

Using SAS to manage diverse data types needed to develop a gas field

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ABSTRACT

At Chevron, we use SAS to manage large quantities of engineering, geologic and geophysical data from a Gulf Coast gas field. Easy access to these data allows us to make better, more timely decisions on where to drill new wells. Using SAS, we piece together these interrelated but diverse data types in ways not envisioned or available from in-house or third-party engineering, geologic or geophysical software.

Developing a gas field entails deciding where to drill the next well within the limits of the field. Three-dimensional (3D) seismic data provides a technological breakthrough in this complex geologic area such that picking the actual drill location is less geologically risky than with two-dimensional seismic data. Given that the 3D seismic data removes most geologic risk, we need to know that the well will recover enough gas to be an economic success. Therefore, we must determine the volume of recoverable gas in the fault blocks that are imaged by the seismic data.

Within this 75-well gas field, we use SAS to integrate well production data, well log data and information from 3D seismic data to determine the volume of recoverable gas in 25 fault blocks. Using this approach, we drilled 9 successful gas wells in 1992. Because we could easily integrate these data, we changed several paradigms that resulted in us drilling and completing more wells than would have been possible using older methods.

INTRODUCTION

As with any technical discipline today, gas field development requires that we be able to quickly integrate large quantities of diverse data to make timely business decisions. The oil industry and many third-party software development firms are currently striving to develop and populate databases that will include these data. Then, specialized applications can be written to help one quickly integrate and analyze these data. The problem, at least at Chevron, is that these integrated databases and applications are not yet available. Therefore, we use SAS as an interim solution to this data management problem.

To develop a gas field we must decide where to drill the next well in amongst other dry and producing wells. These surrounding wells and seismic data provide the essential information to help us with the decision. Typically, it is the job of engineers, geologists, and geophysicists to analyze these data. One problem is that data analysis spans several disciplines but available software often does not. For example, engineers use software to predict well performance from past performance history. Geophysicists use software to interpret seismic data and determine the size of the reservoir. By tightly integrating the two, one might conclude that well performance has more to do with reservoir size and the position of the well within the reservoir than with past performance.

In this paper, we describe how we use SAS to integrate engineering, geologic and geophysical data to determine the volume of gas within a gas field. In the Appendix, we briefly describe several SAS utilities that help us with other aspects of data management.

METHOD

Determine gas volume - overview

To determine the volume of gas in a rock layer, we first represent the rock layer in gridded form. Each grid cell has the same surface area but varies in thickness and gas concentration. The volume of gas in grid cell is the grid cell area times the thickness times the gas concentration. The total volume of gas in the rock layer is simply the sum of all grid cell volumes.

Four types of data are needed to compute the recoverable gas volume in a rock layer. From seismic data, we extract the gridded surface that represents the rock layer. Well data provides the thickness of each grid cell and the gas concentration. Engineering data allows us to account for the fact that the gas volume in the reservoir is less than at the surface and that we don't recover all the gas. Finally, well production data allows us to compare the computed volume to the produced volume. We'll now describe each of these steps in more detail.

Map reservoir area

To determine the volume of gas in a reservoir we must first define the geographic limits of the reservoir using seismic data. Seismic data are the echoes we receive after shaking the ground or setting off explosives near the surface along a line. After substantial computer processing, we assemble these echoes into a display that resembles a vertical cross section of the earth. In a 3D seismic survey, the seismic lines are so close together we can assemble a 3D cube of data. This enables us to view a cross section in any direction or dimension. 3D seismic data usually offer significantly more detail in the correct spatial position than 2D seismic data.

The 3D seismic survey we used covered Chevron's lease over the gas field. The gas field itself is made up of dozens of disconnected blocks separated by faults. We call these fault blocks. The purpose of 3D seismic data is to determine the extent of each fault block and the reservoir depth. Figure 1 is an example of a seismic line from the 3D cube of data. The black-and-white 'fuzzy' areas represent the echoes off different geologic layers. The two vertical lines show the position of wells A and B drilled 10 years ago. Well A encountered gas at the echo labeled GAS SAND (white dots) and has already produced 6 billion cubic feet of gas (roughly equivalent to 1 million barrels of oil). Note that well B almost missed the gas sand. The vertical scale is the time in seconds that it took for the sound to bounce off the geologic layers and return to the surface. We convert this echo time to depth knowing the rock velocity

The seismic line also shows our interpreted position of several faults cutting the display at roughly a 60 degree angle. To a geophysicist, these fault breaks are usually quite distinct and continuous for large distances. They represent reservoir boundaries since engineering data show that faults act as barriers to gas flow. Therefore, mapping the extent of the reservoir entails mapping the position where the echo associated with the gas sand is truncated by the faults. The reservoir map near the seismic line shows the disconnected nature of five fault blocks and the large gaps in the reservoir caused by faulting (Fig. 2). Well C was drilled before the 3D seismic data was acquired. It inadvertently drifted off to the west, encountered a fault gap and is a dry hole.

Using proprietary interpretation software on a workstation, we interpreted the limits of 25 fault blocks from this 3D seismic survey. Since the spacing between the north-south and east-west seismic lines is 82.5 feet, the grid cell size is also 82.5 by 82.5 feet. An average fault block contains 700 grid cells. Our interpretation

software allows us to export a file containing the grid cell location and time (or depth) to the reservoir zone. We store the grid cell values in a SAS SURFACES file that contains 17,000 observations and 25 variables.

Determine the amount of rock filled with gas

Given the areal limits of the reservoir in a fault block, the next step is to determine the reservoir thickness and how much of the reservoir rock contains gas. Reservoir rocks in this area contain 65-85% solid mineral grains with the remaining void space called pores (Fig. 3). The pores contain both water and gas. Well data described below are used to determine the percentage of rock that is pore space (porosity) and the percentage of pore space that contains gas (gas saturation).

After a well is drilled, a device called a wireline tool is lowered in the well (Fig. 4). This device measures rock properties such as resistivity and density as a function of depth. Geologists interpret these well logs to pick the depths to the top and base of the reservoir and other important formation boundaries. They enter this information into a SAS file through a SAS/FSEdit screen. This SAS TOPS file contains one observation for each of the 75 wells with 400 variables per well. The geologist has to manually enter only about 40 of these variables.

Next, we assemble all the well logs into a SAS WELLOG file. We store only the well log values around the reservoir zone sampled every foot. This SAS file contains about 65,000 observations and 40 variables. We use the TOPS file built by the geologist to automatically assign a reservoir or non-reservoir name to every foot of well log.

A log evaluation specialist uses the well log data to determine the reservoir porosity and gas saturation. It is beyond the scope of this paper to adequately describe this log evaluation process. However, using the log values, a half dozen or so critical constants and industry-standard empirical formulas, we can compute the porosity and gas saturation of the reservoir. We wrote a SAS program to calculate these key parameters using the WELLOG file as input. For all 75 wells, this program takes 10 CPU seconds on an IBM ES9000.

Map reservoir properties

The reservoir in this area contains five gas producing layers. Using the results from above, we first determine the thickness of reservoir sand in each layer that will produce gas. Experience tells us that a layer will produce

gas if it has greater than a certain minimum gas saturation and porosity. Then, using PROC G3GRID and PROC GCONTOUR, we map each layer's thickness, average porosity and average gas saturation. These 15 maps cover the entire area of the 3D seismic survey and use the same grid cell size as the SURFACES file. This SAS GRIDMAPS file contains 93,000 observations and 27 variables. Gridding and contouring take about 6 CPU minutes.

Map gas recovery factor

We base our economics on the amount of gas a well will recover. This value is different from the amount of gas in the reservoir for two reasons. First, the gas in the reservoir will expand when it reaches the surface because of the extreme pressure difference between the reservoir and surface. Second, all the gas in a reservoir is not recoverable because eventually the well's flowing pressure drops below the pressure in the pipeline it's flowing into. These two factors are a function of the gas gravity, reservoir temperature and pressure and the pipeline pressure.

Petroleum Information Inc. (PI) tracks data on all petroleum-related wells in the United States. Their commercially available database includes gas gravity and reservoir pressure data for all wells in this field. We extract this information from PI and merge it into the SAS TOPS file. We then estimate the temperature gradient from maximum-recording thermometers on the wireline tools.

Using PROC G3GRID and PROC GCONTOUR, we make maps of gas gravity and the pressure and temperature gradients. We merge these maps with the SURFACES file and compute reservoir pressure and temperature in each grid cell from reservoir depth and the pressure and temperature gradient. Then, using an iterative algorithm, we calculate a recovery factor for each grid cell that accounts for the gas expansion at the surface and the gas left behind due to pipeline pressure. This takes 14 CPU minutes for all 25 fault blocks.

Compute total gas volume

By merging all the above maps with the SURFACES file, we can easily calculate the gas volume in each grid cell for each of the 5 reservoir zones using:

$$\text{Volume} = \text{Thickness} * \text{Porosity} * \text{Gas Saturation} * \\ \text{Recovery Factor} * \text{Grid Cell Area}$$

To compute the total fault block volume we simply add

up the gas in each grid cell for all five zones. This SAS program takes 4 CPU minutes for all 5 zones and 25 fault blocks.

Subtract volume already produced

Many of the fault blocks we mapped already had wells drilled in them. Most of these wells have been producing gas for 10 or more years and will continue to produce gas for several more years. We need to know the volume of gas remaining in the fault block after these wells are depleted. If enough gas remains, we can justify drilling a new well to recover the remaining reserves.

We use PI data to track a well's production rate over time. These wells typically show an exponential decline late in their productive life. We extrapolate this decline to the economic limit to estimate the volume of gas the well will ultimately recover. This ultimate recovery is then subtracted from the total fault block volume.

Check results and iterate

In several cases, we found that a well's ultimate recovery was much greater than the calculated fault block volume. This suggests that the calculated volume is incorrect since a well in a fault block cannot produce more than the fault block volume. Therefore, we changed the log analysis method and more carefully determined the log analysis constants. After hundreds of iterations, we reached a point where the calculated volume was greater than the well recovery in all fault blocks. Given this improved volume estimate, several fault blocks had sufficient remaining gas reserves to justify drilling nine wells in 1992. We expect that all these wells will recover sufficient gas volumes to be economic successes.

It is important to note that we were able to carry out this analysis because we had complete control of and access to the data in SAS format. This common data format allowed us to easily integrate seismic, well log, engineering and production data in new way. The intermediate results told us we needed to change the log analysis method and constants. We probably would have never discovered the problem without being able to relate these diverse data types using SAS.

The rich set of SAS tools and procedures allowed me, a casual SAS user, to easily write the SAS applications that were necessary to solve this fairly complicated problem. Adding new data analysis methods, testing parameter sensitivity and displaying results is part of any scientific study, including this one. All this was made easy using SAS software.

CONCLUSIONS

We use SAS software to integrate the diverse data types needed to develop a gas field in the Gulf Coast. The flexibility of the SAS INPUT statement alone allows us to read the dozens of data formats associated with geologic, geophysical and engineering data. Once these data are in SAS format, we wrote SAS code to easily relate one set of data to another in ways not available from in-house or vendor software.

In the largest application, we used SAS to compute the volume of gas in reservoirs defined by 3D seismic data. We extracted reservoir properties from well data stored in SAS format. Previous production data was extracted from a commercial database. Because we had easy access to all necessary data, we discovered a problem with the standard log analysis method. After fixing the problem, we had more drilling opportunities than previously realized and therefore drilled nine wells using these results. We are confident that all nine wells will recover sufficient gas to be economic successes.

ACKNOWLEDGEMENTS

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APPENDIX

Other SAS utilities

We wrote dozens of SAS utilities beyond those needed for determining fault block volumes. We can group most of these into data reformatting, quality control and analysis. This list gives a brief description of a few of the utilities:

Reformatting

- Well tops from SAS to seismic workstation
- Wellbore deviation from SAS to seismic workstation
- Various well log formats to SAS
- SPOT satellite image to seismic workstation
- Real-world to local seismic coordinates

Quality Control

- Well log data checked for calibration errors
- Reported rig elevation checked for errors

Analysis

- Generating synthetic seismograms
- Identifying 'missed' pay in well logs

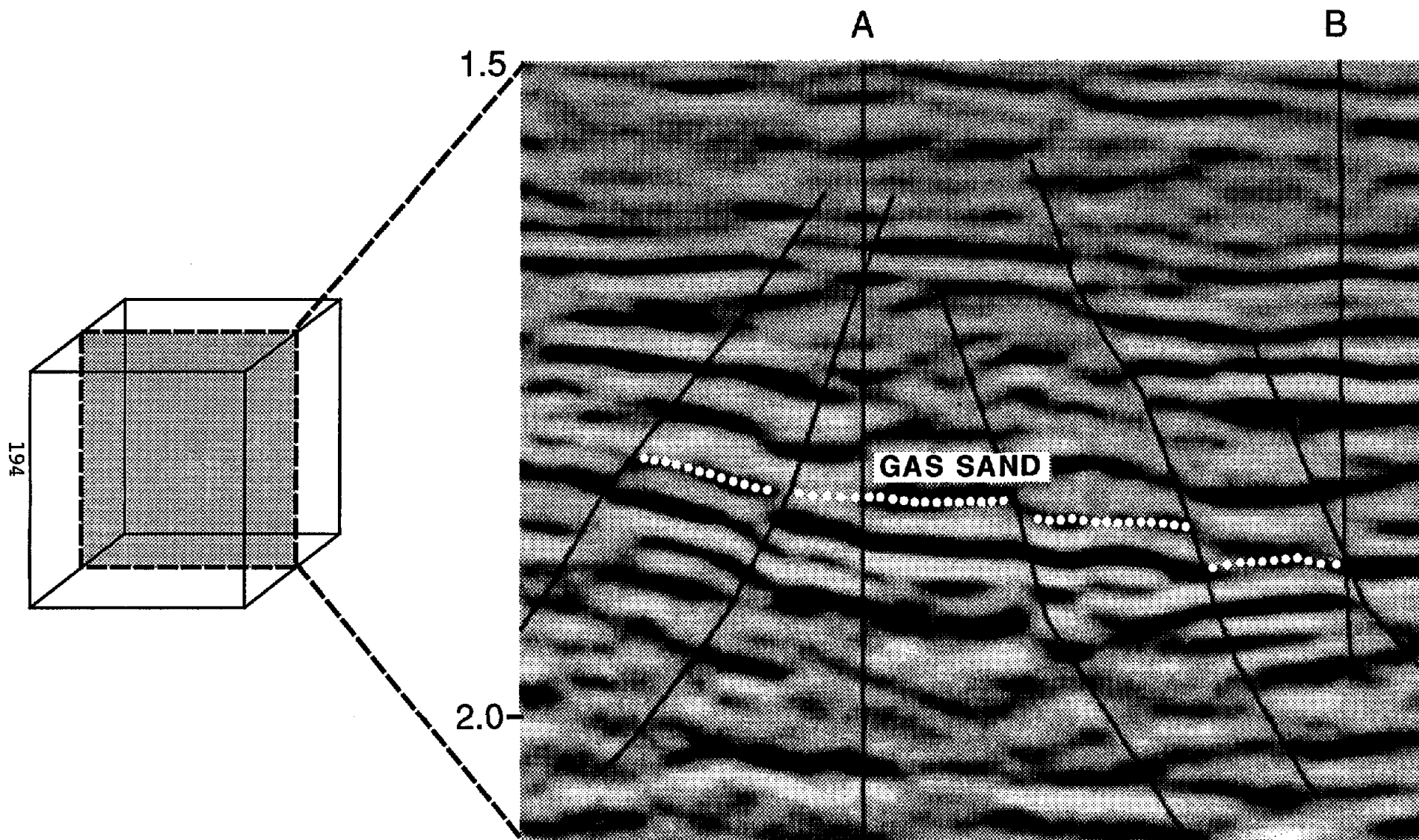


Fig. 1. Seismic line from the 3D cube of seismic data. This is like a vertical cross section of the earth with the 'fuzzy' horizontal areas representing echoes from different rock layers. The dots are at the top of the gas reservoir zone. The line also shows our interpreted position of five faults that segment the reservoir into fault blocks. Wells A and B both encountered the gas sand. Compare this to Figure 2, a map showing the areal extent of the individual fault blocks.

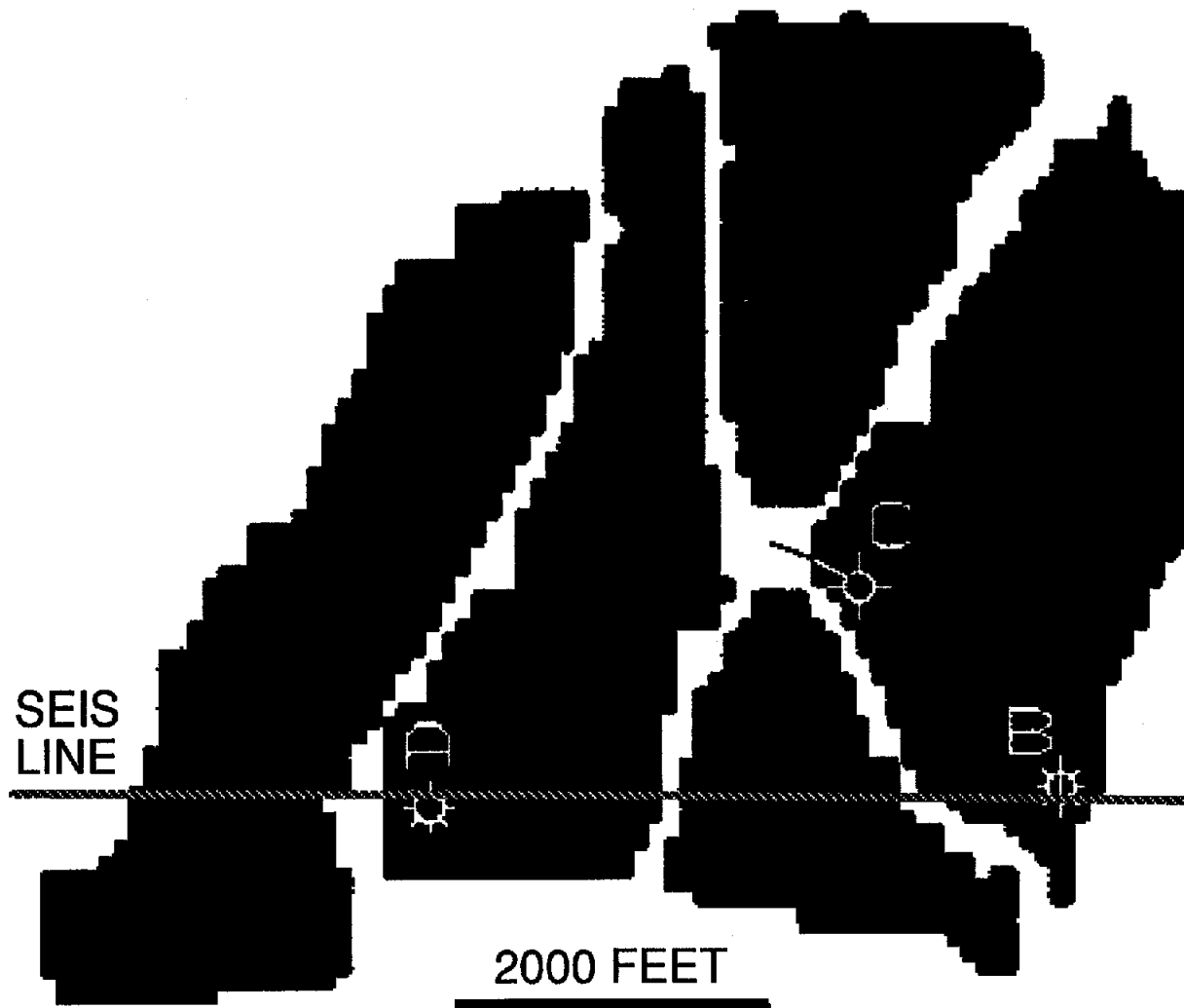


Fig. 2. Map showing the areal extent of five fault blocks made by interpreting the 3D seismic data. Compare this map view to Figure 1, which is a vertical view along the dotted line. Wells A and B encountered the reservoir but well C missed it because it drifted west and found the fault gap separating four fault blocks. The location and reservoir depth for each grid cell in the fault block are stored in the SAS SURFACES file.

$$\text{TANK VOLUME} = \underbrace{\text{AREA}}_{\text{SEISMIC DATA}} \times \underbrace{H \times \% \text{ OF ROCK CONTAINING GAS}}_{\text{WELL LOG DATA}}$$

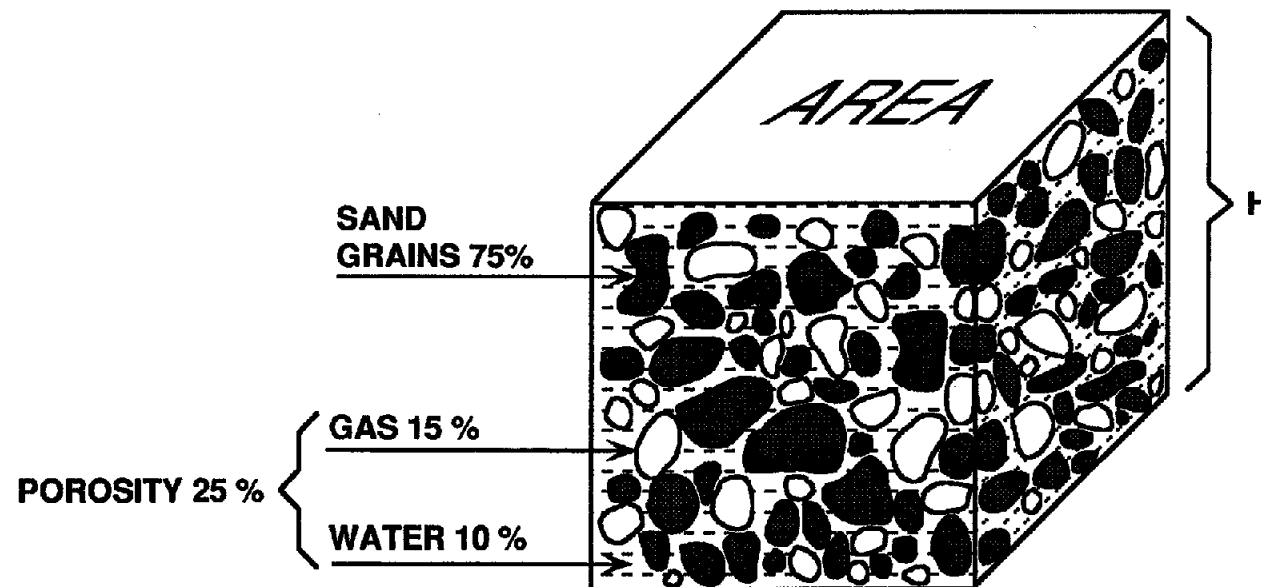


Fig. 3. Diagrammatic representation of what makes up a rock and how it relates to calculating gas volume. The seismic data provides the area of the fault block as shown in Figures 1 and 2. The well log data gives the thickness, *H*, and the percentage of rock that contains gas as shown in Figure 4.

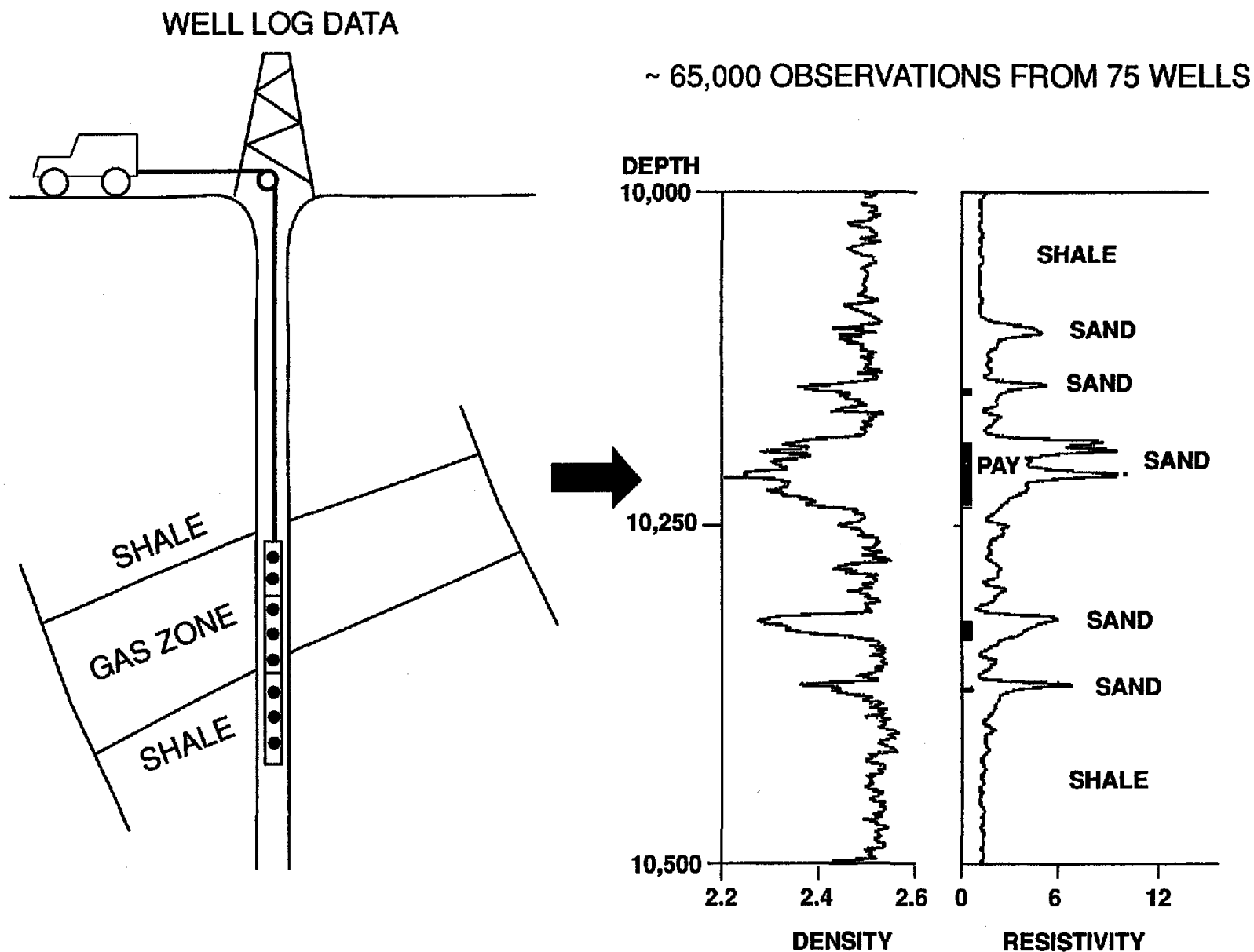


Fig. 4. Example of a resistivity and density log from a well. Every foot of well log data bracketing the reservoir in 75 wells is stored in the SAS WELLLOG file. The pay zone thickness, gas saturation and porosity is determined by log analysis software written in SAS. The top and base of each sand that is a potential reservoir is stored in the SAS TOPS file.