Notes related to PETROLEUM RESERVES EVALUATION

<u>Articles from</u>:

IS IT TIME TO DEVELOP A CERTIFICATION PROGRAM FOR PETROLEUM RESERVES EVALUATORS?

By
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For nearly two years now there has been a lot of publicity regarding internal problems in energy companies, reserves writedowns and concerns about the reliability of reserves disclosures. From the view of oil and gas companies and their investors, to Wall Street and the SEC, reserves are a major factor in the valuation of energy companies. From evaluating fields to buy, to determining whether or not to participate in a certain prospect; from estimating reserves of a new discovery, to determining the proved reserves for a company, the bottom line is how much oil or gas can be placed on the books and produced with an acceptable return on investment.

In the post-Enron environment, the recent reserves writedowns and the passing of the Sarbanes-Oxley Act by Congress in 2002, not to mention investor confidence in our oil and gas industry, the SEC is aggressively examining oil and gas reserves reporting. Some companies have revised reports. There are many challenges in reporting reserves such as which set of definitions to use for specific reserves reports, proved undeveloped reserves, probable reserves, and pricing. In addition there is lots of talk in our industry about the possibility of establishing a program for the certification of both petroleum geoscience and engineering reserves evaluators.

The Energy Forum's Reserves 2004 Series has been primarily dedicated to facilitating discussion and debate on the subject of reserves and the impact of the Sarbanes-Oxley Act and other corporate responsibility laws.

In July of this year, the US House Committee on Financial Services held a hearing in Washington called, "Hearings - Shell Games: Corporate Governance and Accounting for Oil and Gas Reserves". Congressman Michael G. Oxley of Ohio (one of the sponsors of the Sarbanes-Oxley Act) is the Chairman of this House Committee. The Committee oversees the entire financial services industry, including the securities, insurance, banking, and housing industries. The Committee also oversees the work of the Federal Reserve, the Treasury, the SEC, and other financial services regulators.

At the hearings, Dr. Bala G. Dharan, the J. Howard Creekmore Professor of Accounting at Rice University, testified before the US House Committee. He stated, "Having useful and reliable information on oil and gas reserves is enormously important to the US policy makers, managers of the companies, investors and the public. Over 150 publicly owned oil and gas producers file reserve data in their 10-K and their reported total reserves is valued at over $3 Trillion." On a worldwide basis, reserves are estimated to have a value of over $600 Trillion. That's a lot of oil and gas!

Dr. Dharan's testimony agrees with a report published by Lehman Brothers in 2003. They indicate that the value of E&P companies is determined largely by their reserves and production. Therefore, one can conclude that "reserves" is one of the primary factors used to determine a company's total market value. Dr. Dharan cited such industry associations as the AAPG, SPEE and SPE as strong and well-functioning groups that could develop and implement certification program for reserves evaluators.

Whether you wish to invest in an exploratory prospect, purchase a producing field or determine the value of a company, the major factor is the reserves, whether they are classified as proved, probable or possible. It is vital to private and public oil and gas companies, and governments to have reliable reserves estimates.

The importance and reliability of oil and gas reserves and the potential intervention by government in the determination of reserves estimates and disclosure are two primary reasons why a number of industry leaders are recommending the investigation into the possible establishment of a certification program for geoscience and engineering reserves evaluators. The idea centers around the possibility of a joint industry associations program to certify geoscientists and engineers in the practice of reserves estimates and evaluations. Such a program could establish better standards, define recommended geoscience and engineering practices and provide ethics training.

WHAT ARE THE MERITS OF CERTIFICATION?

In general terms, certification may provide a valuable process that allows our industry to demonstrate, that we, have the competencies, as professionals, to accurately estimate and validate oil and gas reserves. Certain oil and gas companies already have internal certified reserves evaluators from both the geoscience and engineering disciplines, while others do not. Since certification should be an entirely voluntary program, people and companies can choose to join or not.

Companies may see a distinct advantage to participate in this program to ensure that their employees have the required training in methods, definitions, standards and ethics regarding reserves estimation and disclosure. For individuals the program may provide needed training, develop a clearer understanding of reserves definitions, develop additional technical skills and brush up on the ethics component from both a domestic U.S., as well as global perspective. Finally, individuals can obtain an industry-wide certification recognized by well established associations and hopefully in the future by state and federal agencies as well.

Certification will acknowledge that a geoscientist or engineer has successfully completed a training program, passed a required test in his or her respective technical area and meets the qualifications established by the industry's respected professional organizations. In addition, annual continuing education will keep the certified evaluator updated on reserves law changes, definitions changes and new techniques applicable to reserves determinations.

SCA is involved in a lot of reserves evaluation work from exploration prospects, to field acquisitions, to company audits. During our 15 plus years in the consultancy business, I must state that most of the problems we see with reserves estimates are NOT the result of fraudulent activities. Errors in the estimates of reserves, up or down, often are the result of a lack of knowledge of reserves definitions, lack of standards, limited training in the proper geoscience and engineering technical methods and techniques required to generate sound reserve estimates and/or careless work resulting from an overload of work and/or limited time.

If you have time, review our Fall and Winter 2003 geoLOGIC Technical Newsletters at http://www.scacompanies.com... These articles cover two geologic areas important for determining accurate reserves estimates. The reserves estimation process includes both the geoscience and engineering disciplines. Without good geology, accurate reserves cannot be determined.

With hearings being held by Congress and the question of whether or not the government should step in to regulate and determine how reserves estimates and evaluations are done, I believe that you will be hearing a lot of discussion on this subject in the coming months. Whether you are for certification or not, or undecided at this time, the topic is on the table and we as an industry must address the issue.

On September 29, 2004 the first meeting of a newly formed Intersociety Committee on the Certification of Petroleum Reserves Evaluators was held in Houston, Texas. This committee is sponsored by both the AAPG and the SPEE, with representation from the SPE as well. Their mission is to evaluate the merits of establishing a program for the Certification of Petroleum Reserves Evaluators. The committee has several subcommittees including: Certification, Definitions, Qualifications, Recommended Practices, and ethics. The committee has a management team composed of Daniel J. Tearpock representing the AAPG, Richard Miller representing the SPEE and Ron Harrell, At Large. The committee has a very distinguished list of members who provide the necessary expertise, experience and professionalism to effectively meet their mission goals.

Whether you wish to invest in an exploratory prospect, purchase a producing field or determine the value of a company, reserves is one of the single most important factors in the decision. With worldwide reserves valued at over $600 Trillion, it is vital that oil and gas companies and governments have reliable reserves estimates. A certification program for geoscience and engineering reserves evaluators may be a plausible solution for our energy industry to provide the evidence to government, that we as an industry, have the experience, expertise, ethics and professionalism necessary to provide accurate and reliable oil and gas reserves estimates and thereby being one step closer to self-regulation.

TOP OF STRUCTURE VERSUS TOP OF POROSITY

How does Top of Structure vs. Top of Porosity Impact you, your prospect and your volumetric?

Subsurface structure maps are drawn on specific stratigraphic units to depict the three-dimensional geometric shape of the geologic structures being mapped. Once the geometry of the structure has been determined, the primary effort is focused on the mapping of all hydrocarbon-bearing stratigraphic units.

At times, for various reasons, a structure map is prepared on a good seismic event or resistivity marker that is correlatable on seismic data or in all or most of the wells in a region or field, instead of mapping an actual hydrocarbon-bearing unit. In some cases this may be done because the hydrocarbon-bearing unit is discontinuous or has great vertical variation not reflecting the true shape of the structure. Therefore, it is necessary to prepare a structure contour map first on a stratigraphically equivalent marker in order to construct a map that conforms to the true structure of the field or region. This marker may be a few feet or several hundred feet above the actual hydrocarbon-bearing unit(s). Once the structural framework is prepared by contouring the data from the stratigraphically equivalent marker, a second map, called a Porosity Top Map, is required on the top of any hydrocarbon-bearing reservoir rock for the purpose of delineating the actual configuration and limits of the productive unit(s) (Fig. 1).

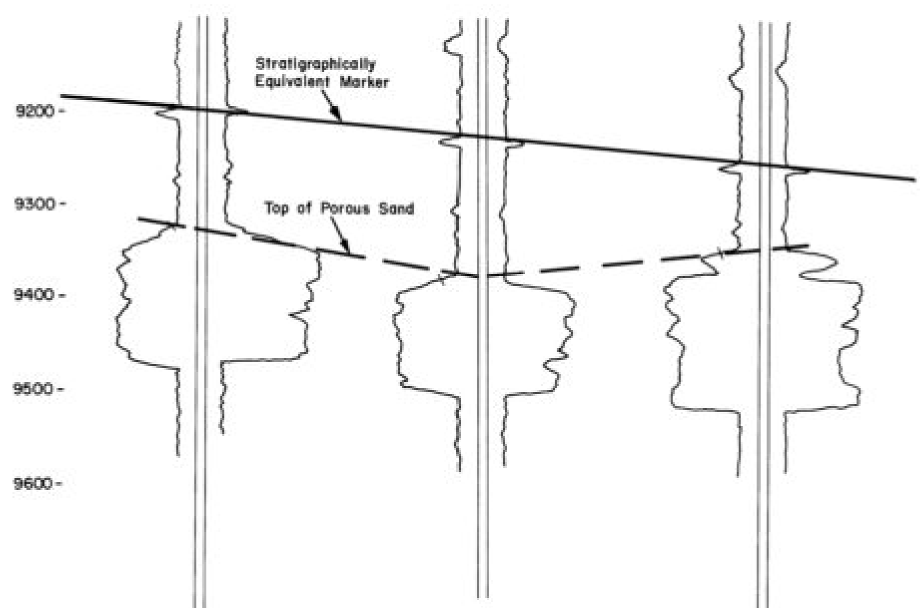


Figure 1

Figure 1 Electric logs from three wells. The upper stratigraphic marker conforms to true structure and is used to construct a map representing the true structural framework of the area. The top of the thick productive sand member does not conform to structure, but it represents a porosity top. It must be mapped separately to delineate the actual reservoir configuration.

It is also common for the upper portion of a particular stratigraphic unit to be composed of nonreservoir-quality rock. This nonreservoir-quality rock is often referred to as a tight zone or tight streak. Although the top of the unit may represent the actual stratigraphically-equivalent horizon, or the marker defined from seismic or well log data, it is underlain everywhere by impermeable, nonreservoir-quality rock. Therefore, the structure maps prepared to interpret the true structure commonly cannot be used to evaluate the reservoir itself.

Once a structure map is completed, the next step is to prepare a top of porosity map for accurate delineation of the reservoir, and for later use in the construction of net hydrocarbon isochore maps. Two parameters are considered in evaluating the importance of separately mapping the top of porosity: (1) the thickness of the zone between the correlative marker and the top of the reservoir unit, and (2) the relief of the structure. A thick zone has a greater effect than one that is thin. Low-relief structures introduce greater error in delineating the limits of a reservoir than steeply dipping structures, particularly if the low-relief structure contains a bottom water reservoir.

Figure 2a shows a structure map and cross section for the 6000-ft Reservoir. This unit consists of nonreservoir-quality rock in the upper 75 ft. The same reservoir is mapped on the top of the porous rock or porosity top in Fig. 2b. Notice in cross section A-A' that by mapping on the top of the unit, in which the upper 75 ft consists of nonreservoir quality rock, the limit of the reservoir (gas/water contact) is extended beyond the true gas/water contact as mapped on the top of porosity. Even though no net pay is assigned to the tight zone, the productive area of the reservoir mapped on the top of the non-productive portion of the unit is larger. In turn, the volume of the reservoir is also larger than that mapped on the porosity top. In this case, the volume, based on net gas isochore maps, is larger by 32 percent. This added reservoir area (Fig. 2c) created by mapping on the top of the stratigraphic unit does not contain hydrocarbons and therefore is not productive; consequently, the volume of recoverable hydrocarbons based on this map is overestimated.

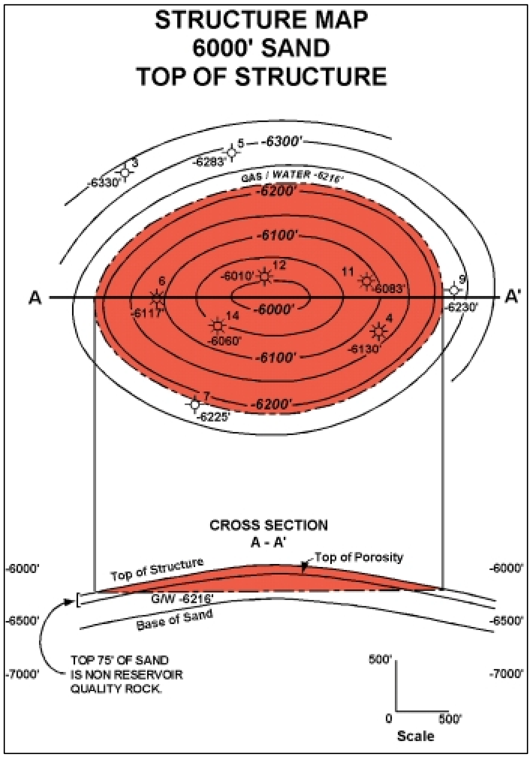


Figure 2 (a) Structure map on top of the 6000-ft Unit, with a gas/water contact at a depth of -6216 ft, and cross section illustrating (1) the top of the unit, (2) top of porosity, and (3) base of unit.

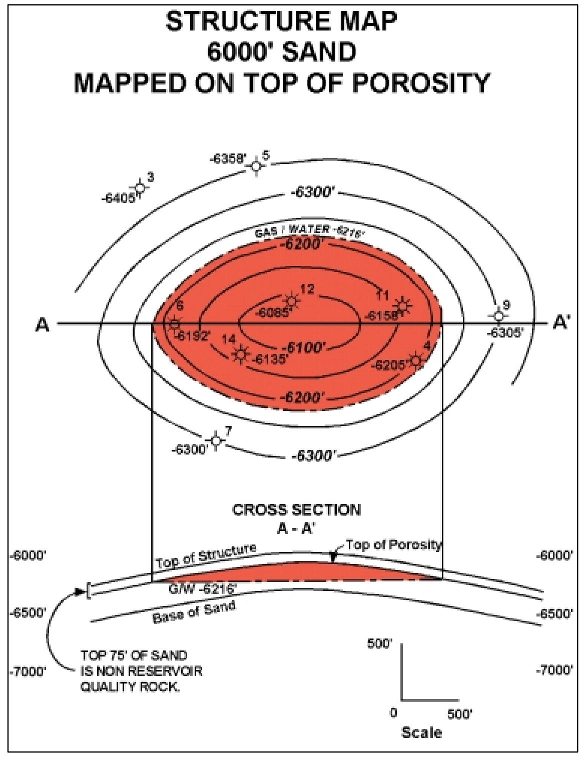


Figure 2 (b) Structure map on the top of porosity for the 6000-ft Unit, with the gas/water contact at a depth of -6216 ft, and cross section.

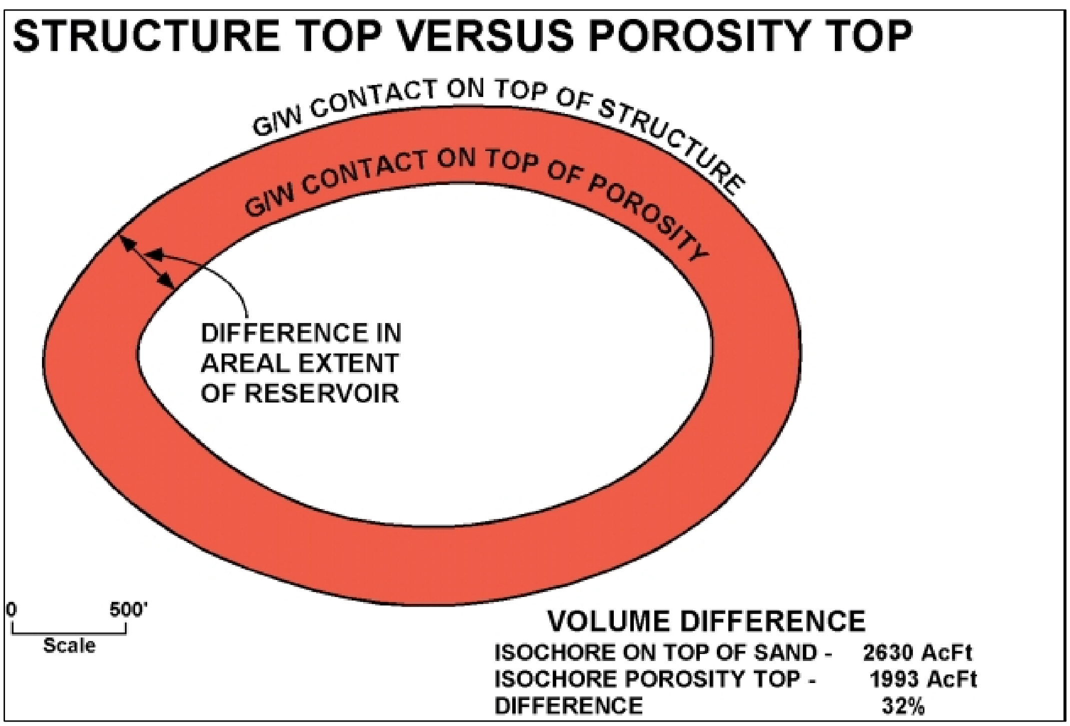


Figure 2 (c) Mapping on top of structure versus top of porosity results in a 32% increase in volume.

The decision to prepare a separate map on the top of porosity, where the upper portion of a unit is not productive or is a correlative marker above the actual reservoir, needs to be made on a reservoir-by-reservoir basis. Depending upon the geometry of the reservoir and thickness of the zone, the difference in volume between a map on the top of a correlative marker and a map on the top of porosity may be too insignificant to warrant additional mapping.

CONCLUSION

In the 2nd Edition of Tearpock and Bischke's Textbook (2002) entitled Applied Subsurface Geological Mapping with Structural Methods, the topic of Structure Top versus Porosity Top is addressed in some detail in both the Structure and Isochore chapters. In certain instances, prospect volumes have been shown to be in error by as much as 50 percent as a result of incorrectly mapping and calculating potential reserves on the top of a correlative structural unit rather than the top of porosity for the reservoir. Don't make this critical error in your next prospect or field evaluation.

THICKNESS DETERMINATIONS FOR VOLUMETRIC CALCULATIONS

INTRODUCTION

In our Fall, 2003 newsletter, we had a geologic quiz regarding a series of questions related to petroleum geology. One question centered around which thickness within a pay zone of an oil or gas reservoir is used for volumetric calculations. The actual question was, "When calculating hydrocarbon volumetrics for a given dipping reservoir, which of the following thickness parameters is used?" True Stratigraphic Thickness (TST), True Vertical Depth Thickness (TVDT), True Vertical Thickness (TVT) or Measured Log Thickness (MLT).

To our surprise only 10 percent of the people who responded to the quiz actually got this question correct. Because of these results, the winter quarterly technical newsletter will address these thickness calculations, as they are extremely critical in determining hydrocarbon volumes.

A geological situation containing dipping beds and directionally drilled wells, can be complex and confusing to understand. However, the understanding and application of the correct data can be vital to a new discovery or development of a mature field.

THICKNESS DETERMINATIONS FOR VOLUMETRIC CALCULATIONS

True vertical thickness (TVT) is the thickness of an interval measured in a vertical direction. It is this thickness that is required to accurately count net effective reservoir quality rock (e.g. sand). It is this thickness that is also used to construct net pay isochore maps for volumetric reserve calculations.

In a vertical well, the actual thickness measured on the electric log is the TVT. In the case of a directionally drilled well, however, a correction factor is often required to correct the exaggerated or diminished measured log thickness (MLT) due to the nature of the deviated wellbore.

For a horizontal reservoir (zero bed dip) the geology is simple; the thickness that is used for net reservoir quality rock or net pay isochore mapping equals the true stratigraphic thickness (TST) which in this case is also equal to TVT. However, if the same reservoir is rotated to some angle, such as 20 deg, the thickness of the reservoir required to determine net reservoir quality rock and for net pay isochore mapping does not any longer equal the true stratigraphic thickness.

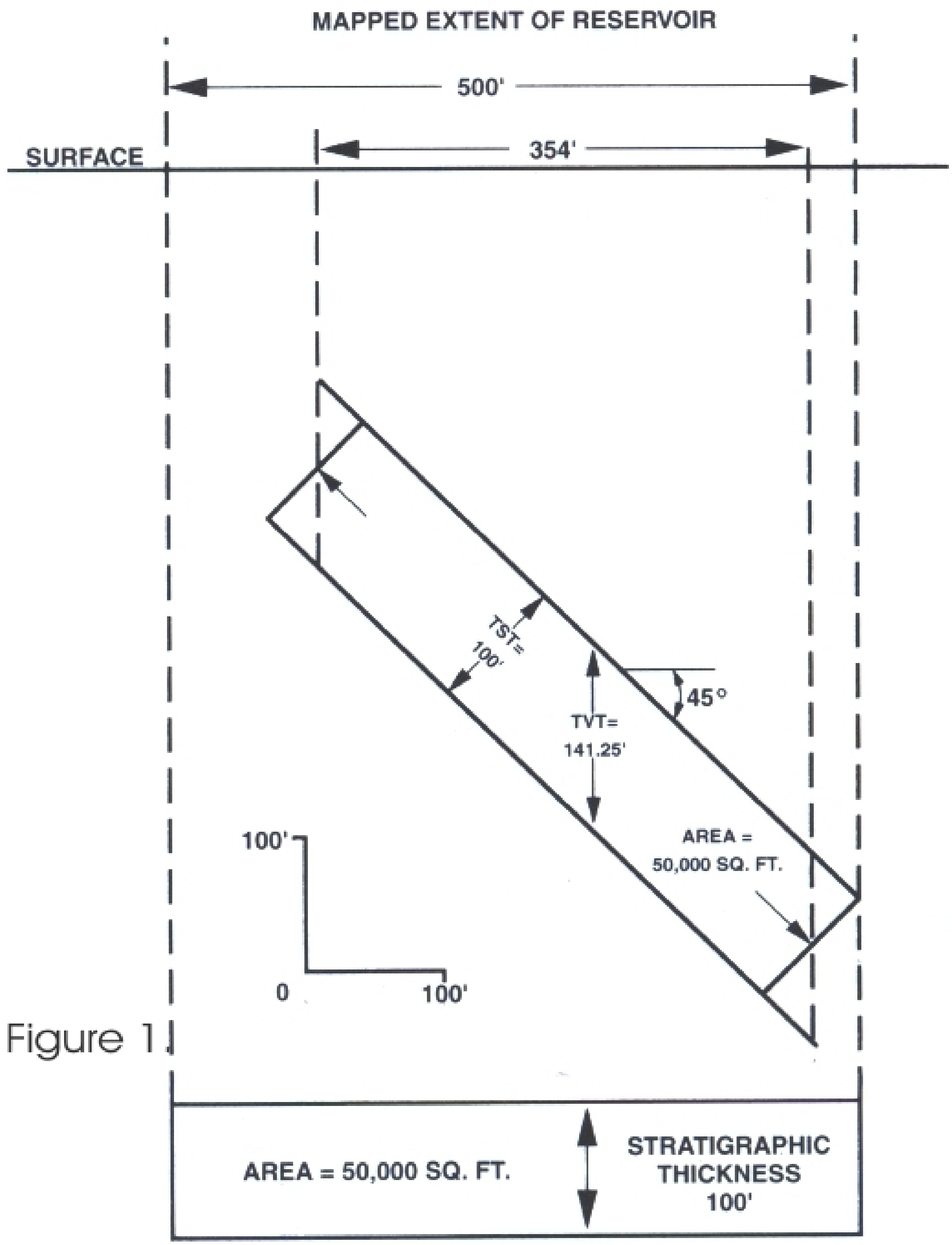


Figure 1

Figure 1 illustrates the cross-sectional area of a reservoir with a fixed width in the third dimension. We use the cross section to represent the volume of a reservoir. The horizontal reservoir (zero bed dip) in the lower portion of the figure has a cross-sectional area of 50,000 sq ft. The reservoir has a length of 500 ft, as seen in map view, and a thickness of 100 ft. Since the dip of the reservoir is zero, the TVT equals the TST (100 ft). If the same reservoir rotates to an angle of 45 deg, as shown in the upper portion of the figure, the length of the reservoir shortens to 354 ft in *map view*. The cross-sectional area of the reservoir has not changed, as the TST remains 100 ft. thick. In order to map the reservoir and maintain a cross-sectional area of 50,000 sq ft, the thickness used must exceed 100 ft. The TVT of the dipping reservoir measures 141.25 ft, and so 141.25 ft x 354 ft = 50,002.5 sq ft. From this example, you can see that as a reservoir of fixed length rotates from the horizontal, the *projected areal* extent of the reservoir decreases in map view. Therefore, in order to maintain the same cross-sectional area or volume of the reservoir, the shortened length must be multiplied by the TVT.

For directionally drilled wells the situation becomes more complex. The log thickness of a given stratigraphic interval can be thicker, equal to, or thinner than that seen in a vertical well drilled through the same stratigraphic section. A correction factor must be applied to the MLT in most deviated wells to convert the borehole thickness to TVT. The correction factor consists of two parts: (1) the correction for wellbore deviation angle within the interval of interest, and (2) the correction for bed dip. In the textbook "Applied Subsurface Mapping with Structural Methods"2nd edition (2002) several sections of the text address this important subject.

Equation 1 shown here is a 3D equation and is considered the preferred correction factor equation because this one equation can be used to calculate the thickness correction factor regardless of the direction of wellbore deviation, and the true dip of the beds is used instead of the apparent dip required in two-dimensional equations. We refer to this equation as Setchell's equation.

Equation 1: Setchell's equation

$$\mathbf{TVT = MLT\ [\cos\ \Psi - (\sin \Psi \cos \alpha \tan \Phi)]}$$

TVT =	True Vertical Thickness
MLT =	Measured Log Thickness
Ψ=	Wellbore deviation angle
Φ=	True bed dip
α=	Δ Azimuth (acute angle between the wellbore azimuth and the azimuth of true bed dip)

If the beds are horizontal, then Setchell's equation reduces to the simple correction factor Equation 2 which is equivalent to correcting for wellbore deviation only, yielding a True Vertical Depth (TVD) thickness.

Equation 2: TVT if beds are horizontal

$$\mathbf{TVT = MLT\ (\cos \Psi\ )}$$

Let's now consider two directionally drilled wells shown in Fig. 2 from Tearpock and Bischke 2002). Look first at the well drilled to the east in a down-dip direction (Fig. 2a). Consider the interval to be a reservoir filled with gas or oil. The well drilled in a down-dip direction has a MLT of 476 ft. which exceeds the TVT. We first apply the correction factor for wellbore deviation only, using Eq.(2). The MLT reduces to 357 ft, shown in the figure as the TVD thickness, or the **true vertical depth thickness (TVDT)**. This thickness also exceeds the TVT of the interval, because the correction for only wellbore deviation does not take into account the dip of the beds. The TVDT is that thickness of an interval obtained from a true vertical depth (TVD) log, and for dipping beds, TVDT does not equal TVT. With the final correction for bed dip, the MLT converts to a TVT of 150 ft, shown in Fig. 2a at the penetration point of the wellbore in the top of the reservoir. Note that the TST is 123 ft.

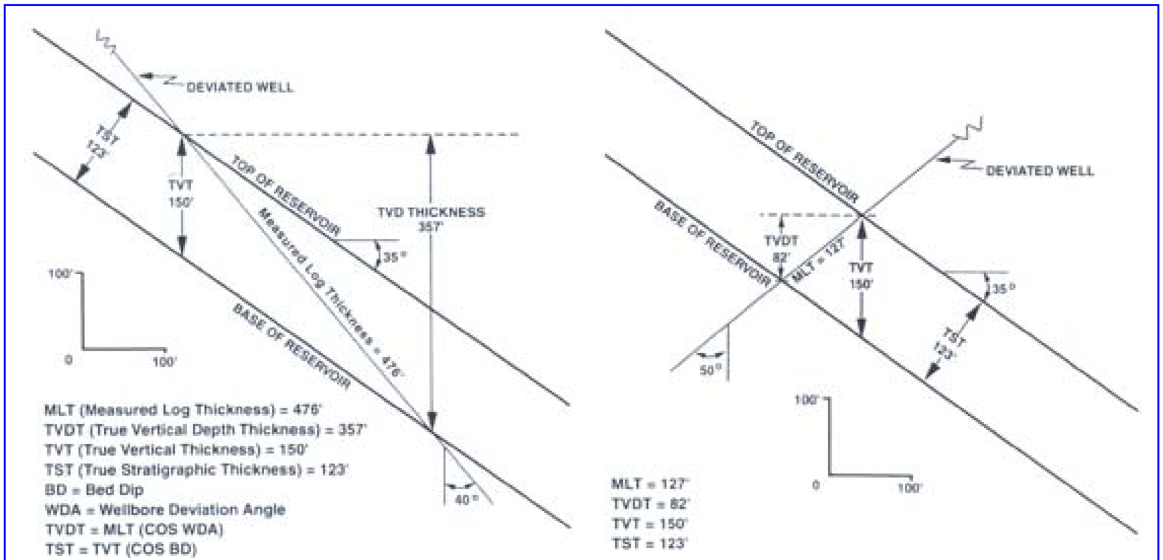


Figure 2

The TST can be calculated by multiplying the TVT by the cosine of the angle of bed dip (35 deg in this example). The TST cannot be used for volumetric calculations for dipping beds. It will underestimate the volumetric reserves.

The well in Fig. 2b deviates up-dip, to the west. The MLT for this well of 127 ft is now less than the TVT. Applying a correction factor for the well deviation angle alone, which is equivalent to the correction to TVDT, provides an even smaller thickness of 82 ft. When Eq.(1), the correction factor equation for both bed dip and wellbore deviation, is applied, the MLT converts to a TVT of 150 ft. This is the thickness needed for net sand and net pay mapping, as well as volumetric calculations.

Various computer programs can be used to create TVD, TVT, and TST logs from measured depth (MD) logs for use in mapping. The deviated well log data, the directional survey for the well, and bed dip information are necessary as input data. The log data are obtained from a logging company tapes or digitized from the actual log. The directional survey data can be furnished by the directional company that worked the well. The bed dip information can be obtained either from completed structure maps or from a dipmeter log. The output logs can be in standard presentation or at any scale desired.

We caution here that TVD logs, which are usually a standard part of the log suite for a deviated well, are too often used for purposes that are not applicable. A widespread misunderstanding exists, that a TVD log prepared from a MD log can be used to (1) correlate with other well logs, (2) determine the vertical separation for a fault, and (3) count net reservoir quality rock (e.g. sand) and prepare net pay isochore maps. **Remember, a TVD log is generated by correcting for wellbore deviation only, and not bed dip**. In areas of flat-lying beds, a TVD log is equivalent to a TVT log because the only correction factor is for wellbore deviation (Fig. 3).

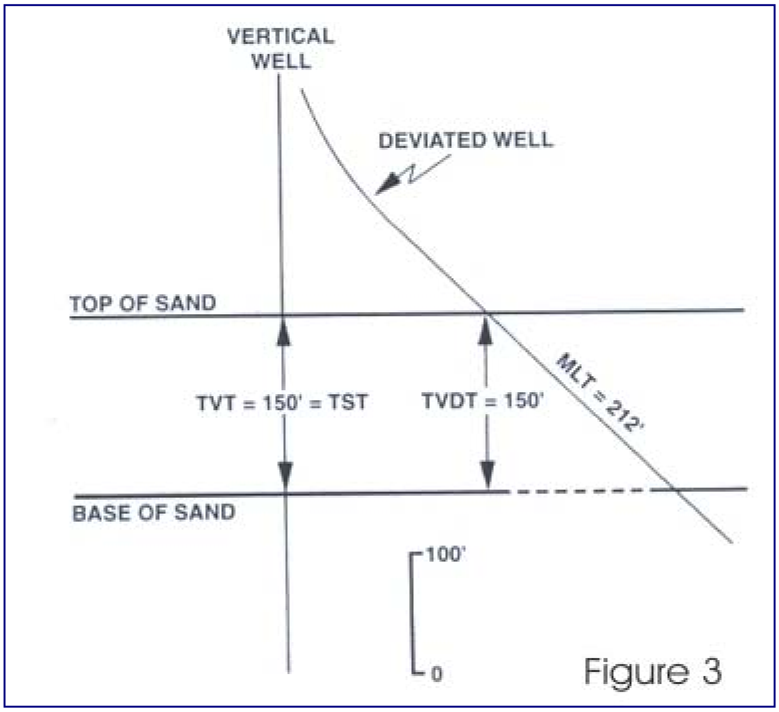


Figure 3

However, if the beds are dipping (particularly over 10 deg), a TVD log typically does not represent the log thickness required to aid in correlation work, to determine the vertical separation for a fault, to count net sand or net pay or to construct net pay isochore maps. For these purposes, we *must* correct a deviated well log so that the log thickness represents the TVT. Look again at Fig. 2and observe the significant difference in thickness between the TVD and the TVT values. To determine net sand and net pay from a deviated well log, we *must* use a TVT log or its equivalent. By the equivalent of the TVT log, we mean calculating and using correction factors for specific intervals of interest, if a TVT log is unavailable, which is commonly the case. Therefore, for each interval on the deviated well log requiring the conversion of MLT to TVT, determine the appropriate correction factors and apply them to the MLTs for the intervals of interest.

THE IMPACT OF CORRECTION FACTORS

Over the past 25 years we have seen significant errors in reserve calculations as a result of someone using the wrong thickness value to determine the reservoir quality sand or to prepare net pay maps for volumetric calculations. Errors of 20 to 30 percent are not uncommon, but on occasion errors of up to 700 percent have been documented.

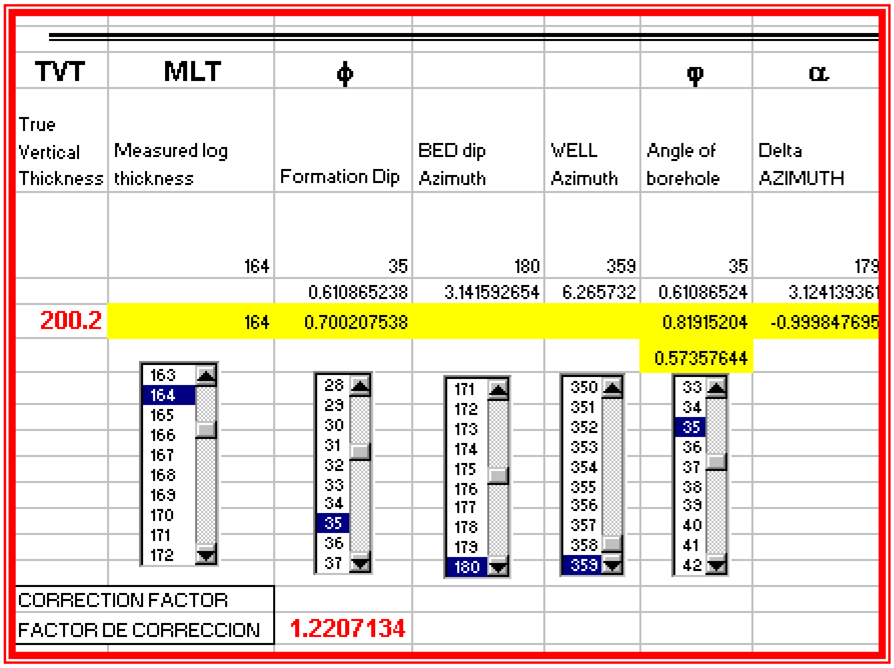
In one field evaluation, the proved producing and proved reserves behind pipe were reduced from an overestimated value to 150MM barrels of oil to 35MM barrels of oil. Most of the overestimation of oil was the result of using the wrong log thickness to count net sand, net pay and determine volumetrics. If we consider an average price for oil of $25 per barrel, this reduction in reserves results in a future revenue write down of about **$2.7 billion.**

From evaluating fields to buy in a data room to determining whether or not to participate in a prospect; from calculating the potential reserves in a new discovery, to conducting a study on a mature field to identify upside potential the bottom line is "how much oil or gas can I produce and what is my return on investment". If the wrong numbers are used for the reserve calculations because of an error in the pay thicknesses used for volumetrics, your economic analysis is worthless.

APPENDIX

Snapshots from worksheet developed by Geosolutions & Interpretations, LLC

To download the spreadsheets go to http://www.geointerpretations.com/



TVT	MLT	ϕ			φ	α
True Vertical Thickness	Measured log thickness	Formation Dip	BED dip Azimuth	WELL Azimuth	Angle of borehole	Delta AZIMUTH
	164	35	180	359	35	179
		0.610865238	3.141592654	6.265732	0.61086524	3.124139361
200.2	164	0.700207538			0.81915204	-0.999847695
					0.57357644	
	163 164 165 166 167 168 169 170 171 172	28 29 30 31 32 33 34 35 36 37	171 172 173 174 175 176 177 178 179 180	350 351 352 353 354 355 356 357 358 359	33 34 35 36 37 38 39 40 41 42	
CORRECTION FACTOR						
FACTOR DE CORRECCION		1.2207134				