can Improve Your Bottom Line



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Two- and Three-Dimensional Seismic Methods:
Effective Application Can Improve Your Bottom Line

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The University of Oklahoma
Norman, Oklahoma
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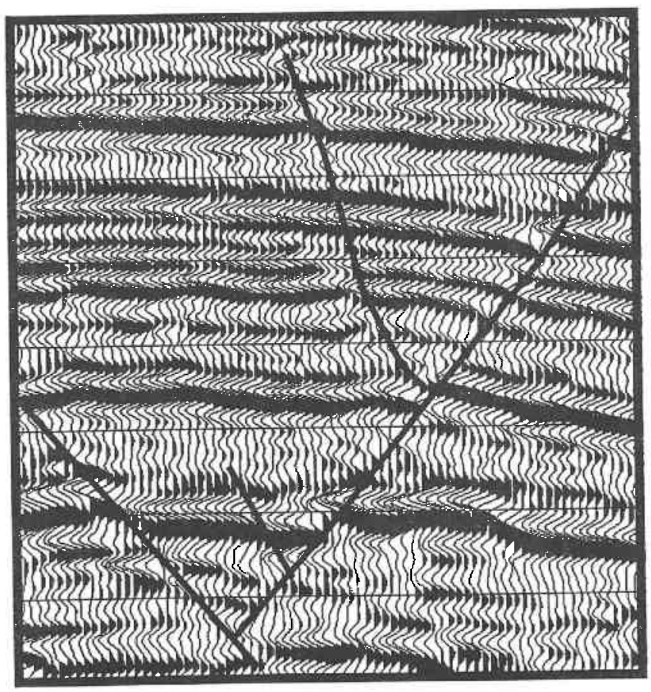
SPECIAL PUBLICATION SERIES

The Oklahoma Geological Survey's Special Publication series is designed to bring timely geologic information to the public quickly and economically. Review and editing of this material has been minimized in order to expedite publication.

***Front Cover.*—**Uninterpreted variable-area display seismic line. Can you interpret the complex faulting on this illustration? (The interpretation is shown below.)

Interpretation by Deborah K. Sacrey



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Introduction to Geophysical Theory

Introduction to Geophysical Theory

Deborah K. Sacrey
and
Raymon L. Brown

INTRODUCTION

Definition of Seismic

The *Encyclopedic Dictionary of Exploration Geophysics* (Sheriff, 1991, p. 262) defines *seismic* as: "**1.** Having to do with elastic waves. Energy may be transmitted through the body of an elastic solid by body waves of two kinds: *P*-waves (compressional waves) or *S*-waves (shear waves) . . . or along boundaries between media of different elastic properties by *surface waves*. . . . Equated with 'elastic,' often with 'acoustic' and 'sonic.' **2.** Having to do with natural earthquakes. Derived from the Greek 'seismos' meaning 'shock.' "

The science of seismology is the study of naturally occurring earthquakes. Seismologists were motivated to understand the destructive forces of large earthquakes. They learned that the seismic waves produced by earthquakes contained valuable information about the structure of the Earth's interior. Much of our understanding of the Earth's layers (crust, mantle, and core) is based on the analysis of seismic waves produced by earthquakes. Seismology is a branch of geophysics—the physics of the Earth.

Seismic waves, when used at a man-made scale, have a more practical use. They are used to find mineral resources. In this sense, exploration geophysics explores the layers of the Earth near the surface, whereas seismology is used for understanding the Earth at depth.

Earthquake waves have periods ranging from a few seconds up to 60 sec, but the waves used in seismic prospecting are much shorter, with periods on the order of 0.01–0.1 sec.

Man-made seismic waves are just sound waves (acoustic waves) with frequencies ranging from ~5 to >100 Hz. As these sound waves leave the seismic source and are transmitted through the Earth, they encounter changes in the rock layers, which cause "echoes" (reflections) to travel back to the surface, where they are recorded by geophones; the recorded information is then converted to electrical signals. These signals are manipulated (amplified, filtered, digitized, etc.) to become the images on paper or at a workstation, where a geoscientist combines the signal information with known geological data from wells to determine the subsurface configuration.

Beginnings of Seismic Methods

The earliest known seismic instrument, the seismoscope, was produced in China about A.D. 100 (Sheriff, 1991). It consisted of a vase with several dragons mounted in circular fashion on the exterior. A small ball was wedged in the mouth of each dragon. An earthquake motion would cause a pendulum fastened to the base of the vase to swing. The pendulum in turn would knock a ball from one of the dragons into the mouth of a toad directly below the dragon. This was supposed to indicate the direction from which the tremor came (Fig. 1).

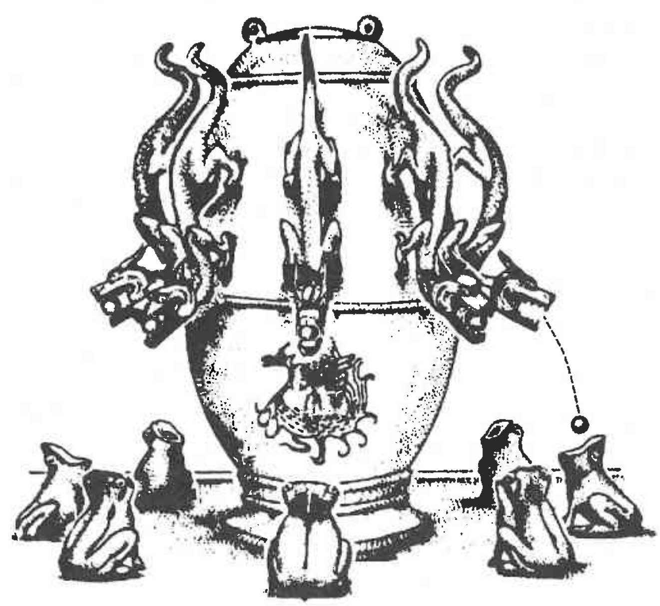


Figure 1. The seismoscope, the earliest known seismic instrument, which was produced in China about A.D. 100. From Sheriff (1991, p. 264).

Studies of the Earth by measuring acoustic waves generated by earthquakes started in the mid-1800s. This was the beginning of earthquake seismology, or crustal geophysics.

Birth of the Seismic-Reflection Method

It is believed that the first seismic-reflection experiments and exploration took place in Oklahoma.

J. Clarence Karcher (1974) wrote a book titled *The Reflection Seismograph, Its Invention and Use in the Discovery of Oil and Gas Fields* in which he outlined the research and history of seismic reflection, to which today's modern seismic methods are directly attributable.

Dr. Ray Brown, Oklahoma Geological Survey staff geophysicist, has written an excellent article (see p. 4) that treats in detail some of the events Karcher described in his book. As the search for oil moved to deeper targets, seismic reflection, not refraction, became the method of choice.

Beginning in the early 1930s, seismic exploration in the United States surged as the technology was developed and refined. Late in the 1950s, and throughout the 1960s and early 1970s, there was a drastic drop in the U.S. crew count. During this period, the ability to record digitized seismic data on magnetic tape was perfected, which was to have a tremendous impact on seismic exploration. Recording the signal on tape, and then processing it with a computer, not only improved the fidelity of the subsurface image but greatly improved the productivity of seismic crews. It is safe to say, in fact, that modern seismic acquisition could not have evolved without the digital computer.

For the last 20 years, the number of seismic crews worldwide has been directly related to the price of oil (Fig. 2). In 1990, U.S.$2.195 billion was spent worldwide in geophysical exploration activity (Goodfellow, 1991).

The late 1970s saw the development of the three-dimensional (3-D) seismic survey in which the data imaged not just a vertical cross section of the subsurface but provided a three-dimensional view as well. This technology has progressed, driven by the cost per unit of commodity, through enhanced processing and acquisition techniques, to bring finding costs to the lowest level (in real dollars) since World War II.

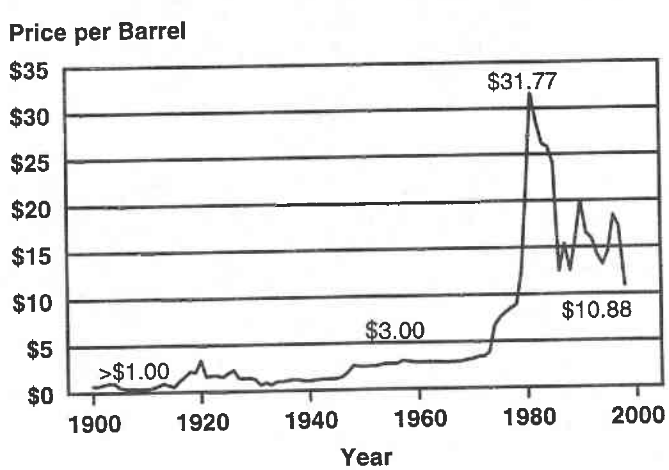


Figure 2. Graph showing price per barrel of oil, 1930–90.

PRINCIPAL SOURCES GENERATING SEISMIC WAVES

Dynamite

The most common source for generating acoustic or seismic waves for recording has been a single explosive charge. A shothole is drilled to a depth ranging from 20 to >200 ft deep. The explosive is then capped and lowered into the hole with a wire, which is attached to the recording equipment. The hole is then filled with sand (sometimes water) to hold the charge in place and force the energy to go downward rather than have it "shoot" out of the hole like a shotgun. Afterward, the hole is partly plugged with cement, with soil filling the remainder (Figs. 3, 4).

A single charge is an *impulsive point source*: all of the energy is generated at one time, in one location. Within reason, the amount of seismic energy produced per shot can be increased by increasing the charge size (to allow deeper penetration of seismic waves into the Earth). At some point, there are diminishing returns as larger charges are used.

Two strategies can be used to overcome the limitations of a large impulsive point source:

1. Distribute the source energy in space. This can be done by dividing a single massive charge into small point charges and firing them together in spatial patterns (source arrays). This method is effective because it produces more seismic energy than does the large single-charge method, and the arrays can be designed to reduce noise problems.

2. Distribute the source energy in time. A single massive charge is replaced by many small charges that are fired sequentially from a single shotpoint. The data are then stacked to simulate the shot of a single massive charge.

Generally, dynamite produces more energy and a broader bandwidth than any other seismic source.

Problems with Dynamite

1. *Environmental issues.*—Explosive sources are often restricted near population centers, wildlife refuges, major faults (the energy can move along a surface fault and damage dwellings), and other environmentally sensitive areas. In marine shooting, dynamite can damage reefs, kill fish, and destroy oyster beds (a big issue in the Gulf Coast region). These issues can be costly to a company trying to acquire data.

2. *Cost.*—It is costly to send a crew out, drill shotholes, put sand in the holes, and repair any surface damage caused by the explosions.

3. *Safety.*—Dynamite is, after all, an explosive, and even modern handling techniques are not completely safe.

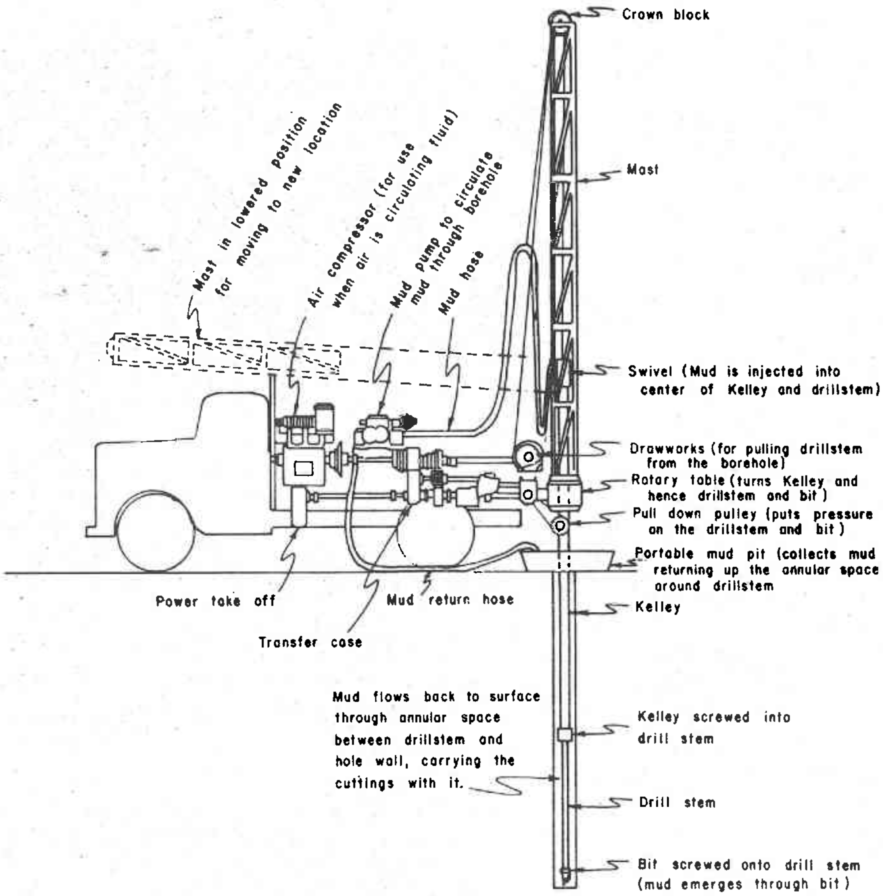


Figure 3. Diagram of a truck-mounted rotary drill. From Sheriff (1991, p. 93).

soft ground. However, because the trucks can easily travel on roads, many two-dimensional (2-D) lines are shot along highways and secondary roads rather than through private property.

2. *Lower energy source.*—Generally, a vibrating source produces a lower frequency signal at depth than dynamite, which could mean shorter shotpoint distances and specialized processing to strengthen the signal at depth. The final result could be higher costs per mile and/or lower quality data.

Thumpers

A variation on the theme addressed in the section on dynamite—distributing source energy in time—would be to use a "thumper." The "charge" is created by dropping a heavy weight on the ground multiple times in the same spot; then, like the multiple dynamite charges, the information is "stacked" to represent one large impulse.

As early as 1924, F. Hubert in Germany claimed that he could obtain reflections from depths down to 15,000 ft from the impact of 200-lb weights hitting the ground after being dropped from heights up to 30 ft (Dobrin, 1960). A commercial system based on this principle was called the Geograph and was first used for oil exploration in 1953.

Thumpers have not been used nearly as much as dynamite, vibrators, or even air guns (which are used in marine seismic exploration) because they generate low-energy–low-frequency seismic waves. In the past few years, weight-drop or thumping devices have made a comeback in the shallow-resolution segment of the industry. Mounted on the backs of all-terrain vehicles

(continued on p. 10)

Vibrating Sources (Vibroseis)

Another way of overcoming the limitations of an impulsive point source by distributing the source energy over time is the use of a continuous vibrating source.

The original *Vibroseis* device was tested by Conoco in 1966. The vibrating source is mounted on trucks the size of a garbage truck weighing as much as 50 tons. It produces seismic energy by vibrating a weight on a pad held in contact with the ground. The weight itself is about 2 tons. The vibrator goes through a "sweep," from high frequencies to low (or low to high). A vibrator creates a relatively low-amplitude signal that may last for 30 sec or more. The data are recorded during the duration of the sweep, and later are processed to make them appear as if they had been shot by an impulsive source (Figs. 5, 6).

Arranging several vibrators in an array and synchronizing their signals in time can then distribute the source energy in space as well as time.

Problems with Vibrating Sources

1. *Surface damage.*—Vibrating sources are usually mounted on large trucks that can wreck

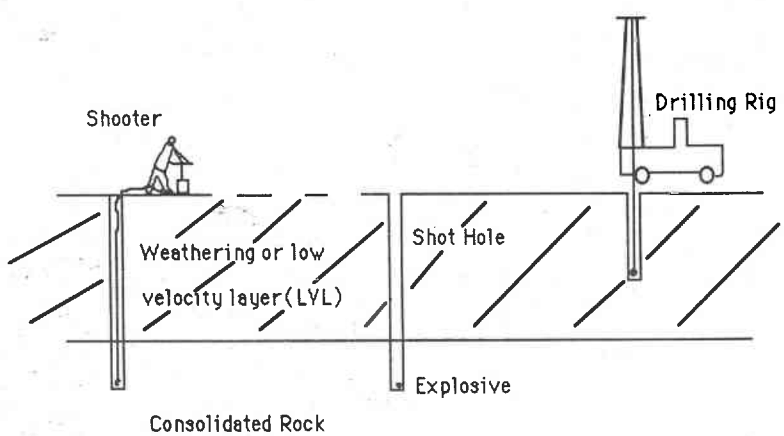


Figure 4. Cross section of the shallow subsurface, showing shotholes. From Evans (1997, p. 105).

Birth of the Seismic-Reflection Method

Raymon L. Brown

BACKGROUND

This story is about J. Clarence Karcher and his role in developing the seismic-reflection method used today for seismic exploration. The first experiments and seismic-reflection exploration took place in Oklahoma.

The story is one of perseverance and persistence. These are exactly the qualities Thomas Edison, the great American inventor, told Karcher he needed in order to complete an idea. I have taken much of the story presented here from Karcher's (1974) book titled *The Reflection Seismograph, Its Invention and Use in the Discovery of Oil and Gas Fields*.

Another man, Reginald Fessenden from Canada, is credited with developing the fathometer (a marine echo sounder) before Karcher actually implemented his studies. Because the fathometer uses reflections to map the sea floor, some authors give Fessenden credit for initiating the seismic-reflection method. However, Karcher's work led directly to the type of seismic-reflection method used for subsurface exploration. There is quite a difference between implementing a seismic-reflection experiment in water and implementing one used to detect layers below the Earth's surface. Thus, Karcher's work led directly to the seismic-reflection method used in the industry today.

KARCHER'S EARLY HISTORY

J. Clarence Karcher was born April 15, 1894, in southern Indiana of German–French ancestry. When he was 5, his family moved near Hennessey, about 50 mi northwest of Oklahoma City. He graduated from high school in 1912. After graduation, he entered The University of Oklahoma (OU) in the autumn of 1912. There, he began the study of electrical engineering. Later, he changed his major to physics. He graduated in June 1916 from OU with a bachelor's degree in physics.

Karcher started graduate school in physics at the University of Pennsylvania in September 1916. He studied X-rays in graduate school and met Thomas Edison during his graduate work. This is when Edison told Karcher that persistence and perseverance were important elements in making an idea work. In addition, he told Karcher to make a note of any unusual phenomena that might lead to potential new ideas. Karcher must have listened carefully to Edison, because his story contains all these elements.

WORLD WAR I—THE BEGINNING OF AN IDEA

The U.S. entered World War I in April 1917. In June of that year, Karcher left the University of Pennsylvania and accepted a position with the U.S. Bureau of Standards as an assistant physicist. While at the University of Pennsylvania, Karcher had taken a course in the theory of sound. The text for the course were the two volumes by Lord Rayleigh (1945) titled *The Theory of Sound*.

When Karcher began working at the Bureau of Standards, the people at the Bureau were already studying the transmission of sound through air and water. In fact, they had already begun developing a method of locating enemy artillery by sound ranging.

Karcher was assigned the task of designing and constructing a device for detecting and recording blasts from the muzzles of field-artillery pieces by using the transmission of sound waves through air. While working on this project, Karcher designed a microphone for the reception of air waves from cannon. During subsequent tests, however, it was soon realized that wind and temperature had a strong effect on air waves.

At this point, Karcher and his associates began discussing the use of seismic waves transmitted through the ground instead of through the air in the hope that such waves would be more useful for locating artillery positions. Two types of geophones were built at the Bureau machine shop, and field testing began. During the testing, Karcher noted, as Thomas Edison had suggested, what appeared to be reflection events on the record. After a week's work, the geophone method was abandoned for artillery purposes. The air sound-wave method was developed into a relatively simple device and was constructed for field service and forwarded to the U.S. battle front in France. Karcher then went to France and worked on an assortment of artillery-related experiments during the war. He never forgot the reflections observed during this wartime testing.

Thus, Karcher's experiments during World War I led him to believe that seismic waves reflected through the subsurface could be observed and recorded. This was the beginning of Karcher's ideas.

RETURN TO GRADUATE WORK—THE GROWTH OF AN IDEA

Karcher returned to the University of Pennsylvania in 1919 to work toward a Ph.D. in physics. During his studies, he remembered the seismic waves that had been observed as reflections during his work with the artillery experiments. It was at this time that he came up with the idea of using the reflected waves to map the depth of hard subsurface limestone layers to aid in the search for oil and gas, which he had learned about while he was in Oklahoma during his undergraduate studies.

On June 1, 1919, Karcher spent

some more time at the Bureau of Standards testing the feasibility of detecting reflections in a rock quarry. This work convinced Karcher more than ever that the reflection method would work. Several patent applications resulted from these studies.

THE OU CONNECTION

While in graduate school in Pennsylvania, Karcher communicated with Dr. W. P. Hasemen and Dr. D. W. Ohern. Ohern was the director of the Department of Geology at OU while Karcher was an undergraduate. Now, Ohern was the Oklahoma state geologist. Haseman was the director of the Department of Physics at OU. In addition, Karcher also contacted Dr. Anton Udden, director of the Department of Geology at The University of Texas.

After Karcher had reported the results of his experiments in the rock quarry, Haseman and Ohern hoped to interest oil producers in the Oklahoma City area in the idea. They began looking for potential investors.

GEOLOGICAL ENGINEERING COMPANY

Karcher graduated with a Ph.D. in physics from the University of Pennsylvania in June 1920 and went to work again for the U.S. Bureau of Standards. In this phase of his work at the Bureau, he designed and built a piezoelectric pressure gauge for obtaining pressure–time curves of the pressures in the breeches of howitzers and other artillery pieces. This gauge was still in use at the beginning of World War II.

While Karcher was involved with his work at the Bureau of Standards, Haseman and Ohern succeeded in getting the oil industry interested in trying Karcher's idea. The result was that Haseman and Ohern talked the Ramsey Brothers and Frank Buttram, a graduate geologist, into forming a company called the Geological Engineering Company. They financed the experimental project with $100,000. Karcher was offered an interest in this company, and he immediately began designing the equipment for the necessary experiments.

THE EXPERIMENTAL PHASE

Farm Near Oklahoma City

The initial testing of the seismic-reflection method as an exploration tool began in the spring of 1921. The first test site was a farm 3 mi north of Oklahoma City. The experiments entailed successions of trial and error, involving changes of instrumentation, shot size, and the distances of shotpoints from receivers.

Arbuckle Mountains

Once the method for recording was developed, Karcher went to a site in the Arbuckle Mountains where limestone of the Ordovician Viola Group is overlain by the Sylvan Shale. Karcher shot a reflection profile over the area and confirmed his reflection calculations when the reflector dip computed from the seismic records agreed with the dip predicted by geologists.

Ponca City

After some additional testing around the Oklahoma City area, the experimentation was taken north to Ponca City, Oklahoma, where seismic profiles were shot over Newkirk dome. Reflections were obtained from the Permian Fort Riley Limestone. The structural position of the limestone was determined from logs of nearby wells, and the seismic data showed close agreement. The experimental work was concluded September 9, 1921.

FIRST EXPLORATION WITH THE SEISMIC-REFLECTION METHOD

On September 13, 1921, Karcher signed an exploration agreement with Marland Oil Company. The seismograph party consisted of J. C. Karcher, W. P. Haseman, Rex Ryan, and field labor. The initial exploration took place in sec. 28, T. 25 N., R. 4 W., in Grant County, northern Oklahoma. Next, the Deer Creek structure on the border between Kay and Grant Counties was explored.

Shortly before this, Garber oil field, near Enid (to the south), was discovered in July 1921, apparently without the benefit of seismic reflections. Additional wells quickly proved the field to have a multimillion-barrel potential. Unfortunately, there was no method of controlling production at that time. As a result, the market demand for crude oil was quickly exceeded, and the price of oil dropped from $3.50 per barrel to $2.00, to $1.00, to 50¢ in 2 months. (Does this sound familiar?)

About two months later, another new and even larger oil field, Burbank, was brought into production 12 mi east of Ponca City. There was a mad rush to buy leases and drill more wells, from which flowed thousands of barrels per day. More oil was produced than could be transported or easily stored. As a result, the price of oil dropped to 15¢ per barrel.

As a result of the low prices and the general feeling within the industry that shallow structures (300–500 ft) could simply be found by drilling, the oil companies and producers lost interest in the seismic-reflection method. On December 22, 1921, Karcher and his associates closed down their company and stored their equipment. Karcher returned to work at the Bureau of Standards, and then he found a job with American Telephone & Telegraph Company.

KARCHER'S SECOND CHANCE

Three years elapsed before Karcher would have another chance to test his ideas regarding the seismic-reflection method. During this time the price of oil had risen from 15¢ to $3.00 per barrel, because the exploration methods in use at that time were not able to bring in enough reserves to maintain the supply. As a result of the increased demand, several companies contacted Karcher about his seismic-reflection method.

The first company to call was Marland Oil Company, whose geologists had cooperated with Karcher during his first efforts in Oklahoma.

Shortly after the call from Marland, Harold V. Bozell contacted Karcher from New York. Bozell had been the director of the Department of Electrical Engineering at OU when Karcher was a student. Now, Bozell wanted Karcher to fly to New York and meet the vice president of Amerada Corporation, an oil company that operated in northern and central Oklahoma, the site of Karcher's early experiments and exploration.

Bozell arranged for Karcher to meet Everette DeGolyer, the Amerada vice president, for lunch. Donald Barton, a staff geologist, was also present. The discussion focused on the use of the seismic-reflection method to produce a contour map of an anticlinal structure capable of entrapping oil and gas. This luncheon led to the formation of a new company.

Geophysical Research Company

DeGolyer and Karcher met on April 10, 1925, in St. Louis and planned a geophysical exploration company. The company would be owned by two oil companies, Amerada and Rycade, and by Karcher. The company was chartered as Geophysical Research Company of New Jersey, with offices in New York City. Karcher was vice president and general manager.

Karcher employed Eugene McDermott, who was a graduate student at Columbia University in the Department of Physics. Another physicist, Dr. F. M. Kannestine, was hired. He had obtained his Ph.D. at the University of Chicago and had been a laboratory assistant to Prof. A. A. Michelson in conducting experiments measuring the various properties of light.

EARLY SUCCESS WITH REFRACTION WORK

Shortly after assembling the staff for the Geophysical Research Company (GRC), Karcher's team heard about the success of a German seismologist, Ludwig Mintrop, who had used the seismic-refraction method to locate salt domes. By September 1925, GRC had fielded its first seismic-refraction crew for experimental testing. Three months later, this refraction crew was leased to Gulf Oil Corporation.

At about this time, the equipment for a first commercial reflection crew was completed and was put to work in the field October 11, 1925. The seismic-refraction method continued to dominate the early seismic efforts, however.

A major difference between the seismic-refraction and -reflection method is the distance between the shotpoint and the geophone. In the refraction method, the distance was usually 3 to 8 mi. No reflected events were recognized during these experiments because of the large distances involved. Only the traveltime from the source to the receiver was obtained from refraction measurements. However, by pointing the refraction instruments in different directions, intrusive bodies such as salt domes could be detected.

By July 1926, GRC had three refraction crews searching for salt domes along the Texas and Louisiana coasts. These crews were directed by E. E. Rosaire, Eugene McDermott, and B. B. Weatherby. Still another man, H. B. Peacock, joined the staff later in July.

During the first 2½ years of operation, GRC refraction crews helped discover 100 domes. Many of these domes were found for Gulf Oil Corporation, which often leased four crews at a time. By 1928, the first marine refraction lines were being used. Because of the large areas covered by refraction surveys, it was soon becoming apparent that with new competition and the limited extent of salt domes, the refraction method had an uncertain future.

THE SEISMIC-REFLECTION METHOD'S NEW FORM

In contrast to the large distances (3–8 mi) between shotpoints and geophones for refraction work, shorter distances were used in the early reflection studies. Generally, the separations were one-fourth or less of the depth to a reflecting formation, such as a limestone or sandstone. In early reflection work, geophones were set out in a line away from the shotpoint, using 100-ft spacing. The greatest offset of a geophone from the shotpoint was generally 400 ft.

Reflections were usually identified on the records by *moveout*, or time differences between the same events on different records. As the quality of the instrumentation increased, the number of geophones increased from 2 to 4 to 8 on each side of shotpoints spaced 100 ft apart so that a balanced pattern could be obtained.

After each point was shot, using the symmetrical pattern described above, the cable and geophones on one side were picked up and advanced to the opposite side of the next shotpoint in a "leap-frog" manner. By repeating this procedure, a continuous profile of reflection depth points 50 ft apart could be obtained. This method permitted great detail in the reflections recorded.

THE SEISMIC-REFLECTION METHOD'S FIRST DISCOVERY

On about October 1, 1925, GRC organized an experimental crew, which was run by J. E. Duncan. His first surveys were made over the top and east side of Nash salt dome in Brazoria County, Texas. He obtained good reflections from the dome's anhydrite cap. After this initial work in Texas, Duncan's GRC crew moved to Shawnee, Oklahoma, on the west edge of a newly developing oil field.

The producing zone was the "Wilcox" sand of the Simpson Group of Ordovician age. In this area, the contact between the Viola limestone and the overlying Sylvan Shale is an excellent reflecting surface. Duncan continued his experimental work in this area with a crew of four or five men.

Encouraged by Duncan's work in the Shawnee area, H. B. Peacock was asked to assemble a crew in Oklahoma City for GRC. Once assembled, the crew moved to Shawnee and began mapping by taking reflections from the Viola–Sylvan contact, above the "Wilcox." At that time, the Shawnee area was the most active in the country in the discovery of new oil fields producing from the "Wilcox."

During the period when Peacock was exploring the area, he was able to find a high point on an anticlinal structure by mapping reflections from the Viola limestone.

On September 13, 1928, Amerada Corporation spudded the No. 1 Hallum well in the NE¼SE¼SE¼ sec. 1, T. 8 N., R. 4 E., Pottawatomie County, Oklahoma. The well was completed December 4, 1928, as a commercial producer at about 4,144 ft total depth. "This was the first oil well in the world to be drilled on structure mapped by a reflection seismograph" (Karcher, 1974, p. 37).

On the basis of seismic-reflection maps, a second well was drilled by Amerada, the No. 1 Edwards, in the SE¼NE¼NE¼ sec. 22, T. 9 N., R. 5 E., Seminole County, Oklahoma. This well was completed November 19, 1929, at a depth of 4,400 ft with an open flow of 8,000 bbl of oil per day. Thus, the seismic-reflection method was originated and proven in Oklahoma.

THE METHOD ACTUALLY WORKS!

In 1929, Amerada elected a new president, who recognized the advantages of the seismic-reflection method for exploration. He decided that GRC would shoot reflection surveys only for Amerada, and refraction records only for other firms. However, it became obvious to Karcher that the demand for the reflection method would be tremendous in a few years. In a bold move, Karcher sold his interest in GRC and left the company on January 1, 1930.

GEOPHYSICAL SERVICE, INC.

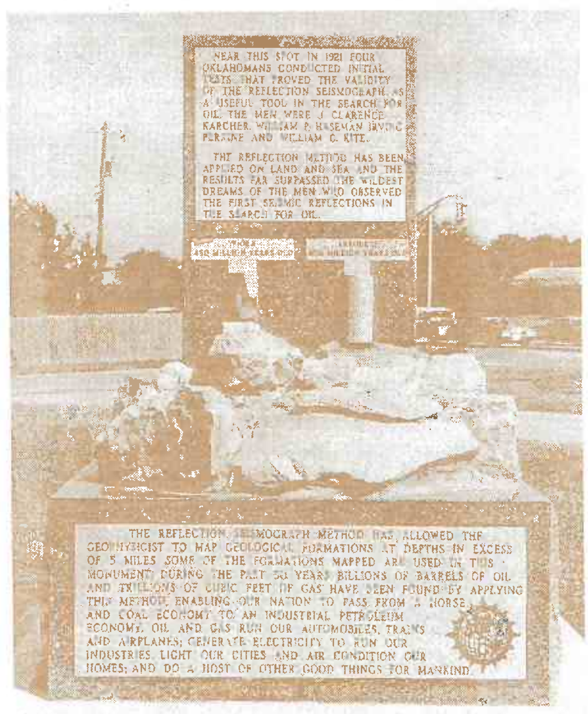
After leaving GRC, Karcher organized a new geophysical company named Geophysical Service, Inc. (New Jersey). He invited Eugene McDermott and H. B. Peacock to join him in this new venture. As soon as it was apparent that they could put their first crew in the field, Karcher designed a form for contracts and made multiple copies.

Armed with the new contract forms, Karcher boarded a train to Houston, where he promptly contracted two crews to each of two major companies. Then seven additional crews were assigned to individual companies in the Houston and Dallas areas as well as in Tulsa.

GSI put its first crew in the field on June 7, 1930, and continued to put one or more crews in the field per month; all 11 crews were in the field before the end of the year. The second GSI crew was run by Peacock. The crew was based in Texas, where a faulted anticline was discovered 12 mi southwest of Palestine. The discovery well was completed in October 1933 as a commercial producer from Cretaceous Woodbine sandstones. This field, Long Lake, was the first oil field in Texas whose discovery resulted from the use of the reflection seismograph. Long Lake field has now produced more than 32 million bbl of oil.

By the end of 1933, GSI had nearly 40 crews in the field and had begun serving the foreign market. Because no seismic-reflection crews were operating when GSI got started, the United States was virgin territory for the first 11 crews. As a result, the number of discoveries over the first 5 years was impressive. During that time, closed structures against a known fault, as well as large anticlinal structures, were discovered by the reflection seismograph.

During the next 10 years, crews in North America numbered more than 300. From 1940 on, the reflection seismograph went worldwide, and by 1960 more than a thousand crews were operating. Depths of exploration now extend to more than 35,000 ft.



This monument, erected by the Geophysical Society of Oklahoma City, honors J. C. Karcher and his fellow researchers. It also commemorates the birthplace of the reflection seismograph. The inscription reads, "Field tests which confirmed the validity of the reflection seismograph method of prospecting for oil were conducted near this spot on June 4, 1921. The shot has virtually echoed around the world."

HONORING KARCHER

In 1971, a monument in honor of Karcher and the reflection seimograph was dedicated by the Geophysical Society of Oklahoma City on the 50th anniversary of Karcher's first successful tests. W. R. Wolfe, then president of the Geophysical Society, made the dedicatory presentation. The monument was erected on the lawn of the Belle Isle Branch of the Oklahoma City Library system.

Part of the dedication text on the monument reads as follows: "Near this spot in 1921 four Oklahomans conducted initial tests that proved the validity of the reflection seismograph as a useful tool in the search for oil. These men were J. Clarence Karcher, William P. Haseman, Irving Perrine, and William C. Kite."

The work of these men led to the most powerful exploration tool, and its outgrowths, in use today.

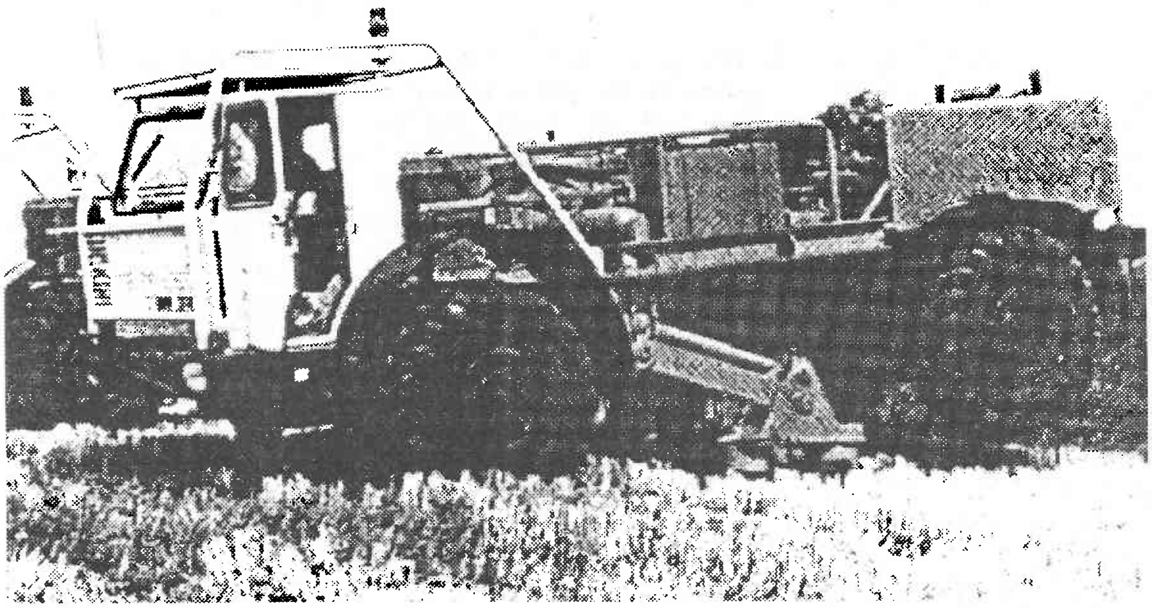


Figure 5. Vibrator sweeping, with rear wheels off the ground. From Evans (1997, p. 114).

(ATVs), these machines have the ability to go cross-country with little surface damage and cover large areas in a short time. The main set-up time involves surveying and setting up the geophone array. The data obtained are stacked and processed, much like dynamite or Vibroseis data, and can be utilized as 2-D or 3-D information. The depth limitation of good resolution depends on the subsurface geology. In the Midcontinent, good resolution can be obtained down to 8,000 ft. In the Gulf Coast region, where the sediment is less consolidated, good resolution can be obtained only down to 5,000–6,000 ft.

Problems with Thumpers

1. *Low-energy source.*—As mentioned, the weight-drop method generates a very low-energy–low-frequency waveform, and multiple drops must be made to stack and process the information so that it can be used. Additionally, surface "noise" generated with the dropping weights can be difficult to process out of the data, creating a larger signal-to-noise ratio.

2. *Cost.*—Even though the ATVs can go cross-country with ease and encounter few environmental complications, the low-energy thumper source demands a denser shot pattern. Group intervals for dynamite or Vibroseis data could be as much as 165–220 ft apart, whereas thumpers could require group intervals as close as 50 ft.

COMPONENTS OF A SEISMIC WAVE

To understand how seismic data are acquired, processed, and interpreted, it is important to review how seismic waves are propagated through the Earth and how they are affected by changes in geology.

After the initial fracturing of the hole around the exploding energy point, further transmission of energy can be explained by assuming that the Earth has the elastic properties of a solid. The Earth's crust is considered completely elastic, and thus the name given to this type of energy transmission is *elastic-wave propagation.*

Several kinds of wave phenomena can occur in an elastic solid. They are classified according to the way in which the particles that make up the solid move as the wave travels through the material.

Compressional Waves (*P*-Waves)

When energy is released at a shotpoint, a compressional force causes an initial volume decrease of the medium on which the force acts. The elastic character of the rock then causes an immediate rebound or expansion, followed by a dilation force. This response of the rock is considered a *primary compressional wave* or *P*-wave.

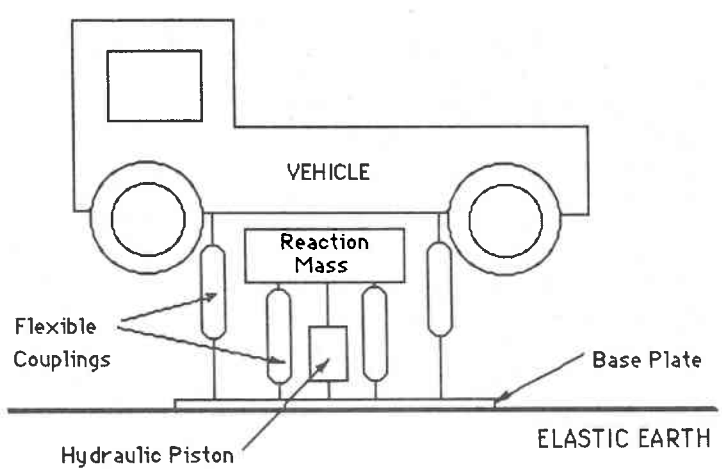


Figure 6. Schematic drawing of a typical vibrator sweeping in the field. From Evans (1997, p. 113).

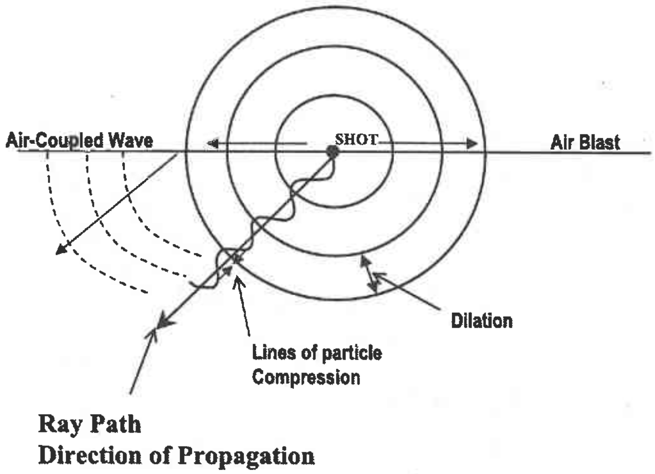


Figure 7. Diagram showing compressional-wave (*P*-wave) transmission.

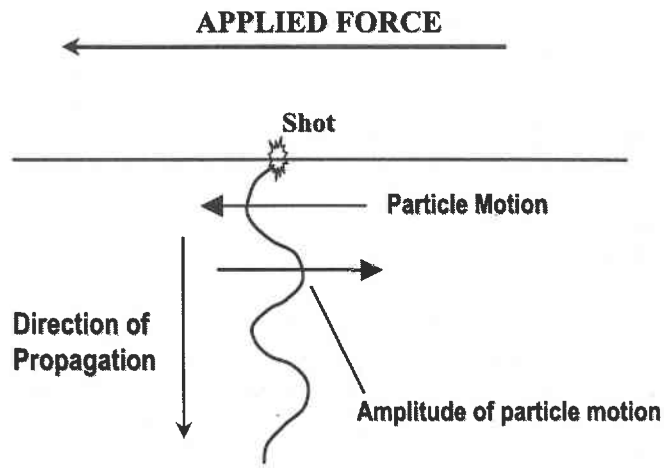


Figure 8. Diagram showing shear-wave (*S*-wave) generation.

In an imaginary sense, if you were to put a finger against a rock in line with *P*-wave propagation, your finger would move back and forth in the direction of wave propagation just like the particles that make up the rock. Thus, particle motion in a *P*-wave is in the direction of wave propagation (Fig. 7).

P-wave velocity is a function of the rigidity and density of the rock. In dense rock, the velocity can range from 7,500 to 22,000 ft/sec. In spongy sand (close to the surface), the velocity of propagation could be as little as 900–1,500 ft/sec.

When looking at old seismic-reflection or seismic-refraction records, the *P*-waves generally can be seen to be the fastest traveling waves and were the "first arrivals" on the records. *P*-waves are the primary waves used in interpretation of data today.

Shear Waves (*S*-Waves)

Shear strain occurs when a sideways force is exerted on a medium; a *shear wave* or *S*-wave may be generated that travels perpendicularly to the direction of the applied force. Thus, the particle motion of a shear wave is a right angle to the direction of propagation. Shear-wave velocity is a function of the resistance to shear stress of the material through which the wave is traveling, which is approximately one-half the material's compressional (*P*-wave) velocity.

Again, if you were to put your finger on a rock being subjected to a shear wave, your finger would move from side to side (90° to the direction of the *P*-wave). *S*-wave movement can be compared to the movement of a guitar string when plucked (Fig. 8).

For years, *S*-waves had been little used in the acquisition, processing, and interpretation of seismic data. Recently, however, companies have started acquiring *S*-wave information along with *P*-wave information. These data are known as three-component (3-C) seismic data if acquired on land, and four-component (4-C) seismic data if acquired in water (owing to specialized energy sources).

The *P*-wave data are processed into a regular seismic-amplitude volume. *S*-wave data are extracted from special recording geophones and are processed into what appears to be a normal-amplitude volume. The information that each volume provides when interpreted is much different, and the use of the *S*-wave vol-

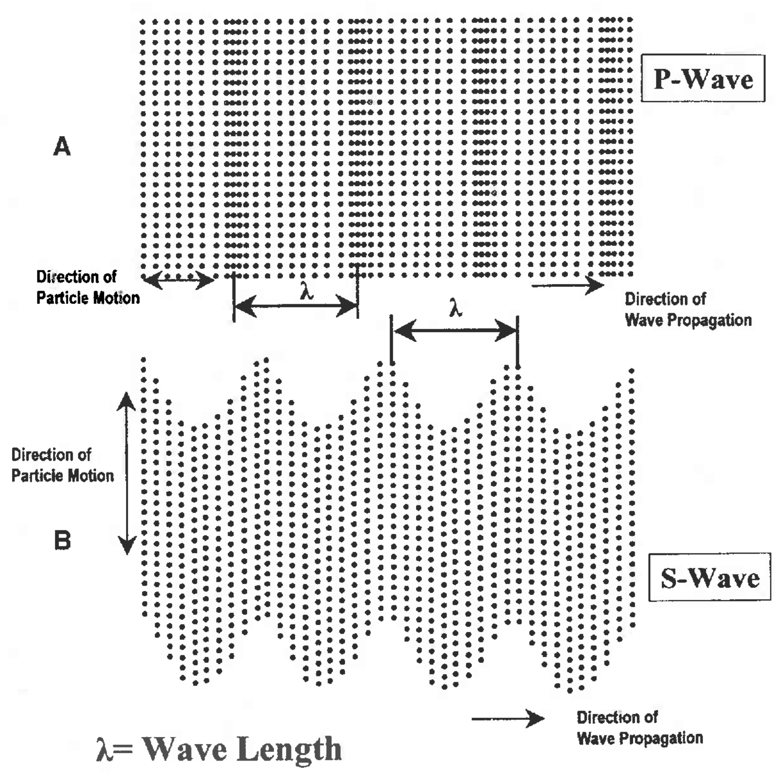


Figure 9. Diagram showing various aspects of *P*-wave (A) and *S*-wave (B) propagation.

ume can give a much better understanding of a rock's internal properties, such as porosity and permeability (Fig. 9).

At this time, acquiring 3-C data volumes is significantly more expensive than acquiring only compressional information and has not been widely used in the industry. Like any other technology, a better understanding of the importance of the data should lead to more use and lower costs.

Other Seismic Waves

Several additional seismic waves deserve mention, because they affect the way seismic data are processed.

One problem with acquiring land data is the surface layer or *weathered layer,* which consists of freshly deposited sediments or surface rock that has weathered to become semi-consolidated. The weathered layer is also known as the *low-velocity layer* or LVL because of the slowness in which the *P*-waves are propagated. The LVL also allows the transmission of surface waves along the air–surface boundary.

Surface waves spread out from a disturbance similar to ripples seen when a stone is tossed into a pond. One type of surface wave is the Rayleigh wave (named after Lord Rayleigh, a physicist who developed an explanation of surface waves), which is a low-frequency wave that travels horizontally away from the energy source with a retrogressive elliptical motion (Fig. 10).

Another type of surface wave is the *Love wave,* which is a surface wave generated within the LVL and has horizontal motion perpendicular to the direction of propagation with no vertical motion. *Direct* or *head waves* represent the expanding-energy wavefront that moves along the "slow–fast rock" interface; these waves have the velocity of the "faster" layer through which they are moving.

Surface waves are also called *ground roll.*

Points to Keep in Mind

Seismic waves are "sound" in rock. The shotpoint is a source of sound, the seismic wave generated and spreading out from the source is a simple sound wave in a solid, and the reflection/refraction is an "echo" from a rock contact.

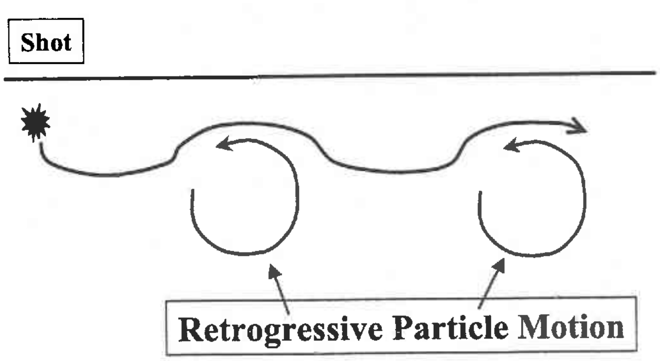


Figure 10. Diagram showing surface-wave motion.

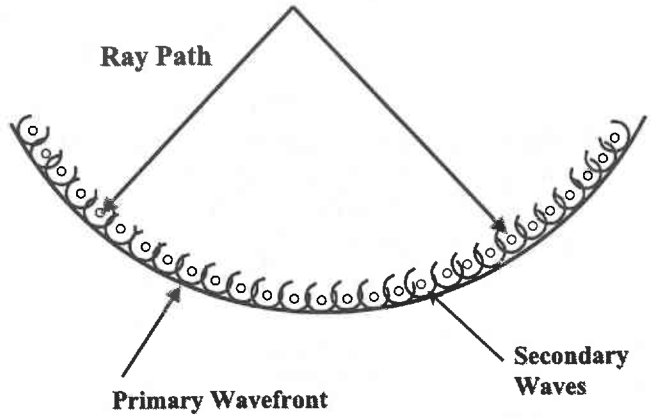


Figure 11. Diagram illustrating Huygens' principle.

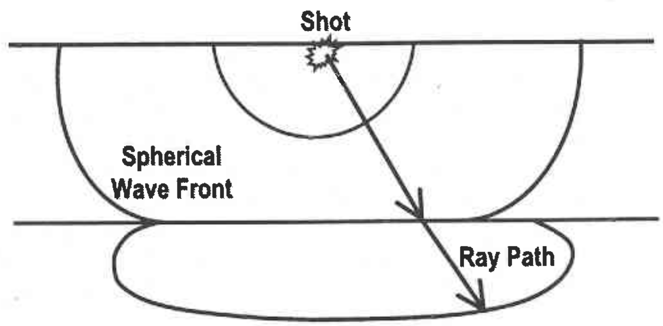


Figure 12. Diagram illustrating raypath trajectory.

That is why you hear the terms *acoustic, amplitude,* and *frequency.* Seismic data are processed much like music today, through filters and amplifiers, to be interpreted (or listened to).

Some echo-ranging systems with which you may be more familiar are *radar*—radio waves that travel at the speed of light—and *sonar*—sound waves that travel through water. Both are recorded and interpreted with echoes, just like seismic data.

SIMPLIFIED RAY THEORY

Seismic waves created by an explosive source move outward from the shotpoint in a three-dimensional (3-D) sense. Huygens' principle (named for Christian Huygens, a 17th-century Dutch mathematician and physicist) states that every point on an expanding wavefront can be considered as the source point of a secondary wavefront (Fig. 11). The trajectory of a point moving outward is referred to as a *raypath.*

From here on, the raypath concept is used to explain what happens when a wavefront expands. For instance, when refraction and reflection methods are discussed, the diagrams will show rays to represent the path of propagation of energy (Fig. 12).

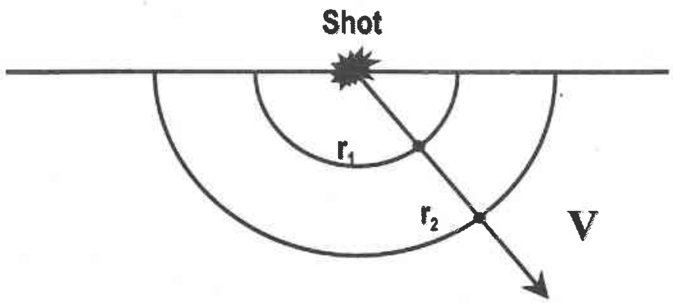


Figure 13. Diagram illustrating spreading loss, one type of amplitude decay.

Amplitude Decay

There are two types of amplitude decay, *spreading loss* and *absorption.*

As a wavefront expands outward from the shotpoint, the energy is spread over a larger and larger area. Ignoring absorption for the moment, this spreading loss means that the wave's amplitude is inversely proportional to the distance traveled. The deeper the wave goes, the "thinner" it is spread (Fig. 13).

Amplitude loss also occurs as a wavefront passes through rock, which vibrates the rock particles. The vibrating particles absorb energy as heat, thus the term *absorption.* Amplitude loss from absorption varies exponentially with distance. For a fixed velocity, absorption loss is *frequency* (the wavefront's energy measurement) and *distance* dependent. At short radial distances from the shotpoint (shallow depths), the spreading loss is greater than the absorption loss. At greater depths, the absorption loss tends to be greater than the spreading loss. The effect of absorption explains why deeper events in shot records generally have a lower frequency content.

SEISMIC-REFRACTION METHOD

The seismic-refraction method, which was used for early seismograph work, requires shot-detector distances several times greater than the depth being explored. This method depends on the refraction back to the surface of waves that have penetrated some distance below the surface.

When seismic data (sound waves) strike a rock layer (interface), going from one hardness (velocity) to another, some of the sound is not reflected (echo producing) but continues on its way. The path through the rocks is not exactly the same but is bent. This change in direction is called *refraction.* The amount of change in direction depends on the degree of difference in velocity (hardness) of the rock (no difference, no bend; slight difference, slight bend; large difference, larger bend).

The bend also depends on the angle at which the sound hits the interface (perpendicular, no bend; slight angle, slight bend; and so forth).

When the interface is a change to a faster velocity (harder rock), the bend is in the direction of an increasing angle from the vertical, causing the energy to bend in a direction away from the source.

As an example, think of how a stick appears when it is placed in a glass of water: it appears straight before it goes in, but it appears bent below the surface of the water (Fig. 14). This is how a refracted seismic wave appears when it reaches a layer of rock having a higher velocity than the previous layer.

For any slow-to-fast rock interface, the sound arriving at an angle leaves at a greater angle. There is a point, however, at which the angle of arrival of the sound will continue along the interface of the faster rock. This is called the *critical angle* (Fig. 14).

Beyond the critical angle, a special type of refraction will take place that will follow the rock-layer interface (assuming a faster velocity for the harder rock), sending energy or reflections back to the surface as it travels. This is a faster path than the sound waves, which travel only through the slower (lower velocity) layer (Fig. 15).

In this way—using geophones placed at large distances from the shotpoint—early interpreters were able to detect the first arrivals of the sound waves traveling along the higher velocity layers and thus could understand more about the lithology between the geophone and the shotpoint source.

Seismic-refraction data were used primarily to detect salt domes in the Gulf Coast region in the 1920s and 1930s, but their limited capability for detecting smaller targets resulted in greater use of the *seismic-reflection* method.

SEISMIC-REFLECTION METHOD

The seismic-reflection method depends on the recognition of waves that are reflected more or less verti-

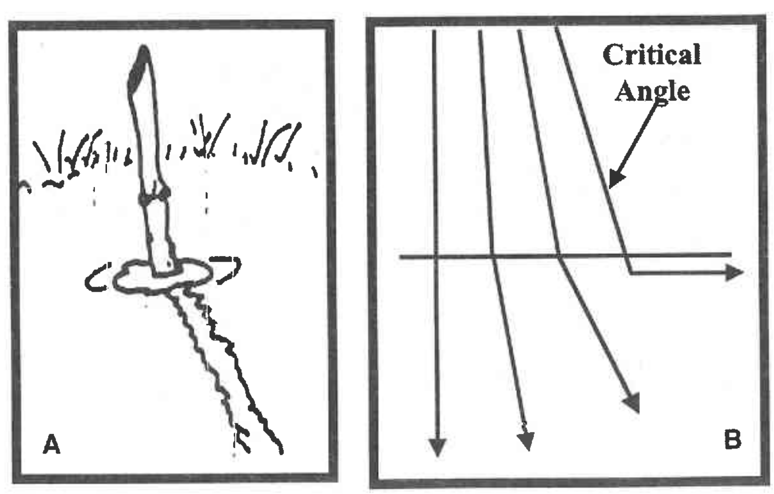


Figure 14. (A) Diagram illustrating refraction of light when a stick is immersed in water. (B) Refraction along an interface, illustrating critical angle.

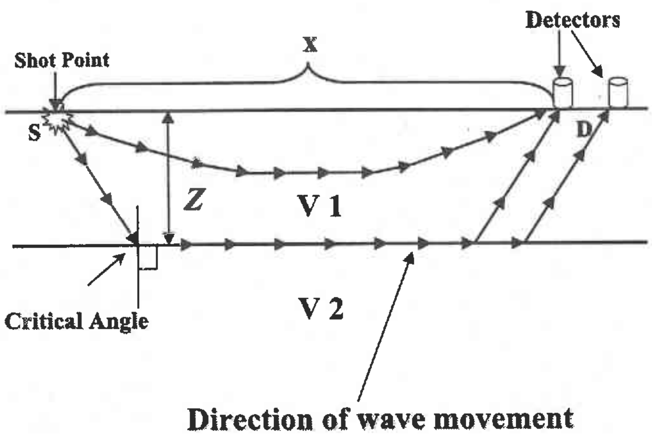


Figure 15. Diagram illustrating seismic-refraction method.

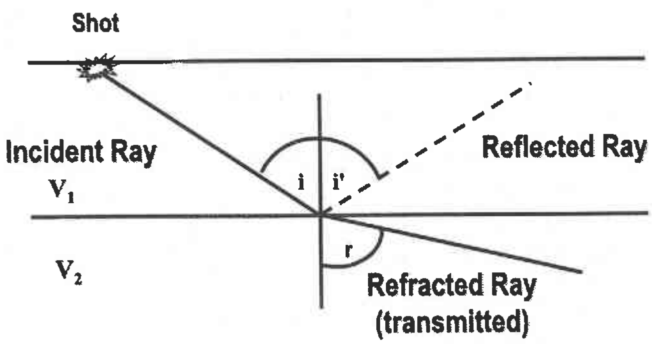


Figure 16. Cross section showing refraction and reflection.

cally to detectors at relatively short distances from the shotpoint and that arrive considerably later than the first disturbances at the detector.

Sound is generally a longitudinal vibration of matter, so it is primarily a *P*-wave. Its velocity depends on how fast vibrations can be propagated in the rocks through which it is moving. Therefore, the velocity depends on the rock's composition, temperature, and pressure.

Reflections occur at any velocity change encountered by the sound waves traveling through the sedimentary section but are stronger where the change in velocity is greater (Fig. 16). Rocks generally have higher velocities if they are more deeply buried, and harder rocks tend to transmit sound faster.

A basic geometrical fact for seismic-reflection exploration is that a sound wave, rebounding from a surface, leaves the surface exactly as steeply as it was approached. Thus, the *angle of incidence* is equal to the *angle of reflection.* This applies as well to a tennis ball bouncing from a concrete surface, or light from a mirror. The idea here is that, for a *flat* surface, the bounce from the energy emanating from a shotpoint will go to the next rock layer and back to the recording geophone at the same angle: two straight lines with equal angles (Fig. 16). The sound is reflected at a point on the rock layer directly beneath the *midpoint* between the shot point and the geophone.

This is a basic principle of reflection shooting: a seismic shot yields data from *midway* between *source* and *receiver.* This picture depends, however, on the assumption that the ground and the rock layers are completely flat. Because the angle of incidence and reflection must be equal, when the source and receiver are virtually in the same place, this reflection must be at right angles (90°) to the rock layer. But what happens if the beds dip?

Think about a tennis ball. To throw it and have it returned to your hand, you must throw it so that it strikes something at a right angle. To have it bounce back from the floor, you throw it straight down. If you throw it against a leaning sheet of plywood, you must throw it outward so that it hits the plywood perpendicularly (Fig. 17). In this case, the point of reflection of sound is not beneath the source and receiver, but offset in the *updip* direction.

For our purposes, we will assume no dip in the rocks so that the reflection point will be in the middle (midpoint) of the shot and receiver. The main value of seismic reflections in exploration is to provide information on the relative depths of rock layers. The reflection of a specific layer is recognized along a seismic section, and the reflected times are determined at different points along the line. The time at which a reflection is recorded is a clue to the depth of the reflector, or layer, from which the reflected energy came. A smaller than normal time for the reflection may indicate a point where the rock layer is structurally high.

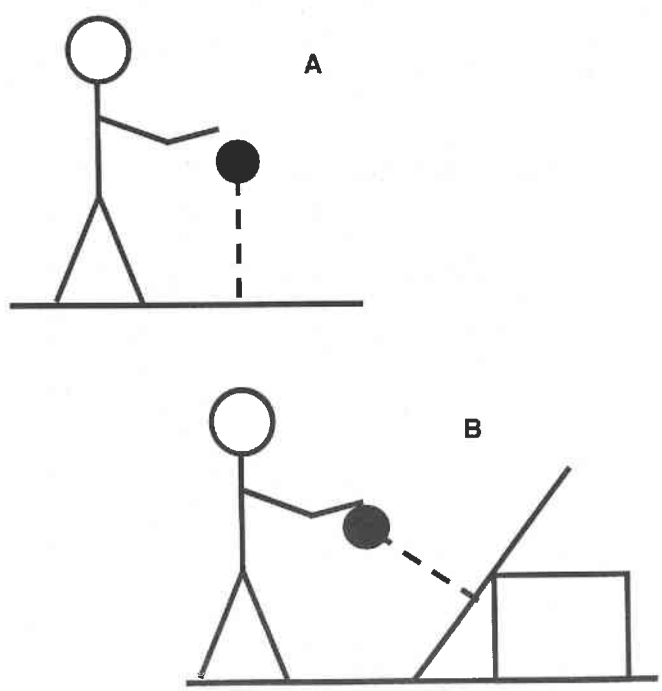


Figure 17. (A) Figure with tennis ball on level surface. (B) Figure with tennis ball on tilted surface.

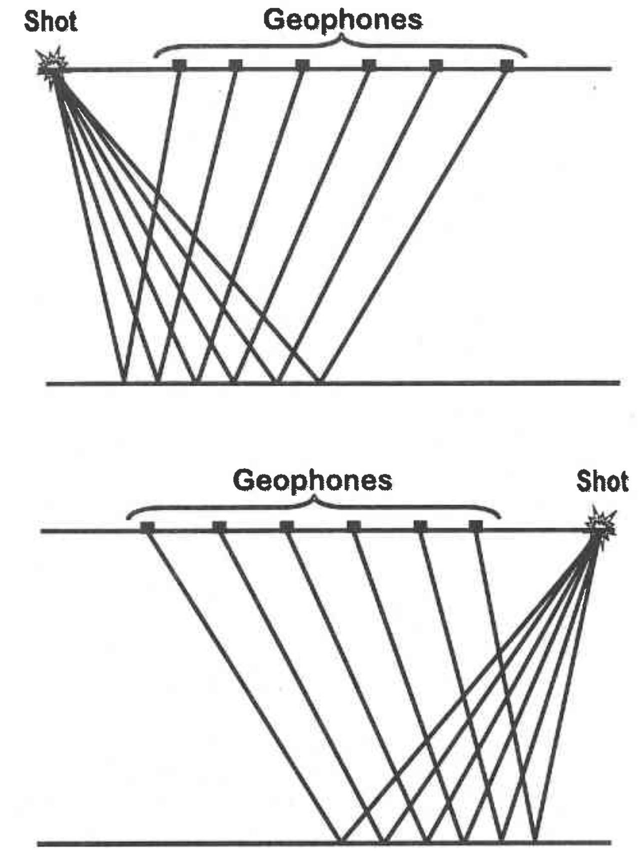


Figure 18. Cross sections illustrating single-ended spread shooting.

Spread

Geophone groups are spaced along an electrical cable. The cables are usually 1.5 to >3 mi long.

In a *single-ended spread*, the cable is laid out in one direction from the shotpoint. Each geophone receives reflection information from a point halfway between it and the shotpoint so that the whole spread gives information from the shotpoint halfway to the farthest geophone (Fig. 18).

After shooting and recording, the cable can be left and another point shot at the other end of the spread. This procedure gives information from the new shotpoint halfway back so that the entire distance between shotpoints is recorded. This complete subsurface coverage is called *single-fold shooting*, or *100% shooting*.

A *split-spread* arrangement is a pattern in which the cable is laid out in two directions from the shotpoint. The reflections received extend from the shotpoint halfway to each end. Coverage of 100% would be achieved as with a single-ended spread, with another shotpoint at one end, but half the cable is moved to extend in the other direction, away from the new shotpoint.

A string of shotpoints using either split or single-ended spreads is a continuous line and can be extended for any distance, giving complete subsurface information (Fig. 19).

A buildup in coverage from 100% to higher percentages is achieved by the *common-depth-point* process, which covers the same distance multiple times, thus producing better data.

Normal Moveout

Early seismic-reflection exploration methods relied totally on gathering 100% data in which single records of a spread of traces were hung side by side to create a continuous line of information about the subsurface.

The reflected energy on the shot records did not appear as flat events but were curved. Such curvature is downward from the shotpoint and represents the differences in time for a wave to reach each successive geophone: the closer the geophone is to the shotpoint, the less time it takes for the reflection to travel from the shotpoint to a layer of rock and back to the geophone (Fig. 20). This process is called *normal moveout* (NMO).

The shallower the reflector (rock layer) is, the more curved it will appear in the shot records. The deeper reflectors will be less curved because of the increased distance and time it takes for the reflections to return to the geophone (Fig. 21).

Common Depth Point (Common Midpoint)

Earlier, we learned that when a ray is reflected from a rock boundary, it is reflected from a point midway between the source and receiver. This point is called the *midpoint*. If another source is placed farther from

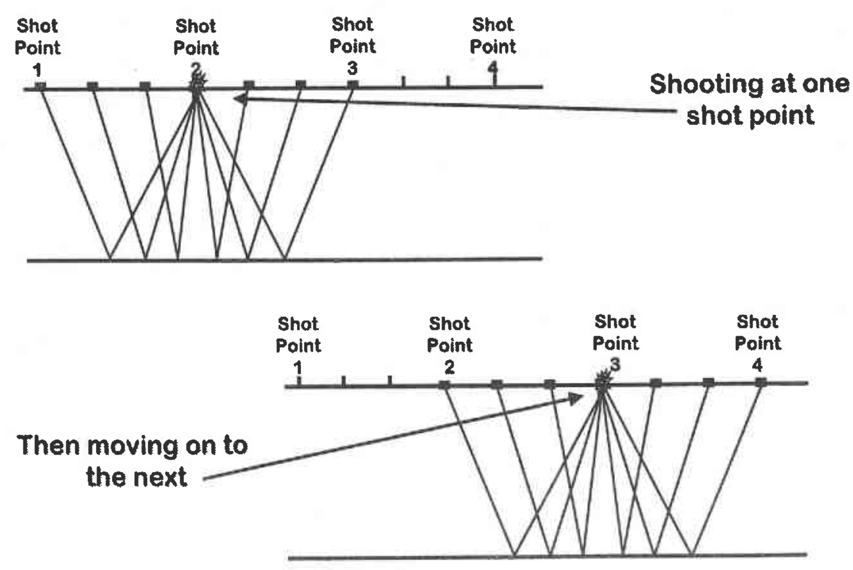


Figure 19. Cross section illustrating split-spread shooting.

the center, and a receiver is placed at an equal distance on the other side, the energy from the second source will be recorded at the second receiver. The reflection point will coincide with the first point, thus the name *common midpoint* (CMP). Because the reflections are at the same point, this point can also be called the *common depth point* (CDP).

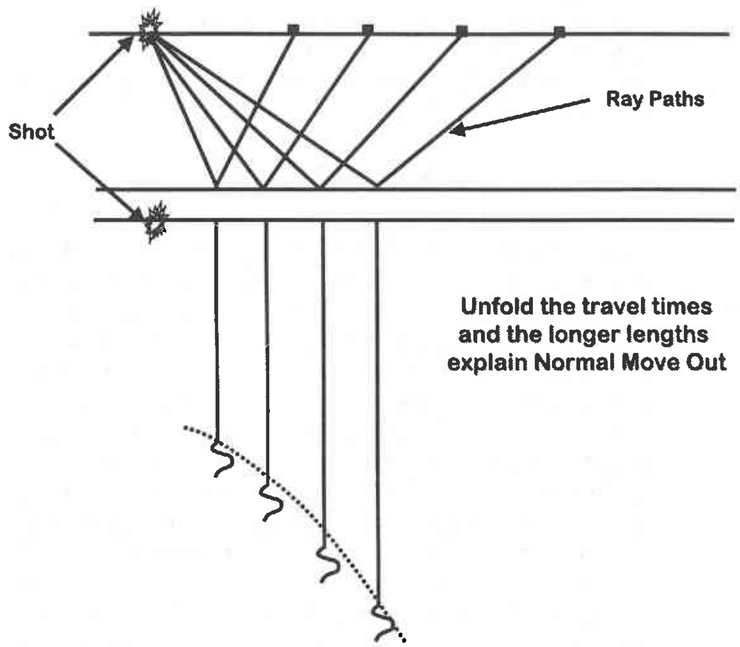


Figure 20. Cross sections illustrating normal moveout (NMO).

The data from the second source and receiver reflections could be called 200% data. If a third source and receiver were added, the result would be 300% data, and so on (Fig. 22). The energy traveling along the same paths gives information on the same point. Part of the longer path can be subtracted to make it the same length as the other, and the two traces can be combined into one. This is what CDP, or *stacking*, is all about.

In actual practice, CDP shooting is not that simple, but it is more economical. Rather than choosing a spot, and taking a succession of more distant shots received by instruments placed at more distant locations, the operation has been streamlined. A long cable is laid out, with many receivers placed at equal intervals. Shots are fired at fairly close intervals along that line (Fig. 23). The various energy paths are sorted out later in the data-processing center for correction and combination of sets of paths that have the same depth (midpoint) point.

The CDP recording method was invented by Harry Mayne (Petty Geophysical) as a way of attenuating noise (ground roll) that could not be handled by the use of arrays. Magnetic-tape recording made the use of the CDP method practi-

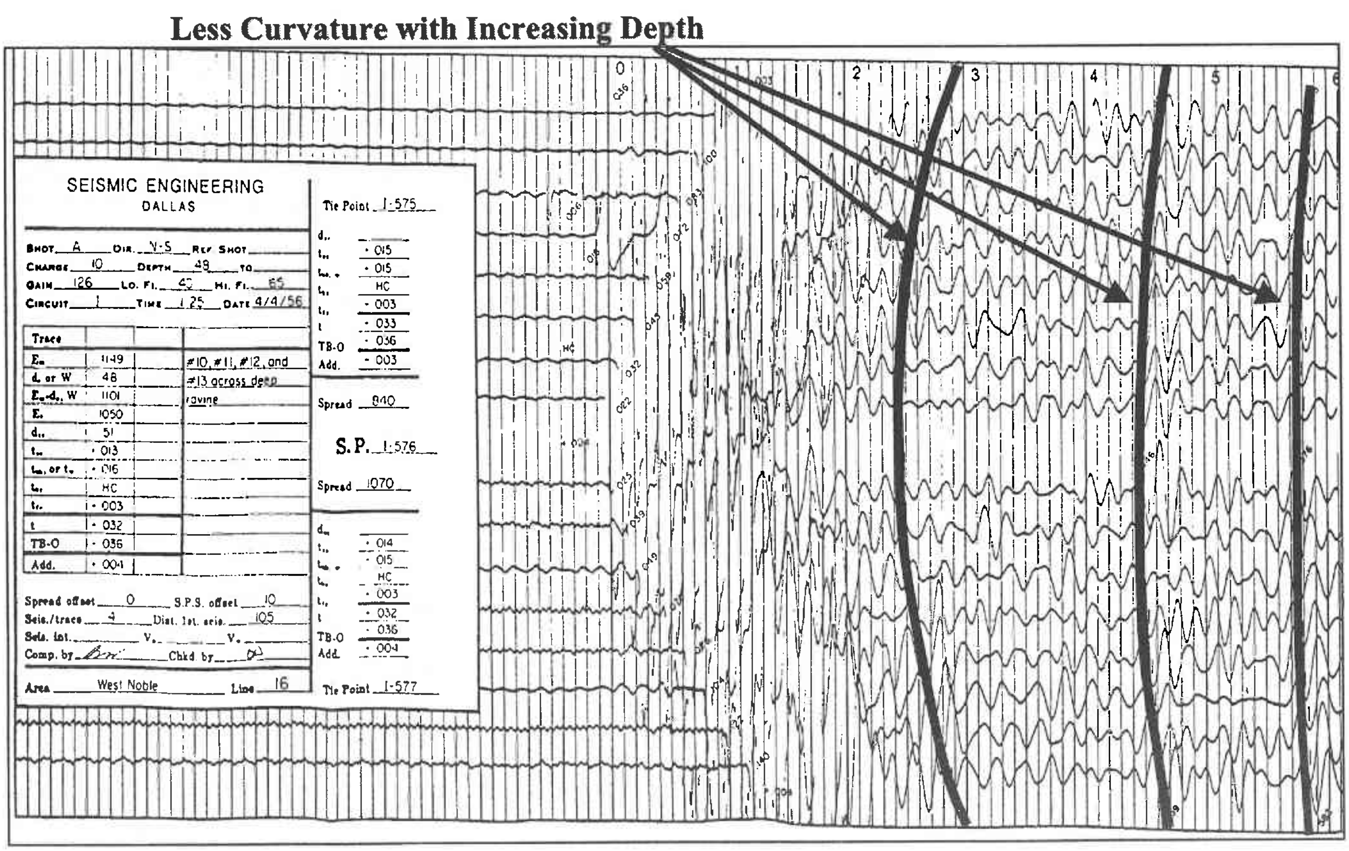


Figure 21. A 100% record, showing decreasing normal moveout (NMO) with depth.

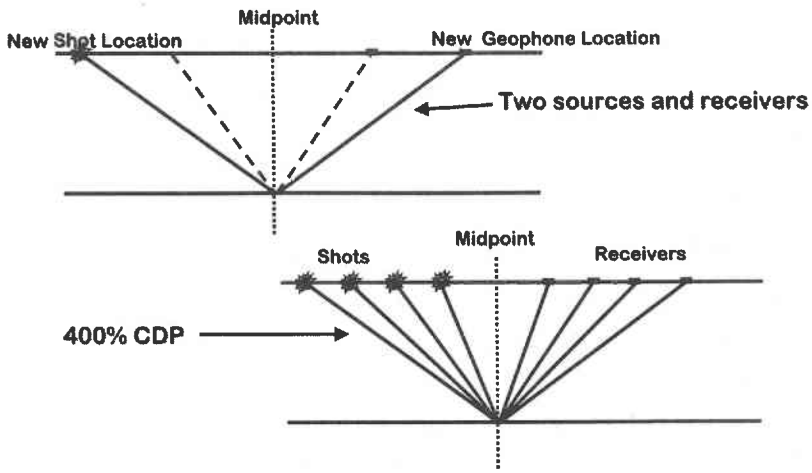


Figure 22. Cross sections showing common-depth-point (common-midpoint) method.

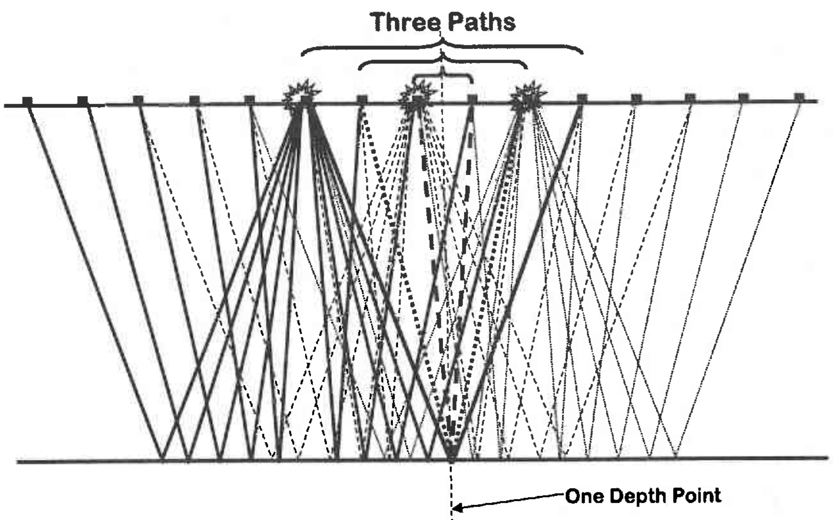


Figure 23. Cross section showing common-depth-point field procedure.

cal. CDP recording began in about 1956 but did not become widely used until the early 1960s. Today, this procedure is universal in the way in which seismic data are acquired and processed—even with 3-D techniques.

Corrections in 2-D and 3-D Data Processing

All the explanations regarding the acquisition of 2-D data, including CDP data, have been simple—one flat layer. However, what happens when you introduce the "real world" of geology into the picture? Certain types of corrections are made to "equalize" the seismic data.

One type of correction is for surface-elevation differences. For example, think about shooting a seismic line through the Ouachitas or the Arbuckles (Fig. 24). A typical elevation correction would be to place both shot and detectors on a datum. The times required for the wave to travel down to the datum from the shot end, and up from the datum to the receiver end, are removed. This excess time is calculated by dividing the elevation difference by the average near-surface velocity (velocity of the LVL). Depths below the datum are calculated from corrected reflection times (Fig. 25).

Weathering corrections must be made to remove the effect of the LVL. The term *weathering* has different meanings to geologists and geophysicists. To a geologist, weathering is a destructive process that breaks down rock by atmospheric agents to loosened or altered material. To a geophysicist, weathering is the material at or near the surface of the ground that has a considerably lower velocity of sound than the deeper rocks. Following the latter definition, the base of the weathered zone is often the water table. Air has a velocity of ~1,000 ft/sec, whereas water has a velocity of ~5,000 ft/sec. So the change from rock and earth material with air in the pore spaces to the same material with water in the pore spaces is the abrupt change that can define the base of the seismic weathered layer (Fig. 26).

One way to avoid dealing with the weathered zone is to drill shotholes (for dynamite) well below this zone. Then the "uphole" time (the time that energy takes to travel from the shotpoint up to the receiver placed by the shothole; Fig. 27) includes all the weathered zone, so that reflections can be corrected for the time spent in the LVL (Fig. 28).

The near-surface corrections calculated in the field are put in the form of instructions to the computer in the processing center to move each trace up or

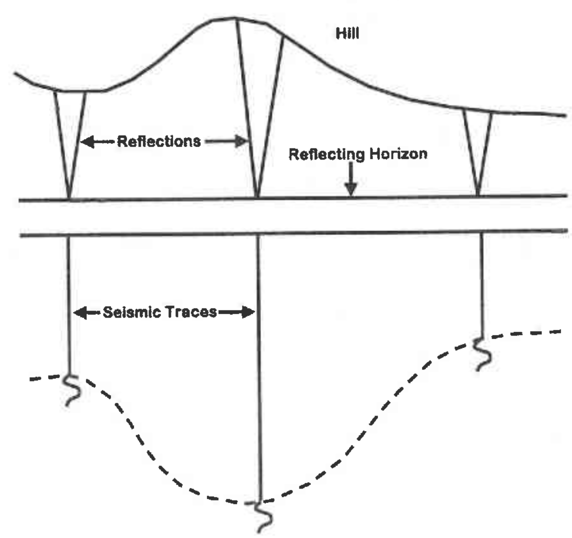


Figure 24. Diagram illustrating the need for applying elevation corrections to seismic data.

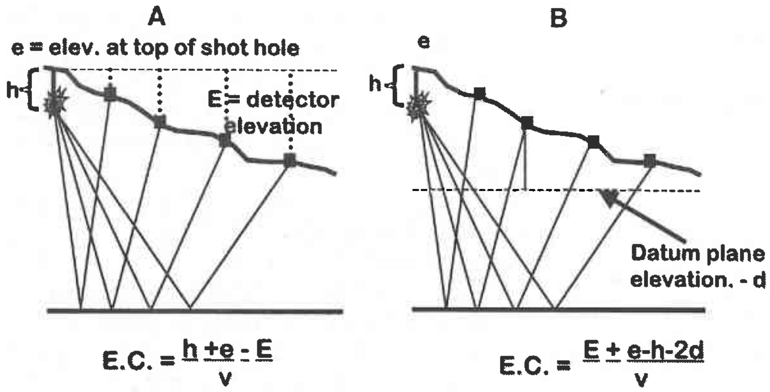


Figure 25. Cross sections showing elevation corrections (A) by putting all geophones at elevation of top of shothole, and (B) by putting both shothole and geophones on datum plane.

down the number of milliseconds called for by the elevation and weathering calculations. These statics serve to smooth out the reflections to the extent that the hills and valleys are no longer discernible in reverse on the reflections so that the weathering is fairly well corrected. At this point, the reflections should line up well.

The LVL can also create another problem—*multiples*. Sound is reflected from places where sharp differences in velocity (hardness) occur. As discussed earlier, a reflection on a seismic section represents energy that has traveled down to a rock layer, is reflected, and then comes back to the surface. The base of the weathered zone is also a strong velocity contrast, and sometimes the reflected energy will "bounce" off the base of the weathered zone and head back down to that rock layer, then up to the surface again. The geophones have then received two sets of information. These bounces, when translated to a record section, appear as two distinct horizons where there should only be one (Fig. 29).

Multiple reflections get weaker with depth because there is only so much energy to keep bouncing around. The CDP method of stacking trace energy helps to reduce the effects of multiples.

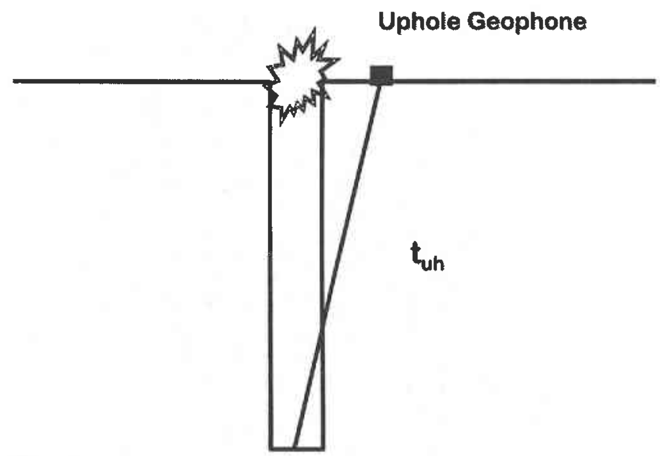


Figure 27. Cross section showing measurement of uphole time.

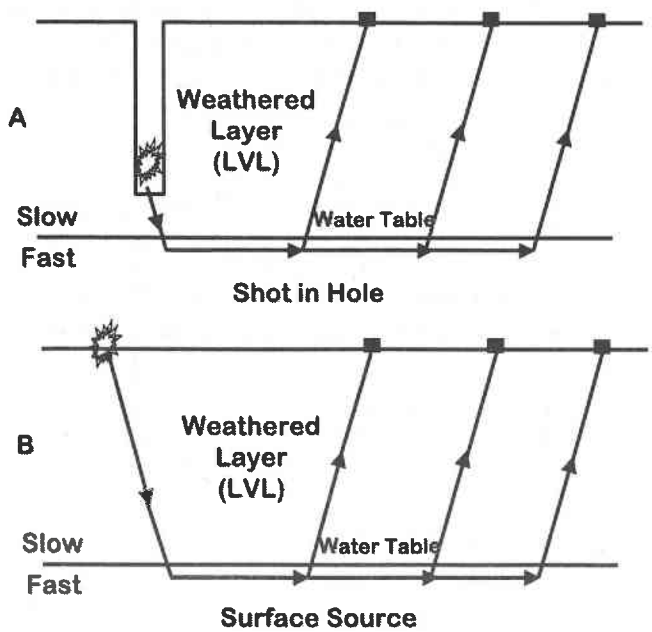


Figure 26. Cross sections showing weathering refraction paths: (A) with dynamite; (B) with Vibroseis.

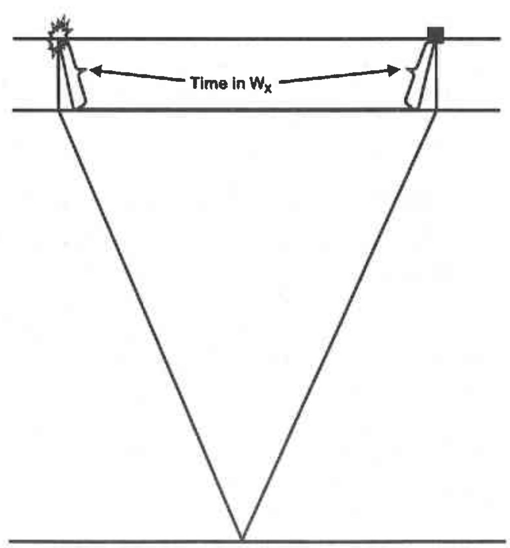


Figure 28. Diagram of weathering correction.

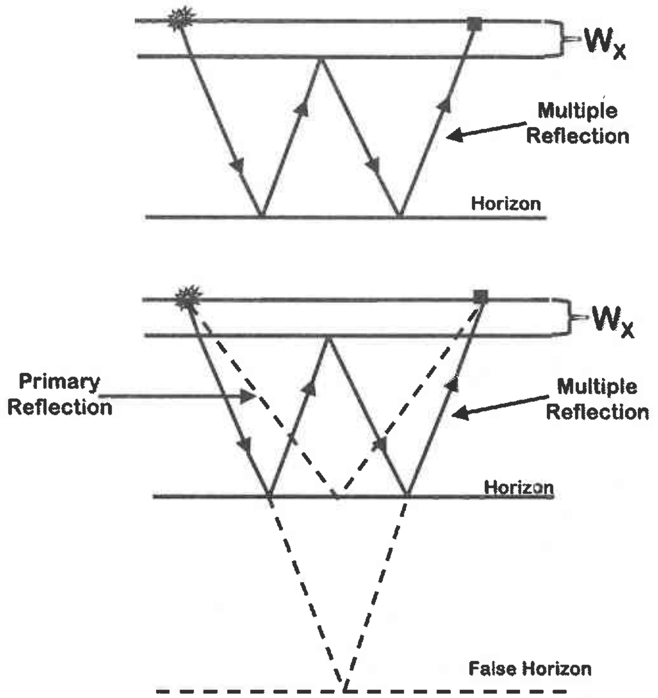


Figure 29. Cross section showing the appearance of multiples.

Probably the most important correction that can be made to seismic data is that of *migration.*

Migration

A seismic section can be assumed to represent a cross section of the earth. The assumption works best where rock layers are flat, and works moderately well where the layers dip gently. As the dip gets steeper, this assumption breaks down, and the reflections appear to be in the wrong places, indicating the wrong angles of dip.

Remember the example of the tennis ball earlier in this documentation. If the horizon is dipping, the energy travels from the source to the horizon by the most direct route, which is perpendicular. The reflection point is not coming from the midpoint location but from a point offset from it. The geometry of the dip makes it offset in the *updip* direction—up the slope of the bed.

This is what happens to the reflection sound. How does it appear on the record section? Traces on a section are parallel. They all hang straight down from the surface, because they are just measurements of the time it takes for the signal to travel from the shotpoint to the geophone.

Let us assume that there is a signal under shotpoint 1, and nothing is known about the dip. All that can be said is that there is a reflection at a certain time. That reflection could have come from any point along a circle whose radius represents that length of time to the reflection. An arc is drawn (by using a compass) to represent that portion of the circle in the subsurface, then the same is done for the reflector at shotpoints 2, 3, 4, and so on. The point at which the arcs start crossing each other represents the true dip position from which the reflection is coming (Fig. 30).

In this manner, *migration* has occurred, meaning that the reflection has been migrated to its true and proper position.

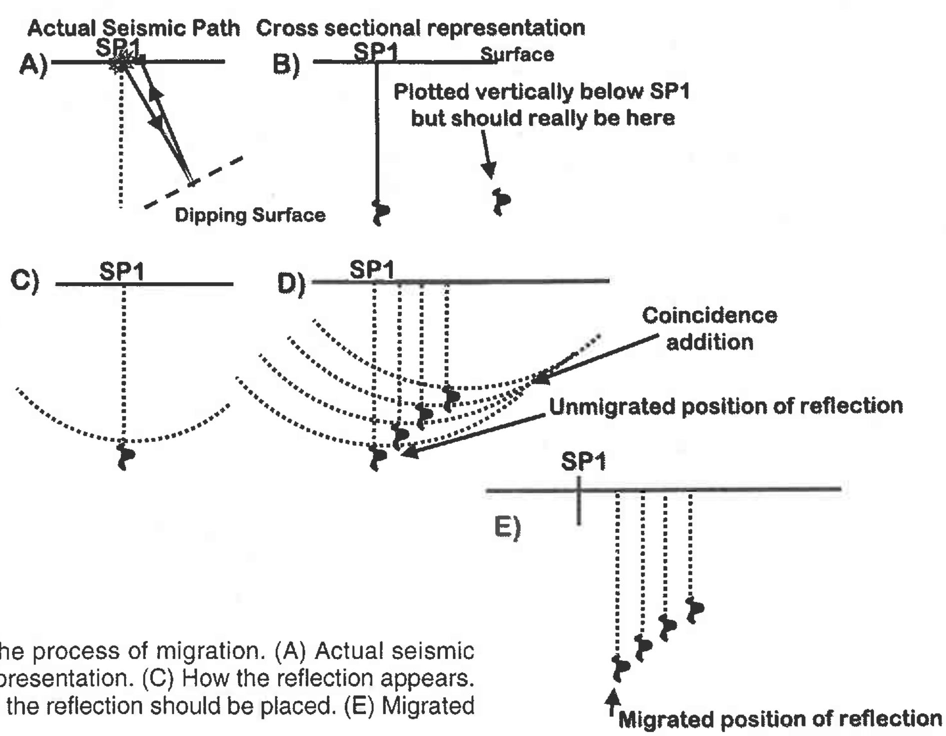


Figure 30. Simple view of the process of migration. (A) Actual seismic path. (B) Cross-sectional representation. (C) How the reflection appears. (D) Using "arc" to find where the reflection should be placed. (E) Migrated position of reflection.

Migration of Data Tends to Produce Several Effects

1. *Reflections move updip.*—See the example just mentioned (Fig. 30), in which the arcs are crossed updip.

2. *Migration tends to "narrow" anticlinal structures.*—In the subsurface, the raypaths reach inward to reflect perpendicularly from the horizon. On a record section, they swing down to the vertical, spreading out, making the feature look broader (Fig. 31).

3. *Anticlines may have less or the same vertical closure.*—The traces swinging down to the record-section position show more relief. An exception is that the dips on the flanks become flat. The flat portion is not affected by migration.

4. *The crest of the anticline does not move.*—Right at the top, there isn't any dip, so that part of the anticline will not migrate.

5. *Synclines become broader.*—The raypaths reach out to be reflected perpendicularly. On a record section they make a narrower appearing feature, so migration must spread it out again (Fig. 32).

6. *The low point of a syncline does not move.*—Just like an anticline, the low point of a syncline is flat, which is not affected by migration.

7. *Crossing reflections may become a sharp syncline.*—If synclines are relatively deep in the section, or narrow, they may appear as raypaths that cross on the way down. One trace may be in a position to receive information from two or more parts of the syncline. Two crossing lineups of energy, with an apparent anticline visible beneath them, will appear on the section. This is spoken of as a *buried focus,* because the seismic energy is crossed, like light rays when focused by a lens (Fig. 33).

8. *Diffractions are migrated back to a point.*—Where a fault breaks a formation, or for some other reason there is an "edge" in the subsurface, that point returns energy to any source within range. Energy is returned to a number of geophones at different distances from the reflection. In a seismic section it will look like an apparent anticline, though very uniform, like an open umbrella. In some cases, only half will be visible so that the broken portion of the formation appears to continue in a smooth curve downward (Fig. 34).

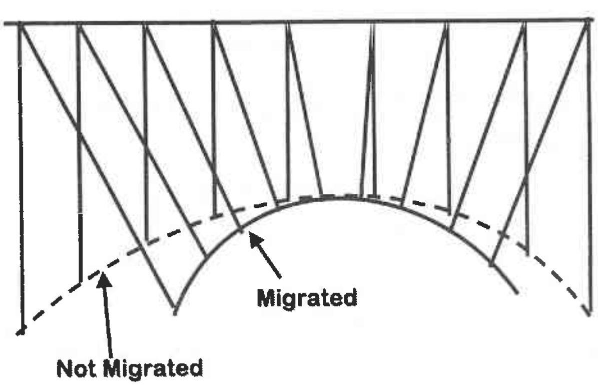


Figure 31. Cross section illustrating how migration causes anticlines to become narrower.

9. *The Fresnel zone decreases in size.*—When sound waves hit a reflector, they actually hit over an area rather than at a distinct point. This area is called the *Fresnel zone,* and the radius of the area can be calculated by taking the square root of the depth to the reflector, times the wavelength, divided by 2. Seismic mi-

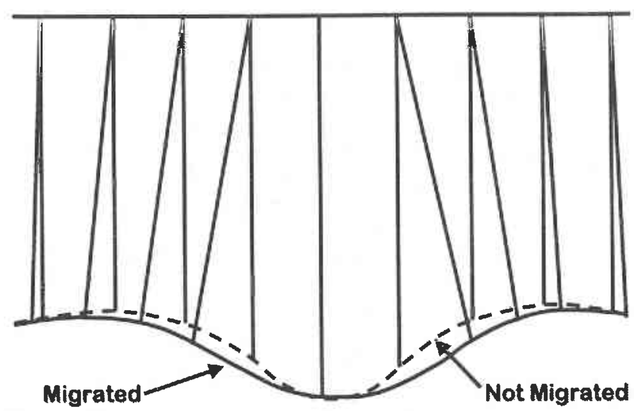


Figure 32. Cross section illustrating how migration causes synclines to become broader.

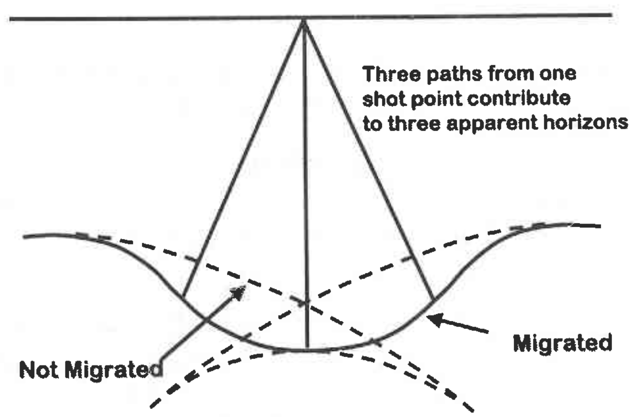


Figure 33. Cross section showing crossing raypaths (crossing reflections).

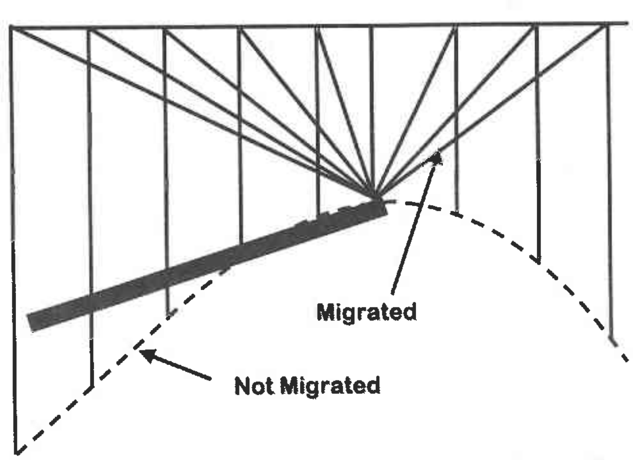


Figure 34. Cross section showing diffractions migrated back to a point.

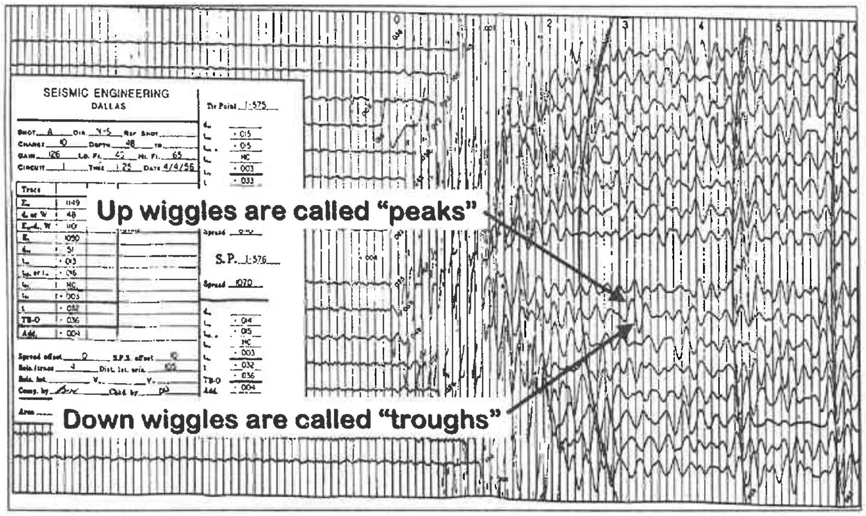


Figure 35. Wiggle traces in a 100% record.

gration can be considered to be a process that acts to collapse the Fresnel zone into a smaller area. Two-dimensional data migration tends to collapse the size of the zone only in the direction of the 2-D line, ignoring out-of-plane signals. Three-dimensional migration tends to collapse the zone from all directions, thus allowing greater detailed horizontal resolution of the stratigraphy.

SEISMIC TRACES AND WAVELETS

A seismic section is made up of traces. A *trace* is the reflection from one shot that is received by one geophone (or geophone group) and is displayed as a wiggly line or in another form.

The term *trace* came from early earthquake seismographs: the line was traced as the ground shook. From early seismic exploration, the terminology used was *wiggles.* If the trace is horizontal, beginning on the left side, and moving with time to the right, the wiggles will be up and down (Fig. 35). The upward excursion of a wiggle is called a *peak,* and the downward excursion, a *trough.* Today, seismic sections are displayed with the traces in a vertical sense so that the peaks are to the right and the troughs to the left (Fig. 36).

An explosive seismic source produces a sudden, brief sound, which contains all frequencies. In going through the subsurface to a reflecting horizon and back to the surface to the geophones, this sound becomes stretched out into a *wavelet.* A wavelet comprises one or two peaks and one or two troughs, and its duration is about 50–100 milliseconds (ms). The peaks and troughs are of varying amplitudes, the highest occurring about 30 ms after the start of the wavelet. The wavelet is the basic seismic response—that which would be recorded if there were only one reflecting horizon in the subsurface. With only that one velocity interface, the recorded wavelet would have a *polarity,* depending on which way the velocity change went—slow to fast or fast to slow—and an *amplitude,* depending on the contrast between velocity (and density) (Fig. 37).

Seismic velocities are varied, both vertically and laterally. The velocity of sound in rock varies with compaction of the rock and with both vertical and lateral

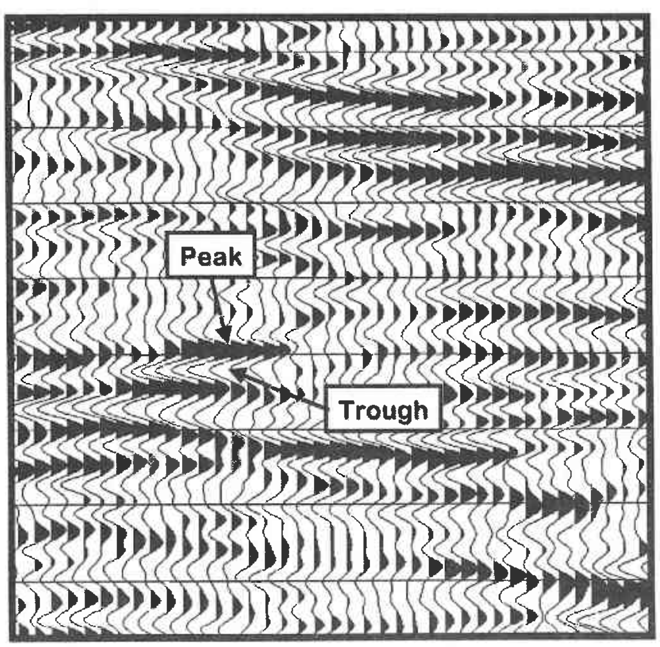


Figure 36. Modern representation of traces. Peaks are to the right, and troughs to the left.

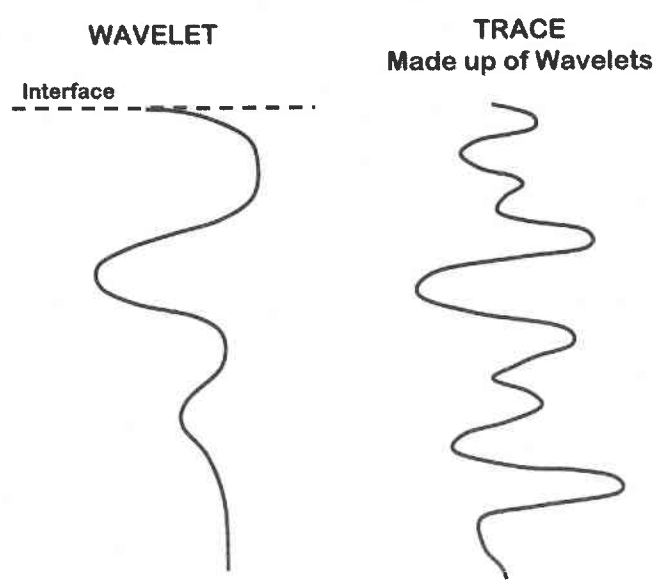


Figure 37. The wavelet (left), and the trace, which is made up of wavelets.

lithologic change. Compaction tends to increase the velocity with depth: the deeper the rock, the higher the velocity. A lithologic change can cause velocity to decrease as well as increase in depth. A change from a shale to a carbonate causes an increase in velocity, and a change from a carbonate to a shale causes a decrease.

Lateral changes occur if a sandstone grades into a shale. For dipping beds, horizontal changes in velocity occur as the dip changes.

All these variations indicate that velocity is a highly variable factor in exploration. With steep dip or faulting, velocities obtained from studying the rocks encountered in a well may not apply to an area 1 mi away. Velocity is discussed further in the section on synthetic seismograms.

What is it that generates a seismic reflection? As discussed earlier, a reflection is generated at the interface between two rocks of *different hardness* (also *velocity*). Although a reflection may be labeled with the name of a formation, it really does not come from that formation but from the contact between that formation and the one above it. If two formations are distinctly different in hardness, the reflection is strong, resulting in a strong amplitude shift in the trace; if they are equal in hardness, the reflection is zero (Fig. 38).

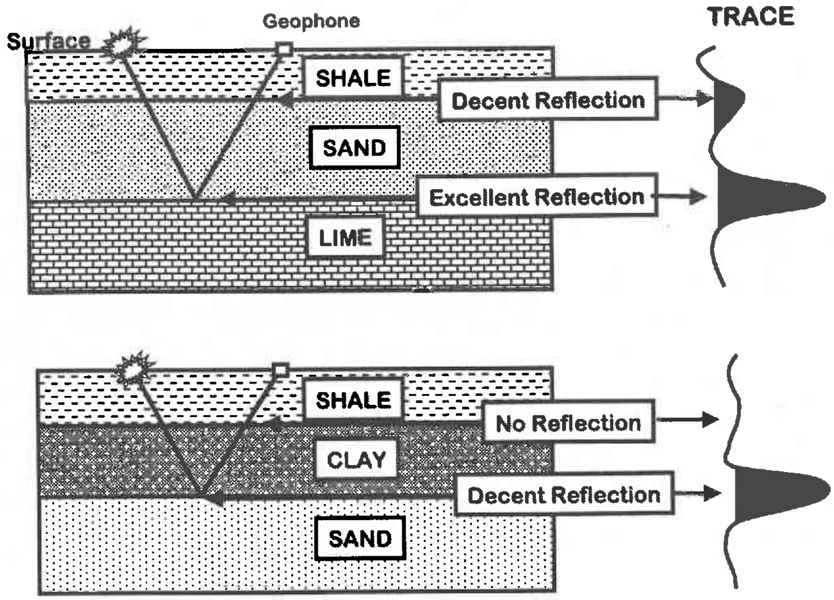


Figure 38. Cross sections representing trace responses to changes in lithology.

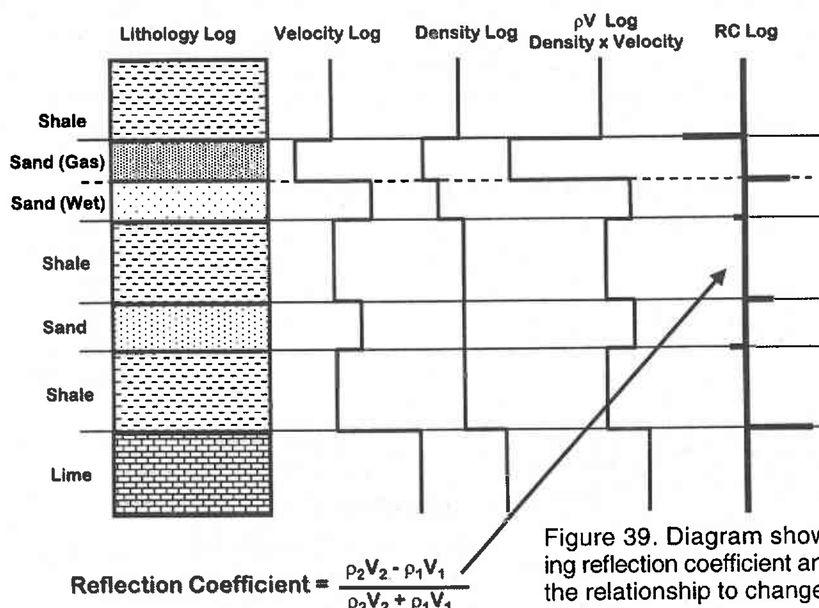


Figure 39. Diagram showing reflection coefficient and the relationship to changes in lithology.

Rock types can be listed in ascending order of hardness: (1) clays, (2) sandstones, (3) limestones, and (4) basement rocks. One could assume that contacts between clay and sandstone, sandstone and limestone, etc., would make for fair reflections. Many factors, however, can materially change the hardness of a rock. One of the most important of these is porosity.

A highly porous, liquid-saturated sandstone might show no hardness contrast with a clay and thus generate no reflection. Therefore, a local change in the strength of a continuous reflection may mean a facies change, a local development of porosity, a change from liquid saturation to gas saturation, or just a processing "bust"!

The term *hardness*, as used here, does not exactly coincide with Mohs scale of hardness, well known to the geologist, although it does approximate it. Hardness, geophysically speaking, needs to be looked at in an acoustic sense. The geophysical term is *acoustic impedance*, which is the product of density and velocity (ρV).

If we look at the hardness contrast across two layers of rock, and a measurement of the relative strength of the reflections is needed (in order to understand the rock hardness and velocity), a calculation of the *reflection coefficient* would be necessary. This calculation would be the difference in hardness across the boundary of the two layers, divided by the sum of the hardness of the two layers, or $(\rho_2 V_2 - \rho_1 V_1) / (\rho_2 V_2 + \rho_1 V_1)$. A big difference in the acoustic impedance makes for a strong reflection (Fig. 39).

A reflection is positive if the contact is from soft rock to hard rock, and negative if the contact is from hard to soft. In looking at a vertical seismic trace, the positive reflection would "pulse" to the right, and a negative one would "pulse" to the left. These features are called *peaks* and *troughs*. In a *variable-area* display, the peaks are filled in black, and the troughs are not filled (Fig. 40).

It is also important to remember that the reflection emanates from the contact of the two formations, not from within a formation.

ANALOG VERSUS DIGITAL RECORDING–THE SEISMIC REVOLUTION

The term *analog* refers to the represention of a quantity of something by a quantity or a quality of something else. A thermometer, the hands of a clock, a seismic trace on a record, all are analog representations. In these cases, temperature is represented by the height of the mercury, time by the position of the hand, and the movement of the Earth by the wiggles in the trace (Fig. 41).

Information in *digital* form means a representation by numbers. Thus, the local weather report, the dates on a calendar, and a seismic trace can be represented by a string of numbers.

In the days before the widespread use of computers, seismic displays were totally analog in nature. The ground would shake, voltage would be generated by a geophone, and traces (wiggles) were recorded on magnetic tape.

Digital recording handles seismic data much differently. These data are still recorded by geophones, but gaps exist in the information. Every 2 or 4 ms, the amplitude of the trace is recorded as a number. The parts of the trace between the "samples" are lost. In analog recording, the trace is continuous. The trace can usually be considered a smooth curve between samples. In exchange for the loss of information, however, there is much to be gained on the "manipulation" side.

As one example, digital recording has a much greater *dynamic range*, the range between the largest and smallest recordable amplitudes. In addition, with the data in the form of numbers, modifications can be performed by mathematical calculations. In order to apply these calculations, a computer program is formulated to make the computer do all the work!

The amplitudes of seismic energy go through a wide variation, from very large at the explosion, or at the point of energy initiation, to extremely small a few seconds later. On a record section, this may go from a mass of traces overlapping each other in a jumbled mess to weak wiggles at depth. To get normalized sections, the application of *gain control* is necessary. The amount of energy is cut back at the beginning of the recording and amplified toward the end.

Early on, gain control was effected by a field technician slowly turning a knob. This method has been replaced in the computer by a programmed gain control called *automatic gain control* (AGC). The drawback to gain control is that some relative information could be destroyed, depending on the strength of the reflections.

With the advent of more advanced computers, *floating-point recording* became the method of choice. This method uses binary numbers in an exponential form. It can handle a much greater range of numbers with the use of magnetic tape. Very large numbers are written with large exponents, and very small numbers, with large negative exponents. This allows the recording to include all of the seismic amplitudes that are recorded, with no gain changes. The relative amplitudes are preserved directly in the data.

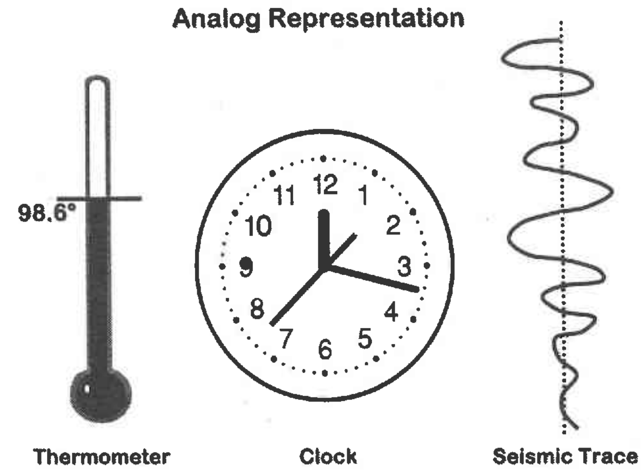


Figure 41. Drawing showing analog representations.

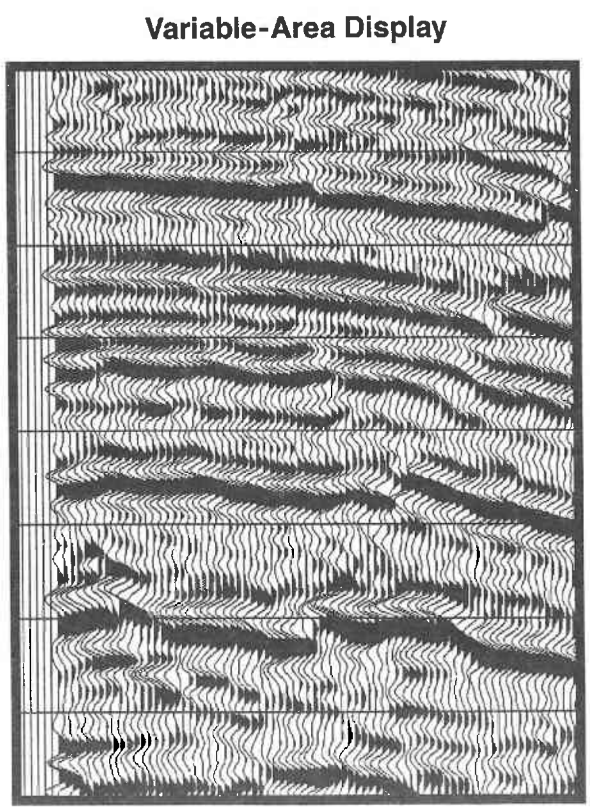


Figure 40. Variable-area display. Peaks are filled in black.

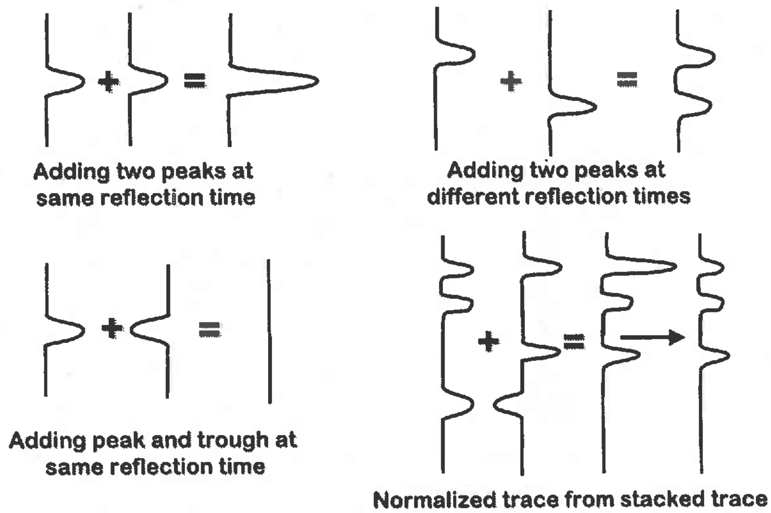


Figure 42. Stacking of traces in common-depth-point (CDP) method.

Stacking, as was mentioned earlier in the discussion of common depth point (CDP), is a means of combining traces where the reflections occur at the same place—the midpoint between the energy source and the geophone.

In digital processing, the amplitudes of the traces are expressed as numbers. Stacking is accomplished by adding the numbers. When this is done, two peaks on two traces will combine to make a peak as high as both added together—if the two peaks express the same time on the same trace. If they express different times, the combined trace has separate peaks the size of the original traces. A peak and a trough lined up tend to cancel each other if the amplitudes are equal, in which case the combined trace will have no energy at all (Fig. 42).

After being combined, the new traces are *normalized*; that is, the amplitude is reduced so that the peaks, which have been reinforced by the adding process, will be of normal height.

Traces can be stacked for different reasons. Stacking can be a test of normal-moveout (NMO) corrections, or determination of velocities in the subsurface. Stacking can also be used to combine two traces so that they can be treated as one trace in the processing sequence.

Although a seismic source of energy is usually audible (e.g., the explosion of dynamite), the energy that travels through the earth comprises a narrow range of frequencies—about 10–100 cycles/sec or hertz (Hz).

Frequencies that do not carry seismic information, such as wind across the geophone, tend to cause "noise" in the recording process. To eliminate noise, *filters* are applied to block out these frequencies, which are not in the seismic range. This is sometimes known as *bandpass filtering*, because it allows a certain *band* of frequencies to *pass*, but not others.

In digital processing, this filtering can be exact. The frequencies desired can be precisely selected. Say, for instance, that seismic data are being acquired near a power line, which emanates a frequency of 50 Hz. This energy is picked up by the geophone cable (especially if the ground is wet) and needs to be eliminated.

One of the first steps in data processing is to determine what frequencies of sound show the reflections best. High frequencies do not penetrate deeply into the subsurface, so the higher frequency records will not have deep reflections. Selections are made of the frequencies that show the data well on the record at a certain time, then ones that show reflections well at another time, and so on. When all the selections have been made, leftover information at other frequencies is eliminated. After these frequency selections are made, filters can be selected to apply and process the entire line of seismic data.

Display Types

A *wiggle-trace* section consists only of wiggly lines. They are close together and overlap where reflections are strong. The section (on paper) is fairly easy to view at a desk but not from a distance (Fig. 43).

A *variable-area* section is a version of the wiggle-trace section. In this case, the peaks have been filled in black, with the troughs being unfilled. Higher amplitude events stand out at a distance; they tend to look like a black line (Fig. 43).

Variable density comprises a narrow band of varying shades, with dark grading into white (or with other colors), replacing peaks and troughs. Whereas these varying shades are easy to interpret at a distance without an autopicker on a workstation, it is difficult to identify the peaks and troughs from trace to trace. The workstation has made variable density much easier to interpret (Fig. 43).

IDENTIFYING REFLECTORS ON SEISMIC DATA

In order to interpret seismic data, a great deal of effort goes into identifying the reflectors. This section discusses certain techniques used for such identification.

In some cases, one simply has to be familiar with an area in order to identify a reflector. Luckily, the Viola Formation was an easy reflector to identify where Karcher performed his early reflection studies here in Oklahoma. Unfortunately, identifying reflectors is generally not this easy. If a well is near a seismic line, a great deal of effort is often expended to tie the well to the line. The problem faced is as follows:

1. The seismic line exhibits a number of reflectors at different reflection times.

2. The depth of the producing zone in the well is known.

3. The question arises: Which reflector on the seismic line best represents conditions at the depth of the producing zone?

The solution to this problem involves finding a relationship between the time measured on the seismic data and the depth to the productive zone (Fig. 44). A simple way of expressing a relationship between time and depth is through the use of measured velocities determined at the well. Before proceeding with a description of such measurements, some velocity definitions should be given to prevent later confusion.

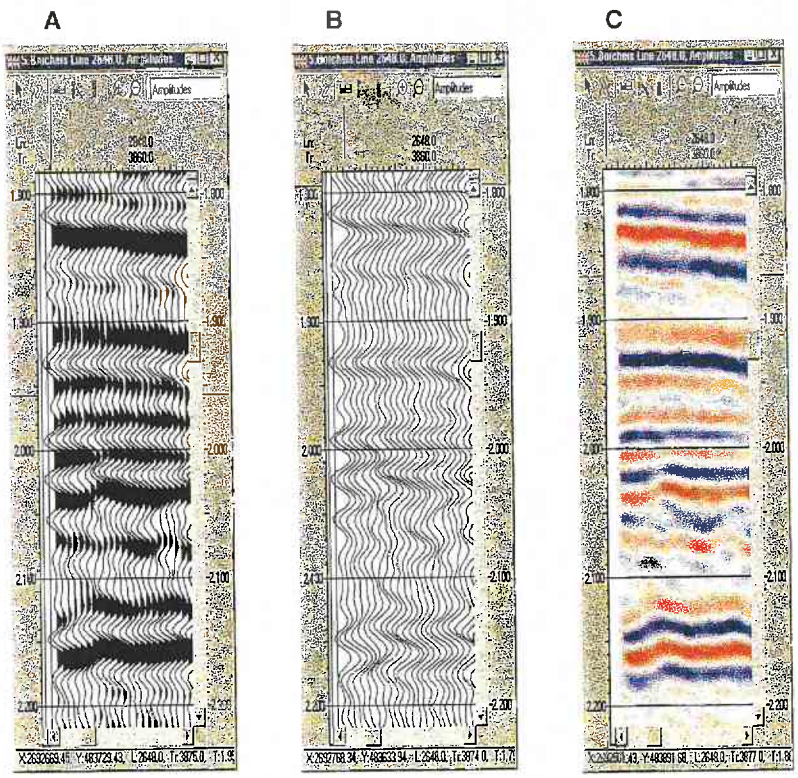


Figure 43. Seismic display types. (A) variable area; (B) wiggle trace; (C) color variable density.

Many kinds of velocities are used in the exploration for oil and gas. Some of them play a role in the conversion of time to depth, whereas others play a role in the imaging of the seismic data—for example, in the stacking or migration of the data. Only four types of velocities are discussed below (average, interval, stacking, and root-mean-square).

Average Velocity

Average velocity is a term used for the velocity along a complicated path (not necessarily a straight path) through the Earth. It is an expression for the total travel path divided by the total traveltime (just remember distance divided by time) (Fig. 45). Average velocity is important because it is the velocity needed to convert from a reflection time observed on the seismic data to a depth measured in the well. Take, for example, a measurement of traveltime for a producing zone on a seismic section at a time, T_0 (two-way time in seconds). Then the following formula can be used to compute the depth to the reflecting horizon:

$$Depth = V_{AVERAGE} \times (T_0/2).$$

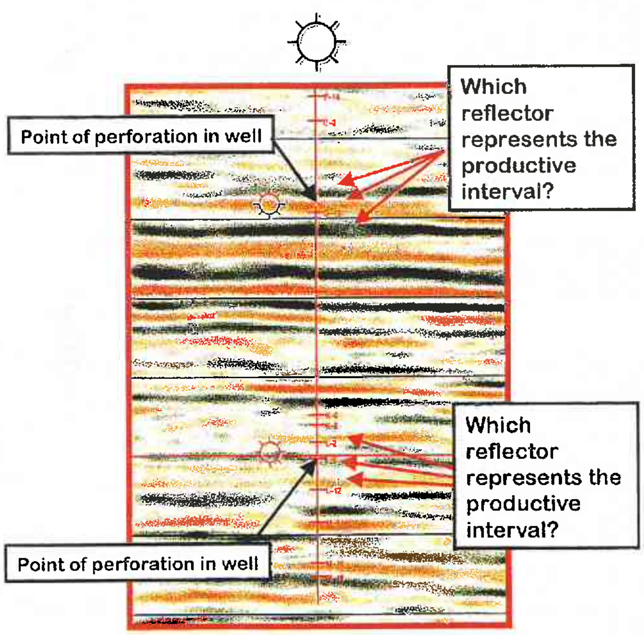


Figure 44. Cross section showing the need to identify which reflector is related to the productive gas zone.

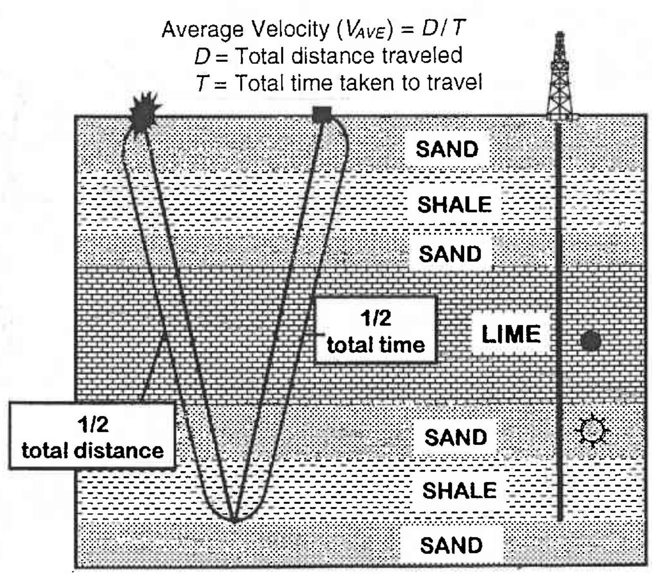


Figure 45. Cross section illustrating average velocity.

Interval Velocity

It is often convenient and more accurate to break the subsurface into smaller zones or intervals that are more similar in character. In this way, some of the variability of the subsurface can be taken into account rather than describing it as a single interval with a single average velocity. The average velocity across a smaller interval (rather than the complete interval down to the reflector of interest) is referred to as the *interval velocity* (Fig. 46). Thus, if the top of a layer of rock is at a depth, D_1, and the bottom at a depth, D_2, and the corresponding one-way traveltimes are (for vertical travel) T_1 and T_2, then the interval velocity for vertical travel (the average velocity of this interval) is defined to be:

$V_{INTERVAL} = (D_2 - D_1) / (T_2 - T_1)$ or $\Delta D / \Delta T$ or *Thickness / One-way Time.*

Interval velocity is just an average velocity over a shorter distance. When information from a well can be used to break up the subsurface into small intervals or layers where the velocity is known, the traveltimes through these intervals can be added together to estimate the average velocity to great depths. This technique is described in greater detail below.

Stacking Velocity

Stacking velocity is another velocity term used in exploration geophysics. However, unlike average velocity or interval velocity, stacking velocity should be thought of as an *imaging* velocity (not necessarily a velocity used to estimate depth directly). The use of stacking velocity helps to bring reflectors "in focus" by correcting for NMO on seismic traces. In looking at a seismic line that has been stacked, you might see a table at the top of the data that lists the stacking velocities and two-way traveltimes at which the stacking velocities apply, such as this one:

T_0 (2-Way Time Seconds)	V_{STACK} (Feet/Second)
1.2	7,200
2.0	7,800
2.5	8,200
3.0	9,000
3.5	9,500
4.0	10,000
4.3	10,500

This chart tells you that the stacking velocity for a reflector at 1.2 sec was 7,200 ft/sec. Similarly, the stacking velocity for a reflector at 2.0 sec was 7,800 ft/sec, and so on. Remember that the velocities listed on a seismic line or section are for imaging purposes, and should not be used directly for converting to depth. In addition, the accuracy of the determination of stacking velocities decreases with depth because the amount of moveout decreases for deep reflectors (Fig. 21).

Root-Mean-Square Velocity

Another velocity term that is often used is *root-mean-square* (RMS) *velocity.* This type of velocity is path dependent, like average velocity. However, the RMS velocity path most often used is vertical. RMS velocity is a theoretical approximation of the imaging or stacking velocity, but a mistake is made in referring to stacking velocities as RMS velocities. RMS velocity is only approximately equal to stacking velocity in certain limited circumstances. It is an imaging velocity (because it is used to make the image), but it does not relate directly to depth.

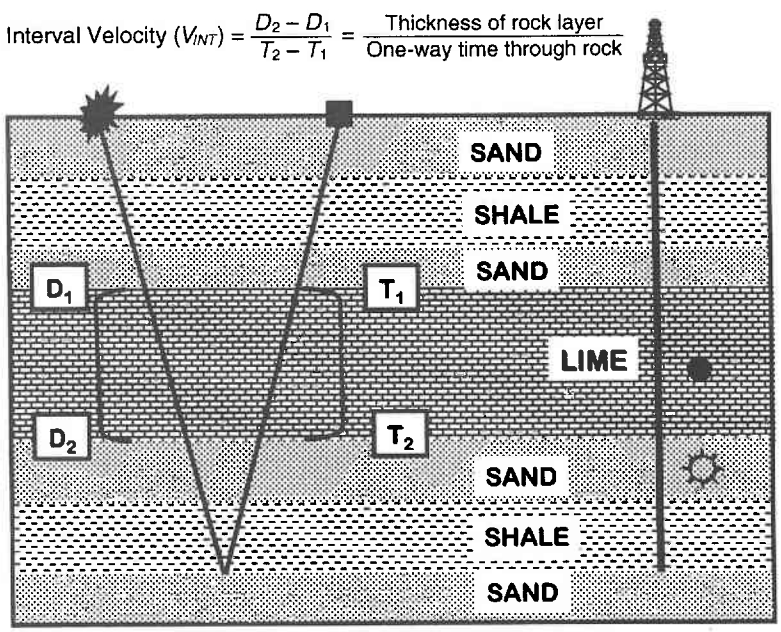


Figure 46. Cross section illustrating interval velocity.

UTILIZING WELL CONTROL

The best way to interpret seismic data is to have some means of confirming which reflectors are being mapped on the seismic data. A critical mistake often made in seismic exploration is the creation of a map based on the wrong reflector!

Check-Shot or Velocity Surveys

One sure way of identifying the depth–time relationship for a geologic horizon is to use a seismic source at the surface and to lower a receiver (geophone) down a borehole to the depth of the selected geologic marker. The traveltime to the reflector is measured and then divided into the depth to obtain the average velocity to the reflector (Fig. 47).

Check-shot surveys often measure a series of traveltimes down the borehole so that a complete table of traveltime and depth can be constructed. These traveltime tables can

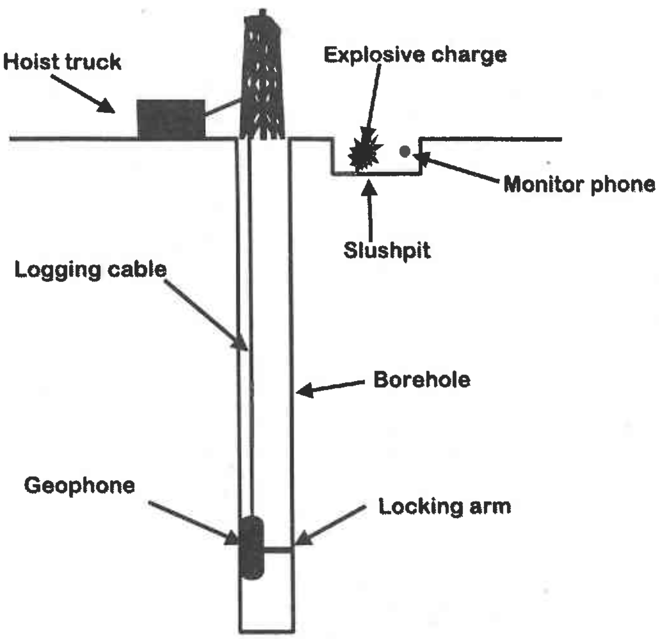


Figure 47. Diagram showing the basic arrangement for shooting a check-shot (or velocity) survey.

then be used by interpreters to identify key reflectors in the well and to map at depth away from the well (assuming that the velocities do not change much in the horizontal direction). Check-shot surveys are used frequently along the Gulf Coast because of time layering, complex fault systems, and the critical need for recognizing the depths to key reflectors (Fig. 48).

Vertical Seismic Profiles

A more labor-intensive, and therefore more expensive, version of the check-shot survey is the *vertical seismic profile* (VSP). This survey requires taking a more densely spaced sequence of measurements down the borehole and then processing the data to simulate the surface-reflection data. In this way, closely spaced reflectors, which are difficult to distinguish when using a check-shot survey record, can be separately identified. This method of using well control is employed less frequently, but it is sometimes necessary for accurately deciphering the seismic signals recorded at the surface.

Sonic Logs

In many cases, a sonic log is available for measuring the sound velocity in a well. Petrophysicists use this type of log as an aid for determining porosity. When a check-shot survey or a VSP is not available, the seismic interpreter can use a sonic log to estimate the traveltime–depth relationship for reflectors.

The sonic log essentially measures the ΔT_1 value for a thin interval. Because the units are usually in microseconds per foot, the interval can be assumed to be 1 ft. If the ΔT_1 values for a series of adjacent intervals are added together, the traveltime through a thicker interval is obtained. In this way, the subsurface can be divided into a series of intervals. The velocity for each interval is obtained by dividing the thickness of the interval by the sum of the sonic times for the interval. Summing the sonic times in this manner is sometimes referred to as "integrating the sonic" over the interval. This summing or integrating the sonic over intervals within a well can be used to build an interval-velocity model (assuming a horizontally layered medium) for that part of the subsurface surrounding the well (Fig. 49).

Once an interval-velocity model has been assembled for the layers of rock adjacent to the well, the average and RMS velocities (estimates of the stacking velocities) can be computed. One potential problem facing the integration of sonic times is the fact that sonic logs are often not run all the way from the surface to the bottom of the hole. This means that some kind of

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I N P U T
One or two way: 2 way time
Correctional Velocity: 6200
Datum Plane: Sea Level
Depth adjustment: 0
Depth unit: English(feet)

O U T P U T
Depth extrapolation: 0
Time extrapolation (ms): 0
Datum Plane: Sea Level
Depth Adjustment: 0
Depth unit: English(feet)

	Input Data ... 2-WAY TIME	DEPTH	Adjusted Data ... 2-WAY TIME	DEPTH	AVERAGE VELOCITY	INTERNAL VELOCITY	SEA LEVEL ELEVATION
1	152	500	152	500	6579	6579	-500
2	300	1000	300	1000	6667	6757	-1000
3	430	1500	430	1500	6977	7692	-1500
4	559	2000	559	2000	7156	7752	-2000
5	669	2500	669	2500	7474	9091	-2500
6	818	3000	818	3000	7335	6711	-3000
7	948	3500	948	3500	7384	7692	-3500
8	1066	4000	1066	4000	7505	8475	-4000
9	1530	6000	1530	6000	7843	8621	-6000
10	1646	6500	1646	6500	7898	8621	-6500
11	1764	7000	1764	7000	7937	8475	-7000
12	1895	7500	1895	7500	7916	7634	-7500
13	2025	8000	2025	8000	7901	7692	-8000
14	2155	8500	2155	8500	7889	7692	-8500
15	2265	9000	2265	9000	7947	9091	-9000
16	2416	9500	2416	9500	7864	6623	-9500
17	2546	10000	2546	10000	7855	7692	-10000
18	2676	10500	2676	10500	7848	7692	-10500
19	2802	11000	2802	11000	7852	7937	-11000
20	2903	11500	2903	11500	7923	9901	-11500
						9804	

Figure 48. Sample from a typical check-shot survey.

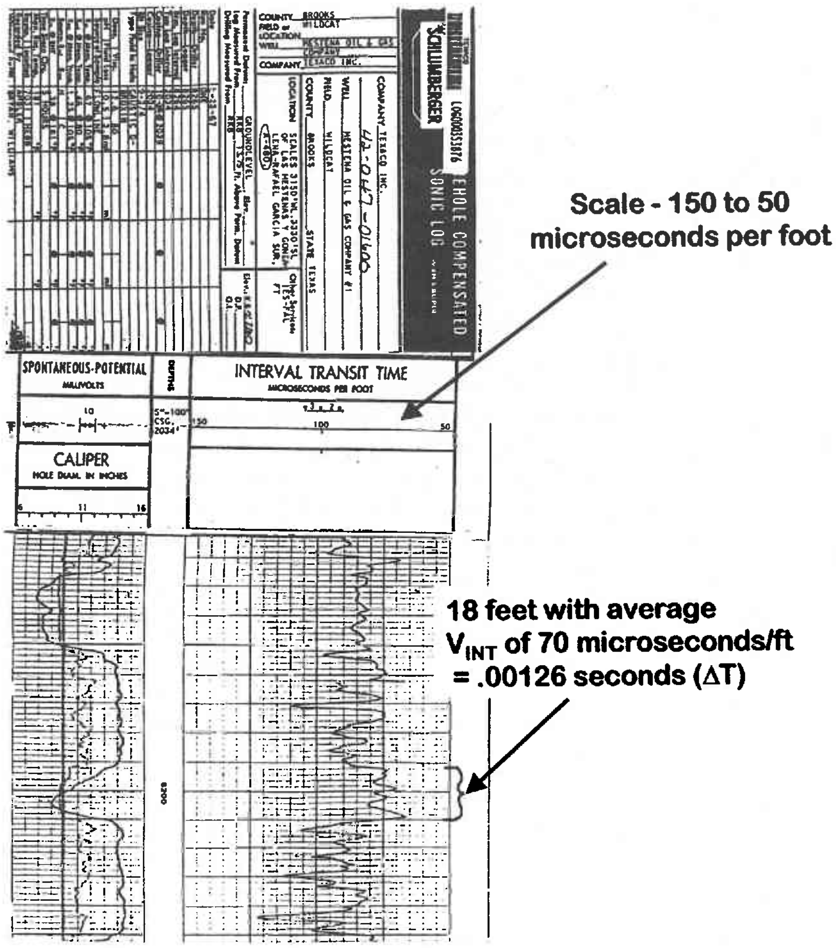

Figure 49. Part of a compensated sonic log.

estimate has to be made for the portion of the subsurface that was not logged. Still other problems are caused by drift and/or errors in the sonic readings. In spite of these problems, integrating sonic readings at least gives a "ballpark" estimate of the time–depth relationship when no other data are available.

SYNTHETIC SEISMOGRAMS

When density and/or sonic logs are available for wells, it is possible to build a layered model of the subsurface. Once this layered model is constructed, a model of the seismic response from the layered model can be constructed. This seismic-response model is called a *synthetic seismogram* because the results are not due to a real seismic experiment. This type of modeling can be used to identify the reflectors found within the seismic data. Because using synthetic seismograms is a cheaper approach than taking a check-shot survey, this method of correlating seismic data with well control is most often used. This approach is not foolproof, however, and should be used with caution. The basic ideas are described as follows.

Reflections of sound waves are caused by density and velocity changes inside the Earth. For waves reflected from an interface between two types of rock, the reflection coefficient can be written in the following form:

$$R_c = (\rho_2 V_2 - \rho_1 V_1) \;/\; (\rho_2 V_2 + \rho_1 V_1)$$

where the product, ρV—the density times the velocity of a formation—is called the *acoustic impedance* of a formation. Reflections are caused by changes in acoustic impedance; this means that changes in density or changes in velocity can cause reflections.

In order to build a synthetic seismogram, density and velocity (sonic) logs are used to build a picture of the acoustic impedance within a well. Next, the reflection coefficients at the boundaries are computed at each depth. The traveltime to each reflector is found by integrating the sonic log. If a check-shot survey is available, any errors in the integration are corrected with the check-shot times. The final result is a series of reflection coefficients plotted as a function of time. This plot is called the *reflectivity,* which is an estimate of the reflection coefficients from those well logs that will be used to model the seismic response.

Once the reflectivity has been estimated from the well logs, some form of wavelet has to be assumed (this is usually a theoretical representation of the wavelet generated at the initiation of the energy source). In addition to the shape of the wavelet, the relationship of the wavelet to the reflecting surface has to be assumed. For example, Vibroseis wavelets are usually centered on the reflecting interface, whereas dynamite wavelets lag behind the reflecting interface. The final synthetic seismogram is constructed by placing (mathematically) a waveform at each of the reflecting horizons. The size of the waveform plotted depends on the size of the reflection coefficient. The polarity (positive or negative) of the reflection depends on the sign of the reflection coefficient. The relationship of the wavelet to the reflecting surface (centered or offset) depends on the type of seismic source being used.

It is easy to visualize the synthetic seismogram where the geology is simple. The problem arises when fine layers contribute to a complicated seismic picture. In addition, the wavelet is usually not known with great precision. Thus, a great deal of guesswork goes into making a synthetic seismogram. First, the interpreter has to guess at how the subsurface layers should be constructed, on the basis of well-log information. This is not always as easy as it might sound. Next, the interpreter has to guess at the type of wavelet form on the data. Changing the waveform or wavelet is often referred to as "changing the phase" of the wavelet. This is

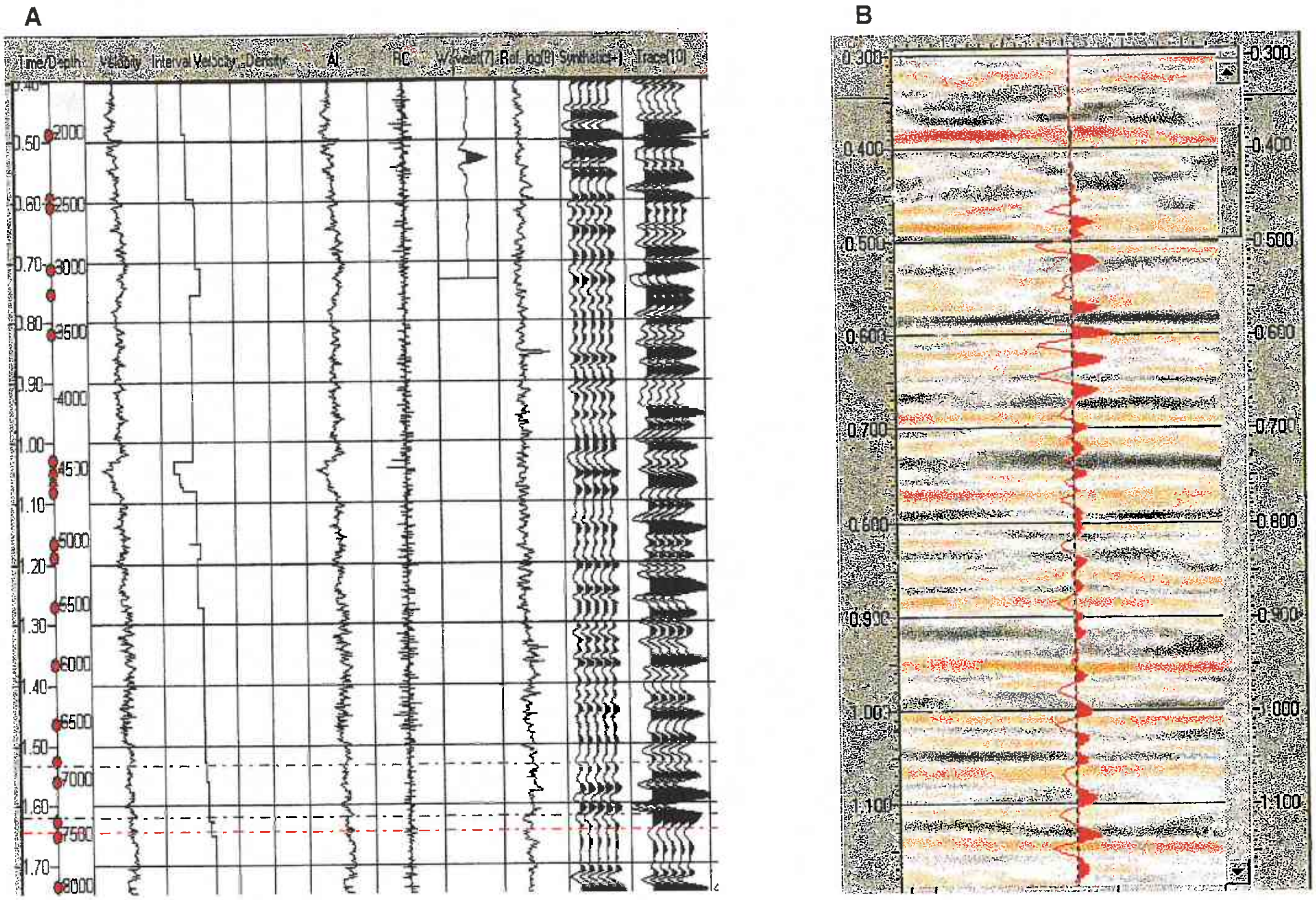

Figure 50. Diagram illustrating a synthetic seismogram and its tie to well data: (A) synthetic seismogram; (B) displayed in wellbore tied to data.

not a trivial exercise: Matching a synthetic seismogram with the actual data can involve considerable trial and error (changing both the assumed model and the assumed wavelet) (Fig. 50).

Synthetics generate varying degrees of confidence in the identification of reflecting boundaries, depending on how well they explain the observed data. For example, if the synthetics successfully explain reflectors all the way from the surface down to the target interval, the interpreter has some justification for trusting the results. However, if the synthetics fit only a small time window within the observed seismic data, the interpreter should be wary of the accuracy of tying the synthetic to the "real world."

ACKNOWLEDGMENTS

In the process of assimilating information for this workshop, the help of several friends was called on. Without their assistance, this workshop would not have been possible. They are: James Holiday (Shell Oil Co., retired), Craig Moore (consultant), Robert Pledger (president, Benchmark Oil & Gas), Charles Mankin (director, Oklahoma Geological Survey [OGS]), and Michelle Summers (technical project coordinator, OGS).

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PART II

Seismic Applications and Examples

Two- or Three-Dimensional Seismic Data? That Is the Question

Deborah K. Sacrey

INTRODUCTION

Part I of this volume covered the basics of seismic data from the early days of refraction and reflection shooting through acquisition and processing of these data. We focused on two-dimensional (2-D) seismic data, but we need to continue along the technological trend into three-dimensional (3-D) seismic data, and examine how it differs from 2-D information.

In the Glossary at the back of this publication, a 3-D seismic survey has been defined as "a survey involving collection of data over an area with the objective of determining spatial relations in three dimensions, as opposed to determining components along separated survey lines."

Basically, a 3-D seismic survey is a dense grid of 2-D lines, but the way in which it is processed and interpreted is very different from that of 2-D data. This difference enables us to take the data from linear information to volume (3-D) information.

The volume concept is important to the interpreter. With 3-D information, the interpreter is working with a volume of information rather than interpolating (guessing?) an interpretation from a widely spaced grid of seismic observations. The subsurface is closely sampled in every direction, so there is no loop for which interpreters must "tie" and no gaps over which they must guess at the subsurface structure or stratigraphy.

WHY USE 3-D SEISMIC DATA?

There are several advantages to using 3-D over 2-D seismic data:

1. *Density of data points.*—Figure 51 is a 3-D view of a 2-D line. A 2-D line is acquired along a path across the surface. It is linear in its dimension, and the geologic information it provides cannot be inferred with accuracy in any direction other than the line along which it is acquired. In fact, even that view is not completely accurate, for it varies according to the surrounding geologic features because of reflections "out of the plane" that have been processed into the 2-D line during the migration of data. The reflections presented in a 2-D seismic section are those recorded as if they were from the surface of a cylinder. Features such as pinnacle reefs, faults, and edges of salt domes can be recorded with a 2-D seismic profile but may incorrectly show the feature as occurring along the traverse of the line.

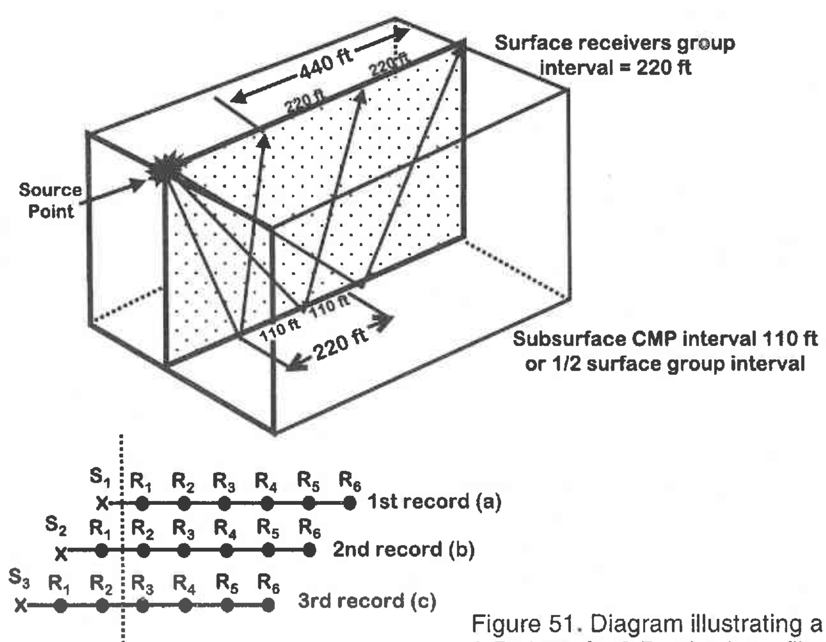


Figure 51. Diagram illustrating a 3-D view of a 2-D seismic profile.

Figure 52 illustrates the same type of acquisition parameters as the previous figure—100-ft midpoints in the subsurface with 220-ft geophone intervals on the surface—but a continuous layout of shotpoints and geophones allows for a dense grid of reflection points in all directions. This dense grid of reflections, when migrated properly, allows for a continuous surface of reflections rather than a straight line of information. In

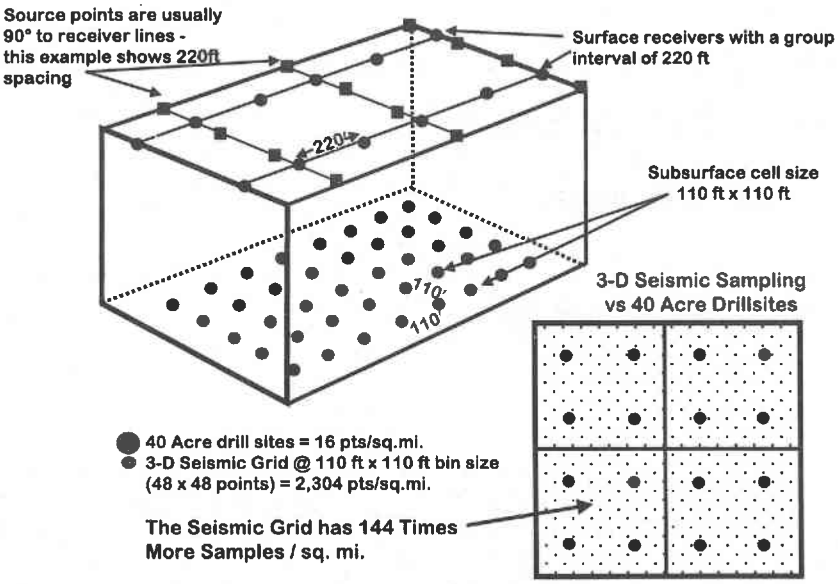
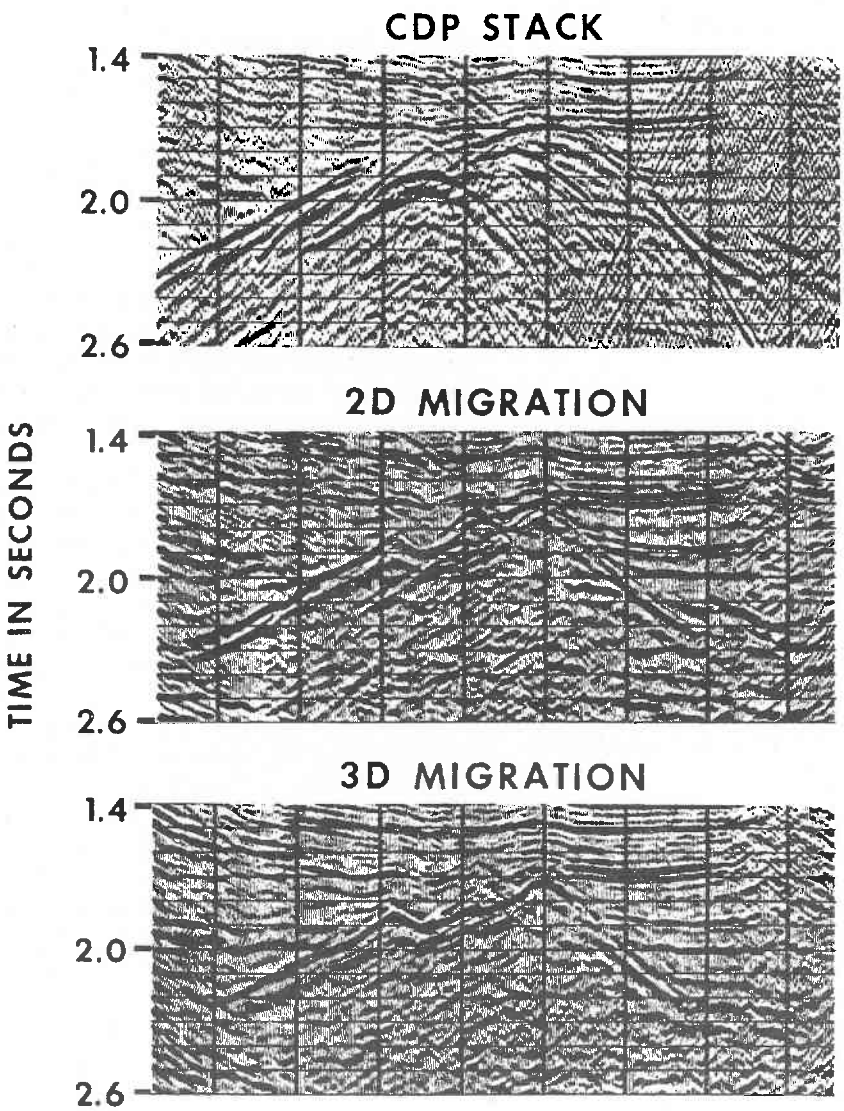


Figure 52. Diagrams illustrating grid density and sampling per square mile of 3-D data.

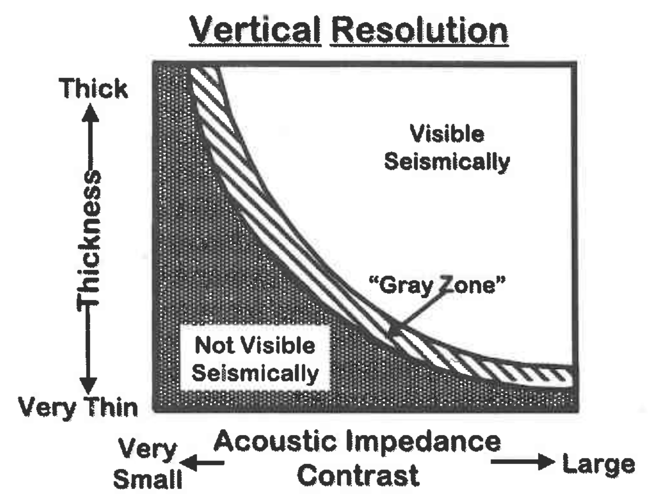


addition, in this figure is an example of the data points gathered in a square mile of 3-D seismic data versus a drilling density of 40-acre spacing. The seismic information is 144 times more dense than the geological control, which, when integrated together, can aid in the delineation of subtle stratigraphic and structural features.

2. *Three-dimensional seismic migration creates accurate positioning.*—Earlier, an example was given to illustrate the effects of dip in the subsurface on the correct positioning of reflections in the seismic data. In the 3-D migration process, the reflection points are analyzed from all directions, not just forward and backward as in the case of 2-D data. Figure 53 is an example of the same information displayed in three panels. The top panel displays raw "stacked" data above and beside a salt dome (see earlier explanations in Fig. 42). The middle panel represents a 2-D migration process. Note the appearance of three "humps" in the middle of the section. The bottom panel depicts the data with a 3-D migration algorithm applied. The structure has lost its middle hump, and the reflectors above the salt are shown with the appropriate drape across the structure.

3. *Improved horizontal and vertical resolution.*—Figures 54 and 55 address the issues of vertical resolution. The ability to "see" a sand body (and identify it as such) in the seismic data depends on its thickness, hardness (velocity), and depth of burial. It is a rule of thumb that a stratigraphic interval will produce separate reflections when that interval is as thick as the wavelength (l) of the seismic signal at that point. Because velocity generally increases with depth (hardness), and the higher frequencies of the seismic signal are lost at depth (owing to various types of absorption), the wavelength of the signal increases with depth (= velocity/frequency). The deeper the reflector is,

Figure 53 *(left)*. Three profiles illustrating improved structural continuity of an unconformity reflection resulting from 2-D and 3-D migration. The top of the salt is more accurately defined in the bottom profile, making it easier to decide where to drill a section that would trap by structural drape. From Brown (1988, p. 6).



Reality:

- ★ **Acoustic impedance contrast with surrounding units and thickness determine whether a bed can be resolved**
- ★ **Top and base of an interval produce separate reflections to ¼ wavelength**
- ★ **The thinnest bed that will produce a reflection is 1/30th to 1/16th of a wavelength**
- ★ **The exact numbers change, depending on noise level in data and the wavelet**

Figure 54. Factors governing vertical resolution.

the thicker the formation must be for positive identification. For instance, if one were interpreting a section in which the signal strength is 60 Hz, and the formation at this depth is a carbonate whose velocity is 15,000 ft/sec, the wavelength at this point would be 250 ft. Using the wavelength (l) rule, the smallest interval that could be seismically "seen" would be 32 ft! Thus, even with the best 3-D data, it is virtually impossible to identify a 10-ft sand at 10,000 ft in 30-Hz data.

4. *Choice of viewing perspective.*—In a 3-D volume, one can look at a seismic profile in any direction and view a horizontal "cut" through the data (known as a time slice). A 3-D survey contains an infinite number of 2-D lines. Figures 56 and 57 illustrate the many ways in which to view data in a 3-D volume. Prior to establishment of the volume concept, time slices and cube views were not available in the 2-D world. Obviously, the ability to view seismic data from every angle greatly enhances interpretation.

MAPPING WITH 2-D VERSUS 3-D SEISMIC DATA

Perhaps the biggest advantage in using 3-D seismic data is the ability to map the subsurface more accurately. Figure 58 is an example of a problem encountered when trying to interpret a grid of four 2-D lines, two of which are oriented north–south and two east–west. The lines form a grid of 1 mi by 1 mi. The left side of Figure 58 indicates the fault pattern observed in the four lines. The right side indicates the relative structural features observed. Figure 59 shows two very different interpretations resulting from the previous observations of Figure 58.

When mapping from a 3-D survey, you can fill in the gaps to develop a more accurate structural and stratigraphic interpretation. Literally, there is a 2-D line everywhere you need one.

This is not to say that interpretations are fixed in a 3-D format. There are still differences in the way in which interpreters evaluate 3-D information, often in the way in which faults are related or in interpreting stratigraphic horizons. The gross differences in interpretation are more likely to be linked to poor data quality or extremely complex structural configurations than to involve an infinite number of ways to link information, as in a 2-D grid.

Figure 60 represents two very different time structure maps. The map on the left is an interpretation based on 2-D data and well control. A close comparison of the two would lead to very different drilling results! For instance, in the 2-D version, a domal structure is depicted between the 16-E-1 and the 15-B-4X wells. This structure looks as if it should be productive, because both of these wells were productive downdip from the closure. However, the same location on the map generated from a 3-D interpretation (right map) indicates a very different structural picture. A well drilled from the high position on the 2-D map would be in a lower position on the 3-D map. Thus, the reasons for the productivity of the 16-E-1 and 15-B-4X wells are distinctly different. Which map would you rather use for exploratory or development purposes?

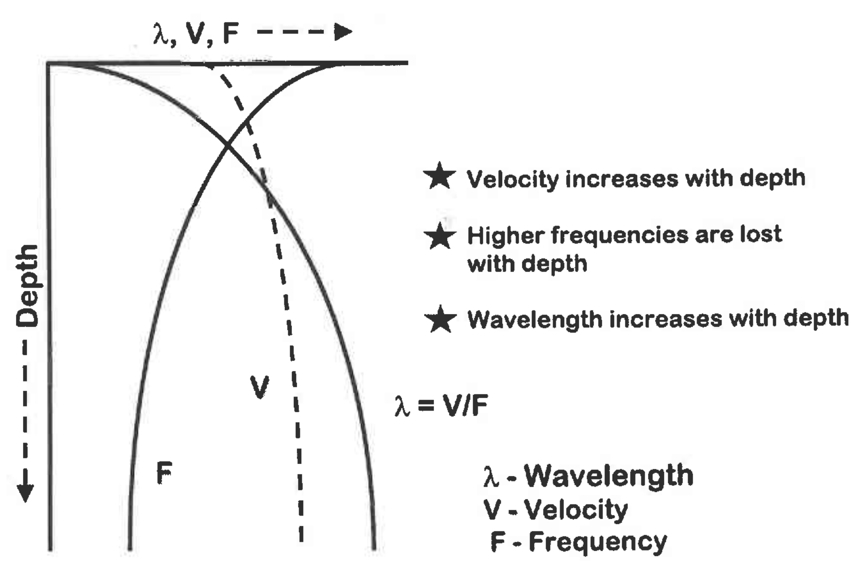


Figure 55. Seismic resolution as a function of depth.

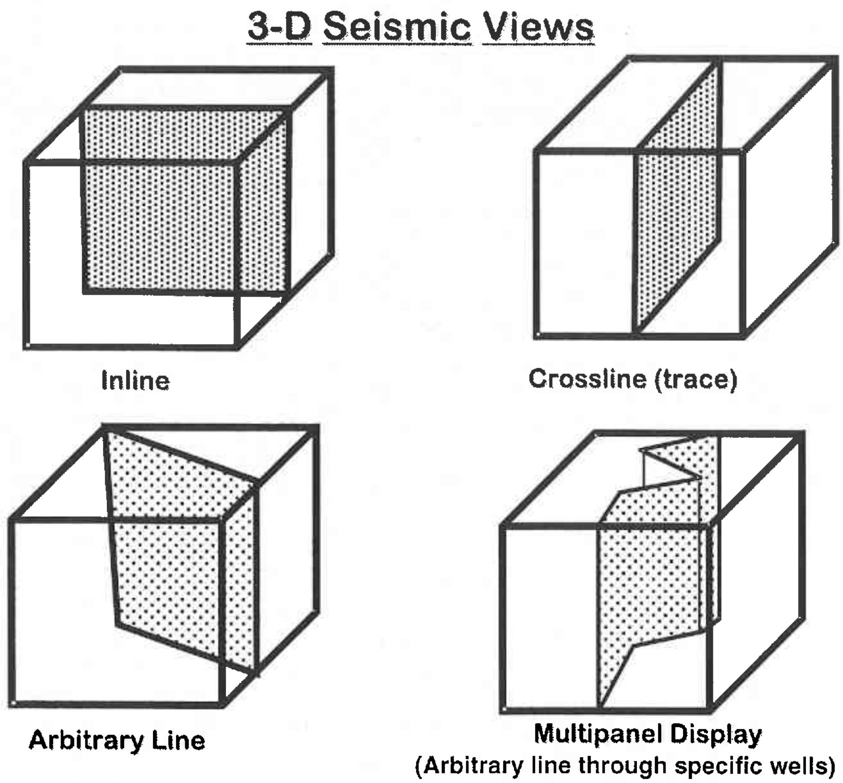


Figure 56. Diagrams illustrating various ways in which to "cut" a 3-D seismic volume.

OTHER ISSUES TO CONSIDER

Other issues to consider when comparing the use of 2-D and 3-D data (if both are available) are as follows:

1. *Cost.*—Obviously, 3-D data are much more expensive to acquire and process than a few 2-D lines. The cost per square mile varies greatly and depends on surface conditions, acquisition parameters, and the depth of investigation needed to solve geological problems. In some areas of the Gulf Coast, especially in environmentally sensitive areas, the cost of acquiring and processing a 3-D survey can be more than $\$100,000/mi^2$. Overall, the average cost for a 3-D survey in the Midcontinent is on the order of $\$30,000/mi^2$. Because of 3-D migration techniques to depict the subsurface properly at depth, a 25-mi^2 3-D survey is designed to see a 1-mi^2 structure at 10,000 ft! This means tying up land in large areas for a long enough period of time to acquire, process, and interpret the seismic information and evaluate drilling locations.

2. *Time.*—Two-dimensional data require much less permitting, less trouble

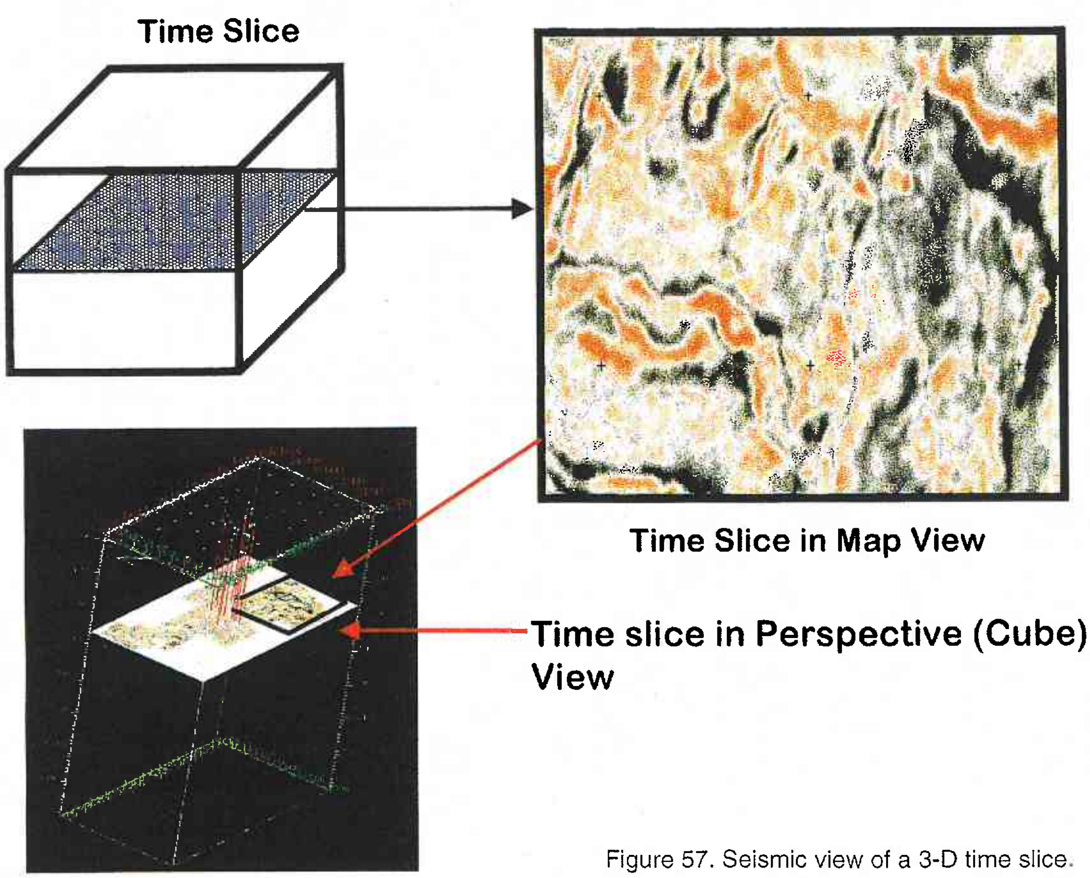


Figure 57. Seismic view of a 3-D time slice.

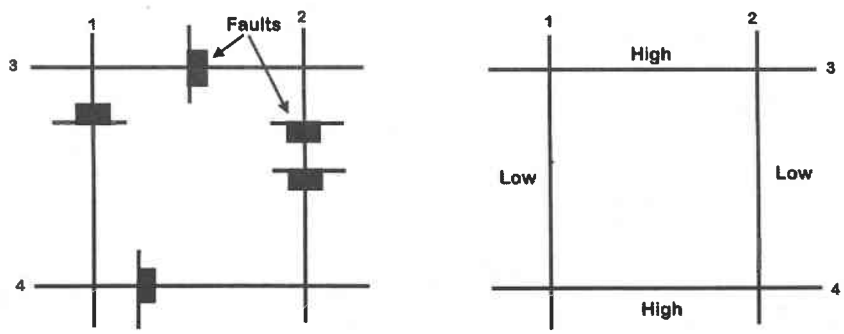


Figure 58. Illustration showing a 2-D mapping dilemma. An interpreter has been given four 2-D lines, two north–south and two east–west, in a grid 1 mi by 1 mi. The observations are indicated.

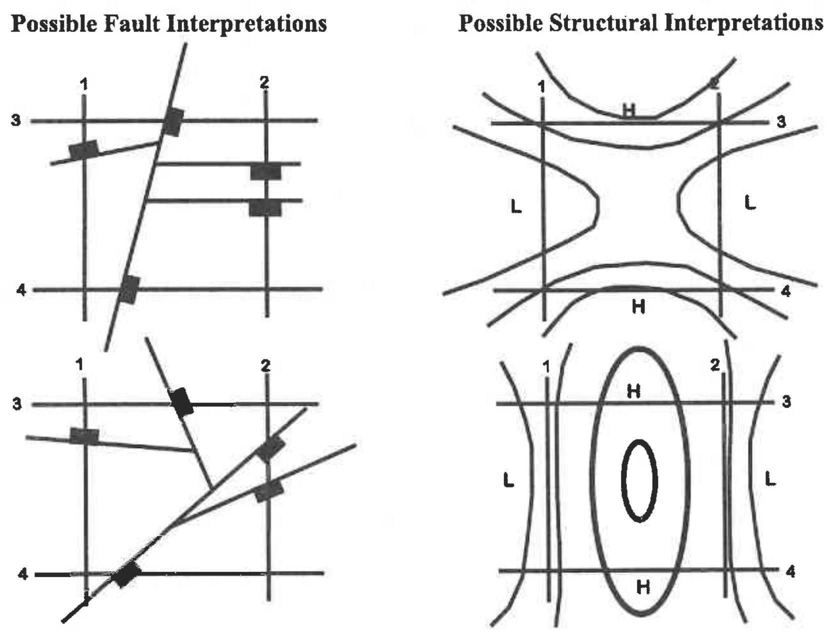


Figure 59. Two possible, very different interpretations from 2-D lines resulting from the observations indicated in Figure 58.

in surveying for source and receiver locations, and less time in processing than even a small volume of 3-D data. Large 3-D seismic shoots may take upward of a year or two to acquire—depending on crops, hunting season, and weather—and then 3 to 4 months for processing. Thus, the time from inception to interpretation easily could be at least a year. Shooting, processing, and evaluating 2-D data take only weeks, or at worst a few months.

3. *Need.*—If you just want to confirm the presence of a fault that is indicated by well control, there is really no need to go to the time and expense of shooting a 3-D survey. If, however, you are looking for subtle stratigraphic changes or complex structures with untested fault blocks, or you want to use seismic signatures (e.g., amplitude anomalies or "bright spots") to delineate potential reservoirs, you should acquire 3-D seismic data.

4. *Use.*—Two-dimensional data usually are used in hard-copy, or paper, form. Three-dimensional data can be printed out (say, every 10th line and cross-line), but the printouts are messy, usually involving lots of paper (depending on the size of the 3-D data), and are cumbersome to use in tying in well information. Three-dimensional interpretation is better accomplished on a computer workstation, where immediate integration of horizons and fault interpretation results in maps without a lot of time-consuming effort. This type of use implies access to an interpreter (geologist or geophysicist) and a workstation. The interpreter and workstation issues are addressed later in this volume.

KNOW WHY YOU WANT OR NEED 3-D DATA

1. Is there a specific geological problem? Is the problem structural or stratigraphic? A complex structural picture probably can be sufficiently deciphered only with 3-D seismic data.

2. Do you suspect there are missed reserves because of lack of well or 2-D seismic control? If attic reserves remain from the produced hydrocarbons, or if there are missed fault blocks, chances are that a grid of 2-D data will not image the missed pay.

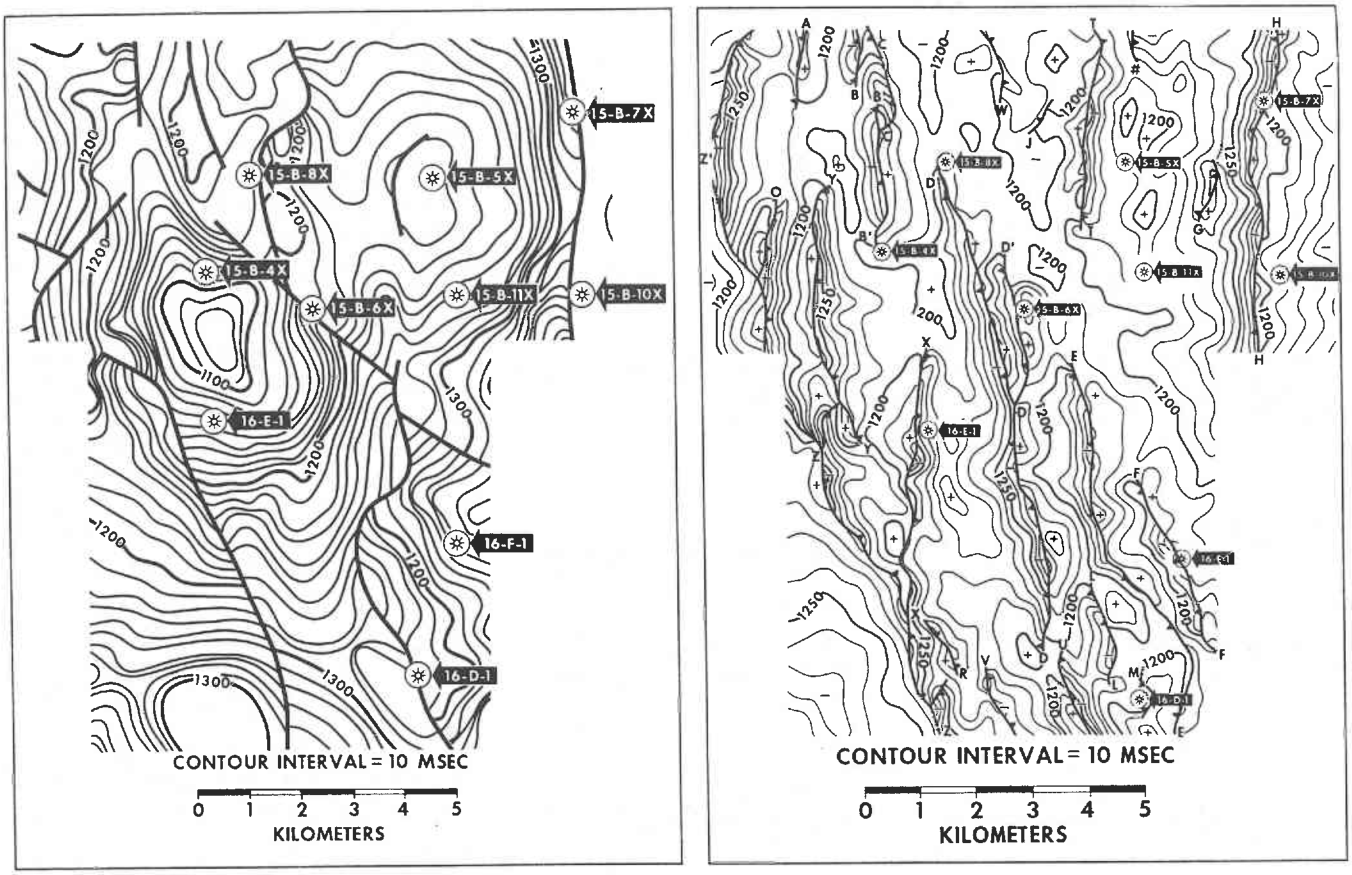
3. Do the current geological data disagree with engineering data? This could come from different bottom-hole pressures in wells thought to be in the same reservoir or from different water levels in wells thought to be in the same fault block.

4. Are your secondary- or tertiary-recovery attempts (waterflooding or injection) indicating barriers that are unexpected? Probably 3-D seismic surveys could help identify subtle permeability barriers, or identify separate sand bodies deposited contemporaneously that might have similar log signatures.

OTHER TYPES OF ADVANCED SEISMIC DATA

Multi-Component Seismic (3-C or 4-C) Data

Multi-component seismic data include the capture and processing of both compressional-wave (*P*-wave) and shear-wave (*S*-wave) data, with the latter being generated and recorded in two directions, each 90° from one another. The 3-C data are generated on land, and the 4-C data in water. Because shear waves do not



Structure map based on 2-D data and well control

Structure map based on 3-D data and well control

Figure 60. Differences in mapping from 2-D versus 3-D seismic data. Which map would you rather use for staking drilling locations? (From Brown, 1988, p. 51.)

propagate through water, a special conversion routine is applied to the compressional data to generate the shear information. This extra step is the additional *C* in 4-C data.

This is "hot-off-the-press" technology. Theoretically, normal seismic (compressional) data are affected by fluid levels in the subsurface, which is why an amplitude difference exists between water-wet sands and gas-filled sands. The shear component in seismic waves is not affected by these fluid levels but can help define internal structure in rocks such as porosity and permeability. Therefore, using a combination of shear and compressional data could more clearly define whether a rock is gas, oil, or water bearing and determine the porosity, permeability, and lithology.

At this time, multi-component technology has been successfully applied to difficult stratigraphic environments, primarily carbonates, in the Rocky Mountains and the North Sea. This process is almost twice as expensive as normal 3-D acquisition because of the specialized recording and processing techniques required to generate the different volumes.

Four-Dimensional Seismic Data

Four-dimensional seismic data are an extension of 3-D seismic data and include the recording and processing of a 3-D survey over the same spot, with the variant being *time*. In this way, subtle changes in reservoirs can be mapped, such as noting depletion, any remaining attic reserves, and the viability of secondary-recovery methods. The 4-D seismic method is primarily an engineering tool, to be used in reservoir characterization on a continuing basis. Because of their expense, 4-D seismic surveys usually are conducted over large prolific fields and are started early in the productive history of such fields.

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Welder Ranch Three-Dimensional Seismic Survey, San Patricio County, South Texas

Deborah K. Sacrey

In 1997, a 90-mi^2 three-dimensional (3-D) seismic survey was acquired over parts of the Welder Ranch in San Patricio County, South Texas. This survey was acquired by a partnership formed by Marathon Oil, Sandalwood Oil and Gas, and Carrizo Exploration.

The area had been heavily explored from the late 1930s through the early 1970s by Marathon (then Plymouth Oil). Production within the area of interest was primarily from the Frio Formation of Oligocene age, which is more than 4,000 ft thick. The Frio spans a depth from 3,500 to 7,500 ft, as reflected in the 3-D survey records.

Major producing fields within the 3-D area include Portilla field, which has a cumulative production of 120 billion cubic feet of gas (BCFG), 405,000 barrels of condensate (BC), and 80 million barrels of oil (BO); Plymouth field, which has a cumulative production of 160 BCFG, 172,000 BC, and 123 million BO; and Taft field, which has a cumulative production of 45 BCFG and 33 million BO.

More than 1,200 well logs were correlated, and major tops, fault cuts, perforation points, and cores/shows were logged in a spreadsheet format. A digital base of well information and cultural information was purchased from Tobin International for use in evaluating the seismic data. Key wells within the 3-D area were surveyed for accuracy and tied in to the well data base.

Figure 61 is a base map from a part of the survey area and represents approximately 18 mi^2. The well density indicates that the opportunity for discovery of new reserves could be a higher risk in comparison to areas with fewer wells.

Structure maps were created from well control to identify potential prospective areas. These maps depict the top Frio level, the middle Frio level, and the lower Frio–Vicksburg levels (a datum change to the Vicksburg Formation was made necessary because of the lack of well control). Figure 62 represents a part of the structure map of the middle Frio before the 3-D survey was acquired.

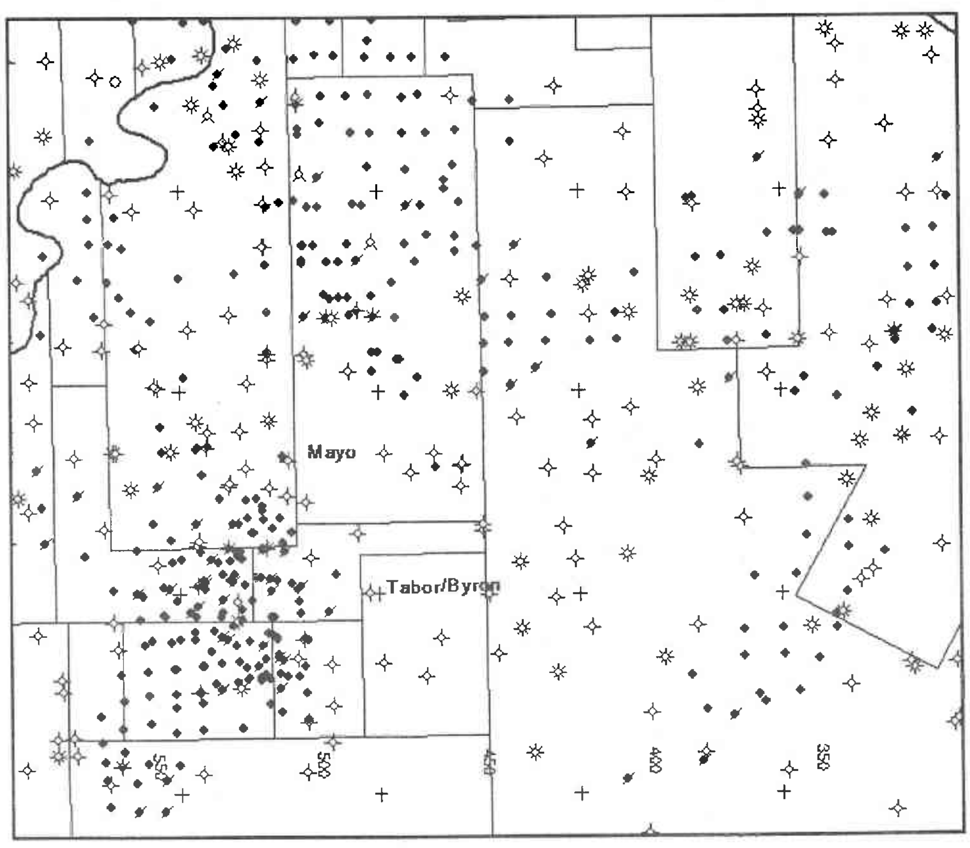


Figure 61. Base map of approximately 18 mi^2 within the 3-D survey area, showing well density.

Following interpretation of the seismic data, the fault picture and other structural aspects of the middle Frio had changed considerably. Figure 63 is a time structure map of a middle Frio reflector, identified by tying the geological information to the seismic data by synthetic seismograms from nearby deep wells for which check-shot surveys were available.

It was discovered that the faulting was much more complex than originally thought, and the opportunity for discovering untested fault blocks was a distinct pos-

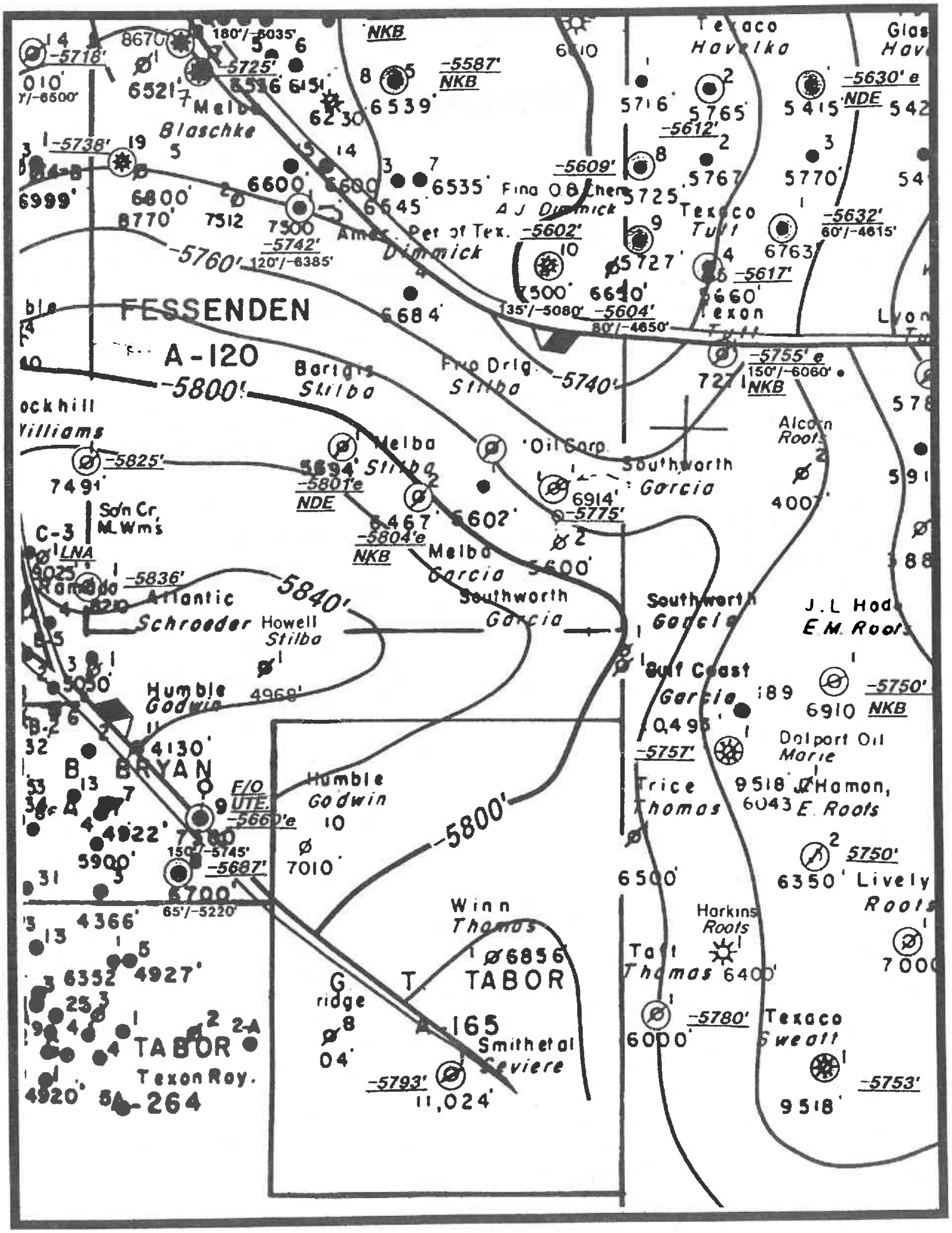


Figure 62. Structure map of middle Frio marker. Contour interval, 20 ft.

sibility. Figure 64 shows an arbitrary line, *A*—a dip line—through such a fault block. This line is expressed in Figure 63 by a red line with an *A* on either end.

The Smith No. 1 Seviere well was drilled in 1975 to a depth of 11,024 ft, with shows in the lower Frio and Vicksburg Formations. Mapping in 3-D indicated that a well could be drilled in a structurally higher position than the Seviere well and possibly find an accumulation of gas and condensate. Figure 65 is an arbitrary line, *B*, that crosses this newly identified fault block in a

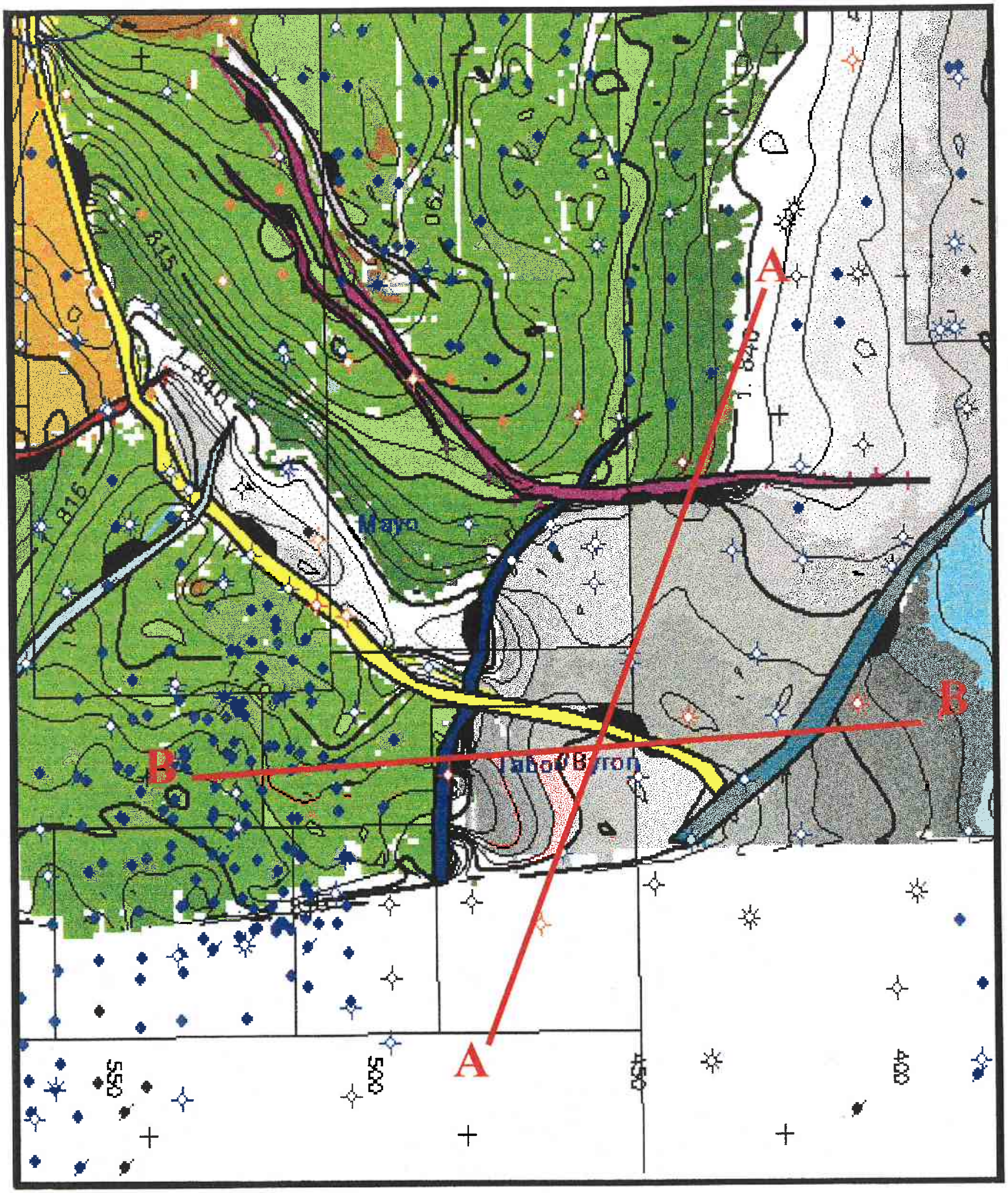


Figure 63. Time structure map of middle Frio marker. Contour interval, 5 ms. Lines A and B shown in Figures 64 and 65, respectively.

strike direction, which indicates an anticlinal structure within the fault block. Other wells had been drilled nearby but either had stopped short of the middle and lower Frio section or had been caught in the faults, with key sands faulted out.

In the course of the 3-D seismic interpretation, a Coherence™ volume was processed. Figure 66 is a time slice at 1.932 milliseconds (ms), showing the faulting. Low coherence values (black) indicate changes in structure or stratigraphy, and high coherence values

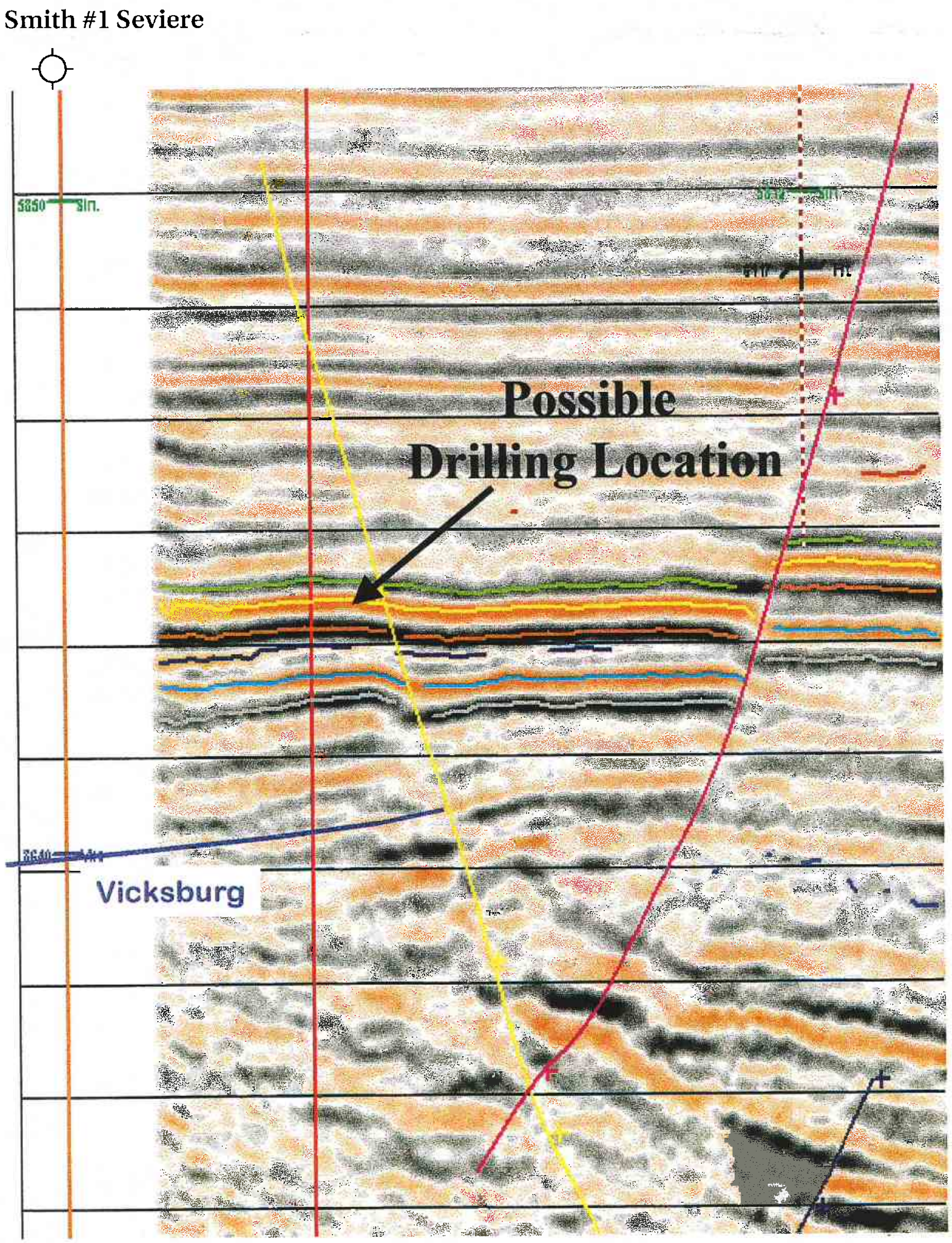


Figure 64. Arbitrary line A (dip direction through Smith No. 1 Seviere well). Line of section shown in Figure 63.

(white areas) indicate a more homogeneous lithology. The coherence time slice gave further evidence that the faulting was more complex than originally believed, and helped the interpretation.

In December 1998, the Sandalwood No. 1 Thomas Brown well was drilled to a depth of 8,620 ft and encountered four productive sands in the lower Frio and Vicksburg Formations. The well was tested and has been producing at the rate of 3 million CFG plus 200 BC per day from the lowest of the four productive zones.

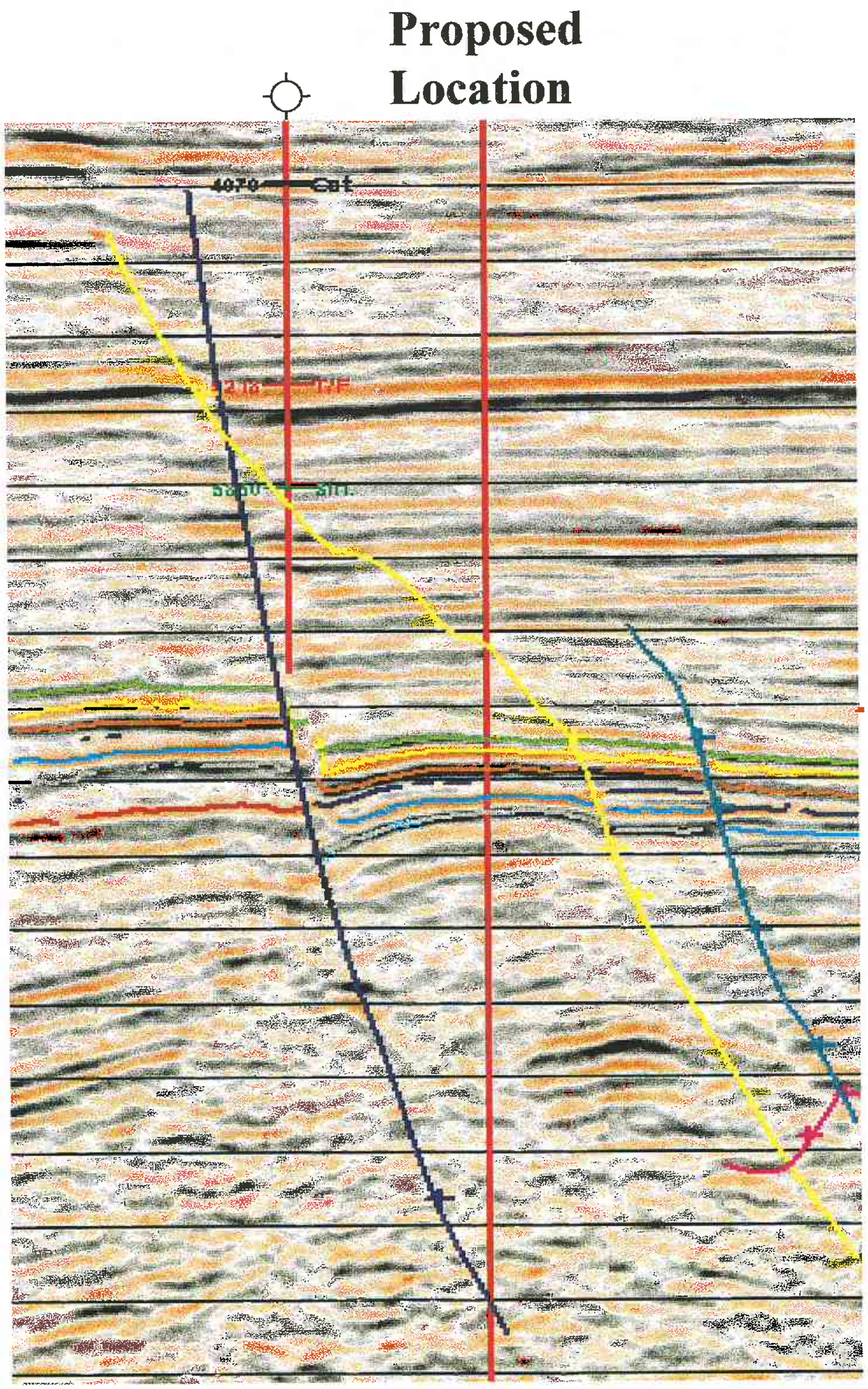


Figure 65. Arbitrary line B (strike line across fault block with proposed location). Line of section shown in Figure 63.

On the basis of well density in the area, this well probably would not have been drilled. Several nearby tests had shows at a similar structural level as the No. 1 Thomas Brown's productive zones, but the 3-D records were the key to understanding the structure. Those wells were in separate fault blocks, downdip to production, and were easily interpreted when tied to the seismic data.

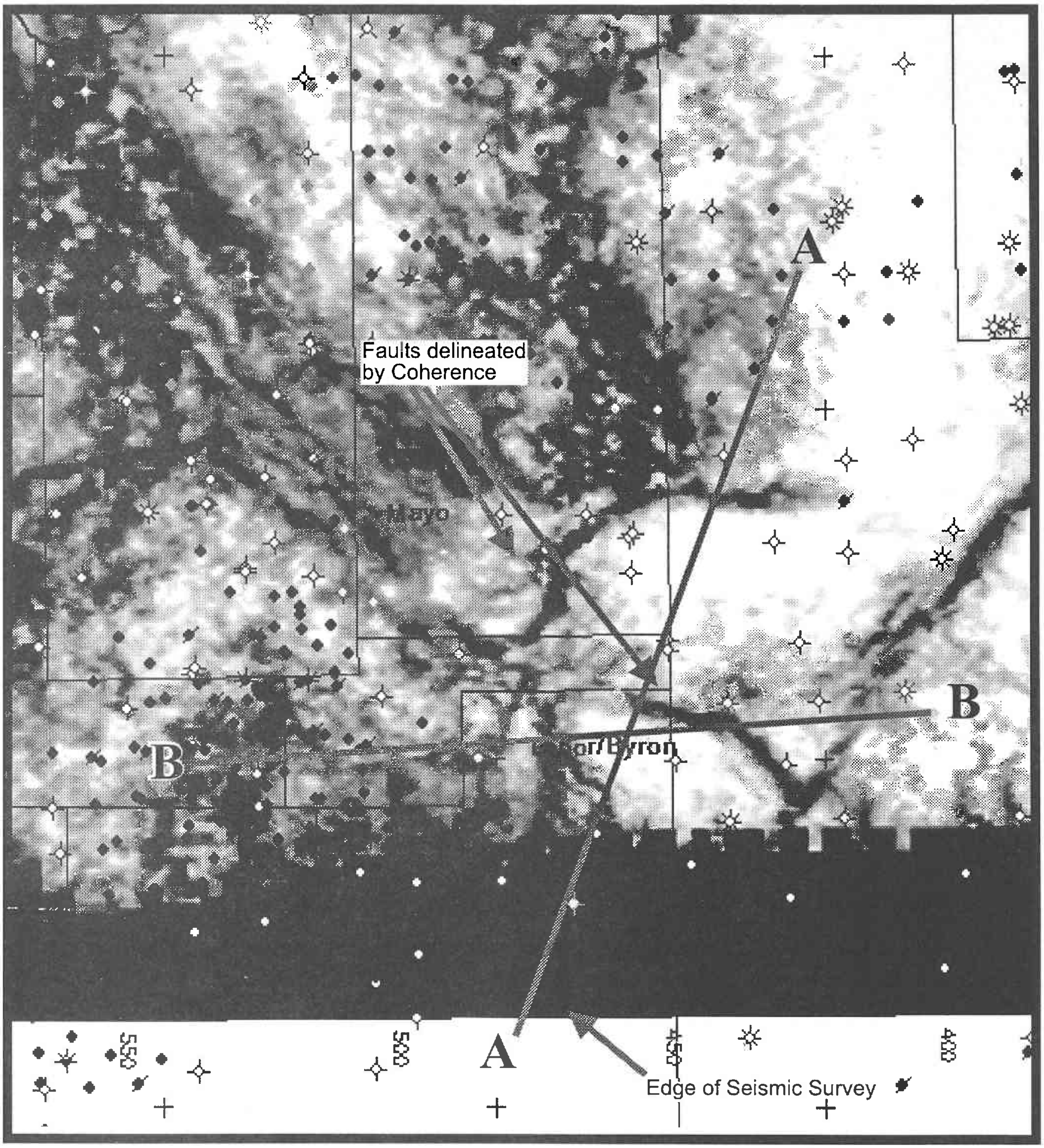


Figure 66. Time slice in Coherence™ at 1.932 ms, showing faulting in middle Frio.

A Sampling of Seismic Data from Oklahoma

Raymon L. Brown

INTRODUCTION

This article examines a sampling of seismic data from several counties of Oklahoma in order to justify the use of seismic data in these areas. The sampling is not exhaustive by any means but should give the reader some idea of what can be accomplished here in Oklahoma. Specific examples include a structural feature at the Cromwell sand interval (Pennsylvanian, Morrowan) and a stratigraphic play in the Booch channel sands (Pennsylvanian, Desmoinesian).

One of the first questions raised when using seismic data in a new area is the quality of the data that can be obtained for the area. Because Oklahoma has an extensive exploration history, the guesswork has been done for you. Most areas of Oklahoma are friendly to seismic data in the sense that both structure and stratigraphy can be studied by seismic methods. As examples, consider the two-dimensional (2-D) lines in Figures 67 through 72. These types of 2-D lines can be used (1) to directly evaluate prospects and (2) to evaluate the potential use of three-dimensional (3-D) seismic surveys for prospecting. The choice depends on how much information you need in order to firm up your prospect.

CROMWELL STRUCTURE

Consider Figure 72, in which the Cromwell sand reflector (about 0.68 sec) exhibits a gentle anticline. Note the clarity of the reflections and the ease of mapping in

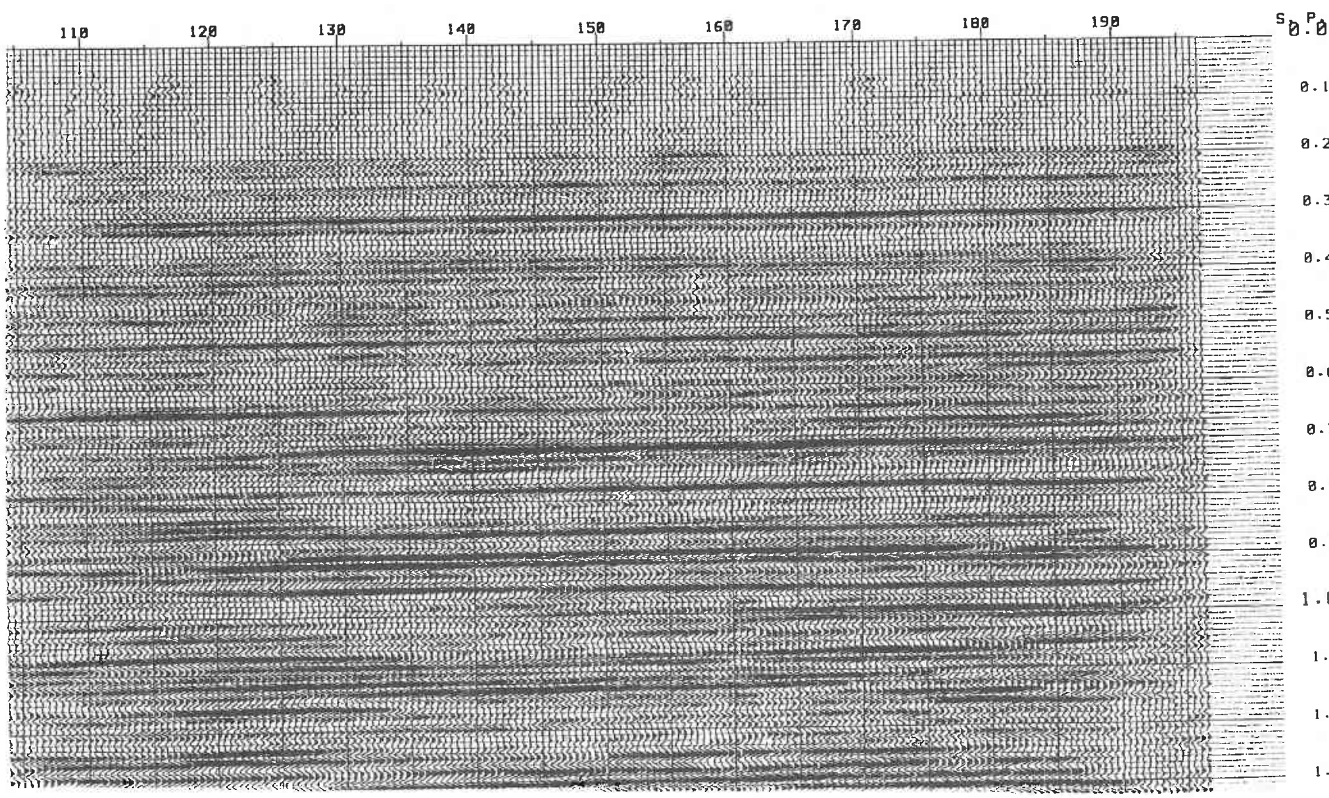


Figure 67. Sample 2-D seismic line, Grant County. (Figures 67 through 78 and data courtesy of Kenneth Rigdon, Nemaha Resources, Tulsa.)

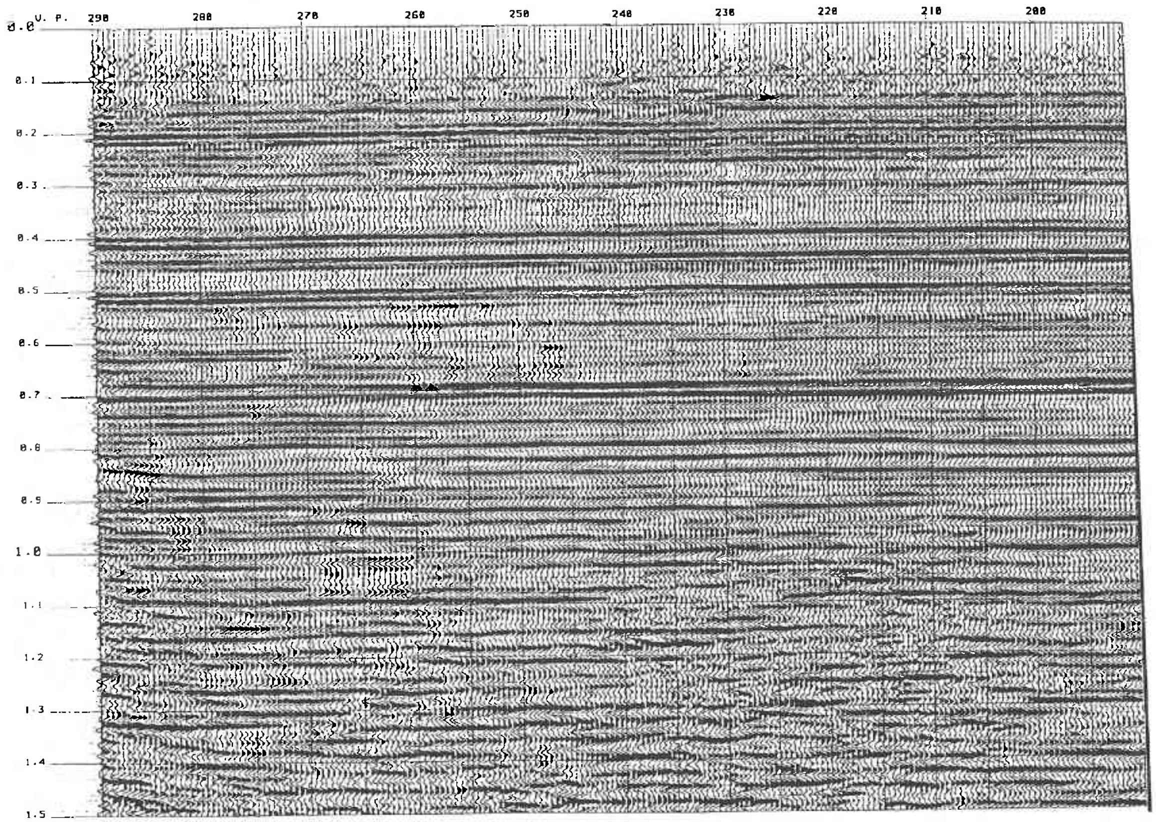
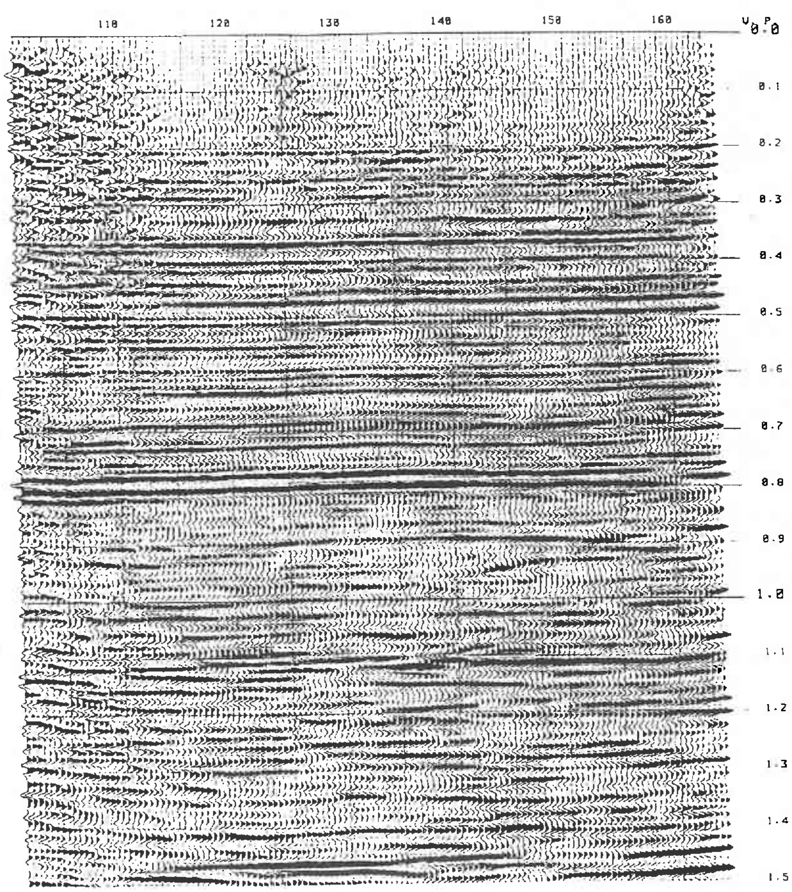


Figure 68. Sample 2-D seismic line, Noble County.



this area. If you are pursuing the structural aspects of this play, then seismic exploration is definitely the tool of choice in this area of Oklahoma.

Although structural interpretation of seismic data is the easiest to understand because you can readily see the structure on the seismic section, stratigraphic interpretations are also a viable tool here in Oklahoma. However, the latter require an understanding of how the waveforms can vary with the stratigraphy. Let's consider an example.

BOOCH CHANNEL SANDS

In Figure 73, a sonic log and synthetic seismogram from Okmulgee County are shown. Note on the sonic log that the Booch sands exhibit faster velocities than the surrounding shales. This means that the areas where the channels are located will give a different type of reflection than those areas dominated by flood-plain deposits. This simple test means that seismic data could be very successful in this region. In fact, 3-D seismic surveying was the method of choice for mapping the channels.

Figure 69 *(left)*. Sample 2-D seismic line, Hughes County.

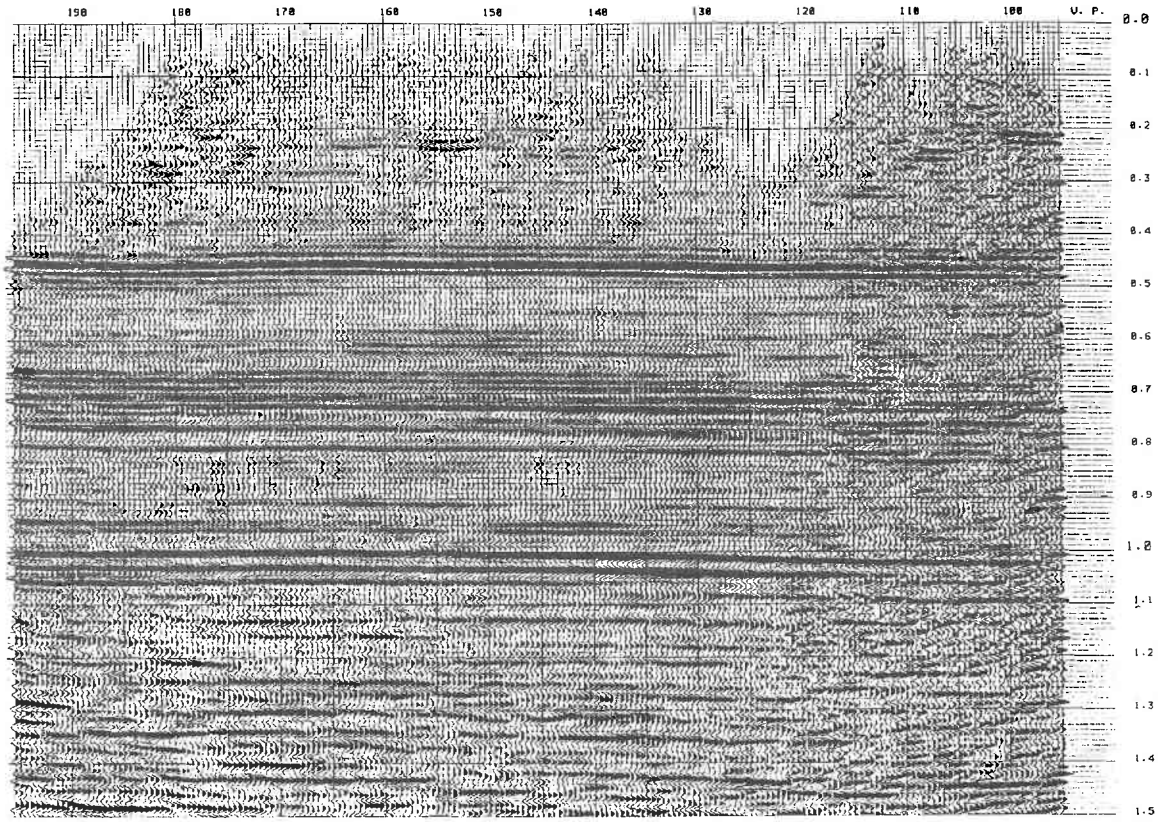


Figure 70. Sample 2-D seismic line, Pottawatomie County.

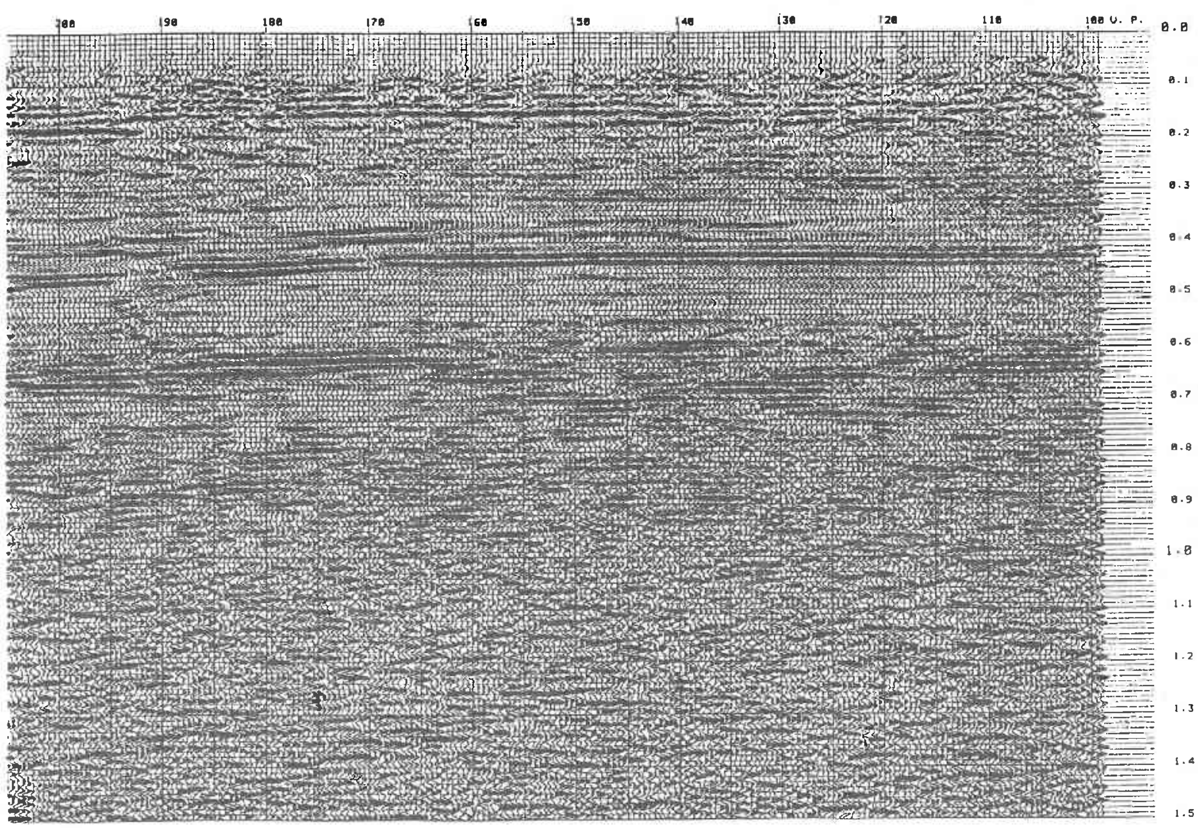


Figure 71. Sample 2-D seismic line, Okmulgee County.

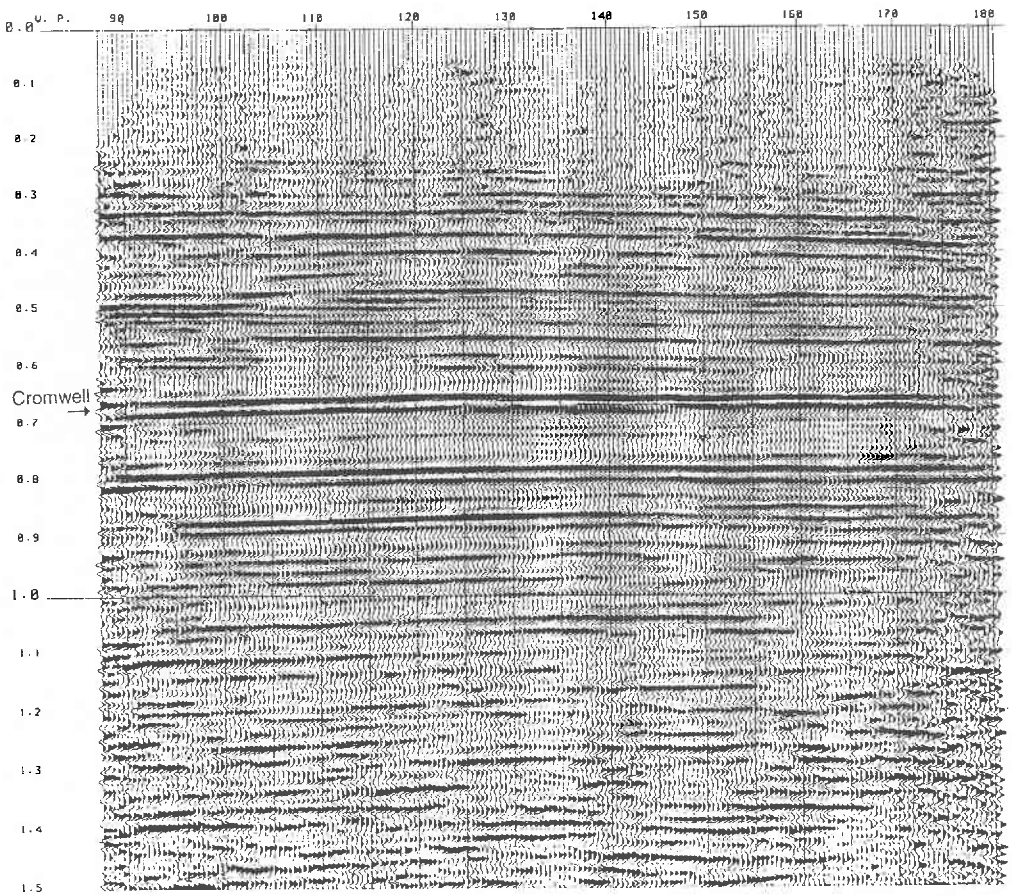


Figure 72. Sample 2-D seismic line, Seminole County. Cromwell reflector at approximately 0.68 sec. Note hint of anticlinal structure at Cromwell horizon.

Figure 74 illustrates the arrangement of the source lines and receiver lines during the shooting of the 3-D survey in Okmulgee County. When lines and sources are laid out in this manner, the 3-D pattern is referred to as a *cross-swath*. The *swath* refers to the use of parallel lines of receivers, and the *cross* refers to shooting across the lines (usually at right angles). The basic pattern that is repeated is called a *template*.

One important feature of seismic data is the *fold* of the data, which indicates how many traces are added together to get a single seismic trace. The more traces that are added together (with signal), the better the final picture or seismic section is.

Figure 75 illustrates a map of the fold distribution for the cross-swath pattern shown in Figure 74. Note how the fold builds toward the center of the 3-D-seismic study area. This is where your prospective area should be. However, in many areas of Oklahoma, even low-fold data are useful. Perhaps this is why Oklahoma is the home of the first successful seismic-reflection exploration.

Figures 76 and 77 show two 2-D sections taken from the 3-D cube of data. Note the quality of the reflectors at all levels. This particular study was aimed at the Booch channel sands. Figure 78 shows a time slice through 3-D

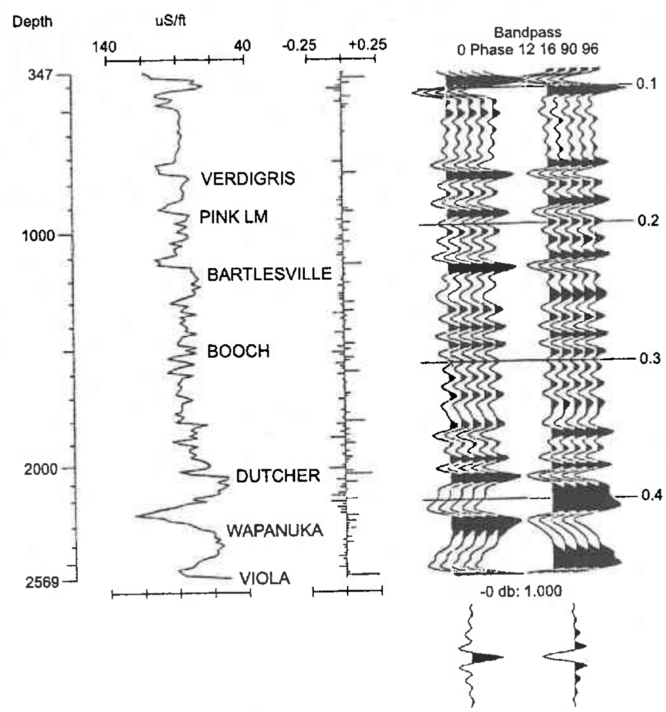


Figure 73. Synthetic seismogram from a well in Okmulgee County.

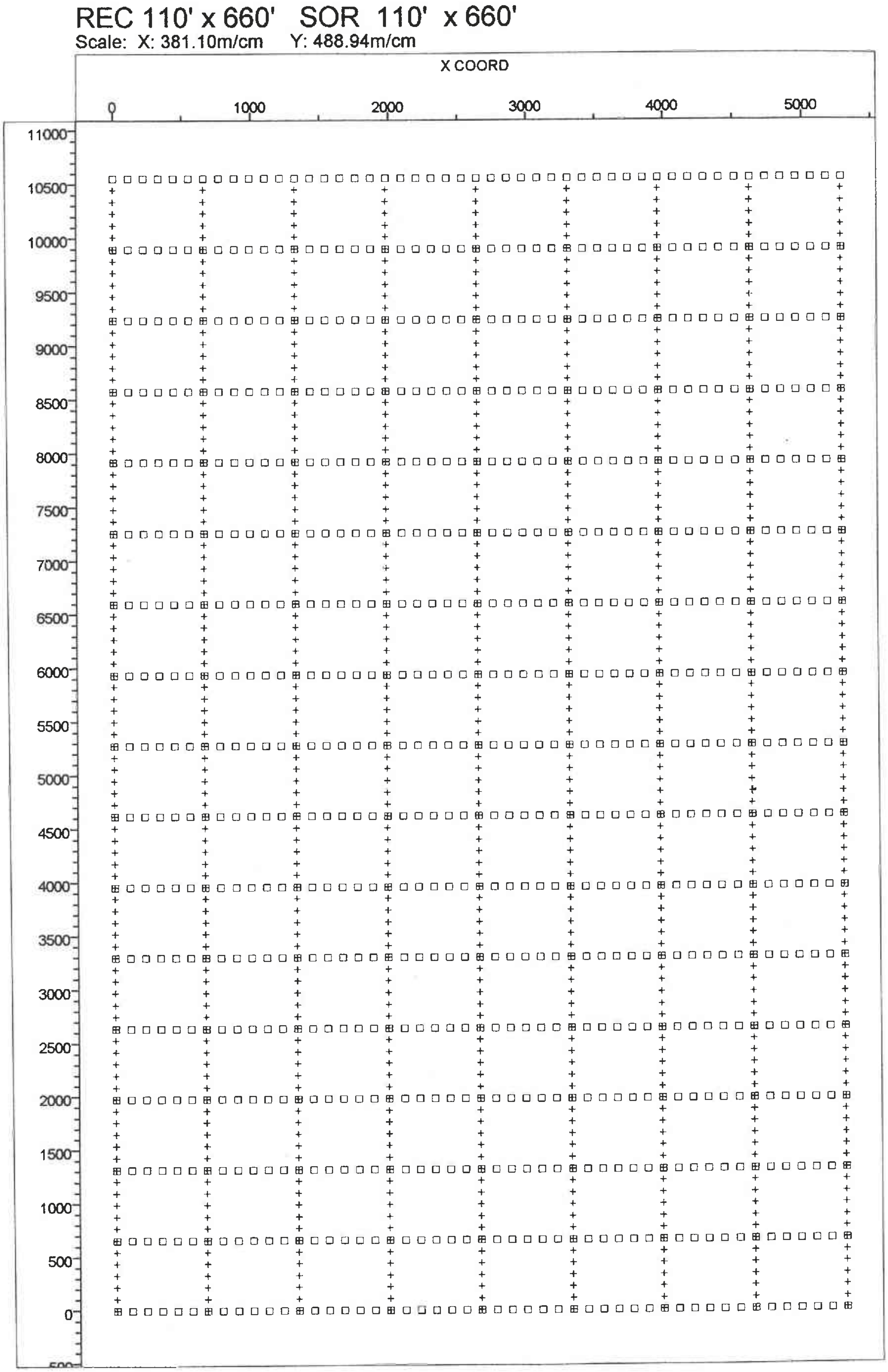


Figure 74. Map of source (boxes) and receiver (+) positions for 3-D survey in Okmulgee County.

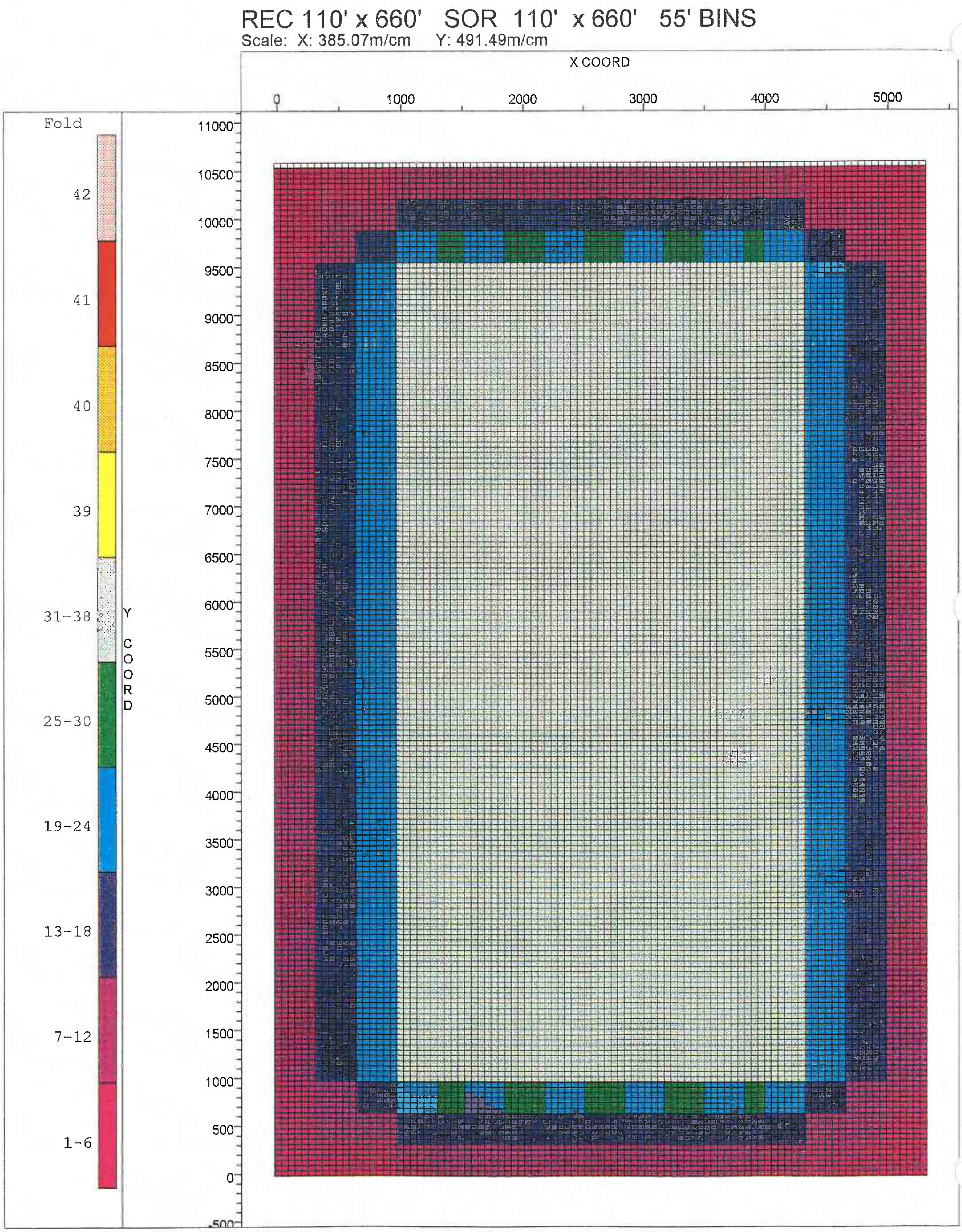


Figure 75. Plot of fold for 3-D seismic line in Okmulgee County.

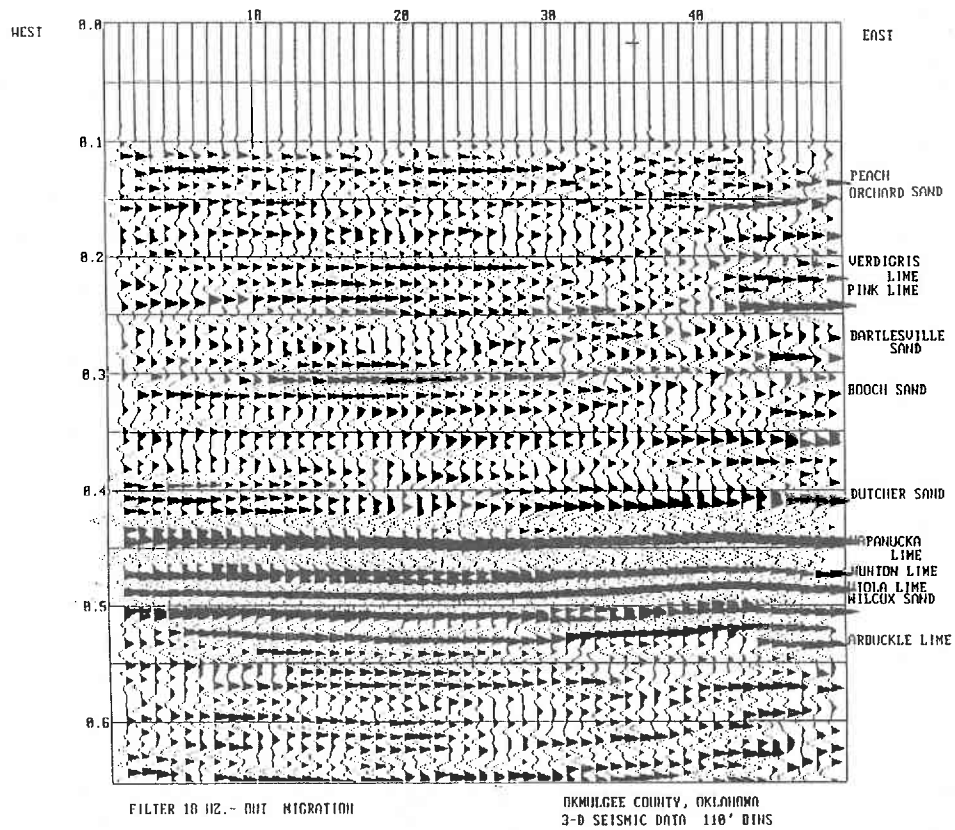


Figure 76. An east–west 2-D seismic section from 3-D seismic data, Okmulgee County.

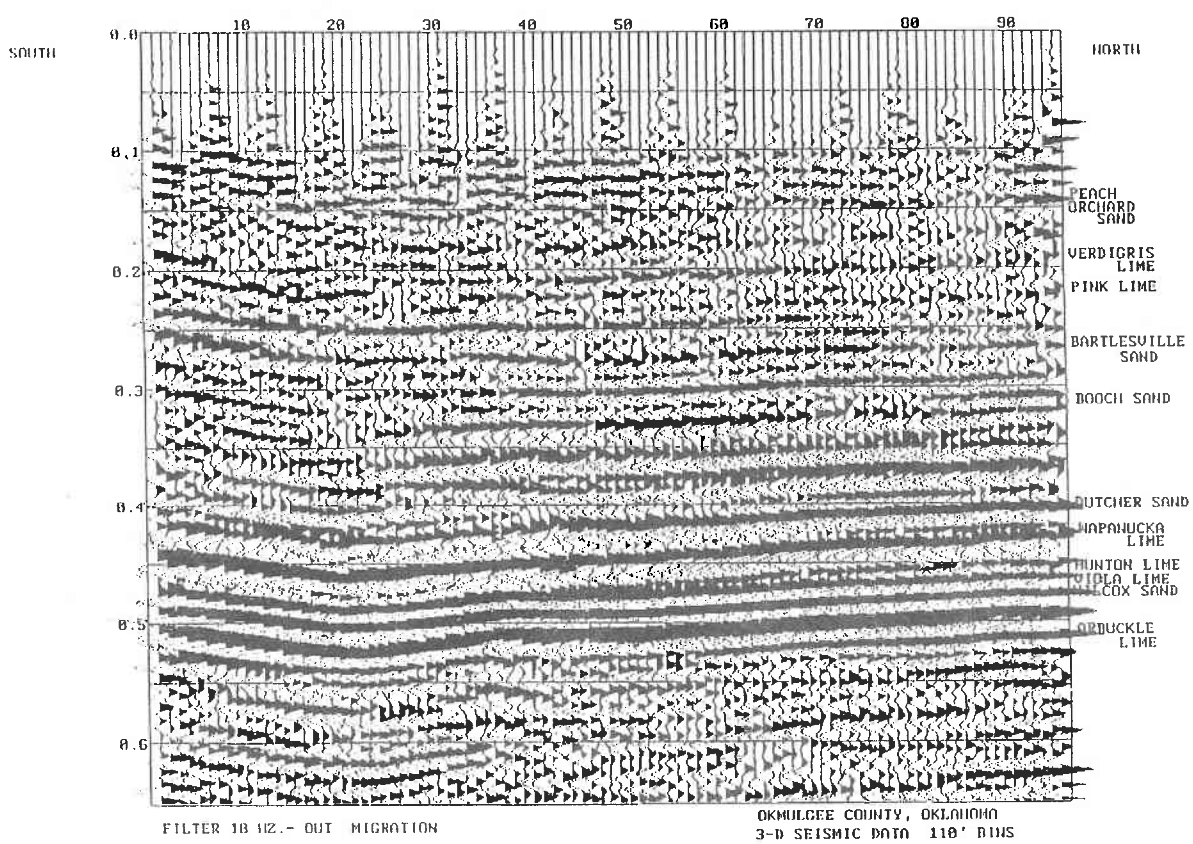


Figure 77. A north–south 2-D seismic section from 3-D seismic data, Okmulgee County.

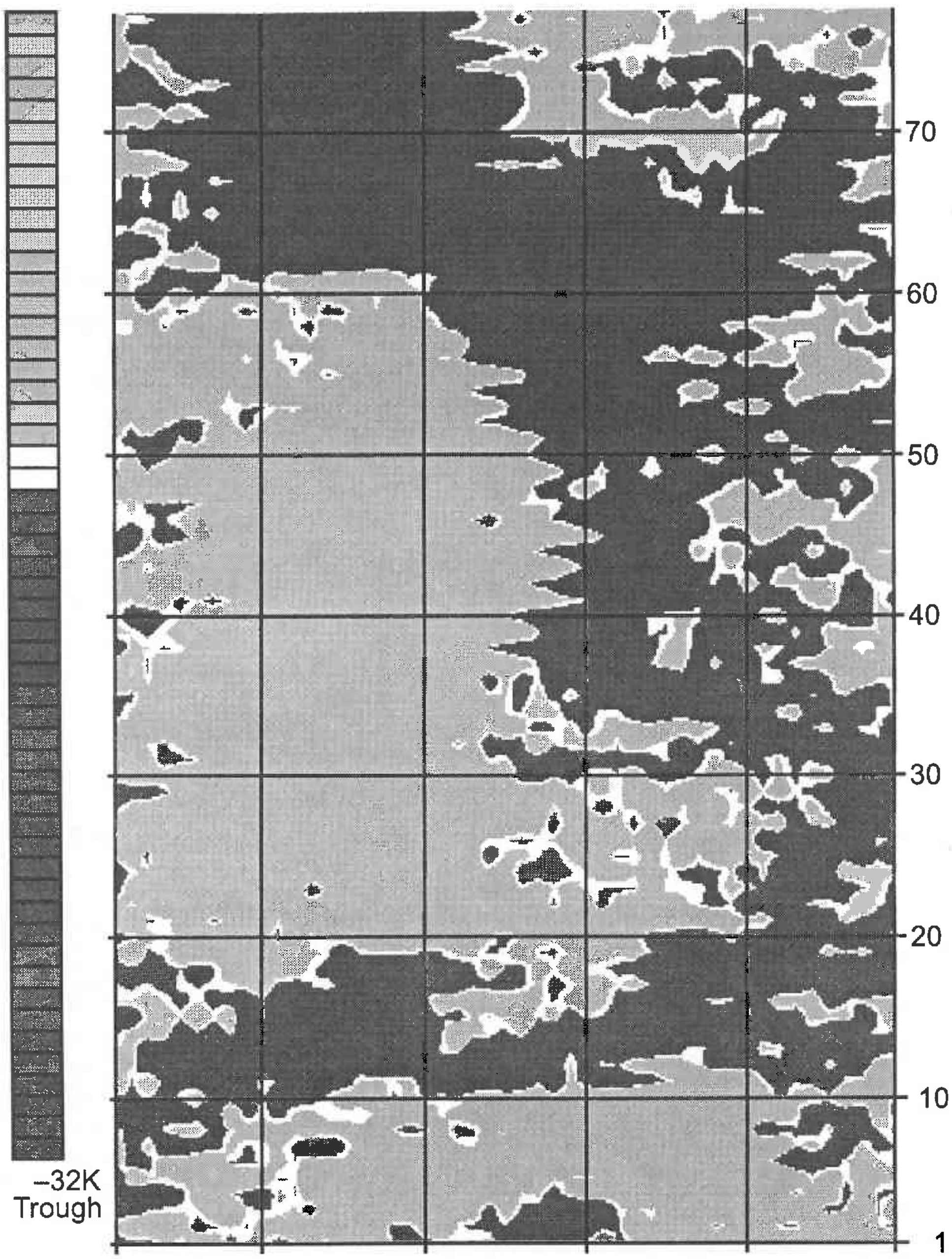


Figure 78. Time slice (306 ms) through 3-D seismic data in Okmulgee County. Horizon shown is the Booch sand. This technique is used to map sands in the area.

seismic data at the level of the Booch sands. Can you see where the Booch channels are located? Tying these data to well control offers a powerful tool for exploration.

SUMMARY

In summary, we have taken a brief tour of seismic data acquired in several Oklahoma counties. Both structural and stratigraphic plays are important within these areas and can be followed with the high quality of the seismic data for the regions shown.

In order to use the data described to best advantage, you should correlate the data with available well control. For structural mapping, you simply have to find a reflector (not necessarily the target horizon) that reflects the structure of the target horizon. For stratigraphic mapping, you have to identify and interpret the target horizon directly. When the correlation is accomplished, you can easily map structures for gas sands such as the Cromwell (as shown in Fig. 72) and follow the stratigraphy of gas sands such as the Booch channel sands (as shown in Fig. 78).

ACKNOWLEDGMENT

The data shown in this article were supplied through the courtesy of Kenneth Rigdon, Nemaha Resources, Tulsa, Oklahoma.

Three-Dimensional Seismic Examples from Southern Oklahoma

Bob Springman, Raymon L. Brown, and George Burris

INTRODUCTION

Three-dimensional (3-D) seismic exploration involves a financial investment that causes many operators to hesitate before using these advanced seismic methods. This article describes some 3-D-exploration examples in Garvin County, Oklahoma, in which 3-D seismic data have made a big contribution to exploration and development efforts by reducing risks and opening new prospects. (The oral presentation covers parts of Grady County as well.)

MAKING THE INITIAL INTERPRETATION

Imagine for a moment that you have a preliminary map of a region such as the one shown in Figure 79. This map was most likely made from well control and a few scattered 2-D seismic lines. In addition, assume that you know that areas shown in solid black on this map are productive. Your problem, then, is to explore this area and find the remaining reserves by identifying any productive trends. Although this map was made primarily with well control and sparse seismic data, it does indicate a number of areas that could be potentially productive. The problem is identifying and upgrading any potentially productive prospects based on your knowledge of the area and the current production.

In the following discussion, we illustrate some Oklahoma examples in which the preliminary structural understanding of an area was significantly changed by 3-D seismic surveys. All these examples show the utility of 3-D seismic data in confirming a prospect. One of the points we want to make is that your goal or target with 3-D seismic data should be realistic and obtainable. Although this sounds as if we are stating the obvious, some companies have approached 3-D seismic methods as if they can perform a miracle that is not possible with conventional 2-D seismic methods.

For example, some people have tried mapping very small stratigraphic variations that are beyond the resolution of conventional 2-D seismic data. It is unrealistic to expect any seismic method, even 3-D, to go beyond the physical detection limits of the seismic method. Another example of misuse of 3-D methods is an attempt to map along a mountain front with steeply dipping formations where conventional 2-D methods have not been successful.

This is not to say that 3-D surveying cannot give better results for either of these circumstances. What we are saying is that 3-D seismic methods are subject to the same problems in these areas as 2-D seismic methods are. If your stratigraphic target is beyond the resolution of your 2-D seismic survey, it will most likely be beyond the resolution of your 3-D survey. If your structural play is so complex that your 2-D survey does not

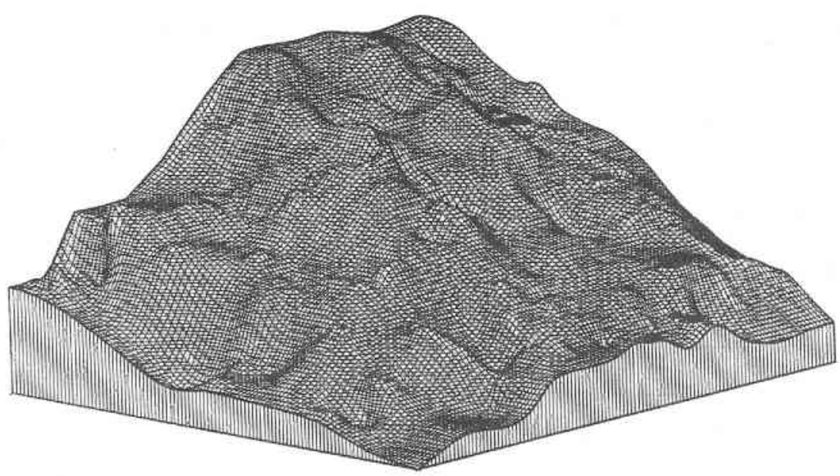


Figure 79. Preliminary structure map of a region targeted for exploration (3-D projected view). Such a map is usually made from sparse 2-D seismic data and/or well control. Solid-black areas represent oil fields. The problem facing an exploration program is how to find remaining reserves in this region. (Figure courtesy of Springman E&D.)

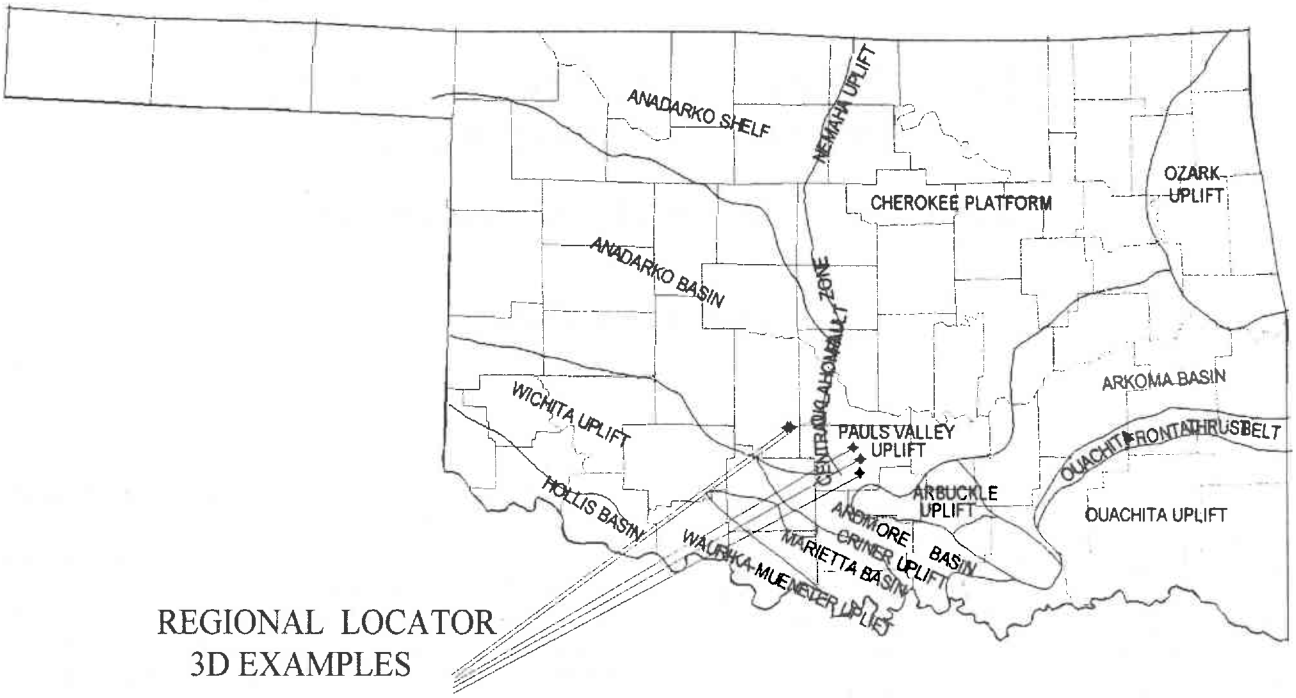


Figure 80. Index map of Oklahoma showing principal structural features. Examples in Grady and Garvin Counties are indicated. (Figure courtesy of Springman E&D.)

get data from the horizon you are exploring, then it is unlikely that your 3-D seismic survey will work either. The main idea to be stressed here is to keep your objectives with a 3-D survey realistic.

In spite of the warning about 3-D seismic data, we are convinced that when 3-D seismic data are viable, they work beautifully. These data reduce risk and greatly improve the development of reserves. Both of these characteristics mean better profits. These are the reasons that 3-D seismic surveying should be used here in Oklahoma. The examples discussed in the following sections illustrate the value of 3-D seismic data. Figure 80 is an index map of Oklahoma indicating the approximate locations of these case histories. Figure 81 shows a preliminary structure map of the region discussed. The solid-black areas represent oil fields. The target horizon is the basal Oil Creek sandstone of Middle Ordovician age.

WHITEBEAD OIL FIELD

The first example is Whitebead oil field. The first step toward exploring an area is to get comfortable with identifying the reflectors associated with your exploration target. Figure 82 illustrates a sonic log and a synthetic seismogram for the area of Garvin County shown in Figure 81. The carbonate zones tend to dominate the reflection character of the area, as shown on the synthetic seismogram in Figure 82, but a good reflector is also identified within the target zone, the basal Oil Creek sand. This reflector was used to map the structure. In some areas of Oklahoma, the basal Oil Creek sand reflector cannot be followed directly. In

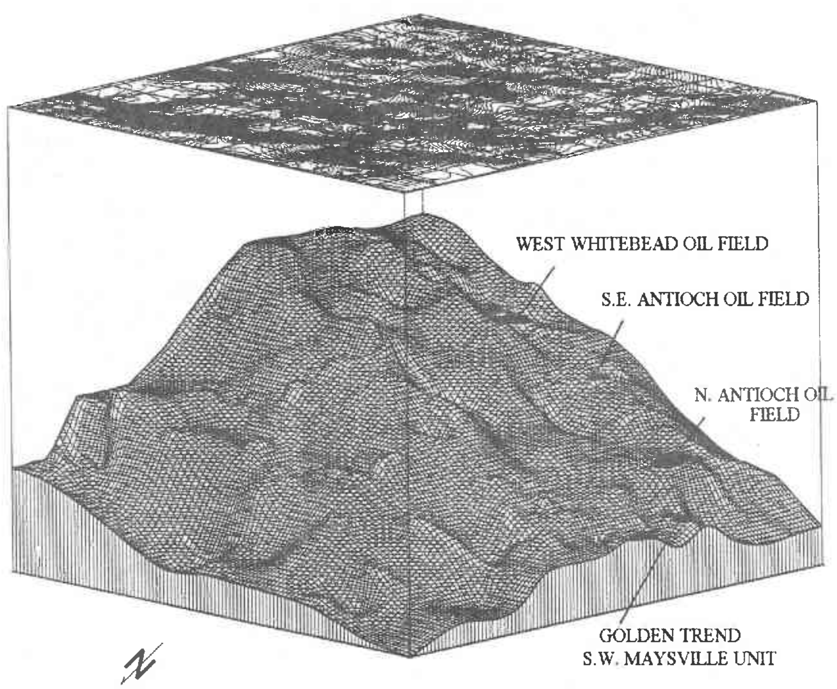


Figure 81. Map for Garvin County examples; 3-D projected view of structure map (top). Solid-black areas represent oil fields. Exploration target is basal Oil Creek sand. (Figure courtesy of Springman E&D.)

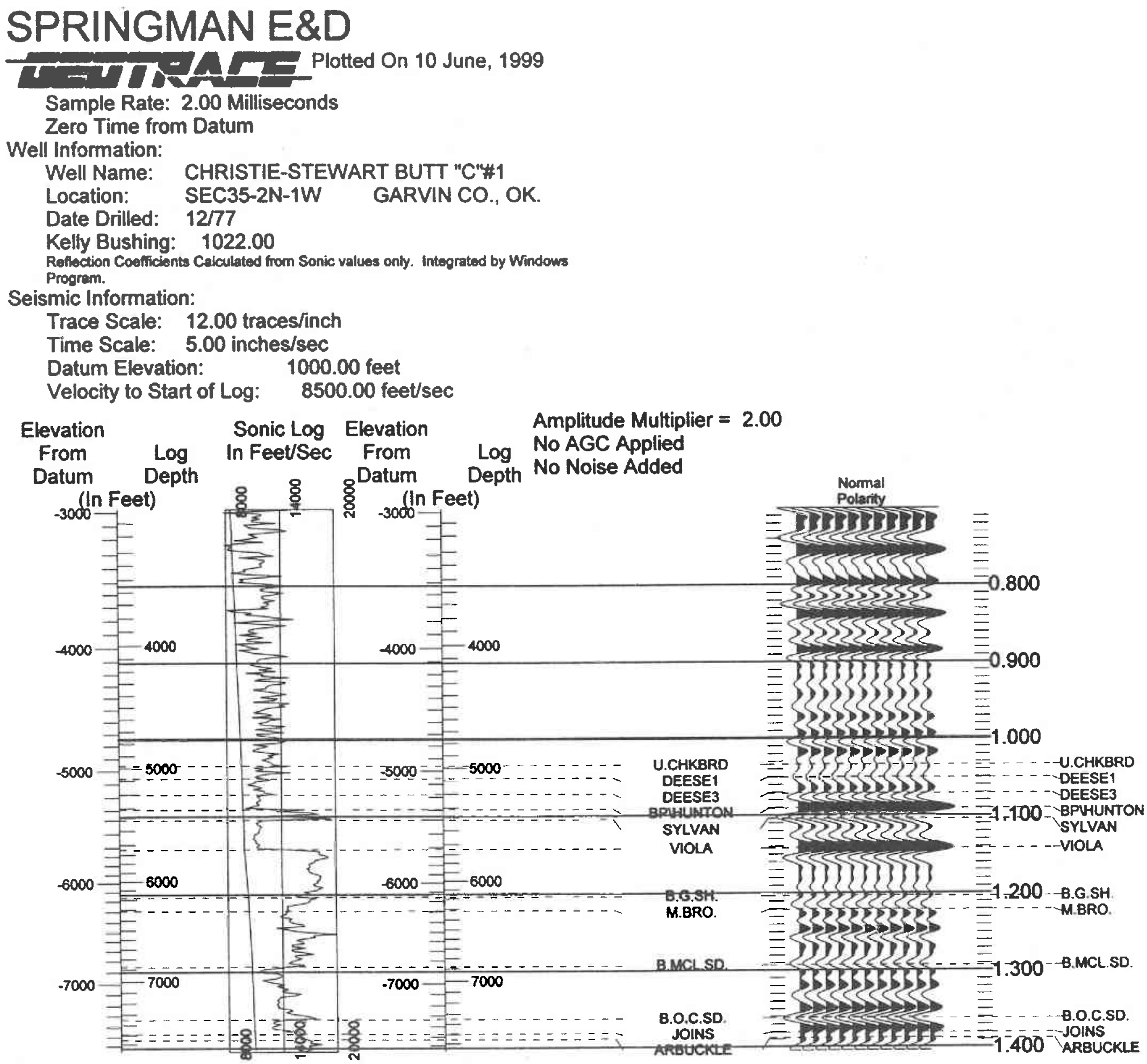


Figure 82. Sonic log and synthetic seismogram for Garvin County area. Note strong reflections at Hunton, Viola, and Arbuckle. Exploration target is basal Oil Creek sand (*B.O.C.SD.*). (Figure courtesy of Springman E&D.)

these areas, the interpretation depends on adjacent reflectors.

Figure 83 illustrates a *shot gather*. A single shot is fired, and a linear array of geophones is used to record the signal. The recorded traces when plotted in this fashion are referred to as a shot gather. Note that a number of reflectors can be identified on the shot gather without even using any seismic processing. Some of the same reflectors observed on the synthetic seismogram in Figure 82 can be observed on this shot gather. When you can identify reflectors on the raw records (very much like J. Clarence Karcher did in his original seismic experiments), you can bet that the quality of the data after recording and processing will be very good. This is an indication that both 2-D and 3-D data will record good signals in this area.

Figure 84 illustrates a 2-D seismic line in this area of Garvin County. Note the clarity of the seismic response from some of the key reflectors. Because 2-D data are highly successful in this area, we are not expecting any "miracles" when we move into using 3-D seismic data. The target interval, the basal Oil Creek sand, is simply a structural play. The goal, then, is to use 3-D seismic data to identify prospects. Figure 85 shows a 2-D record section taken from a 3-D survey. Although there appears to be a slight improvement in the quality of the signal shown in Figure 85 in comparison to Figure 84, this simple 3-D view does not show the real advantage of 3-D methods.

Figure 86 is a structure map of Whitebead oil field, based on available well control and 2-D seismic data. This initial picture is not very indicative of additional reserves. Below, we describe how 3-D seismic data were used to find additional reserves in the field.

Figure 87 illustrates a revised structure map over a part of Whitebead oil field that resulted from the 3-D survey over the field. The revised structure map and the hatched area in Figure 87 are compared with the preliminary structure map for the field in Figure 88. The additional potential of the field (shown hatched in Figs. 87, 88) would not have been detected without the benefit of the 3-D seismic study. Figure 89 illustrates a 3-D projected view of the structure and gives a clear picture of the high position of the new well in comparison to the existing wells in the area. Figure 90 shows the suite of logs through the basal Oil Creek sand in the successful production well, the Lario No. 4-5 West Whitebead Unit.

In summary, 3-D seismic data were used to find additional reserves and optimize well positioning in Whitebead oil field. The first step in mapping the area was to identify the reflector in the target interval, the basal Oil Creek sand. Next, a 3-D seismic survey was used to gain a detailed structural picture of the field. Because 2-D methods were useful for structural mapping, no "miracles" were expected from the 3-D survey. The result was a new well and improved production from the field. Oklahoma is filled with potential examples like this one.

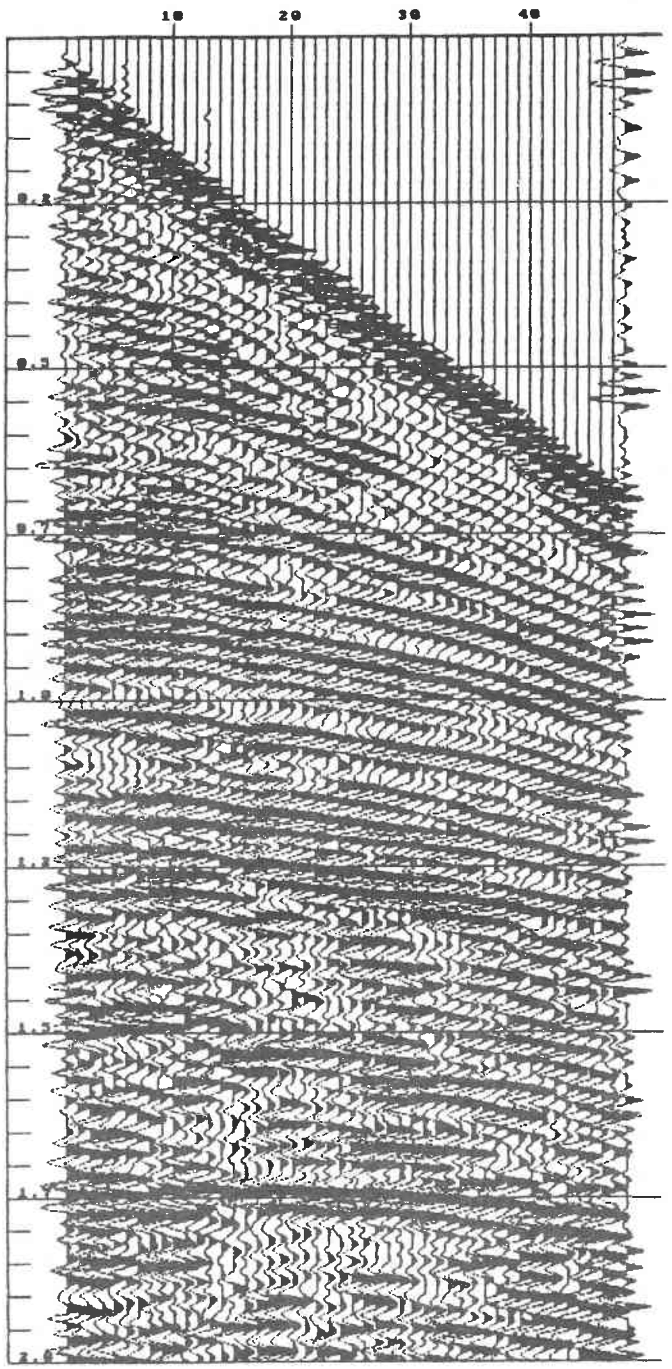


Figure 83. Shot gather collected in Garvin County. Some of the reflectors identified are the same as those observed on the synthetic seismogram in Figure 82. See text for further explanation. (Data furnished by Morris E. Stewart Oil Company.)

SOUTH BRADY OIL FIELD

The next example of a successful application of 3-D seismic data is also in Garvin County. Figure 91 shows a preliminary structure map of South Brady oil field, based on available 2-D seismic data and well control. The surprising aspect of this example is the density of 2-D data available for the field. It is tempting to believe that a dense grid of 2-D lines is equivalent to a 3-D seismic survey. This example shows that 3-D surveys can be used to detect structures that cannot be mapped or were not mapped using a dense array of 2-D seismic lines.

Figure 92 illustrates a revised structure map that resulted from a 3-D seismic survey over the area. Note the revised faulting and structural changes. Figure 93 illustrates 2-D-line segments of the 3-D seismic survey over this area. Line A (Fig. 93A) illustrates how closely the 3-D data can be used to predict fault positions at the basal Oil Creek sand. Line B (Fig. 93B) illustrates a synthetic seismogram embedded in a part of the line in comparison to the actual data around the basal Oil Creek sand interval. Because the reflectors are dipping in this area, a slight shift is allowed between the synthetic seismogram and the actual reflectors to account for the dip of the reflectors. Note how clearly the faulting stands out on these sections.

In summary, the 3-D seismic picture improved the interpretation of the area and actually led to some new thinking that cannot be discussed in this publication. However, it is clear from the maps of South Brady oil

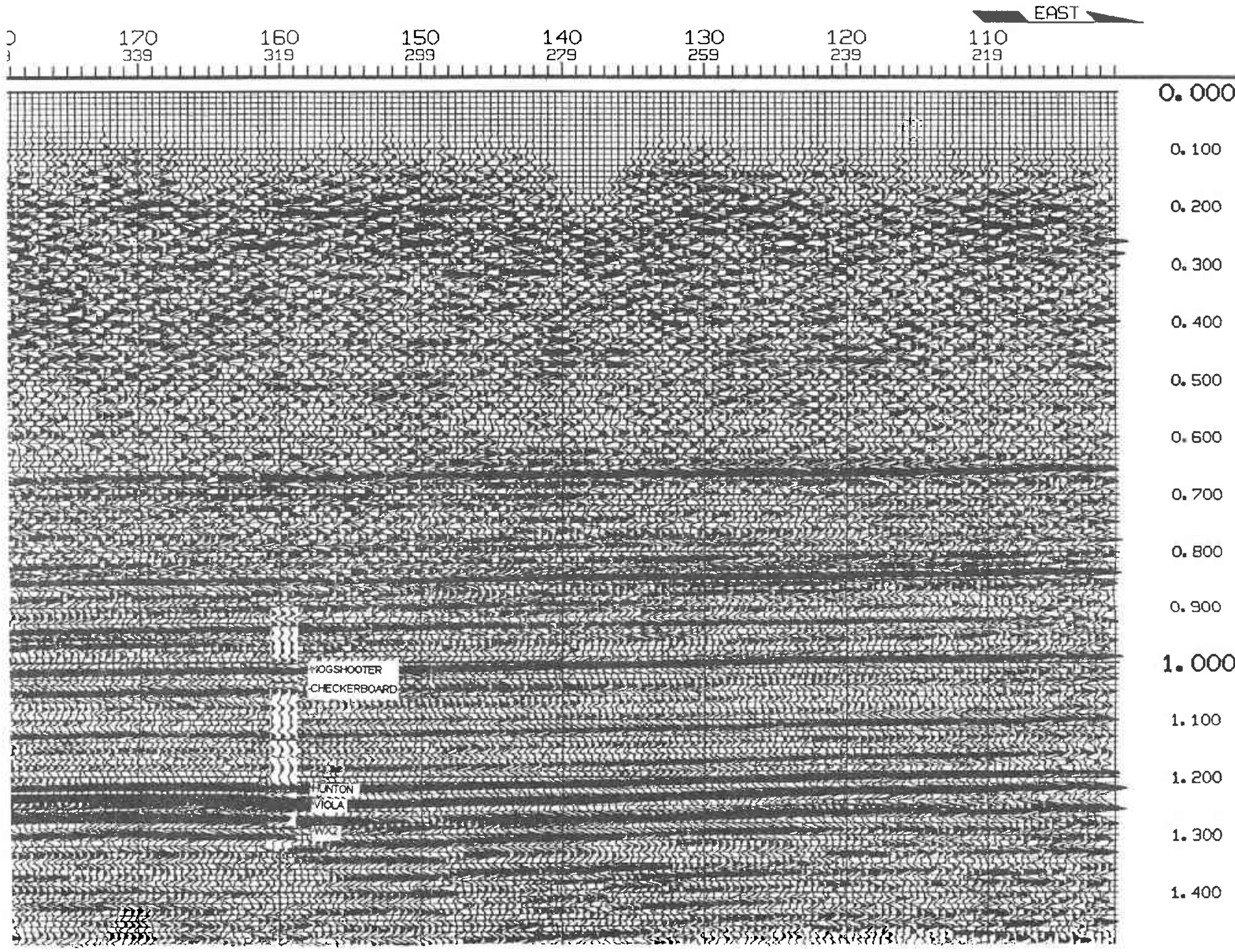


Figure 84. A 2-D seismic line, Cleveland County. (Data furnished by Morris E. Stewart Oil Company.)

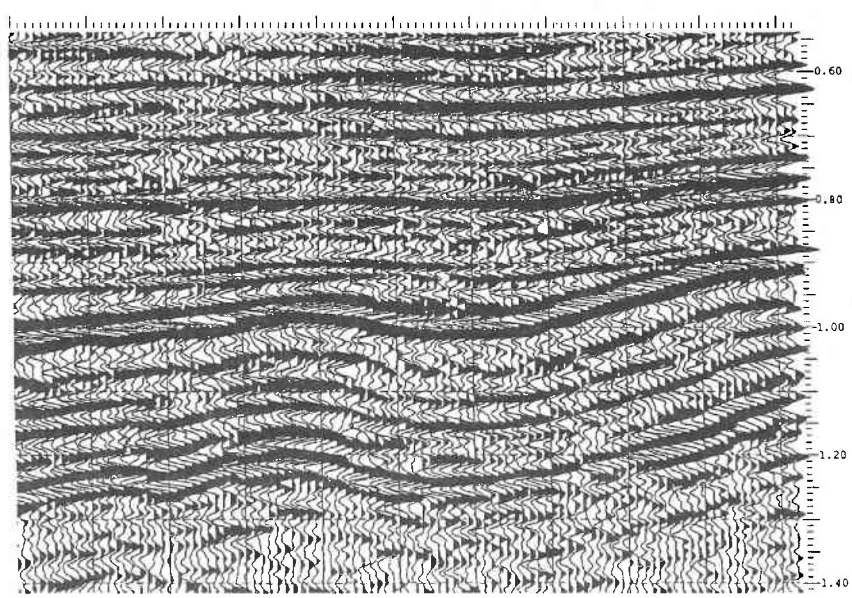


Figure 85. A 2-D section taken from a 3-D seismic survey in Garvin County. (Data furnished by Morris E. Stewart Oil Company.)

field that the 3-D data were able also to clarify where one should not drill. What more can one ask of a technology than to lead to new prospects and eliminate dry holes? Another conclusion from this study is that a dense array of 2-D seismic lines like that shown in Figure 91 is not equivalent to a well-designed 3-D study.

NORTH BRADY OIL FIELD

Moving slightly north of South Brady oil field, an example from North Brady oil field, Garvin County, is examined. Figure 94 illustrates structure maps made before (left side of figure) and after (right side) a 3-D survey was conducted. Some prospective areas thought to have potential were identified (shown hatched on the left map in Fig. 94) before the 3-D survey was shot. Note the number of dry holes in attempts to

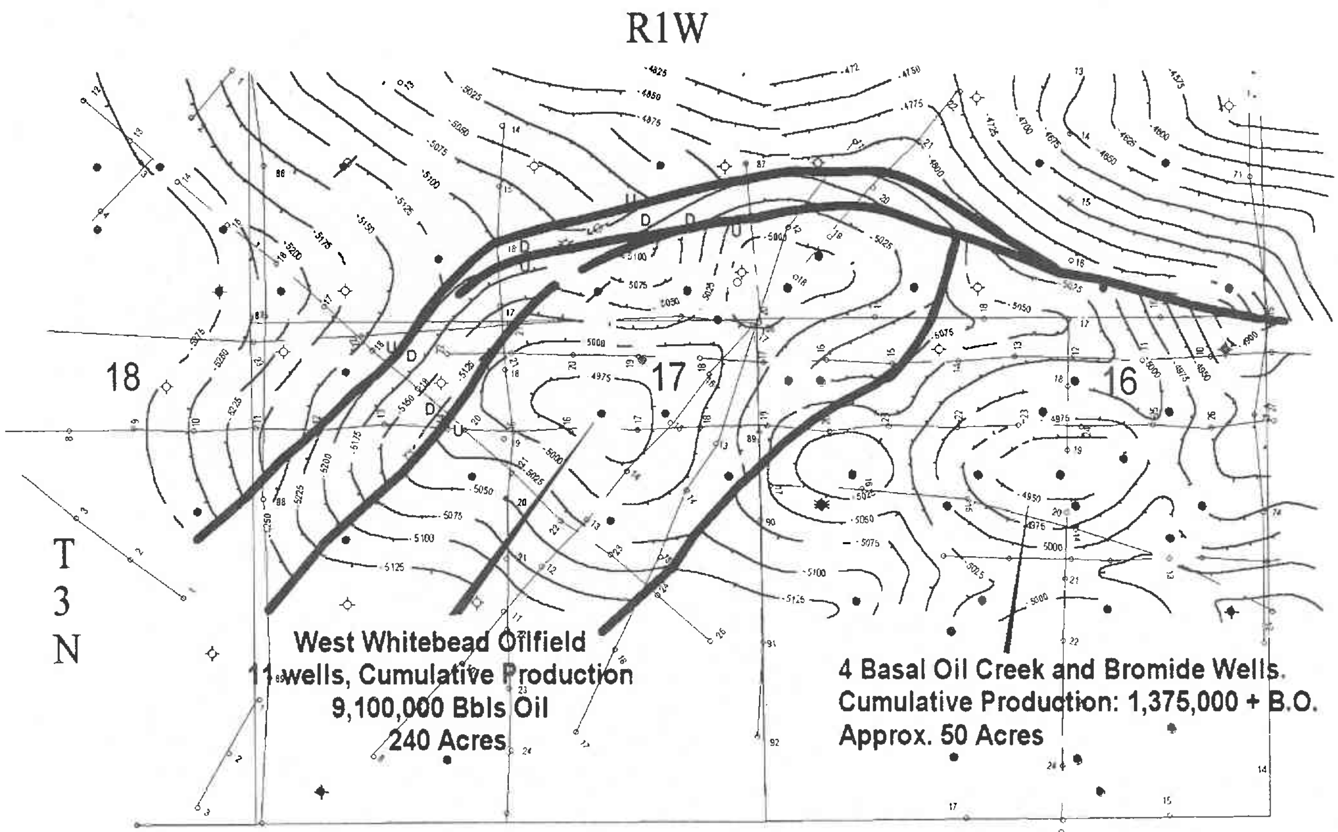


Figure 86. Structure map of Whitebead oil field in Garvin County. Based on well control and 2-D seismic lines. (Data furnished by Morris E. Stewart Oil Company. Figure courtesy of Springman E&D.)

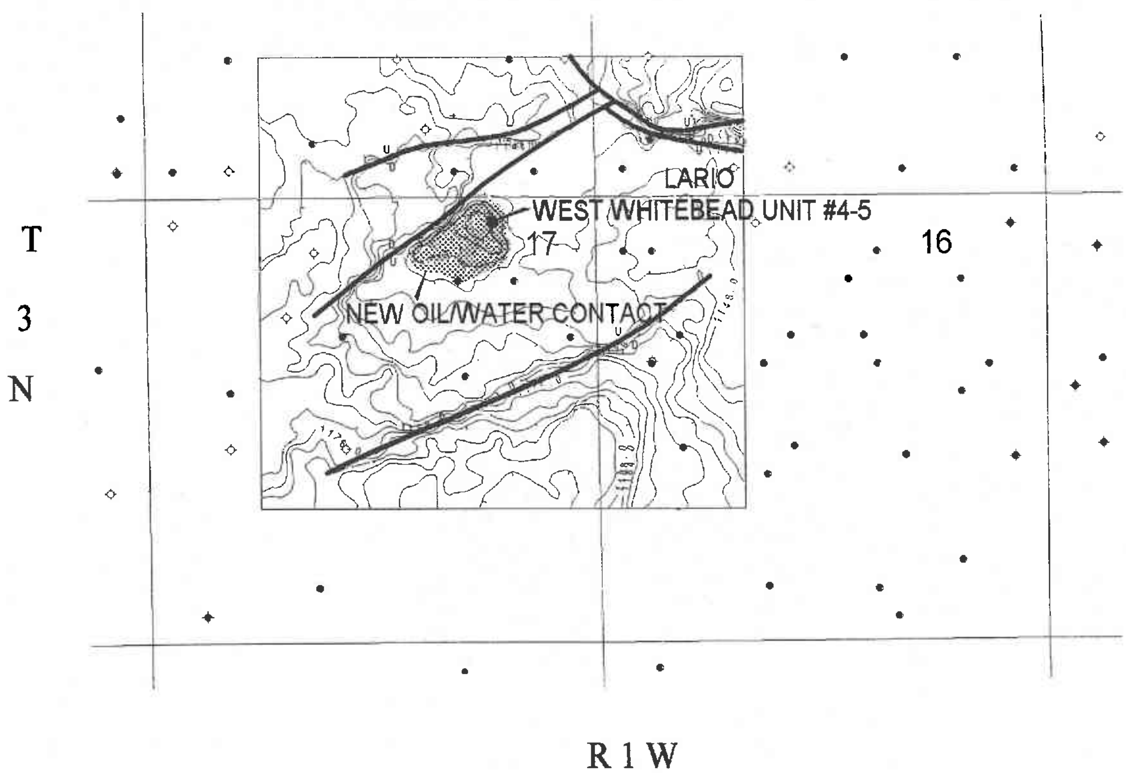


Figure 87. A 3-D revised structure map of part of Whitebead oil field. Hatched area represents additional oil above a nearby well. The Lario No. 4-5 West Whitebead Unit was a successful production well that resulted from the 3-D survey. (Figure courtesy of Springman E&D.)

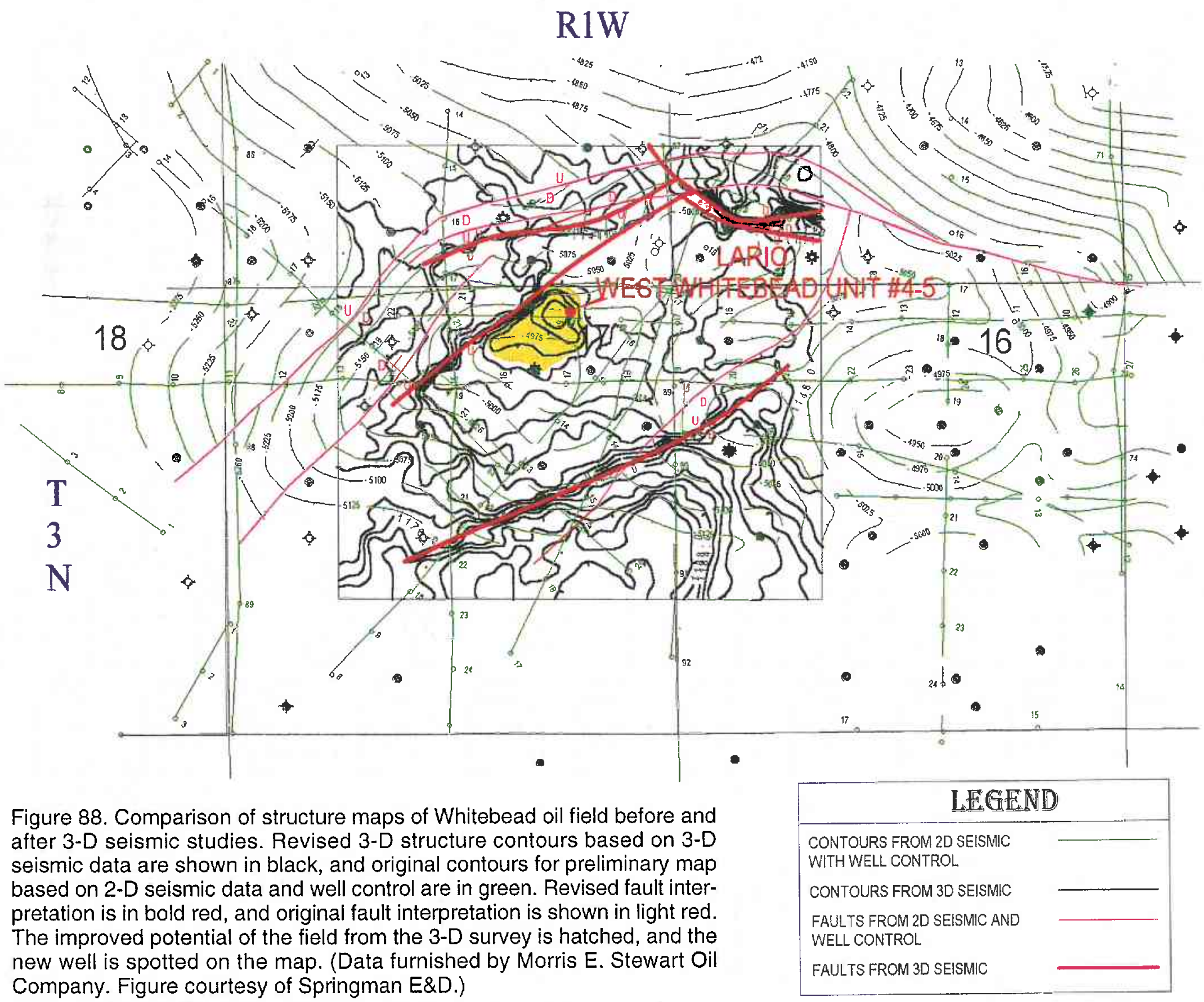


Figure 88. Comparison of structure maps of Whitebead oil field before and after 3-D seismic studies. Revised 3-D structure contours based on 3-D seismic data are shown in black, and original contours for preliminary map based on 2-D seismic data and well control are in green. Revised fault interpretation is in bold red, and original fault interpretation is shown in light red. The improved potential of the field from the 3-D survey is hatched, and the new well is spotted on the map. (Data furnished by Morris E. Stewart Oil Company. Figure courtesy of Springman E&D.)

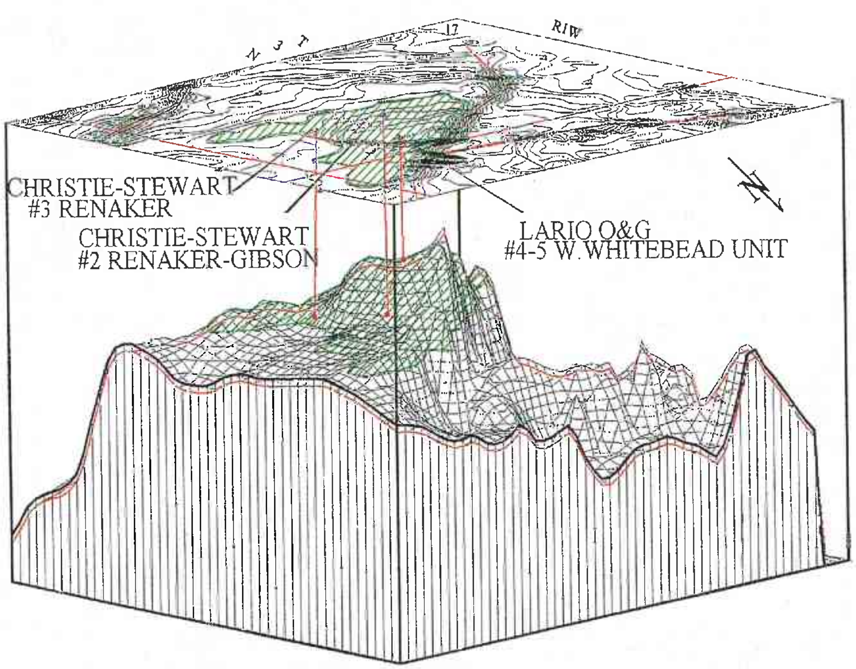


Figure 89. Illustration of the improved understanding of the structure of Whitebead oil field as a result of the 3-D seismic survey. This new understanding led to optimum development of the field. (Data furnished by Morris E. Stewart Oil Company. Figure courtesy of Springman E&D.)

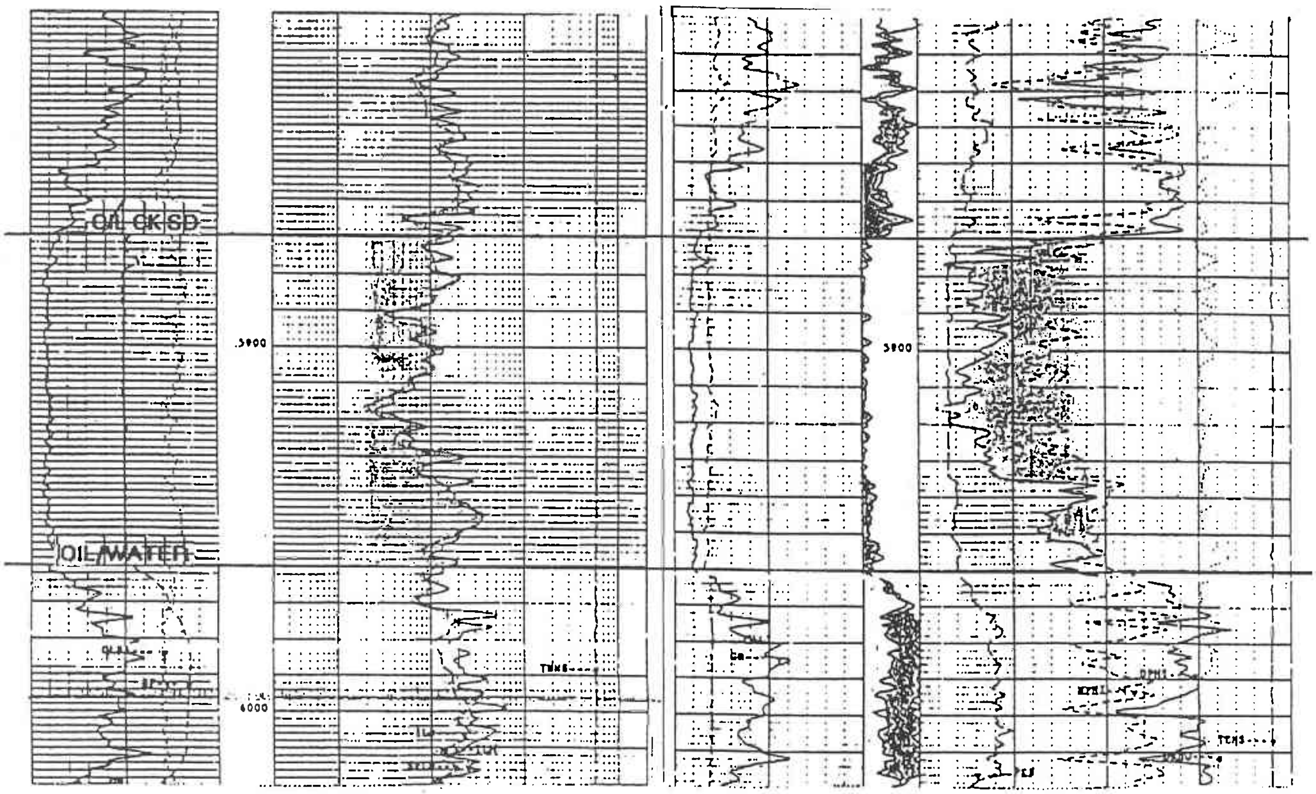


Figure 90. Suite of logs illustrating porosity and pay zone of basal Oil Creek sand in the Lario No. 4-5 West Whitebead Unit well, which improved reserve estimates for Whitebead oil field. (Data furnished by Morris E. Stewart Oil Company. Figure courtesy of Springman E&D.)

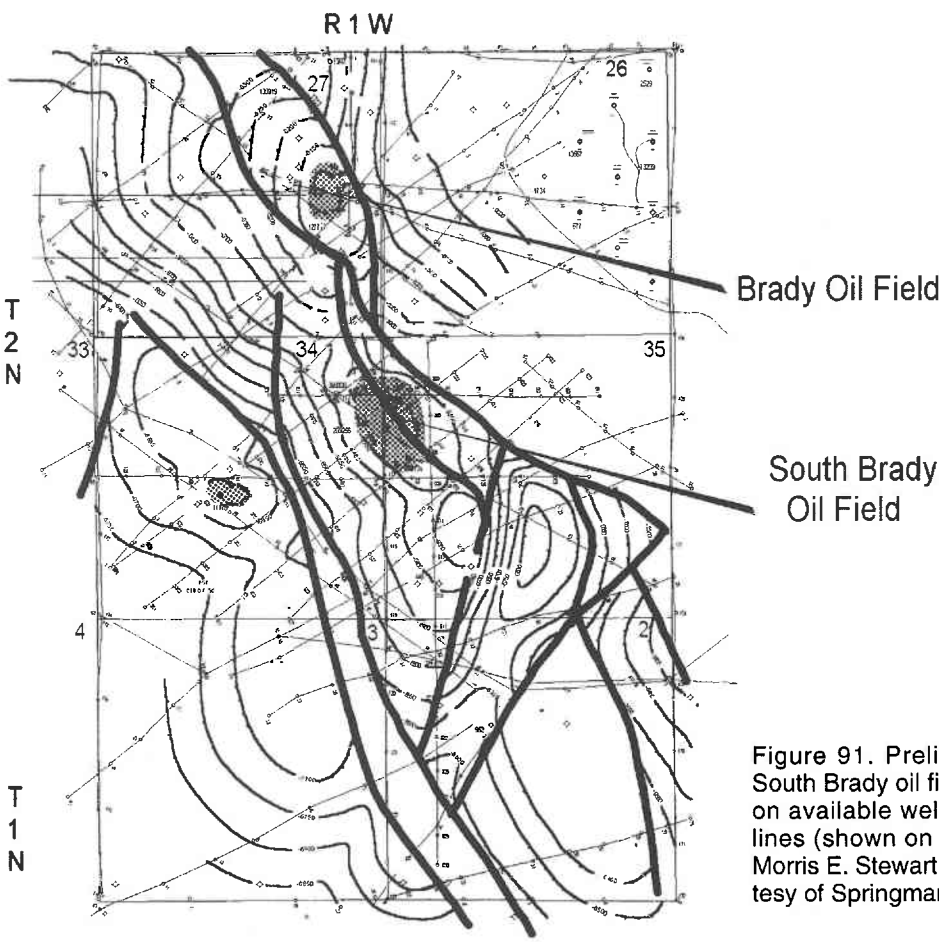


Figure 91. Preliminary structure map of South Brady oil field, Garvin County, based on available well control and 2-D seismic lines (shown on map). (Data furnished by Morris E. Stewart Oil Company. Figure courtesy of Springman E&D.)

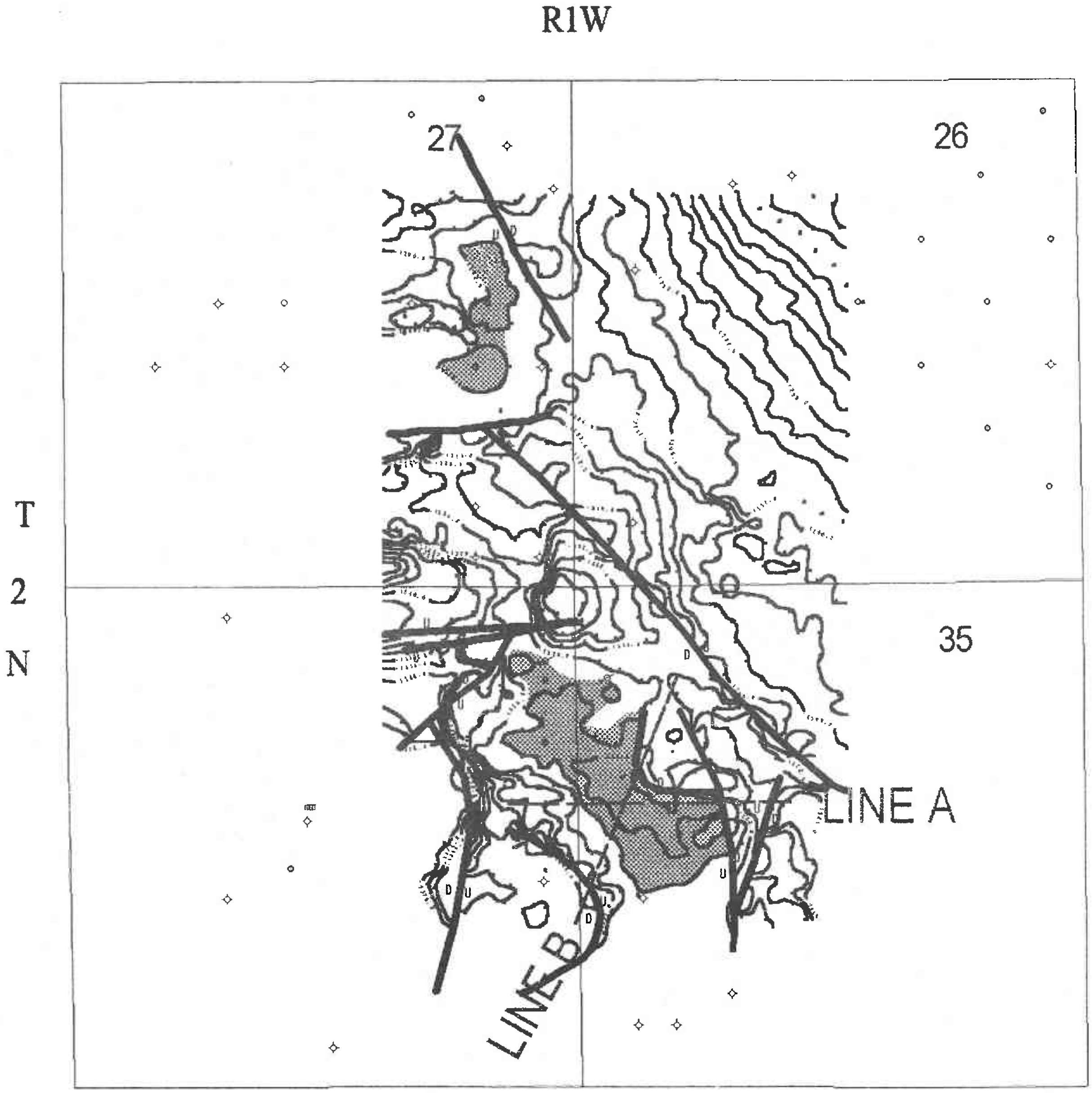


Figure 92. Revised structure map of South Brady oil field, based on a 3-D seismic survey shot over the field. Note revised faulting in comparison with Figure 91 as well as other structural changes. Also indicated are parts of extracted 2-D lines from the 3-D survey (see Fig. 93). (Data furnished by Morris E. Stewart Oil Company. Figure courtesy of Springman E&D.)

extend the productive area from one well in the east-central part of the left map in Figure 94. After conducting the 3-D study, a new structural high was found in the field (shown hatched on the right map in Fig. 94). This area was drilled and found productive. None of the original thinking proved to be correct in this case. Once again, 3-D seismic data show a clear benefit over dealing with sparse data.

IN OKLAHOMA, "WHEN IT RAINS, IT POURS"

When drilling in Oklahoma, finding a reservoir at one horizon often leads to the discovery of reserves at other levels. Figure 95 is a current structure map of North Brady oil field time-colored at the target horizon (so that the colors indicate the structure). Note the wells developed off the crest of the high in the western part of the map (the same high indicated on the right map in Fig. 94). These wells were a pleasant surprise, with production from other zones. Hence the saying in Oklahoma: "When it rains, it pours." This is what makes exploration in Oklahoma so exciting. There is always the potential for additional pay zones associated with a target horizon. In this case, the structure found at one depth was mirrored in the structure that led to the discovery of producible oil in the basal Oil

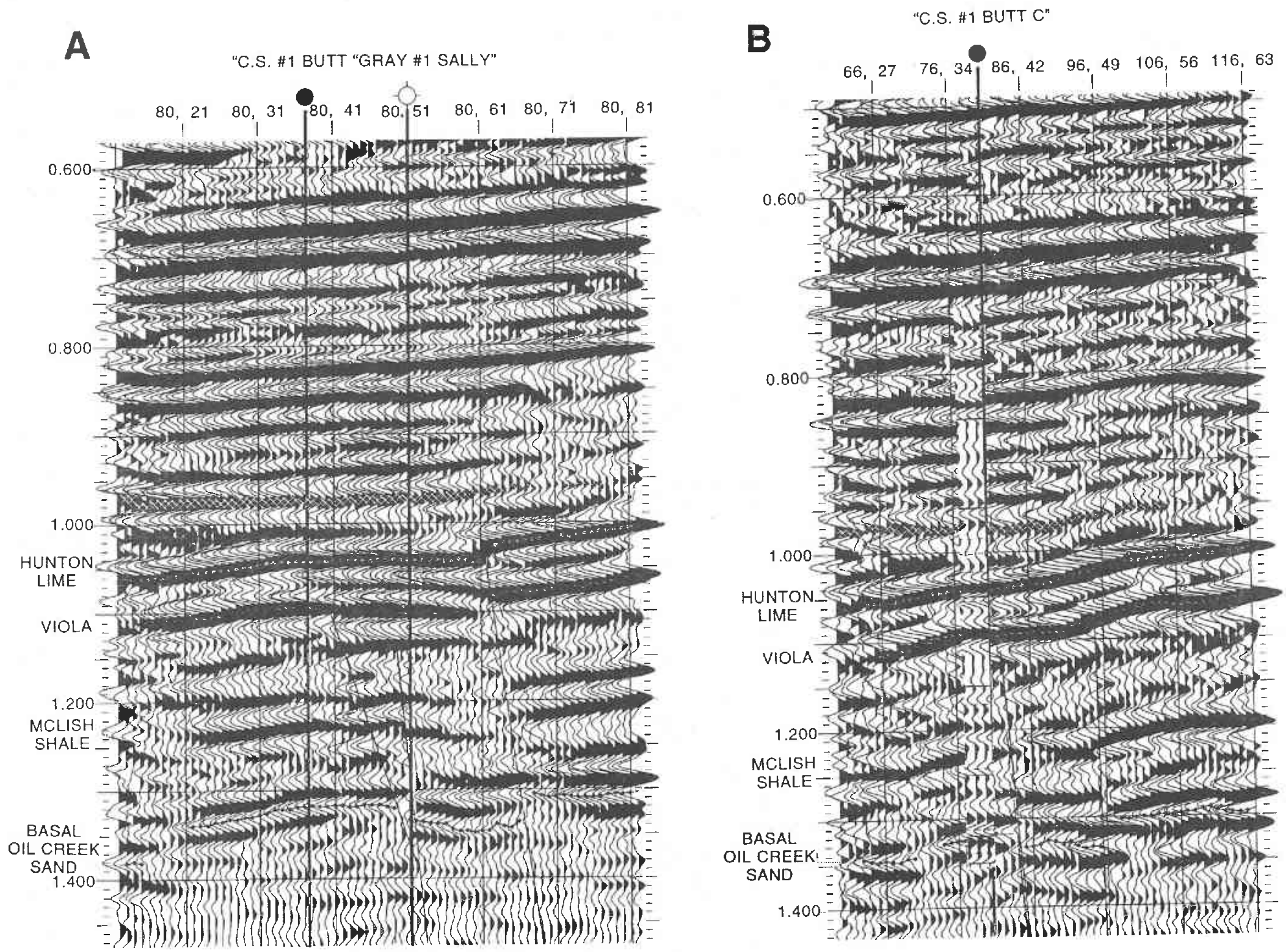


Figure 93. Extracted 2-D sections from the 3-D survey, South Brady oil field. (A) A 2-D record (line *A* in Fig. 92) taken from the 3-D seismic survey. Note faulting and the clear separation on the seismic record between productive and nonproductive wells. (B) Line B (see Fig. 92) and a synthetic seismogram embedded in the section (shown by traces with increased spacing). Note faulting observed at level of basal Oil Creek sand. (Data furnished by Morris E. Stewart Oil Company.)

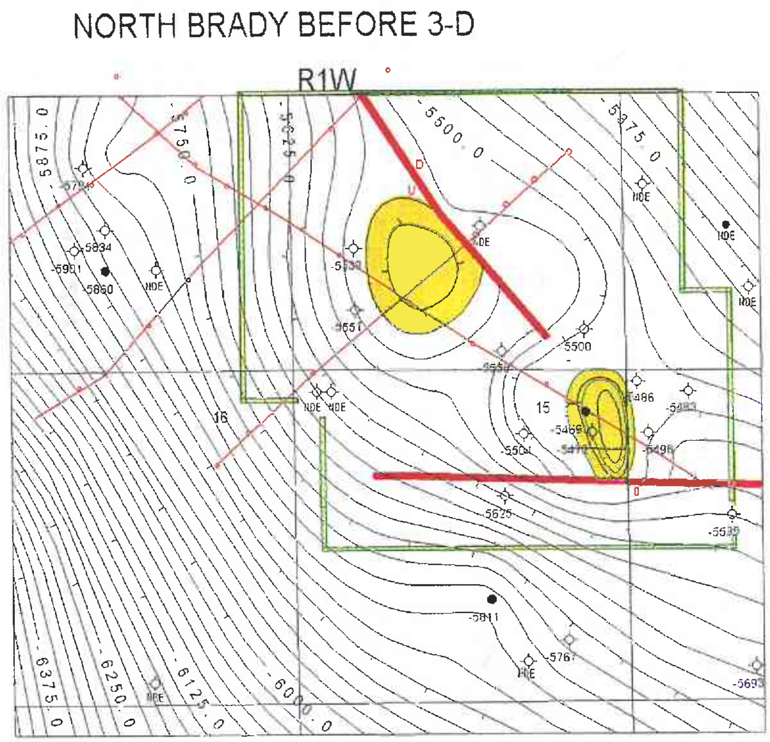
Creek sand. Figure 96 illustrates the log response from the well that was drilled in North Brady oil field. Figure 97 shows a sonic log and a synthetic seismogram used to guide the mapping of that area.

SUMMARY AND CONCLUSIONS

In summary, we have covered examples that clearly indicate the advantages of the use of 3-D seismic data within Oklahoma. Our advice is to keep your objectives simple when using 3-D methods. Do not expect miracles. In the area of study described in this article, 2-D seismic methods were capable of mapping reflectors. However, 2-D surveys do not offer the density of coverage that is usually required to find additional reserves. The examples shown previously clearly illustrate that 3-D seismic surveys led to the drilling of additional productive wells within the fields described. Besides delineating the basal Oil Creek sand, the studies led to additional productive zones at other depths. This makes Oklahoma a prime target for infill drilling guided by 3-D seismic surveys.

ACKNOWLEDGMENT

The authors thank Western Geophysical of Oklahoma City for permission to show some of their data during the oral presentation of this workshop.



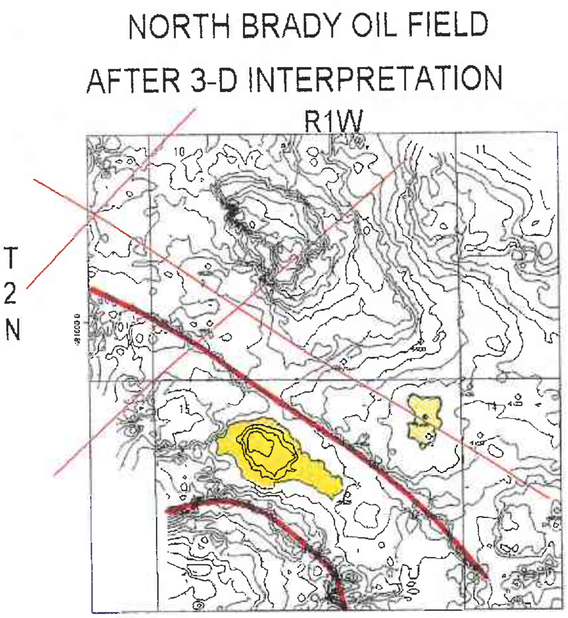


Figure 94. "Before" and "after" 3-D structure maps of North Brady oil field, Garvin County. Structure (depth) map on left indicates preliminary thinking about this area using 2-D seismic lines and well control. Hatched areas were prospective before the 3-D survey was shot. Structure (time) map on right is based on the 3-D survey of the area. (Data furnished by Morris E. Stewart Oil Company. Figure courtesy of Springman E&D.)

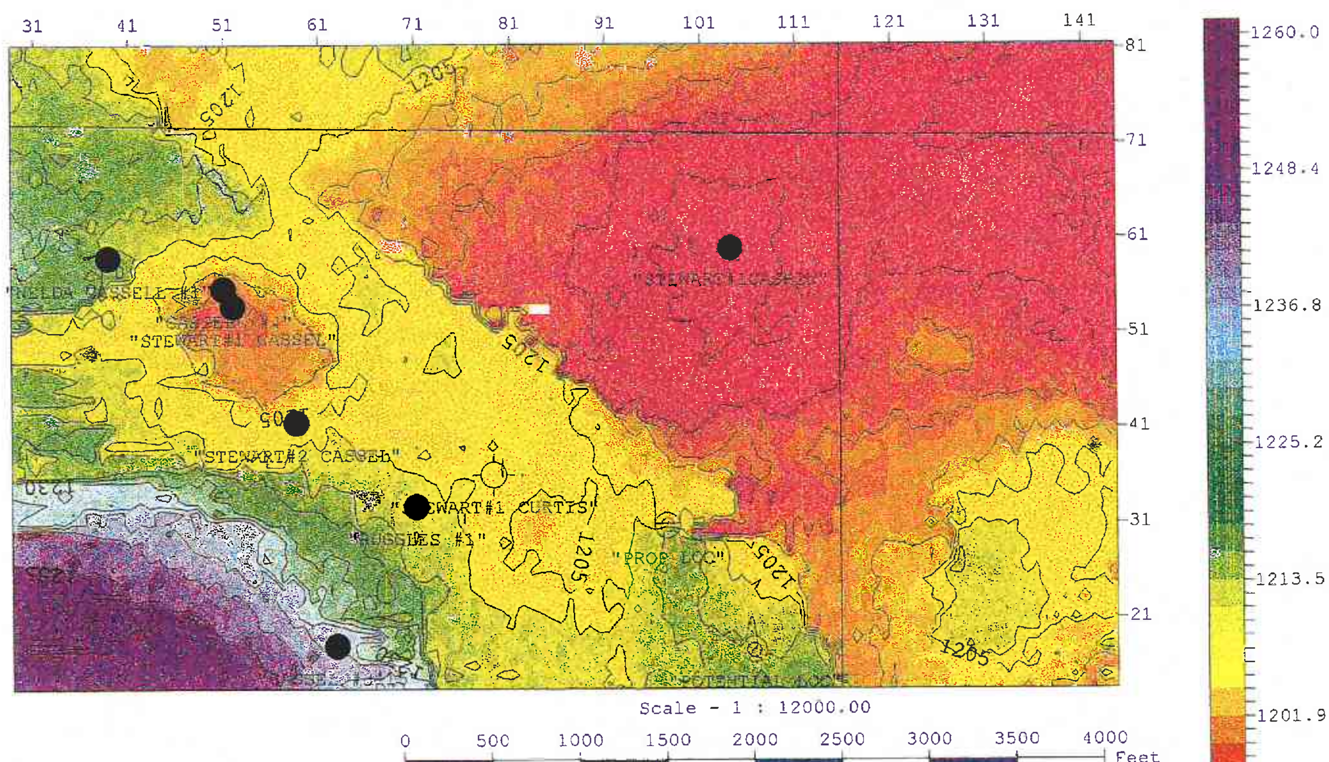


Figure 95. Map showing structure by color (time). Revised time structure based on 3-D seismic survey over North Brady oil field. Also shown are additional wells that appear to be off the crest of the structure; these wells are productive from deeper zones. (Data furnished by Morris E. Stewart Oil Company. Figure courtesy of Springman E&D.)

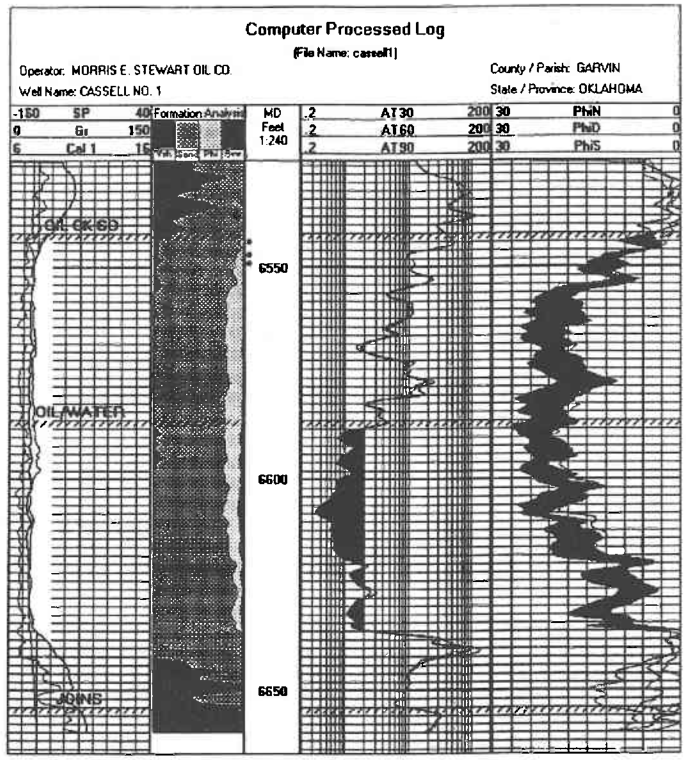


Figure 96. Log response for the productive new well in North Brady oil field. This well was drilled as a result of the 3-D seismic survey over the field. (Data furnished by Morris E. Stewart Oil Company.)

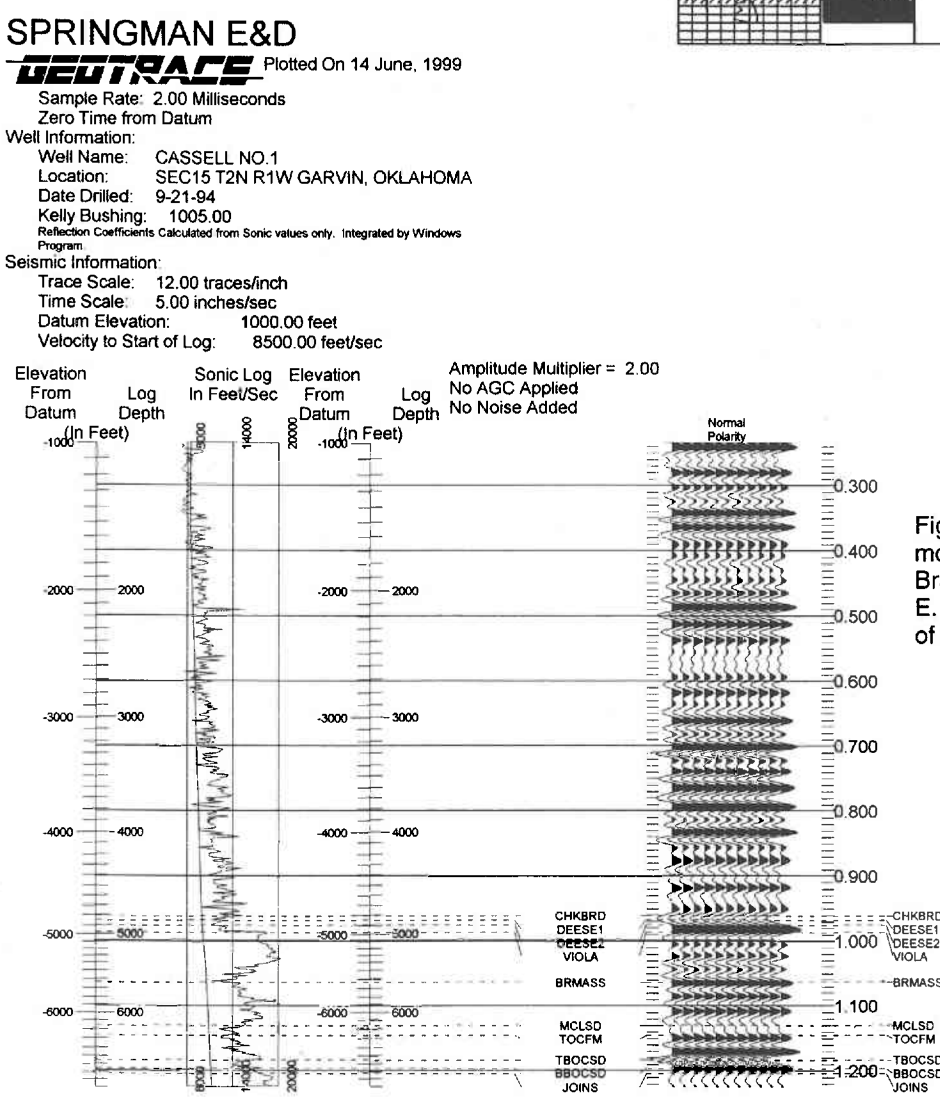


Figure 97. Sonic log and synthetic seismogram from the new well drilled in North Brady oil field. (Data furnished by Morris E. Stewart Oil Company. Figure courtesy of Springman E&D.)

The Chester Formation in South Eubanks Field, Southwestern Kansas

Ernie R. Morrison

INTRODUCTION

This paper covers parts of T. 29 S., R. 34 W., and T. 30 S., R. 34 W., in Haskell County, Kansas (Fig. 98). The information presented here was gathered from the records of more than 40 wells that were drilled to develop Mississippian Chester reserves in south Eubanks field.

During development of the field, two cores were taken. The MLP No. 4-3 Black well, in sec. 3, T. 30 S., R. 34 W., was cored from 5,411 to 5,491 ft, through a part of the Chester formation. The MLP No. 2-9 Clawson well, in sec. 9, T. 29 S., R. 34 W., was cored from 5,389 to 5,434 ft, also through a part of the Chester formation.

In addition to describing the core, well-site geologists examined drill cuttings from all the wells. The normal evaluation of porosity and permeability of the cores was performed by Core Laboratories. Stim-Lab, Inc., used thin-section, scanning-electron-microscope, and X-ray-diffraction analyses to help determine the depositional environment.

Electric logs were run to help evaluate the wells and determine water saturation and porosities. Acoustic

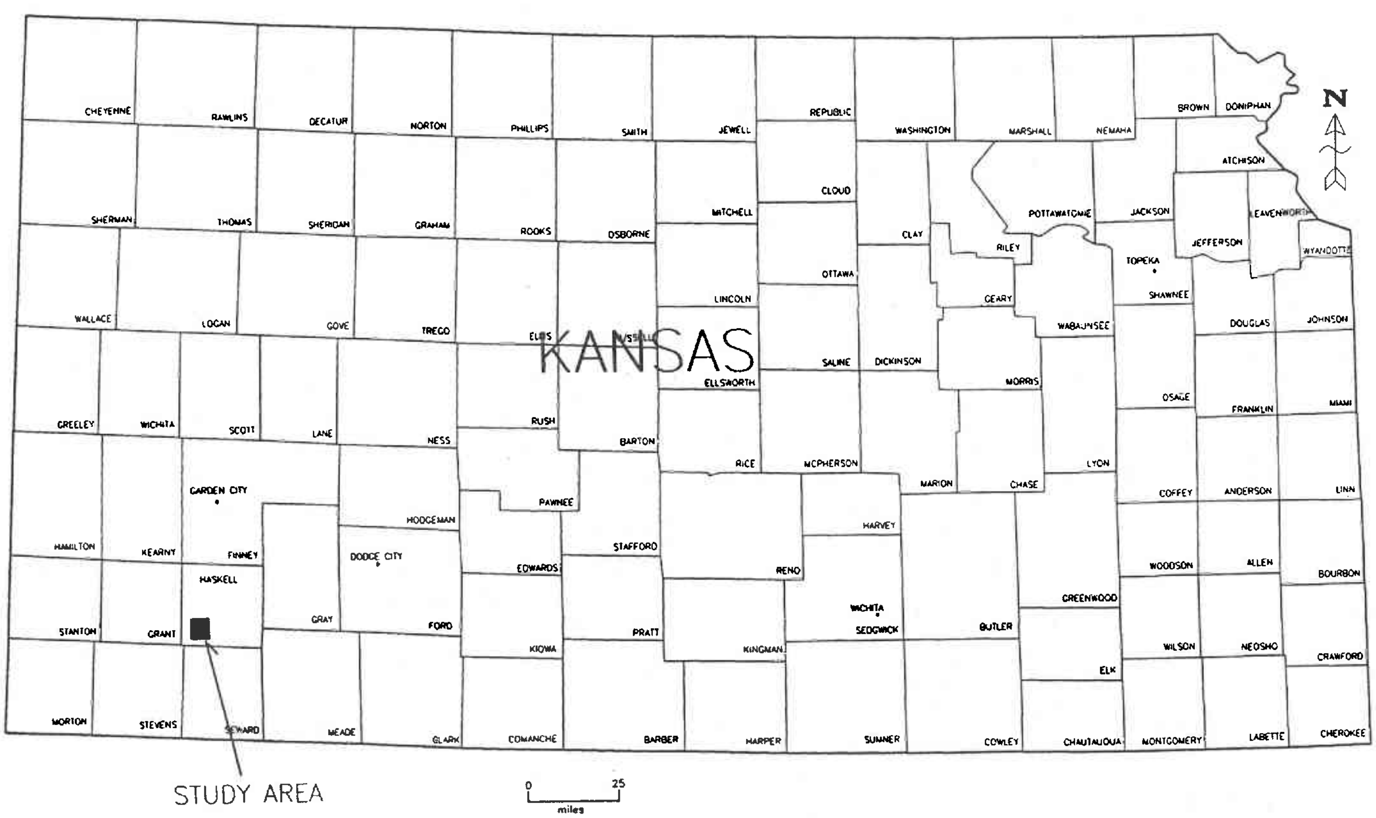


Figure 98. Index map showing location of study area in Haskell County, southwestern Kansas.

logs were run in most of the wells to tie back to a three-dimensional (3-D) seismic survey.

REGIONAL SETTING

The area this paper covers lies in the Hugoton embayment of the Anadarko basin within the boundaries of the Permian Hugoton gas field. Various operators are now in the process of drilling for deeper Pennsylvanian and Mississippian pay zones. Eubanks field is on the north end of the study area, and Victory field, on the southeast end (Fig. 99). Eubanks was discovered in 1958, and Victory in 1960.

Mississippian Chester sandstones constitute some of the main pay zones in these fields. Also productive are the Lansing, Kansas City, Marmaton, Cherokee, and Morrow units of Pennsylvanian age, and the St. Louis Limestone of Mississippian (Meramecian) age (Fig. 100).

The Chesterian Series disconformably overlies the Ste. Genevieve Limestone, and at some places, the St. Louis Limestone (Fig. 100). The Chester is unconformably overlain by the Pennsylvanian Morrowan Series. Kreisa (1983) and Severy (1975) conducted two informative studies of this area.

EXPLORATION EFFORTS

Early deep drilling in the study area used subsurface information from the shallow "Hugoton" wells to project deeper structural features. Two to three shallow wells per section allowed for good control for the Permian strata. In the 1980s, Mesa Petroleum conducted an extensive two-dimensional (2-D) seismic shoot across the area. This seismic survey worked well for major structures but did not depict smaller structural features or areas where Chester sandstones may have been deposited on scoured surfaces of the underlying Ste. Genevieve or St. Louis Limestone. In 1994, the No. 1-9 Clawson, drilled in sec. 9, T. 29 S., R. 34 W., encountered a scour feature containing Chester sandstone. This well site was chosen on the basis of subsurface geology.

As development drilling progressed, it was evident that a 3-D seismic survey would be an exploration tool that could enhance the success of delineating these narrow channel scours. So a 26-mi^2 3-D seismic survey was shot to help define the subtle features that make up the Chester sandstone reservoir in this area. The shoot was designed to take advantage of the known structural orientation. The bin size of the survey was 110 by 82.5, with the 110-y axis in a north–south direction. This design allowed for the imaging of the narrow scour features. The 3-D interpretation indicates a regional fault on the west side of the shoot and a linear scour feature that extends from north to south throughout the survey area (Fig. 101). Hugoton Energy Corporation drilled 14 successful wells in succession within this major scour feature. Many of the features that are visible on the 3-D records are small, but this seismic method has allowed Hugoton Energy to identify and drill these features with a high degree of success. Mark Grommesh was the seismic interpreter. The major scour feature is less than 1,000 ft wide in most places (Fig. 102A,B).

The 3-D seismic survey also indicates a series of karst features that are visible in the Chester and deeper strata. To date, these karst features have not been tested.

LITHOLOGY AND DEPOSITION

The total Chester section in this area ranges in thickness from approximately 100 ft on the north end to almost 300 ft on the south end. The upper part of the Chester consists of a limestone and shale sequence (Fig. 103). The lower Chester is sandstone rich, and these lower sandstones make up the reservoir rock. The major depositional environment of the Chester appears to be a transgressive sequence with marine and near-marine influence.

From drill cuttings, the upper limestones are described as tan to light brown and mottled. The limestones are microcrystalline, with some crystalline porosity. They are slightly fossiliferous and contain oolites. Several well-site geologists noted a trace of glauconite. According to core descriptions, the limestones are light to dark gray, fossiliferous, and interclastic. The clasts are typically well rounded and poorly sorted. The fossil grains are made up of crinoid and mollusk fragments. The rock is a shallow-marine limestone representative of a marine transgressive sequence and the deeper part of an estuary. Both cores were taken from the deeper part of the major scour feature.

Most of the shales described from the drill cuttings are light to medium gray, although some are black and carbonaceous. In addition, gray-green shales were noted. Descriptions of the shales from cores are similar; these shales were observed to be dark gray, calcareous, and fissile, with interbedded mudstones. Some thin-bedded coals were also observed in the cores.

The lower part of the Chester in this area contains the reservoir section. The sandstones range from absent to >100 ft in thickness. The sandstones can be divided into at least three separate units within the scour feature, with the lowermost sandstone being the most pervasive. The drill cuttings from the sandstone have been described as clear and white to very light brown. Some samples exhibit brown staining and scattered shows of free oil or gas bubbles. As these sandstones are drilled they often produce a sizable gas kick and usually are characterized by a distinct drilling break. The drilling break is not always noticeable, however, and some sandstones are very hard because of carbonate cementation. The sandstones are fine grained and well sorted. Visible porosity is good to excellent, as an abundance of loose sand grains often can be seen in the samples.

Descriptions of the core samples vary more than those of the drill cuttings, but for purposes of this paper a generalized description is presented. The sandstone

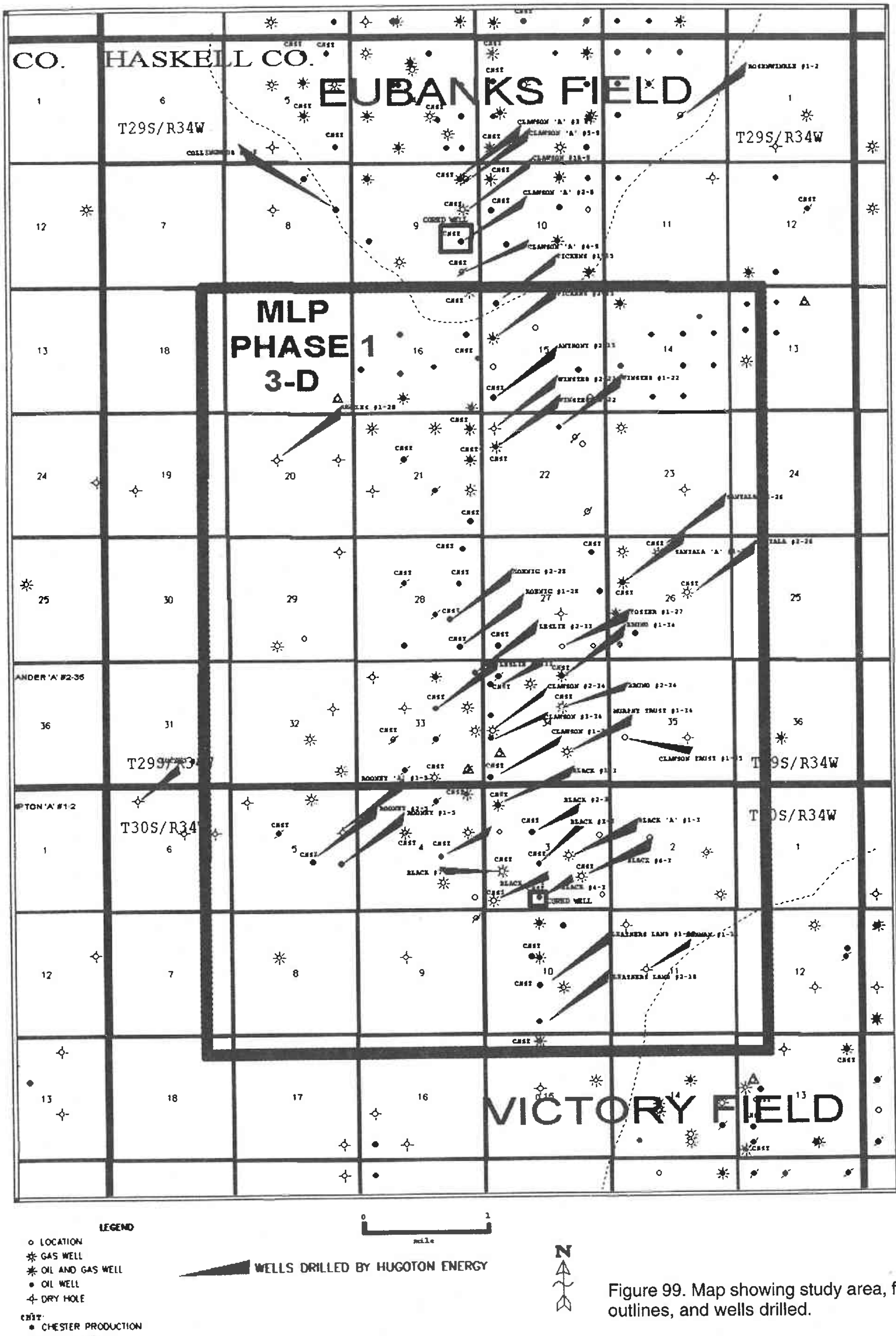


Figure 99. Map showing study area, field outlines, and wells drilled.

is a very fine to fine-grained quartz sandstone with minor amounts of chert, feldspar, and heavy minerals. Illite and smectite are the most abundant clay minerals, with lesser amounts of kaolinite. The sandstone is cemented by quartz overgrowths and calcite. Intergranular porosity predominates, with minor amounts of secondary porosity. Minor vertical fracturing is also present.

Neutron/density–porosity-log cross-plot values of 11% to 14.5% porosity are seen within the reservoir intervals. The average cross-plot value across the pay zone is 12.3%. The Core Laboratory analyses calculated porosities ranging from 8% to 13.7%, with an average porosity of 9.6%. Measured permeabilities ranged from 0.39 to 141 millidarcys (md), with an average permeability of 19.7 md.

The depositional environment for the Chester sandstone is middle to upper intertidal flat with some evidence of sand-wave–tidal-bar deposition. Some evidence of an estuarine channel was observed in the MLP No. 4-3 Black core. A typical fining-upward sequence, overlain by a channel-bar or channel-bottom deposit, was observed from 5,440 to 5,490 ft. Stim-Lab interpreted the overall depositional environment for the MLP No. 4-3 Black core to be an estuary–tidal flat.

The MLP No. 2-9 Clawson appears to have encountered more of a marine-influenced environment, as indicated by skeletal fragments, coated carbonate grains, and glauconite.

The overall depositional environment was controlled by the erosional surface of the underlying Ste. Genevieve or St. Louis rocks. The exposure of these surfaces and their subsequent erosion allowed the transgressing seas to deposit the sands that make up the lower Chester reservoirs. The long scour feature that cuts across the area is channel-like in appearance but shows little evidence of a fluvial depositional system.

Southwest Kansas Stratigraphy

System	Series	Stratigraphic unit
Pennsylvanian	Virgilian	Admire Wabaunsee Shawnee Douglas
	Missourian	Lansing Kansas City Pleasanton
	Desmoinesian	Marmaton Cherokee
	Atokan	Atoka
	Morrowan	Morrow
Mississippian	Chesterian	Chester
	Meramecian	Ste. Genevieve
		St. Louis
		Salem
		Warsaw
	Osagian	Osage
	Kinderhookian	Gilmore City ls. Hannibal sh.

Figure 100. Stratigraphic column showing subsurface Mississippian and Pennsylvanian units in southwestern Kansas. Note the disconformable relationship of Chester sandstones with the underlying Ste. Genevieve and St. Louis Limestones, and the unconformity at the base of the Morrowan Series.

WELL COMPLETIONS AND RESERVOIR PRESSURES

The first Chester well that Hugoton Energy Corporation drilled was on the flanks of Eubanks field in sec. 9, T. 29 S., R. 34 W. Hugoton Energy's standard practice was to drillstem test (DST) most sample shows of oil and gas as the well was being drilled. A DST showed the bottom-hole pressure (BHP) in this first well to be 838 psi. This well was drilled on the basis of 3-D seismic records in the NE¼ sec. 3, T. 30 S., R. 34 W., with a near-original BHP of 1,506 psi. Low BHPs extend within the main scour feature from sec. 3, T. 29 S., R. 34 W., southward to sec. 28, T. 29 S., R. 34 W. The wells drilled in the 3-D seismic "thick" or within the main scour feature penetrated multiple sandstone deposits. The wells outside the scour feature penetrated a much thinner overall Chester section and a thinner sandstone section but still are characterized by economic production.

The ultimate recovery on an average per-well basis is 100,000 barrels of oil. The secondary-recovery potential for waterflooding within the scour feature is high. Hugoton Energy engineers used a drainage area of 40 acres with a 15% recovery factor. Some of the wells produce with minimal stimulation, but after initial flush production these wells are fracture treated to enhance production. Some of the wells in the northern part of the area with lower BHPs exhibited almost no shows after an initial treatment and had to be fracture treated to produce. The Chester reservoir does not have an active water drive, but minor amounts of water are produced from these wells. The trapping mechanism is a combination structural–stratigraphic trap. The lower sandstone that lies unconformably on the Ste. Genevieve or St. Louis contains an associated water portion and can be completely wet. The sandstones above the lowermost sandstone tend to be productive within the dictates of porosity and limestone content.

CONCLUSION

The use of subsurface mapping and 3-D seismic methods has led to a better understanding of the deposition of the Chester formation. As drilling continues, the knowledge base will expand for this area, and

Hugoton Energy Corporation (Chesapeake Energy) can apply this knowledge to other areas.

ACKNOWLEDGMENTS

I wish to thank Jim Gowens, of Hugoton Energy Corporation, for allowing me to publish this paper, and Kathy Fowler, of Stim-Lab, Inc., for her analyses of the two cores.

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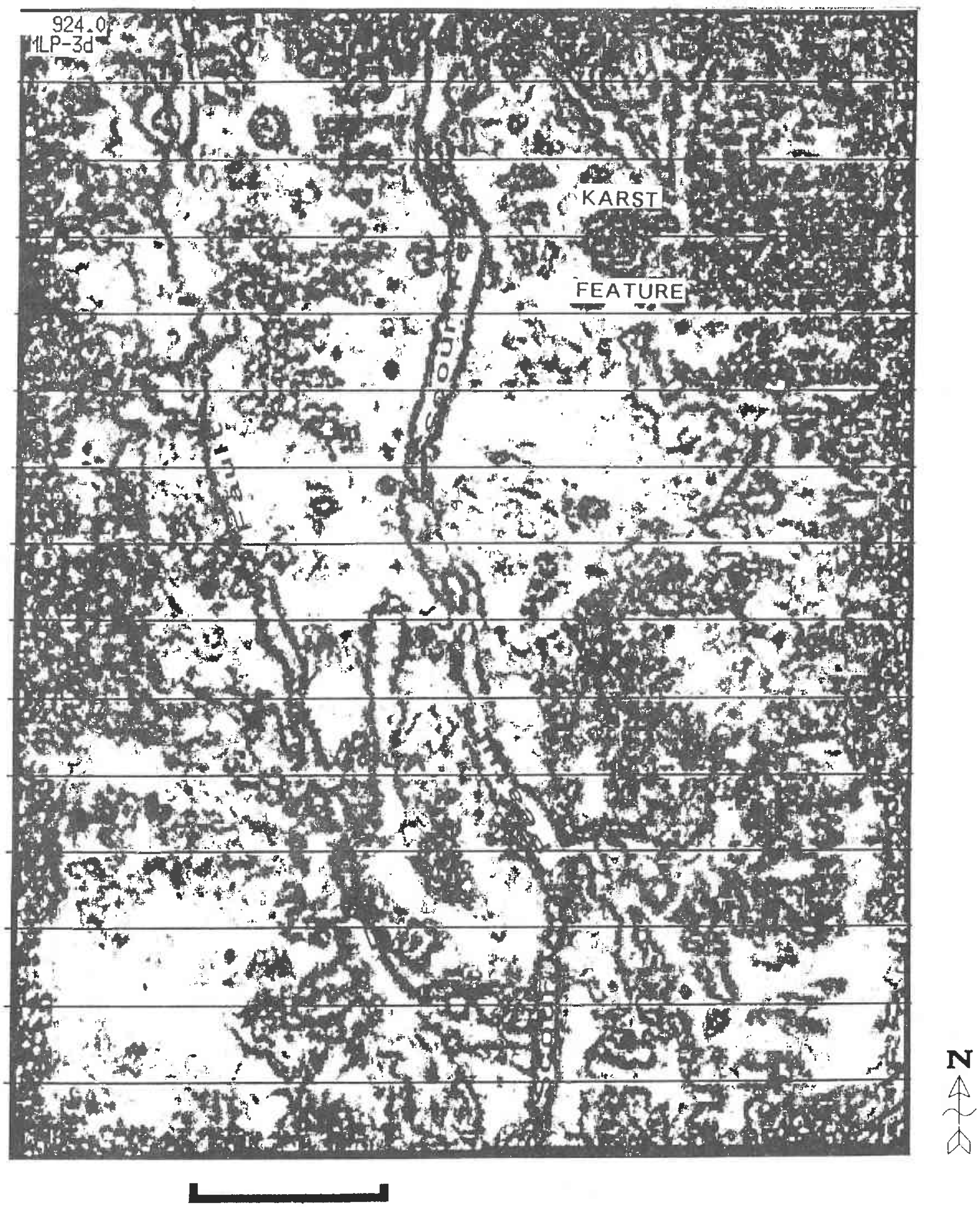


Figure 101. Three-dimensional (3-D) seismic interpretation of the study area, showing a north–south linear scour feature (center) and a regional fault to the west.

A

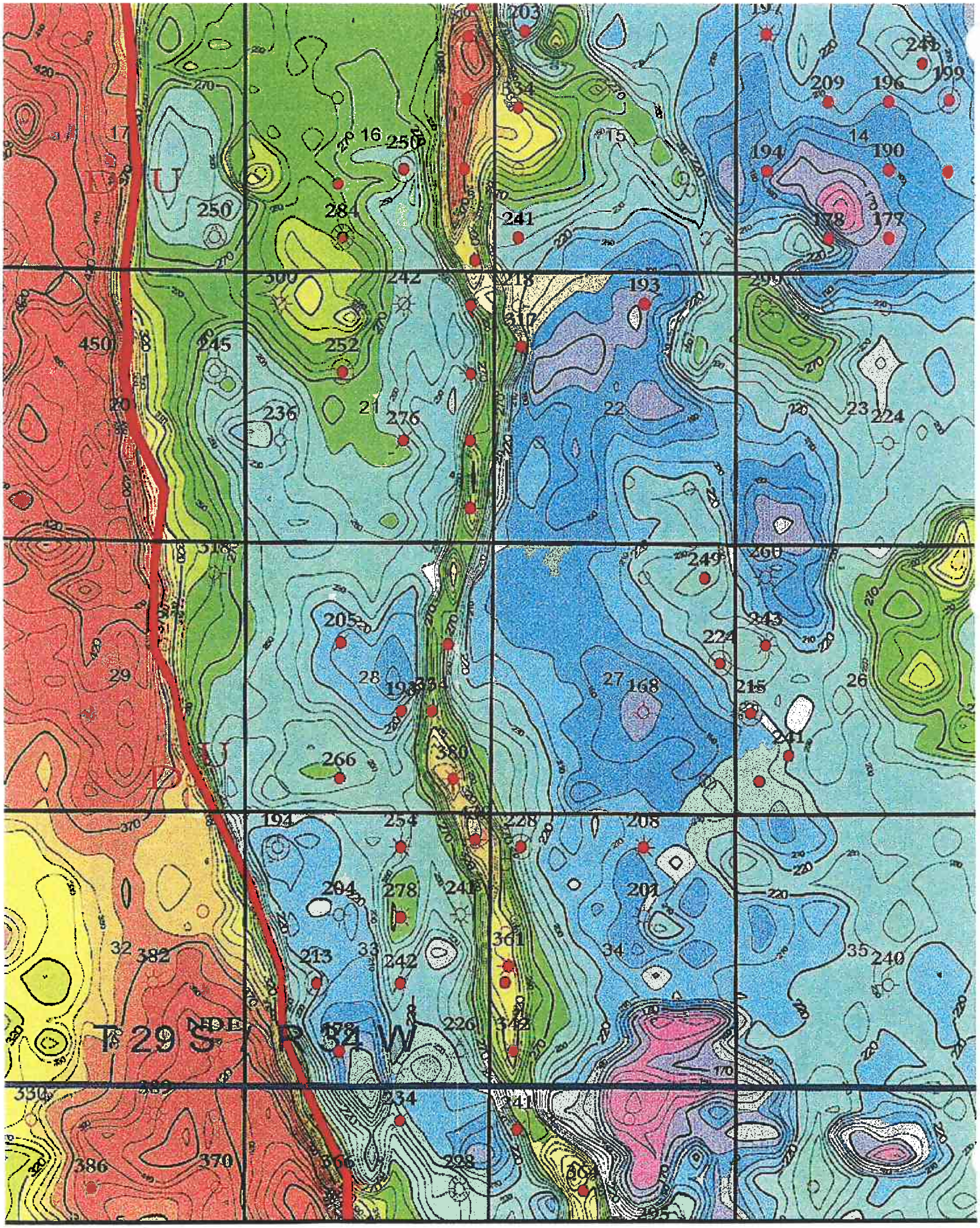
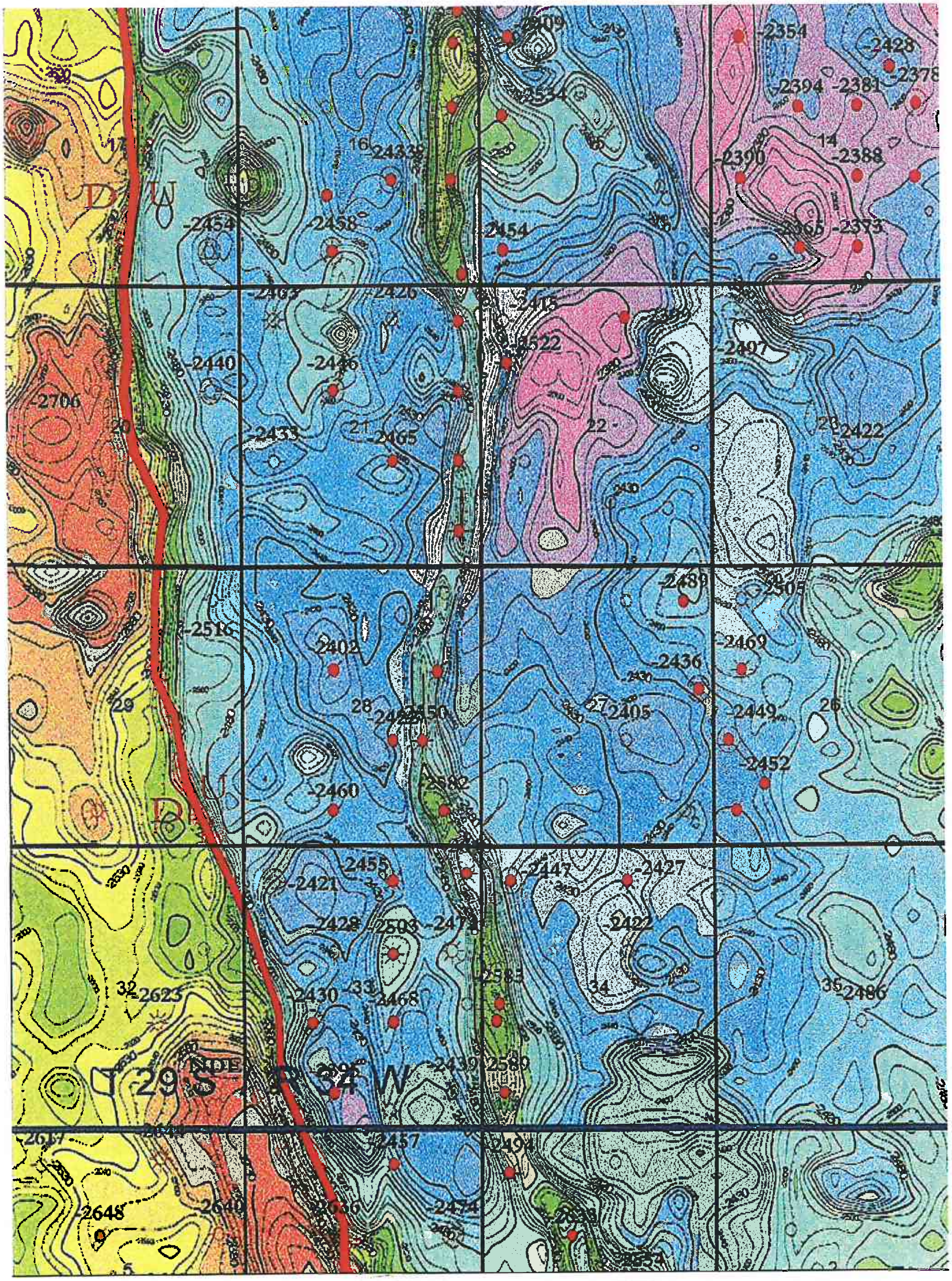


Figure 102. (A) Isopach map of the study area, based on the 3-D seismic survey, of the interval from the top of the Morrowan Series to the top of the Meramecian Series. Isopach interval, 10 ft. (B) *(facing page)* Structure map of the disconformity (top of

B



Ste. Genevieve Limestone), based on the 3-D seismic survey. Contour interval, 10 ft; datum is mean sea level. Clearly indicated on both maps are the north–south linear scour feature and the regional fault to the west.

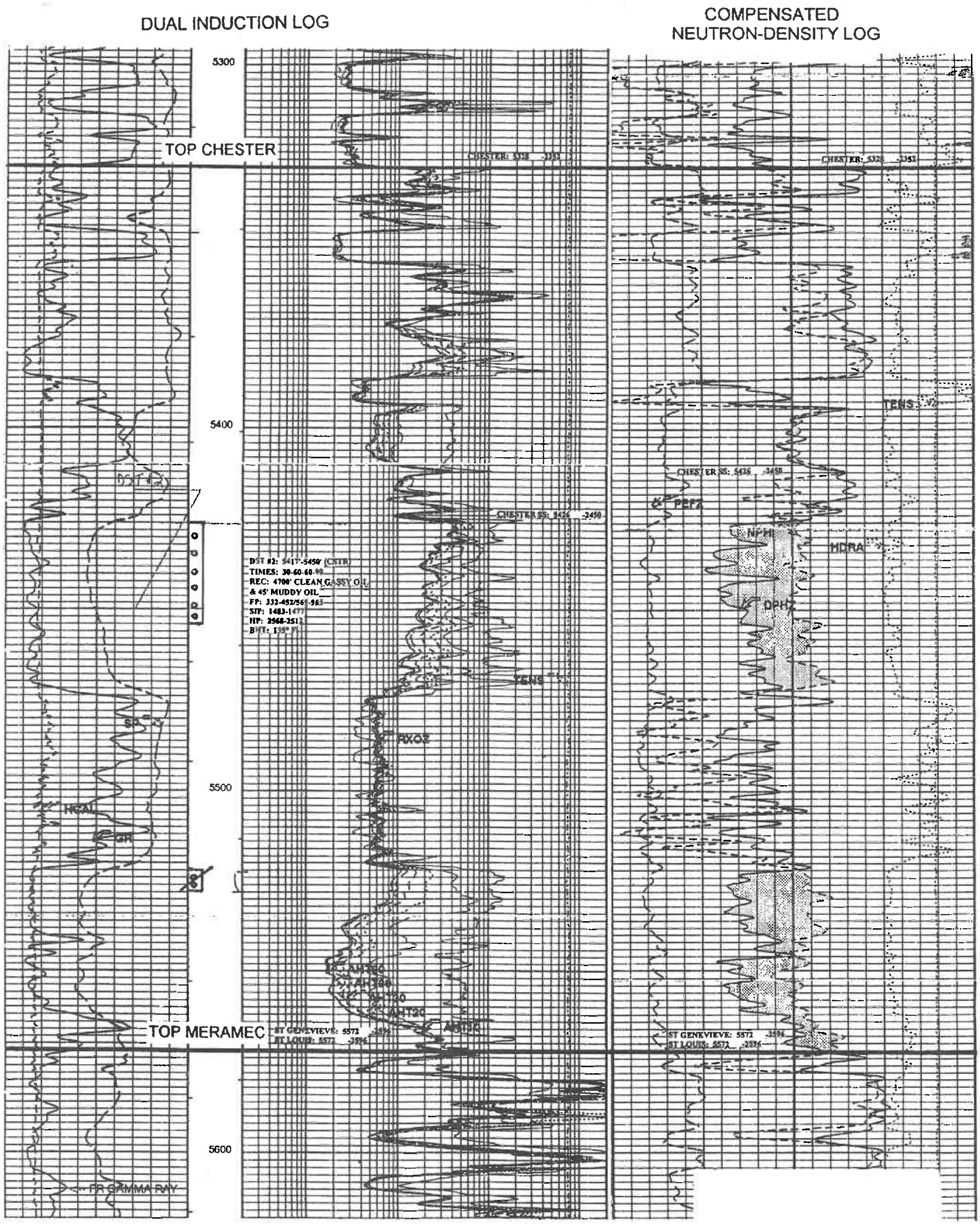


Figure 103. Log suite illustrating Chester sandstone deposited on scoured surface of underlying Meramecian units. Here, the Ste. Genevieve Limestone is almost completely missing.

Buying Seismic Data from a Broker

Raymon L. Brown

INTRODUCTION

This section describes how to buy seismic data that are for sale to the general public. Those who sell such data are called *brokers*. The brokers often represent other people or companies. As a result, once you contact a broker, the broker may have to contact his/her client in order to move forward with a deal. Once a data broker has been selected, several viewing and selection options are open to a potential buyer.

DATA BROKERS IN THE MIDCONTINENT REGION

At least four seismic-data brokers operate in the Oklahoma, Kansas, and Arkansas region, as listed below. Each broker presents the data in a slightly different manner. If you are interested in purchasing data, just call one of the numbers; the broker will be glad to help guide you through the process.

Mid-Con Data Services, Inc.
Mid-Con Center
3601 S. Broadway, Suite 1000
Edmond, OK 73013
Phone: (405) 478-1234
FAX: (405) 478-4442
cprather@midcondata.com
www.midcondata.com

Seismic Exchange Inc. (SEI)
5101 N. Classen, Suite 206
Oklahoma City, OK 73118
Phone: (405) 848-8005
FAX: (405) 848-8371
jbooher@seismicexchange.com

Geodata Corporation
211 S. Cheyenne St.
P.O. Box 3476
Tulsa, OK 74101
Phone: (918) 584-3366
FAX: (918) 585-5272
geodata@iamerica.net

Michael Crouch, Inc.
1650 East 2nd St.
Wichita, KS 67214
Phone: (316) 264-4334
FAX: (316) 264-4344

SPECIFYING AN AREA OF INTEREST

Before talking with a broker, you need to have some idea of the counties to be covered. However, if you are interested in an area with ample seismic coverage, the broker may be able to help you make a selection that includes a specific area for which an abundance of seismic data is for sale. You may want seismic data near a particular well. Filling this order is usually more difficult, but most of the time the broker can tell you quickly what data are available for the area. Your task will be to specify the limits of the area of your interest. In Oklahoma, Kansas, and Arkansas, this usually means specifying sections, townships, and ranges.

VIEWING THE DATA

The type of viewing available depends on the limitations placed on the data by the owner (not the broker) of the data. Some data can be viewed for a limited period (5–10 minutes) in order to determine the quality of the data. Usually this viewing is accomplished without the benefit of a base map and/or shotpoint values (so you won't know the actual position of the line).

VINTAGES OF DATA

"One Hundred Percent" or "Single Fold" Data

When viewing the data, you will notice that a wide range of data is available on the market. Some of the oldest data are called "100%" data. Another expression is "single fold." Essentially "100%" implies that no real processing was done (e.g., stacking). In other words, you are looking at the raw records recorded in the field. These data usually are the cheapest; some consultants are still around who can interpret this type of data. When 100% data were originally collected, the data were sold in the form of single seismic traces. Today, some companies have processed the 100% data to look like modern data. The simplest processing makes the 100% data appear like the stacked data. This means that the actual position of a reflector may be slightly incorrect as viewed. Other forms of 100% data have been migrated so that the reflectors are in the correct positions. It is important to find out how the data have been processed in order to use 100% data effectively.

1950s–1970s

Data shot and collected in the 1950s was primarily "stacked" data. During this period, W. H. Mayne (1962) developed the idea for stacking data. Data shot and processed from the 1950s through the 1970s were probably limited to stacking. Stacked data can depict the formations nicely, but the actual positions of these data are not always correct. One has to correct the picture or have the data migrated to better predict the actual location of an exploration target.

Often, the data being viewed have been reprocessed. You need to ask your broker about this possibility.

Post-1970 Data

In 1971, Jon S. Claerbout introduced the idea of using wave-equation migration to locate the reflectors properly on a seismic section. As a matter of routine, data shot in the late 1970s and later were stacked and migrated. Thus, most data collected since the late 1970s have been migrated. The most common type of migration is called *time migration*. Time migration is cheaper and easier to accomplish, but it is subject to some errors of position where the velocity above a reflector changes rapidly. In this case, a *depth migration* is needed. Probably not many data on the market today have been depth migrated. If you suspect that you may have problems with rapidly changing velocities, it may be worth your effort to talk to a processing company about depth migration.

SELECTING HARD-COPY AND DIGITAL FORMATS

The next item for you to decide is the form in which you want the data. You may only want a paper copy. However, you may need mylar or some other medium that will allow you to make multiple copies of the data. For example, copies can be made from seismic data on mylar at a price of approximately $10 per mile. Copies from film versions are roughly 4 times the price of copies made from mylar. If you are really working with your seismic data, the paper gets folded and refolded and begins to fall apart. You may want a neat copy in order to make a presentation of your interpretation to potential investors. In addition, an unmarked copy is needed so that interested persons can make an independent judgment of the interpretation.

If you want to load your data on a workstation, you will need to get a copy of the data in a format that can be read by your computer. CD-ROM and 8-mm tape are popular examples.

If you want to process the data, you will want a copy of the original field records and the field data (the data before processing). The field data and records for data shot before the 1980s were not often kept. However, most recent data are available in all forms. This type of field data can be obtained on a 9-track tape or other formats that are used by processors.

OTHER SERVICES

In addition to the simple purchase of a single line, active companies can subscribe to a yearly service from the data brokers. The brokers provide a CD-ROM and the necessary software to plot the seismic lines at different scales. This kind of service is very nice when you want to lay your plotted lines over your exploration map.

PURCHASING THE DATA

The final step is the decision to purchase the data. Prices for two-dimensional (2-D) data may range from $700 to $1,650 per mile. Some brokers have a minimum mileage (e.g., a 5-mi minimum). This is not an unreasonable stipulation, because an overall assessment of faulting, for example, may require this length of data. The prices for 3-D data range approximately from $10,000 to $20,000 per square mile. There is not a set minimum for 3-D seismic data. This is handled on a per case basis per approval of the owner of the data. Once the buyer has made a decision, the broker contacts the original owner and makes arrangements to get the data to the buyer.

The data are not actually *purchased*, however. Usually you are buying the right to *use* the data and to show the data to potential clients under limited conditions. The basic idea is that the owner of the data retains ownership. Dealing with the broker is basically purchasing the right to use the data in your exploration efforts and to show your interpretation to potential clients. It is important to understand the restrictions placed on data purchased in this manner.

ACKNOWLEDGMENT

The author thanks Cindy Prather, of Mid-Con Data Services, Inc., for her help with this article.

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When Should You Spend Extra Money for Three-Dimensional Seismic Data?

Raymon L. Brown

INTRODUCTION

Deciding which technology to purchase in pursuit of an exploration target is one of the constantly recurring problems facing an exploration program. The answer depends on the size of the target and the risk associated with finding the target. Surprisingly, even some important logging is eliminated by operators because of the economics. This means that for some circumstances in which dip measurements are critical, dipmeter logs are not available. It also means that when sonic logs are sometimes required for correlating with seismic data, an operator has decided to save money by eliminating certain logs. This kind of "economy" is difficult to justify when one considers the cost of a well. However, saving money on seismic data is somewhat easier to justify, because modern three-dimensional (3-D) seismic surveys can become a significant fraction of the cost of a well.

This article describes how to address the issue of when to use seismic data. The ideas have been taken from a presentation given in 1999 by Kim Head of Veritas GeoServices Ltd. in Oklahoma City. Although the article is focused toward the use of 3-D seismic data, the ideas presented here can be applied to all technologies used for exploration.

The basic issues and answers addressed by Kim in his presentation are as follows:

- Why we need to predict the value of 3-D data.
- How 3-D data influence outcomes.
- How we value outcomes.
- How we can estimate the value of a 3-D survey.

The approach taken by Kim Head uses risk-analysis methods. This means assigning probabilities to events and determining the economic values associated with the events. Even if one is not adept initially at assigning probabilities, one gets better with experience. For example, someone flipping a coin may not have much of a background in statistics, but it will not take long to appreciate that the probability of throwing "heads" is 50%. The ability to assign probability is a skill that is learned from practice. Published statistics and direct experience are both contributors to our estimates of probability. Let's assume for the moment that you are comfortable with assigning probabilities to events. How then do we answer the questions listed earlier regarding the potential use of 3-D seismic data?

NET PRESENT VALUE

The answer depends on the net present value (NPV) of an economically successful prospect ($NPV_{SUCCESS}$) and the net present value of an economic failure ($NPV_{FAILURE}$). Net present value is an expression that accounts for the time value of money. In particular, any inflation and/or other time-dependent effects of money are taken into account so that the value of the project today can be stated in terms of today's dollars. These two expressions then estimate the amount of money (in terms of today's dollars) that you could win or lose. If you don't think time is an issue, you can simply use the amount of money you expect to win or lose in the deal for these values.

EXPECTED MONETARY VALUE

Now if we can assign a probability of economic success, P_{ES}, then the probability of economic failure, P_{EF}, is given by the following equation:

$$P_{EF} = 1 - P_{ES}$$

The criterion used to judge a prospect is called the expected monetary value (EMV) of money. The following equation is used to evaluate the EMV:

$$EMV = (P_{ES} \times NPV_{SUCCESS}) - (P_{EF} \times NPV_{FAILURE})$$

The above equation is a statistician's way of evaluating whether the prospect will make money (on average) or lose money (on average). If the answer is positive, then the prospect can be considered a viable prospect (assuming that all the statistical assumptions are correct and the company has an infinite reserve of money that can be used to test the statistics). If the EMV is negative, the project is judged to be a potential failure. These basic ideas are used to evaluate prospects. Now let's expand on these ideas and see how the purchase of 3-D seismic data can affect the value of a prospect.

EVALUATION OF THE PROBABILITY OF ECONOMIC SUCCESS

To evaluate the probability of economic success (P_{ES}), it is sometimes convenient to express this as a product of the probability of scientific success, P_S (correctly predicting the source, migration, reservoir trap, and seal), times the probability (P_{ENOUGH}) that if you find a working hydrocarbon system it will be large enough to exploit economically. Thus, we can express the probability of economic success in the form:

$$P_{ES} = P_S \times P_{ENOUGH}$$

The separation is made here because we want to identify the contribution that seismic data (3-D seismic in this discussion) will make to our "scientific success." There is nothing we can do to change the value of P_{ENOUGH}. That value is determined by "Mother Nature." Our task in exploration is to modify P_S.

VALUE OF INFORMATION (VALUE OF SEISMIC DATA)

To determine the value of information, a statistical evaluation can be used that is based on the economics of the prospect. The basic idea is a simple one. Simply evaluate the EMV with the seismic data, and the EMV without the seismic data. The difference is called the Value of Information (VOI):

$$VOI = EMV_{WITH\ SEISMIC} - EMV_{WITHOUT\ SEISMIC}$$

This equation suggests that the value of information (3-D seismic data in this case) depends on (1) the probability of scientific success and (2) the amounts and timing of expenditures and cash flow (the time value of money). We will not elaborate on the time value of money at this point. Below, we concentrate on the value of seismic data and how these data contribute to the evaluation of a prospect.

EFFECT OF 3-D SEISMIC DATA ON THE EVALUATION OF A PROSPECT

As described above, the VOI depends on the probability of scientific success and the NPV of the prospect. Seismic data affect both of these quantities. The influence of 3-D data on the probability of scientific success is as follows:

- Reduces structural uncertainty by about 38%.
- Improves drilling success rates and prevents dry holes by about 23%.

Seismic data also affect the NPV of a prospect in the following manner:

- Identifies bypassed areas, increases reserves, and may increase surface facilities.
- Increases the number of locations drilled.
- May accelerate field development and payout.
- Optimizes well locations and can improve recovery factors.
- Increases costs.

Many large companies (e.g., Amoco and Exxon) have reported an increased drilling success of 20% when using 3-D seismic data versus the conventional use of 2-D seismic data. The 3-D data act to optimize the staking of well locations so they are positioned properly from a structural and/or a stratigraphic viewpoint (a "sweet spot"). Improving drilling locations in this manner ultimately boosts the recovery factors for a field.

SUMMARY AND CONCLUSIONS

In summary, the value of 3-D seismic data to a prospect can be evaluated by using the basic equation below:

$$VOI = EMV_{WITH\ SEISMIC} - EMV_{WITHOUT\ SEISMIC}$$

Positive values for the above equation indicate that the seismic data should be purchased and used. Negative values indicate that the use of 3-D data should not be considered. Published industry probability data and their anticipated impact on NPVs can be used to estimate the value of 3-D seismic data. These equations should be useful to anyone wanting to support or argue against a proposed 3-D seismic survey.

The value of seismic data to a prospect is ultimately a function of the additional costs of the data and other value changes to the prospect compared to changes in the risk of the project. Acquiring 3-D seismic data also makes the NPVs of a prospect change because of increased costs, changes in field-development scenarios, and cash-flow timing. In addition to affecting the NPVs of a prospect, 3-D seismic data ultimately raise the probability of economic success and lower the probability of economic failure. What more can you ask from a technology?

Consultants and Workstations

Deborah K. Sacrey

CONSULTANTS

You have purchased (or want to purchase) seismic data that cross productive property you own, so what do you do with these data?

Generally speaking, operators (unless they are exploration companies) do not have staff geologists or geophysicists. Typically, consultants are used for short-duration projects to interpret either two-dimensional (2-D) or three-dimensional (3-D) information. It is advisable to take a consultant with you when viewing data at a broker's office if you are not familiar with seismic information. The consultant can advise you on the quality of the data, negotiate (to some degree) the price, and understand how much data you need to solve your particular stratigraphic or structural problem.

When looking for a consultant, you need to consider several points and options:

1. *Contact the nearest local geological or geophysical society.*—In the Midcontinent, local societies are present in such major metropolitan areas as Wichita, Oklahoma City, Tulsa, Ardmore, Amarillo, Dallas, and Fort Smith. The officers of the local societies will know experts in their areas who can address your particular problem.

2. *Another organization to contact is SIPES.*—SIPES (the Society of Independent Professional Earth Scientists) is a multidisciplinary, certifying organization made up of small independents and consultants who are geologists, geophysicists, and engineers. The national office is in Dallas and has a full-time administrative secretary to handle calls (telephone, 214/363-1780). The organization maintains a national data base of members who are consultants and will answer inquiries by furnishing two or three names of persons meeting the criteria you need. Local chapters of SIPES in the Midcontinent are in Wichita, Oklahoma City, and Dallas. These chapters also can furnish information about interpretive consultants in their areas. SIPES members tend to be among the "who's who" in their respective areas, and they adhere to high ethical standards.

3. *Word of mouth.*—Ask other producers in your area if they have used seismic data to enhance their production. If they have purchased and applied seismic technology, ask about the consultants they used and whether they were pleased with the results.

When you have found a consultant who has expertise in your area, there are several steps you need to take:

1. *Establish the scope of your project early.*—Write down what tasks you need to accomplish. This may range from the quality control of data through interpretation, integration of well information, and map generation. Be specific about the maps you want generated.

2. *Get a written cost proposal in response to your scope of project.*—Find out if the consultant has a minimum charge on a day rate (many have a minimum charge for half a day even if you need only 1 hour's work). Find out the cost per hour, per day, or for a longer period. Often the cost goes down the longer the project lasts. If possible, get bids from more than one person, with a clear understanding of the time involved in completing the project. Ask for references, and contact those references! You want to make sure you are getting what you need in terms of expertise.

3. *Negotiate the terms (cost) of the project, and get it in writing.*—Many consultants want to be paid a retainer or a percentage of the bid before beginning a project. When you are satisfied with the results (depending on the length of time), then the balance of the contract is paid. Some consultants are willing to trade consulting time for a small overriding royalty interest or a cash bonus (they are willing to risk their time and expertise for more value). Be sure you have a written contract with the consultant, especially if it is someone with whom you are not familiar.

4. *If you have purchased 3-D seismic data.*—Make sure the consultant has access to and understands the use of a computer workstation. As stated earlier, interpreting 3-D data from paper is time consuming and messy, and the interpreter is not able to compute the seismic attributes (amplitude maps) that may enhance drilling opportunities. It is much more efficient to interpret 3-D seismic data at a workstation. Remember that a consultant who is experienced in 3-D interpreta-

tion has a workstation and will be more expensive than a consultant hired to interpret one 2-D line. The 3-D consultant has gone to some expense to purchase a workstation and learn the interpretive software. There are also increased overhead costs associated with the right to own and use the software. This may add as much as $75–$100/hour in costs, but the efficiency in interpretation and manipulation of the data far outweighs the cost. You will be responsible for purchasing any digital base maps and well files needed to integrate the seismic data with your productive area, but you will also own the license to those data. Have the consultant give you the estimated costs of providing this information.

5. *If you have purchased 2-D seismic data.*—The consultant will need several prints of the lines, probably at different scales, and clean base maps. You may need to provide well-log information, production information, formation tops, and any other geological information for use in properly evaluating the seismic data and integrating it with the geology.

WORKSTATIONS

Two main types of interpretive software packages are available on the open market to consultants: those that run in the Unix Operating System, and those that run on a standard personal computer (PC). The Unix systems are familiar names to many in the industry—for example, Landmark, Geoquest, Photon (although they no longer exist under that name), and Charisma. The PC packages are Kingdom, Seis-X, Vest, SeisVision, and a few others. Most consultants who have their own workstations work on the PC variety for at least two reasons:

1. *Cost.*—A typical Unix hardware and software workstation costs upward of $150,000. The same PC version costs less than $30,000. This means that consultants with Unix workstations have to charge considerably more for their time to cover the higher cost of such machines.

2. *Maintenance.*—Once a consultant has purchased a Unix-based workstation, the software companies (like Landmark and Geoquest) charge a maintenance fee to use the software—usually about $30,000/year. The maintenance fee covers new releases of the software as well as technical support. Because the cost of PC software is so much less, the maintenance costs are also less. Typically, PC interpretive software costs $6,500–$10,000, with maintenance costs running 14% to 18% of annual costs. Again, consultants who own Unix machines not only have to charge fees to recoup the costs of their workstations but also have to cover overhead costs in keeping the software. A consultant working on a PC workstation tends to be much more competitive in cost while having the same functionality (in terms of software capabilities) as the Unix counterpart.

Many people feel they are not getting an "official" or the best possible interpretation unless it comes from a Landmark or Geoquest machine—and that is just not true. Great strides have been made in PC hardware and software during the past several years—so much so that PCs are actually faster than Unix machines, and PC software has the same capabilities as the Unix brands. All this is an advantage to the consultant using a PC-based workstation and to you, because you can get the same information at a much more competitive price.

In the long run, the end result is what is important, and your satisfaction with the technology and its application to add new reserves is why we are all here!

Glossary

Glossary of Terms

(as used in this volume)

Most definitions modified from R. E. Sheriff, *Encyclopedic Dictionary of Exploration Geophysics* (third edition, 1991), published by the Society of Exploration Geophysicists (SEG), Tulsa, Oklahoma.

absorption—1. A process whereby energy is converted into heat while passing through a medium. Absorption for seismic waves is typically about 0.25 dB/cycle and may be as large as 0.5 dB/cycle. **2.** The process by which radiant energy is converted into other forms of energy. **3.** The penetration of the molecules or ions of a substance into the interior of a solid or liquid.

acoustic—Implies the absence of shear and of *S*-waves. Usually refers to *P*-waves, sometimes is restricted to *P*-waves in fluids (liquids and gases). Synonym: *sonic.*

acoustic impedance—Seismic velocity multiplied by density. Reflection coefficient at normal incidence depends on changes in acoustic impedance.

amplitude—The maximum departure of a wave from the average value.

amplitude decay—Loss in strength of amplitude by absorption or spreading loss as energy is reflected/refracted through the subsurface.

analog—1. A continuous physical variable (such as voltage or rotation) that bears a direct relationship (usually linear) to another variable (such as motion of the Earth) so that one is proportional to the other. **2.** Continuous, as opposed to discrete or digital.

angle of incidence—The acute angle that a raypath makes with the normal to an interface. This is the same angle an approaching wavefront makes with the interface in an isotropic medium. In the anisotropic case, it is the angle between the raypath and the normal, the raypath not necessarily being perpendicular to the wavefront. The angle of incidence may be complex.

angle of reflection—Equal to the angle of incidence, but as the raypath is reflected from an interface toward the surface.

array—A group of geophones or other seismic receivers connected to a single recording channel (*geophone array*) or a group of sources to be activated simultaneously (*source array*).

automatic gain control (AGC)—A system in which the output amplitude is used for automatic control of the gain of an amplifier. Seismic amplifiers used to have individual AGC for each channel, although multichannel control was sometimes used. Also called *automatic volume control* (AVC).

average velocity—The distance traversed by a wavelet divided by the time required, both with respect to some particular travel path and to a certain datum. For reflections, often refers to a ray reflected at normal incidence, sometimes to a vertical travel path. See *velocity.*

band-pass filtering—Often specified by listing low-cut and high-cut component filters.

bandwidth—1. The range of frequencies over which a given device is designed to operate within specified limits. **2.** The differences between half-power drops to half the peak power (3 dB). **3.** The effective bandwidth is where $P(v)$ is the power at the frequency, v, and P_{max} is the maximum power. It is the width of a boxcar with the same total power and the same peak power. **4.** The rate at which a computer resource can carry (accept or deliver) data. Usually expressed in bytes per second or bits per second.

bin—A linear distance for 2-D surveys or a rectangular area for 3-D surveys over which seismic traces are summed together in the stacking process.

check-shot survey—A method of determining the average velocity as a function of depth by lowering a geophone into a hole and recording energy from sources on the surface.

coherence—A method of presenting 3-D seismic data that enhances the definition of faults and other structures.

common depth point (CDP)—Also referred to as *common midpoint* (CMP). Having the same midpoint between source and detector. Sometimes called *common reflection point.*

common midpoint (CMP)—See *common depth point.*

compressional wave—A *P*-wave or primary wave. An elastic body wave in which particle motion is in the direction of propagation. The type of seismic wave assumed in conventional seismic exploration.

critical angle—Angle of incidence, q_C, for which the refracted ray grazes the surface of contact between two media (of velocities V_1 and V_2): sin $q_C = V_1/V_2$.

cross-swath—A method in which seismic receivers are laid out in parallel lines (swath) and the sources are shot in lines perpendicular (cross) to the receivers.

digital—Representation of quantities in discrete (quantized) units. A digital system is one in which information is contained and manipulated as a series of discrete numbers.

direct wave—A wave that travels directly by the shortest path. Other waves traveling by longer routes may arrive earlier because they travel at higher velocity.

dynamic range—The ratio of the maximum reading to the minimum reading (often noise level) that can be recorded by and read from an instrument without change of scale.

elastic—The ability to return to original shape after removal of a distorting stress. The return of shape is complete and essentially instantaneous rather than gradual.

elastic-wave propagation—Seismic-wave movement (including *P*- and *S*-waves) through the subsurface.

filter—A part of a system that discriminates against some of the information entering it. The discrimination is usually on the basis of frequency, although other bases such as wavelength, moveout, coherence, or amplitude may be used.

floating point—A number expressed by the significant figures times a base raised to a power. Thus, 139,000 might be written as 1.390×10^5 to indicate four significant figures. Writing numbers in floating-point format prevents the loss of significant figures in case the number becomes too small or too large for a fixed register. Computers usually use bases that are a power of 2 rather than the base 10.

fold—The number of traces that are added together in the stacking process.

four-component (4-C) seismic survey—A three-component (*P*-wave, and two directions of *S*-wave) seismic survey that has been acquired in a marine environment. The fourth component is created when air guns are used as an energy source (shear waves do not propagate through water) and the shear waves are created by the conversion of pressure waves at rock-property boundaries.

four-dimensional (4-D) seismic—The use of 3-D surveys taken at different times to monitor the time-dependent changes of a reservoir.

frequency—The repetition rate of a periodic waveform, measured in "per second" or hertz (Hz). The reciprocal of *period.*

Fresnel zone—The portion of a reflector from which reflected energy can reach a detector within one-half wavelength of the first reflected energy.

gain control—Control for varying the amplification or attenuation of an amplifier, used to compensate for variations in input signal strength. Gain control is often automatic, using a feedback loop whereby the output level controls the gain so as to keep the output level within certain limits.

Geograph—A *Thumper,* or other type of weight-drop method. *Geograph* is the trade name of Mandrel Industries.

geophone—The instrument used to transform seismic energy into an electrical voltage. A coil is suspended by springs in a magnetic field. A seismic wave moves the case and the magnet, but the coil remains relatively stationary because of its inertia. The relative movement of magnetic field with respect to the coil generates a voltage across the coil, the voltage being proportional to the relative velocity of the coil with respect to the magnet (when above the natural frequency of the geophone).

ground roll—Surface-wave energy that travels along or near the surface of the ground.

hardness—In this case, the term refers to the relative density of various sediments and rocks (i.e., sandstone is generally harder than clay, and limestone is generally harder than sandstone).

Head wave—A wave characterized by entering and leaving a high-velocity medium at the critical angle.

hertz (Hz)—The measurement of a unit of frequency, the same as cycles per second = cps. Named after Heinrich Rudolph Hertz, German physicist who discovered electromagnetic waves.

impulsive point source—A source that produces a very sharp wave of very short duration and that somewhat simulates the generation of an *impulse.* An explosion is an example of such a source.

interval velocity—The velocity of an interval in the subsurface measured by determining the traveltime over a depth interval along some raypath. In sonic-log determinations the interval may be 1–3 ft; in well surveys it may be 1,000 ft or more. Usually refers to *P*-wave velocity.

Love wave—A surface seismic-channel wave associated with a surface layer that has rigidity, characterized by horizontal motion perpendicular to the direction of propagation with no vertical motion. Named for A. E. H. Love, English mathematician.

low-velocity layer (LVL)—A near-surface belt of very low-velocity material, also called *weathering* or *weathered layer*. The LVL is very important in seismic interpretation because it can have marked effect on the arrival times of reflections.

midpoint—The point midway between a source and a geophone.

migration—An inversion operation involving rearrangement of seismic-information elements so that reflections and diffractions are plotted at their true locations. The need for this arises because variable velocities and dipping horizons cause these elements to be recorded at surface positions different from the subsurface positions.

multiple—Seismic energy that has been reflected more than once.

noise—Seismic energy other than primary reflections; includes microseisms, source-generated noise, multiples, tape-modulation noise, harmonic distortion, etc.

normalize—Forming a ratio with respect to a standard (the normal). A normalized value usually is dimensionless. Normalizing often consists of scaling such that "something equals one."

100% shooting—Continuous coverage without redundancy, as opposed to common-midpoint coverage. Also called *single-fold shooting*.

polarity—The condition of being positive or negative. A reflection indicating an increase in acoustic impedance or a positive reflection coefficient begins with a downward deflection, which by SEG standards is represented by a negative number (negative polarity).

primary wave (*P*-wave)—See *compressional wave*. An elastic body wave in which particle motion is in the direction of propagation.

radar—A system in which short electromagnetic waves are transmitted and the energy scattered back by reflecting objects is detected. Ships use radar to help "see" other ships, buoys, shorelines, etc.

Rayleigh wave—A type of seismic wave propagated along the free surface of a semi-infinite medium. Particle motion near the surface is elliptical and retrograde (i.e., the particle moves opposite to the direction of propagation at the top of its elliptical path). Named for John William Strutt, Lord Rayleigh, English physicist.

raypath—A line everywhere perpendicular to wavefronts (in isotropic media).

reflection—The energy or wave from a seismic source that has been reflected (returned) from an acoustic-impedance contrast (*reflector*) or series of contrasts within the Earth.

reflection coefficient—A ratio of resistivities, *r*, as derived from the method of images. The difference of hardness across the boundary of two layers divided by the sum of the hardness of the two layers would define the reflection coefficient at the interface.

refraction—The change in direction of a seismic ray on passing into a medium with a different velocity.

seismic—Having to do with elastic waves. Energy may be transmitted through the body of an elastic solid by body waves of two kinds: *P*-waves (compressional waves) or *S*-waves (shear waves).

seismic wave—An elastic disturbance that is propagated from point to point through a medium. Seismic waves are of two main types: (a) body waves (*P*- and *S*-waves) and (b) boundary waves or surface waves (Love waves, Rayleigh waves).

seismograph—A seismic recording instrument or system.

seismology—The study of *seismic waves*, a branch of geophysics. Especially refers to studies of earthquakes or to seismic exploration for oil, gas, minerals, engineering information, etc.

seismoscope—An instrument that indicates the occurrence of an earthquake.

shear wave (*S*-wave)—A body wave in which the particle motion is perpendicular to the direction of propagation.

shot gather—A group of seismic traces plotted together that are associated with the firing of a single shot.

shothole—The borehole in which an explosive is placed for blasting.

shotpoint—The location where an explosive charge is detonated, but also used for the location of any source of seismic energy, such as Thumper drops, air-gun pops, Vibroseis excitations, etc.

single-ended spread—A reflection profile that is shot from one end. Also called *end-on spread*.

single-fold shooting—See *100% shooting.*

sonar—Sonic (acoustic) waves in water. Used for navigation, positioning, and communications.

sonic—Pertaining to acoustic or *P*-waves in fluids. Sometimes includes other wave modes and hence becomes synonymous with *seismic* and *elastic.*

sonic log—A well log of the traveltime (transit time) for seismic waves per unit of distance, which is the reciprocal of the *P*-wave velocity. Also called *acoustic-velocity log* and *continuous-velocity log,* it is usually measured in microseconds per foot.

split spread—A method of reflection surveying in which the source point is at (or perpendicularly offset from) the center of the geophone spread.

spreading loss—Referring to energy loss from an expanding wavefront with depth. As a seismic wave expands outward from a shot, the energy per unit area of the wavefront is inversely proportional to the square of the distance from the shot because the total energy has to spread over an increasingly larger area.

stacking—The process of creating composite records made by combining traces from different records. Stacking involves filtering because of timing errors or waveshape differences among the elements being stacked.

stacking velocity—Velocity calculated from normal-moveout measurements and a constant-velocity model. Used to maximize events in common-midpoint stacking.

surface wave—Energy that travels along (or near to) the surface. Motion involved with the wave falls off rapidly with distance from the surface. In seismic exploration, this is usually referred to as *ground roll.*

synthetic seismogram—An artificial seismic-reflection record manufactured by assuming that some waveform travels through an assumed model.

three-component (3-C) seismic survey—A seismic survey that is shot and that records the *P*-wave reflections in addition to *S*-wave energy recorded with two directional components. The *P*-wave-amplitude data supply information about depth and fluid content of the subsurface, while the two directional components of *S*-wave energy supply data pertaining to the internal makeup of the rocks, independent of fluid content, such as permeability, porosity, and lithology.

three-dimensional (3-D) seismic—Refers to a survey involving collection of data over an area with the objective of determining spatial relations in three dimensions, as opposed to determining components along separated survey lines.

Thumper—Device for dropping a weight to provide seismic energy. Typically, a 3-ton weight is dropped 10 ft. Trade name of Geosource, Inc.

trace—A record of the data from one seismic channel, one electromagnetic channel, etc. A line on one plane representing the intersection with another plane, such as a fault trace.

traveltime—The time between time break and the recording of a seismic event.

two-dimensional (2-D) seismic—Having no variation in the direction perpendicular to the plane (usually vertical), which includes the line of measurement. A 2-D seismic line records seismic information along one path.

variable area—A display in which the width of a blacked-in area is roughly proportional to the signal strength. In normal-polarity displays, the black area represents a positive-amplitude display and tracks to the right.

variable density—A display method wherein the photographic density is proportional to signal amplitude.

velocity—A vector quantity that indicates time rate of change of displacement. Usually refers to the propagation rate of a seismic wave without implying any direction.

velocity survey—A series of measurements to determine average velocity as a function of depth, as in *well shooting.* May also refer to running a *sonic log.*

Vibroseis—A seismic method in which a vibrator is used as an energy source to generate a controlled wavetrain. Developed by Conoco.

wavefront—The surface over which the phase of a traveling wave disturbance is the same. The wavefront moves perpendicular to itself as the disturbance travels in an isotropic medium.

wavelet—A seismic pulse usually consisting of only a few cycles. A *basic wavelet* is the time-domain reflection shape from a single positive reflector at normal incidence.

weathered layer—A near-surface low-velocity layer, usually the portion where air rather than water fills the pore spaces of rocks and unconsolidated earth. The term *low-velocity layer* (LVL) is often used for seismic weathering.

weathering correction—A correction of seismic reflection or refraction times to remove the delay in the weathering or low-velocity layer.

wiggle trace—A graph of amplitude against time, as on a conventional seismic recording with mirror galvanometers.

Notes