# Synthetic Helps Spot the Target

*(Editor's note: The Geophysical Corner is a regular column in the EXPLORER and is produced by the AAPG Geophysical Committee. This month's column is the first of a two-part series on using synthetic seismograms in exploration: why and how.)*

By THOMAS E. EWING

Okay, so you have a prospect and some 2-D or 3-D seismic data. How do you identify your target level on the seismic data?

If you have a "bright spot" play you might guess by observation. If you have no wells, you have to guess. But a lot of dry holes result from guessing wrong – even on 3-D seismic data!

What you need is a way to tie depth-based log data from key wells into time-based seismic data. In other words, you need a time-depth chart, or a velocity function (since depth = velocity x time).

There are three ways to do this.

❒ Stacking Velocities derived from seismic data provide the poorest time-depth control. There are several reasons for this, such as the processors' need to avoid multiples and the limited offsets of real seismic data.

Stacking velocities are essential in frontier plays where other data don't exist.

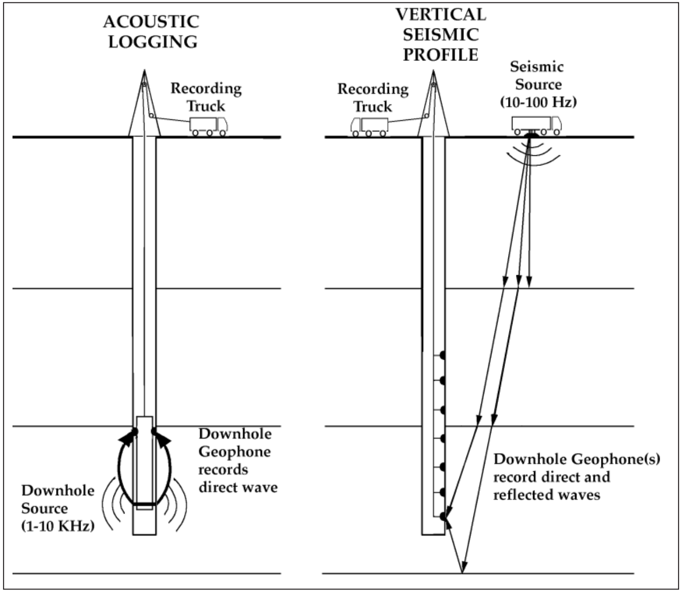


Figure 1. Configuration of a Velocity Survey or VSP.

❒ Velocity Surveys and Vertical Seismic Profiles (VSP) give the best velocity control. They use a surface source and geophones downhole (Figure 1).

The checkshot uses "first breaks" (first reception of energy downhole after the shot), while the VSP analyses the full sonic waveform over more closely-spaced geophone positions.

If the first breaks are detectable, compression wave (P-wave) time vs. depth is determined as accurately as possible.

❒ Synthetic Seismograms derived from well data are a widely useful way to tie seismic time to log depth (Figure 2).

Visual matching of seismic and the synthetic can reliably identify the sought-after reflector. Also, the synthetic shows how the detailed waveform and amplitude of the reflectors near the target are generated from the lithology. The interpreter can modify the logs to see what a hydrocarbon reservoir would look like if present. All it takes is a sonic and density log from a well of interest.

On the minus side, synthetics do not give you an absolute time-depth equivalence; and the synthetic may be a poor match for the real data.

Synthetics may be used with a velocity survey to give best possible time-depth values together with information on reflection character.

**Basics of the Synthetic Seismogram**

In creating a synthetic seismogram you are trying to simulate seismic data acquisition in your computer.

The *unknown* physical properties of

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the earth beneath a seismic survey are *known* properties at a wellbore – P-wave acoustic velocity and bulk density.

So how do we acquire seismic data?

At the simplest, a seismic compressional wave (P-wave) is generated with a surface source. The wave travels at the acoustic velocity of the rock, which varies with lithology. The wave bounces off surfaces across which the impedance – the product of velocity and density – varies.

We measure the strength of the reflection with a reflection coefficient, which is the difference in impedance over the sum of the impedances. The wave then returns to the surface, where geophones detect the P-waves returning vertically.

The time from generation of energy to its recovery at a geophone is the **travel time**, and depends on the velocities of the units traversed. The amplitude of the recovered energy is governed by the **contrasts in velocity and density** across the interfaces.

We record all the various geophone groups, process the data, and generate an output section. Then the interpreter tries to identify target reflectors in time, analyze the seismic response to geology and fluids, convert to depth, and drill.

In other words, we send a source wave through a velocity field and a series of reflectors which yield seismic data, or:

See **Geophysical Corner**, page 17

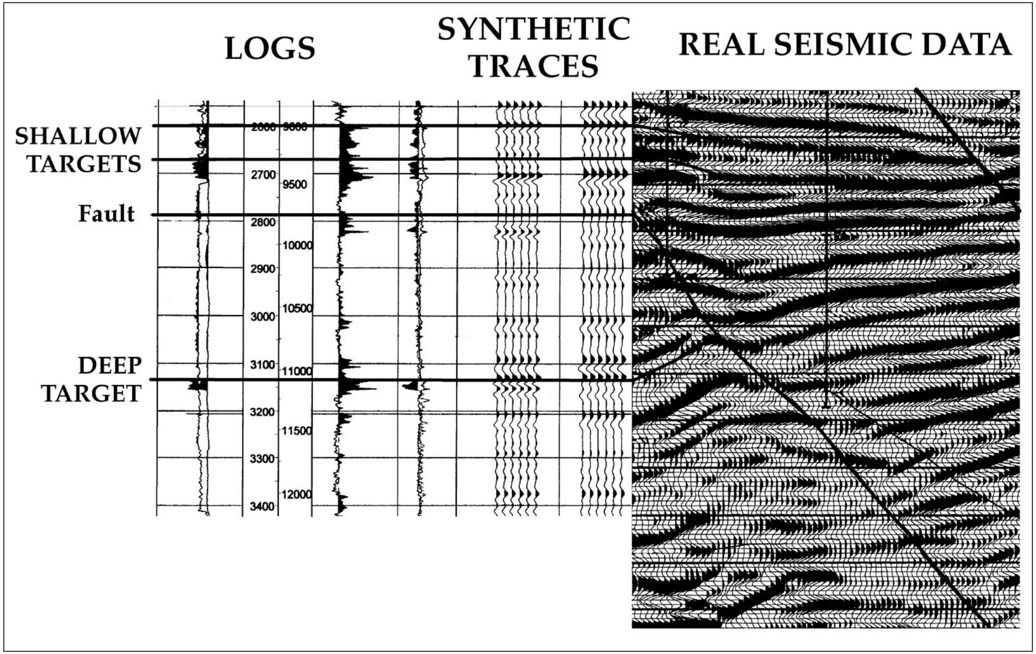
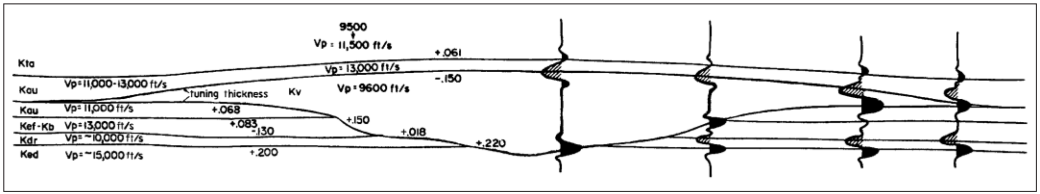



Figure 2. Synthetic Seismograms

Figure 3. A 2-D envelope model of a volcanic tuff mound; from Ewing and Caran (1982).



# Geophysical Corner

from page 15

(Source Wave)*(Velocity Field)*(Reflection Series) = Data.

Geology and hydrocarbons control both velocities and reflections. We want to resolve the reflection series using the data, knowing the source wave and estimating the velocity field:

(Reflection Series) = Data 8 (Source Wave)*(Velocity Field)

This is an "Inverse Problem." There are direct and useful ways to do this (called "seismic inversion"), if you know the phase of you data, and can add back the very low-frequency components of velocity and density that are not captured in seismic data.

One of the simplest ways to work the inverse problem is to take sonic velocity and density data from wells, run the seismic experiment with the sonic-derived velocity field and the sonic- and density-derived reflection series, assume a source wave similar to your seismic data and compare the result to the data.

Or the well data can be varied to match what might exist away from the wellbore, but within the seismic survey. This can be done before the survey is acquired, to answer a question like: "Is a likely target visible?"

**Doing Synthetics**

A simple synthetic can be made on the back of an envelope, if there are only two or three reflections and great accuracy isn't desired. Useful models can be done this way (for example, Ewing and Caran 1982; Figure 3 on page 15). But for quantitative work on well logs, and to get synthetics to match real data, you need software.

Several good programs exist for synthetic generation – either stand alone or as a part of a seismic interpretation package. Input log data come from digital files (LAS or LIS), from digitized logs or from files produced by someone else's digitization.

Output can be to an inexpensive printer, or to a SEG-Y file that feeds directly into a workstation. One can even hire out the process, send a paper log out and get a synthetic back; but this process isn't interactive and won't get the most out of the data.

Here is a flowchart suggestion for generating synthetics and tying them to real seismic data:

1. Input sonic and density logs, and other log curves as needed for correlation.

2. In your synthetic generation program, run a Frequency Scan, which calculates traces with a range of frequency filters. The first trace should include high frequencies, to show the best possible time resolution of events. The other traces cut off at lower frequencies, and bracket the actual frequency of your data at the target depth.

Compare to real data, and select the best frequency filter. If the real data has automatic gain control (AGC) and AGC window can be applied.

3. Run a Phase Scan. This set of traces should include zero, 90°, 180° (reversed polarity), 270° and minimum phase. Compare to real data, and select the best phase.

Most airgun or dynamite data is minimum phase; most vibrator data is either zero or 90° phase.

4. Tie data and synthetic and identify reflectors. Since log curves don't start at the surface, you can expect a few hundred milliseconds of mistie.

You can calculate the time delay vs. the depth to the top of the synthetic for a given correlation, and see if the resulting velocity makes sense – or compare to a nearby velocity survey.

Most programs allow you to enter time-depth pairs from a survey, and will stretch or squeeze the synthetic to fit. This should give a fairly close match to the real data; pay attention to the datums of the synthetic and the seismic.

The process of generating synthetics and calibrating them to real seismic data is as much an art as a science!

*(Editor's note: Ewing is with Venus Exploration in San Antonio.)*

continued from previous page

and chaos in our personal lives, our career and our organizations.

It is crucial that we set goals and stay focused – that we decide what we want to create and then pursue it with great energy and commitment.

If things get too comfortable, too organized, too rigid we will lose the creative competitive edge. If it slides toward undisciplined self-interest, nothing will get done.

We must join with and support leadership to realize a mutually developed and mutually held vision of success for the future.

Living in transition is not easy, but it may prove to be highly stimulating and productive. It is a new set of circumstances with new rules that have yet to be codified.

Don't go hide in a cave with a candle waiting for order to be restored. Seek the opportunities that abound in this "new reality."

*(Editor's note: Wantland, a geologist and AAPG member, is a writer, speaker and seminar leader on career development of petroleum professionals and on building creative environments.)*

# Real Answers for Synthetic Issues

*(Editor's note: The Geophysical Corner is a regular column in the Explorer and is produced by the AAPG Geophysical Committee. This month's column is the second of a two-part series on using synthetic seismograms in exploration.)*

By THOMAS E. EWING

Part I of this series (in the July EXPLORER) went through the theory of synthetic seismograms and one way to make and calibrate them. This month is a look at some problems, some compromises for inadequate log data, and extra added features such as AVO and modeling routines.

## Problems

My synthetic won't tie!!! The most common problem. Variants include:

❒ Reflectors seem to come in at the wrong times.

I can't tell which reflector corresponds to my target. Velocity problems are the main suspect. Synthetics usually need to be stretched or squeezed to fit data. This is usually because of an inadequate measurement of the velocities in the wellbore. Why does this happen?

✔ The hole is washed out; the sonic log fails to read true formation velocities. There may be cycle skips (which can be edited out). The log "noisiness" may be different for Long-Spaced Sonic vs. old-fashioned sonic logs.

✔ The formations are anisotropic. In real seismic, the energy doesn't travel purely vertically, but has a horizontal component which increases at far offsets. If the velocity of a formation depends on the direction of propagation, the rock is anisotropic, the far-offset seismic waves won't travel the same as those in a (vertical) borehole.

✔ There are dispersion effects. Sonic data in wells are acquired at kilohertz frequencies, while seismic waves are usually less than 120 Hz. If velocity varies with frequency, that's dispersion.

The best solution to the problem is to use checkshot information; that's why we run them!

Vertical Seismic Profile (VSP) surveys are super-checkshots. VSPs also give you a direct look at the near-wellbore reflectors at the frequency band of real seismic; use'em if you have'em.

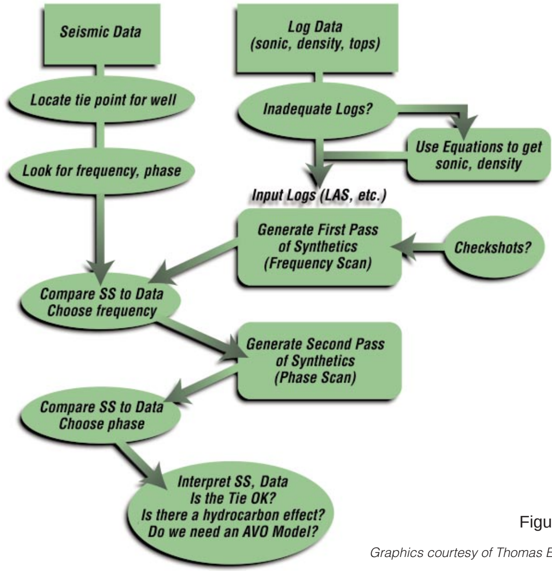



Figure 1

*Graphics courtesy of Thomas Ewing*

❒ The wiggles look different.

Try adjusting the frequency and phase content of the wavelet used to create the synthetic. Try minimum phase to match dynamite or airgun data, and zero or 90-degree phase for vibrators. Look at the final bandpass filters on the header (or do a spectral analysis of your data on your workstation).

Compare synthetic to VSP data, if available. Synthetics are an interactive process.

❒ I have extra reflections on the real data.

Real data may contain "multiple energy," due to multiple bounces between reflectors within the earth or bounces off the surface interface. Multiples are usually very weak, because the stacking of modern, high-

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fold data discriminates against them. But if the data is low-fold; the target is very deep; or the velocity profile varies significantly, multiples may be found in final sections.

Most synthetic programs allow you to turn multiples on or off. Off is usually preferable, but it is simple to compare the two cases.

❒ The wiggles are a lot stronger on the real data than on synthetics, especially at depth.

If the real data is generally strong at depth, the real data may have had an Automatic Gain Control (AGC) filter; check the header. The synthetic seismogram can be run with the same AGC filter.

However, if only one or two reflectors are a lot stronger, this could be an Amplitude vs. Offset (AVO) effect, due to an anomalous amplitude in the far-offset seismic traces.

(The Amplitude vs. Offset technology will be discussed in more detail in a later article. These amplitudes are due to shear-wave generation at an interface by non-orthogonal traces. Simple synthetic seismograms assume vertical incidence, "zero-offset", so AVO effects are not dealt with.)

Also, there is usually a considerable difference between the synthetic and the real data due to sampling area. The well-based data sample a cylinder less than a meter in radius from the well. By contrast, a properly-migrated 3-D seismic trace may sample an area some 10 meters in radius, and the sampling zone in 2-D data could be hundreds of meters in width perpendicular to the line. Sonic and density properties may vary considerably.

VSP data is a major help here, since it samples the earth at a scale closer to that of real seismic data.

**Compromises: Fabricating Log Data**

Proper synthetics use sonic and density data – but often we only have one or the other, or perhaps only a resistivity curve.

Can we use these wells?

Yes – sometimes!

Statistical relations exist between velocity, density and resistivity. These vary by area and by rock type. The two general forms are: the Gardner equation, relating density and velocity; and the Faust equation, relating resistivity and velocity. The effects of these techniques are shown in Figure 2.

If you have sonic and no density, synthetics can generally be run as usual. The time relationships between horizons will be accurate, since time is based solely on velocity; but the reflector amplitude will not be completely accurate, since that is based on impedance (velocity times density).

If you have density but no sonic, an inverse Gardner relationship should be used. Not all software has this built-in.

(Many wells these days come with only a density/porosity curve, not a bulk density. The porosity curve can be used if you know the mud type; see the log interpretation manuals.)

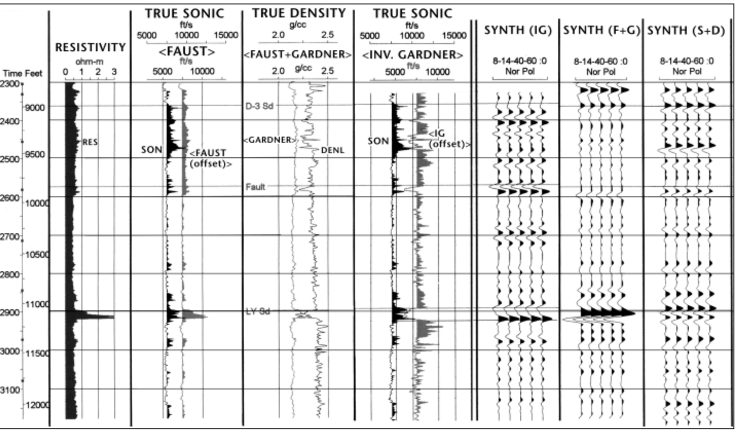
If you have only resistivity, then you have to use Faust's equation (Figure 2).

Resistivity-generated sonic data usually need extensive stretching and squeezing to be valid. This requires a good velocity function, preferably a trusted velocity survey.

In some areas resistivity will be a poor substitute – but it may be all you

See **Geophysics**, next page

Figure 2: Comparison of three synthetic seismograms for a deep Yegua well. The left-hand panels show the comparison of true sonic and density and the logs calculated using Faust, Gardner and Inverse Gardner (IG). All logs and synthetics are displayed in time and are corrected by velocity survey (the uncorrected IG-sonic was considerably too high). The deep, porous gas sandstone depresses density but not sonic, leading to errors using IG.



have in some areas.

For best results, you should take those wells in your project area with good log suites and do crossplots of velocity, density and resistivity in order to determine your own coefficients for the two relationships.

(Neither relationship handles gas-bearing sandstone very well, nor will they handle evaporites, unless you identify them specifically and handle them separately.)

**Extras**

First, you also can also generate synthetics that incorporate AVO effects.

These effects are very useful, even critical in many trends for identifying gas-bearing reservoirs or favorable lithologies. The AVO response of an interface is sensitive to the ratio of compressional-wave (P-wave) to shear-wave (S-wave) velocity. Therefore, in order to generate an AVO model, you need S-wave velocities as well as P-wave velocities.

The shear velocities come from either a full-waveform sonic log in fast rocks, or a dipole sonic log in slow formations. If no shear information is available, lithology estimates allow an estimation of Vp/Vs, but this is not as good.

If you do run dipole or full-waveform sonic logs in any well, you should go ahead and look at the AVO synthetic. You might be surprised!

Second, if you do a series of synthetics in which you vary density and velocity to simulate a geologic or fluid change, you are creating a 2-D model. A set of varying synthetics stitches together along a traverse approximate a migrated seismic section, but includes no raypath-dependent effects.

Such models are quick, and very useful for understanding the seismic response to geologic changes. There is software available for this in many synthetic packages.

However, if dips or lateral velocity changes are substantial, or if amplitudes are important, then you need a raytracing algorithm. These raytracing modelers create a synthetic migrated section, but include shadowing effects due to the bending of raypaths.

More on all of this later.

*(Editor's note: Ewing is with Venus Exploration in San Antonio.)*