Hearing on Oil & Gas Accounting & Disclosures

COMMITTEE ON FINANCIAL SERVICES

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I am Matthew Simmons, Chairman and CEO of Simmons and Company International, an investment banking firm that has solely concentrated in providing energy research and corporate finance advice to corporations and institutional investors for the past thirty years. Our firm has been the advisor on over 500 individual projects, public and private offerings and mergers and acquisitions. The cumulative value of the projects the firm has completed exceeds $60 billion. I am also a member of the National Petroleum Council, The Council on Foreign Relations and the Atlantic Council of the United States.

I am honored to have the opportunity to address the topic of the accounting and financial disclosure of our oil and gas industry to this important committee that has led the way to a higher standard of corporate governance. The topic we are discussing today is timely and important as I feel our entire energy reporting system globally and in the United States is badly in need of reform. Our current system lacks the reliability and transparency that should be mandatory for something as important to our economy and way of life as energy.

Until Shell Oil Company shocked the world with a 20% reclassification of its proven reserves, followed by a litany of other publicly held oil and gas company reserve write-downs, most energy industry observers casually assumed that the information presented by our publicly held oil and gas companies contained quite accurate assessments of individual oil and gas company results. In fact, the system has always had numerous flaws that grew in magnitude in recent years as fewer appraisal wells were drilled, as new oil and gas exploration and exploitation projects increased in complexity, as decline rates in existing oil and gas fields accelerated and as new projects got increasingly smaller in terms of potential reserves.

A tell-tale sign that the reported oil and gas results were askew was the wide number of public companies which routinely reported additions of 120 to 150% in proven reserves compared to their annual oil and gas production while fewer and fewer of these same companies showed any meaningful growth in their production volumes. In reality, a host of time-tested measures to assess reserves and their potential recovery dwindled as the price of oil and gas stayed too low to commercially afford the "standard tests." The industry ended up using far fewer outside third-party reserve engineers to help assess the level of proven, probable, and possible reserves. The number of appraisal wells that always follows a new field discovery dwindled by a substantial degree. The use of coring to test a new reservoir rock's properties fell and often limited flow tests, or no flow tests were conducted. Instead, the industry began relying heavily on far less geophysical data accompanied by expensive well bore testing (though these tests only measure a small radius beyond the well bore itself.) Computer simulation models then produced estimates of the amount of hydrocarbon a hydrocarbon-bearing structure might contain and the 90% or highly certain part of these hydrocarbons that represent "proven reserves." Lacking in this new era of high technology was the old system of testing what the reservoir rocks contained.

While geophysical technology improved by quantum leaps, as did computer techniques to "interpret" what this data meant, none of these techniques could easily determine the limits to where easily producible reserves lie. Since the cost to obtain seismic data and computer costs to analyze this data were infinitely less expensive than drilling more actual wells, the expenditure to "prove up" reserves plummeted. Furthermore, since few appraisal wells were drilled, there was less knowledge of the geological limits to producing a structure. As a result, with less well-bore data, it became easier to feel "comfortable" that a field contained a certain level of proven reserves.

In the low price environment that the industry struggled through for too long, the pressure mounted to declare "proved reserve" status as early as possible so all additional costs could be capitalized.

In my opinion, all these trends led to a widespread industry bias of booking higher levels of proven reserves while being able to spend far less money to create these reserves than would have been spent one or two decades ago. This not only created a cushion of proved reserves that might or might not ever get produced, but it also led to a possible illusion that finding and development costs per barrel were far less than the amount of money that needed to be spent to accurately assess a new reservoir's real reserve potential. Some of these reserves and some of the apparent cost reductions might end up being illusionary.

Proven reserves and accurate costs per barrel are not the only deficiencies in our system of capturing and reporting accurate and timely energy statistics. Today, the single biggest factor to begin estimating a single company or a country's future oil and gas production is to properly assess the rate of decline occurring in a company's existing oil and gas production. Yet there are no reports issued by any of the public, private, or national oil companies that even hint at the annual decline rates by each production region, let alone any field-by-field data.

If these flaws were not bad enough, we also ended up with no requirement today for a company to produce a detailed report of its aggregate total reserves. The only reports that companies are required to detail are the reserves each company deems to be "proven." Since proven status is what is deemed to be a 90% or better certainty, there is no way to create any uniformity for what constitutes "90%" from one company to another.

Even if a way was created to make these reported reserve numbers precise, the data still does not provide an analyst with a reliable tool to begin assessing field-by-field decline rates, or the degree to which a reporting company is being overly conservative or overly aggressive. This lack of reliable disclosure is not limited to only publicly held oil and gas companies. The problem extends to global oil and gas supplies. In fact, the problem of lack of detail and little transparency is far worse for all the national oil companies, particularly all the OPEC member countries. We have now evolved into a systemic “Trust Me” era for all energy providers.

With the capital intensity of the industry now starting to soar, the world’s remaining spare oil capacity slim to possibly now becoming non-existent, and petroleum inventories now operating on a just-in-time basis, the “Trust Me” era needs to end. The time has come for all key oil and gas producers to join in a reform of how reserves and current production is reported.

The Energy Information Agency (EIA) in the United States has recently requested that all natural gas producers begin supplying current production data to our government. Absent this reform, the best supply information lags real production by as many as 6 to 18 months. We can no longer tolerate such a time lag with natural gas supply probably in a permanent decline. While the reporting of their production data to the EIA would be too costly, I argue it is too costly to our economy’s well-being not to have timely, accurate production data.

This fall, the International Energy Agency (IEA) in Paris is calling for a mandated new set of reserve reporting and detailed field-by-field production reports by all key global oil producers. I applaud both the EIA and the IEA’s data reform efforts and would urge the IEA to also extend these efforts to natural gas.

As the IEA presses all national oil companies, but in particular all OPEC producing countries for this new data reform, it is important that all U.S. publicly held oil and gas producers take the lead in such a data reform. Otherwise, it will be easy for all OEPC producers to balk at reform if ExxonMobil, BP, Shell, etc., are not held to the same standards.

In my opinion, the best data reform is for all global key producers to begin timely reporting of field-by-field daily oil and gas production (or production from key producing units) and accompany this new disclosure by the number of producing well bores from each production unit so analysts and public policy planners can finally begin to assess field-by-field decline rates. Absent such data, there is no way to even guess at future supplies by company or country.

On the proven reserve side, it will remain impossible to set a unified way of assessing a common definition of proven reserves. An important change would be to report, by key production unit, three key reserve estimates. First is the current estimate or the original hydrocarbons in place. Second is the current estimate of ultimate recoverable reserves. Third is the cumulative production already produced. The remaining “recoverable reserves” can then be broken into proven, probable and possible. With this added layer of disclosure, it is not so crucial that every producer meets the same 90% probability test. Analysts can gauge the quality of the layers of reserves left to produce and then dig out better answers through follow-up analysis. Today, there is so little data disclosed that analysis is difficult.

These new reforms also need some form of third party expert certification to insure the data is as accurate as GAAP accounting should be if properly applied. Third party reserve engineers do not need to calculate proven reserves just as CPA firms do not need to produce a company's financial statements. But, it adds a degree of comfort to have an independent expert certify that the data was properly prepared.

What this suggested reform will do, if implemented, is begin to lay out the same level of data as that which was required by our public companies when key business segment detailed reporting began being mandatory at the tail-end of the conglomerate era. Before this business segment reporting was enforced, a company could simply report total revenues and earnings with no segment breakdown. This, too, represented a "Trust Me" era and it, too, came to an end.

The beauty of enacting a detailed breakout of key production and reserve data by key units is that all companies already possess this data. It is exactly the data a lender requires when a company wants to borrow funds against reserves. It is what any company wanting to sell reserves needs to furnish to a knowledgeable buyer.

If it means a company has to add even 20 to 30 more pages to its financial reports, this is a small cost when compared to today's system which leaves too many shareholder owners or potential shareholders in the dark. Why should shareholders not have access to the same data any lender or reserve buyer demands?

If this data reform happens, and it could happen quickly if all stakeholders join in the request for such key details, the whole world will be better off. We will begin an era when genuine analysis of our energy system's reliability and true profitability can be ascertained.

The time for this reform is at hand. This Committee can play an important role in helping this reform be effected.

Thank you for the opportunity to address these issues.

THE PROVEN RESERVE "SCANDAL" CAN LEAD TO ENERGY DATA REFORM

by
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Does the oil and gas industry now have a proven reserve scandal? Will the current rash of proven reserve reclassifications soon run its course, or could the industry now be seeing just the tip of a much larger iceberg? Does it even matter if a growing number of our leading oil and gas companies have overstated their initial proven reserve bookings? Has not the industry always ultimately ended up with sizable proven reserve appreciation as more and more is known about individual oil and gas fields? Are proven reserves even important anymore as either a valuation metric or a predictor of future oil and gas production?

These are all serious questions. It <u>does</u> matter if proven reserves have been too optimistically booked, as proven reserves are still the raw material for all future production growth. If proven reserve bookings have been too large, then the likelihood of future reserve appreciation is also low. It also suggests the industry might have created an illusion of lower per barrel costs by dividing the cost pool by an unrealistically large amount of proven reserves.

Do we now have a true Proven Reserve scandal? It is impossible to know. What is truly scandalous is the total lack of quality data available for analysts and/or shareholders to begin assessing whether this reserve booking issue is an industry-wide systemic problem or just a series of individual company mistakes.

The problem with estimating “Proven Reserves” stems from how difficult and challenging it still is to calculate the amount of oil and gas in place (commonly referred to as OOIP), let alone judge the amount that can ultimately be recovered. Once a calculation is determined on the estimated ultimate recoverable reserves (commonly known as EUR or URR), these are then narrowed into three categories: Proven reserve status (P1), probable reserve status (P2) and possible or contingent reserves (P3). As the filter narrows from OOIP to final proven booked reserves, the odds of anyone being exact to the extent of a 90% certainty in these calculations (or even close) plummets, unless the field is exceptional in reservoir quality or the initial estimate is extremely conservative.

It is unfortunate that the term “Proven” was ever adopted for what has always been a mere estimate of the oil and gas reserves that seem highly likely to be extracted from the ground. Estimates of total reserves are never proven until the last barrel is produced and the producing wells in a given field are capped. This is analogous to the process of estimating a human being’s life span, the ultimate proof being when the obituary is written.

Is getting the quantity of proven reserves correct important? The answer is both "yes" and "no." "No" is the correct answer if the estimate is likely to be extremely conservative. For many of the early discoveries of land-based oil and gas fields, or even the offshore fields found in shallow waters, there was never a need to be extremely precise on the total amount of reserves that could be produced. The critical test was always whether the field had sufficient reserves to amortize the cost of building roads, a pipeline for transportation of the produced crude or a shallow water platform. Thus, operators tended to drill enough appraisal wells to make sure these costs could be recovered. Once development wells were underway, large fields grew as wells were drilled further and further from the field's crest where the New Field Wildcat is almost always drilled.

This practice of always leaving some "money in the bank" for what we now call "legacy assets" gave rise to the high level of reserve appreciation as time passed and the number of development wells grew. Thus, for the conservatively estimated giant discoveries, "No" was the correct answer to how critical it was to precisely gauge proven reserves.

As legacy assets dwindled and fields became smaller or occurred in more challenging water depths or more challenging reservoirs, or both, assessing the total amount of OOIP, let alone the EUR/URR became more complex. Because the price of oil stayed low, it became increasingly difficult to justify new projects but it was far more important to try to assess the highest level of reserves a field might have. Otherwise, a potential project's authority for expenditure (AFE) might fail to pass muster as being commercially attractive. For this generation of oil and gas fields, it did become more critical to precisely define the reserves that could be recovered.

In the low price environment of the past decade or two, it also became increasingly important to book potential project resources into "proven reserve" status as early as possible when a field was about to be developed. If this was done, all the field's remaining development costs could be capitalized and then expensed over the life of the field as depreciation, depletion and amortization or "DD&A", otherwise all costs incurred would have to be expensed.   This earnings sensitivity undoubtedly "nudged" many oil and gas companies into booking proven reserves quicker than a perfect world's data would justify.

How are proven reserve estimates calculated? Has the process vastly improved over the last few years in concert with the oilfield technology revolution? Or, is the process of estimating proven reserves still largely an art form of applying a series of scientific guesses to a series of unknown or partially known "facts"?

The process of calculating proven reserves begins with the technology of mapping a field's size. Modern 3-D seismic surveys now create images of incredible quality compared with what used to be gold standard 2-D technology. The new suite of logging tools employed to determine the characteristics of a reservoir and gas/oil/water saturation has improved immensely. But, this well logging data only covers a few feet beyond the well bore. New reservoirs now being developed are often much more complex than a decade ago. In many cases, the technological advances allowed more complex structures to be developed but the increased complexity also simply offset the added value of the technology.

Despite the many technical advances of the past decade or so, the process of finding oil and gas and then properly booking the estimated reserves to be ultimately recovered still involves a complex series of guess work. The principal elements of the process have remained essentially unchanged for a decade.

When a structure that looks as if it has hydrocarbon potential is first mapped, the most likely place to drill is identified (usually at the structural crest or “up-dip”). A new field wildcat well is then drilled in this location. Most of the time, or about 70% of the time, there is insufficient evidence of commercial oil and gas and the effort is deemed a “dry hole.” Too often, a structure being drilled seemed to have all the ingredients of a great new oil field but when a wildcat was drilled, the hydrocarbon had already apparently migrated elsewhere instead of being trapped as the geologist working up the project had assumed.

While the lack of sufficient oil or gas to prove commercial viability creates dry holes, the history of the industry has also been littered with tales of a dry hole condemning a new prospective region, and years later, fresh reviews of the data suggests that the new field wildcat should have been drilled in a different spot. Some of the great oil and gas finds of the past 50 years were in areas someone mistakenly labeled “dry”.

If a new field wildcat well is successful, it does not immediately prove the new field is a commercial success. Whether there are enough hydrocarbons to cross an economic success threshold is usually determined by then drilling a follow-up series of “appraisal wells” to test the thickness of the hydrocarbon-bearing column and the extent to which this column or series of columns extends across the areal extent of the structure.

After an operator drilled a series of appraisal wells, the new and enhanced well data was intensely analyzed by the reservoir engineers and compared to data from similar fields which are called “analogs.” (In the investment banking world, we call this process using “comparables”.) The reservoir engineers need to assess the reservoir characteristics across the structure to determine the permeability and porosity of the hydrocarbon bearing rocks. Some fields have exceptional “homogeneity” in that most of the entire reservoir has relatively uniform characteristics while others exhibit a high degree of heterogeneity, meaning that the reservoir characteristics vary significantly either laterally, vertically or both.

To obtain the highest quality knowledge in any new field which is expensive to develop, not only are a multiple series of appraisal wells important to drill but it is important that these appraisal wells are also both cored (a process involving cutting a sample of the actual rock that has trapped the hydrocarbon) and flow-tested for some period of time to determine how the flow properties of the rocks in various parts of a complex field actually work in producing commercial quantities of oil or gas.

Ideally, appraisal wells need to be drilled as close to the "edge" of a potential structure to fully test the ultimate size of a field. But, each added well can increase the total project cost significantly, so there is always a tradeoff between the search for perfect data and the limit to what can be spent.

The cost to properly drill multiple appraisal wells and then cut cores and flow-test the wells can be extremely high, even when drilling costs are low. Cutting cores and flow-testing can easily add up to 30 days to drilling an offshore well. But, operators who religiously practice this technique swear that it is the only insurance policy against developing a project that ends up being a commercial failure because the reservoir rocks did not behave as anticipated.

All the well data, seismic data, logs and "analog" analysis are ultimately entered into a reservoir simulation model. The model helps reservoir engineers develop their estimates of the OOIP, the EUR/URR, and finally the 90% certain portion of

URR/EUR. This forms the basis of “proven reserves” (or a reasonably certain standard as set by the SEC) that are booked as a field’s development sanctioned process gets underway.

The ultimate factors that determine the recovery parameters are set or limited by the reservoir rocks. Mother Nature is still the main arbitrator of EUR/URR.

The role which modern technology plays in this whole process is often misunderstood and sometimes badly hyped as introducing a certainty into this inherently ambiguous process that is simply not possible.

Seismic technology and applications have advanced by great strides over the past two decades. The image quality is a step-change improvement from just a few short years ago. 4-D seismic shot over a series of different time periods can tell a great deal about the historic movement between the three phases of an oilfield: gas, oil and where the cursed water finally begins. But, a significant element of these crisp pictures is merely how a computer interprets this data. Thus, much of the sharper image is based on a series of assumptions, not facts.

Logging tools can now measure with far greater precision the true nature of the reservoir along the face of the well-bore, although these logs do not capture most significant changes which may occur in the rocks beyond a very short distance from the well-bore face.

Modern reservoir simulation modeling technology creates an unusually clear picture of what the reservoir probably looks like, though the simulation is still merely a mathematical representation of the myriad rock, fluid, pressure and temperature characterization. Simulators are only as good as the assumptions that drive them. Small changes to key assumptions can dramatically change the conclusions drawn from a simulation analysis.

It is important to note that neither 3-D seismic nor reservoir modeling can sense the true nature of the various types of rocks within a reservoir and how they actually allow hydrocarbon to flow. Only through drilling multiple wells that are cored and flowed can this key data be known. Even with this added knowledge, actual production over time can end up creating a dramatically different picture of a reservoir's true potential.

Over the course of the last two decades of low oil and gas prices, there is no question that the industry ended up drilling far fewer appraisal wells and cored even fewer of such wells. The process was simply too expensive in the low cost world the industry was forced to live with for too long.

Without drilling these multiple appraisal wells, the cost of finding new proven reserves plummeted. However, the extent of knowledge of a field's productive limits was often also reduced. This may have enabled a reserve estimator to feel comfortable in booking a high amount of proven reserves as no conflicting data indicated otherwise.

How much the process of spending less and finding more contributed to finding and developing (F&D) costs plummeting from what was once as high as $20 to $25 per barrel to less than $5 in recent years might never be known. I suspect it had an enormous impact and created the illusion that the cost to extract oil and gas had come way down while the money spent to extract the oil and gas was steadily rising.

How commonplace has it been for companies to book aggressive amounts of proven reserves? It is impossible to know today as almost no data is ever revealed by any of the publicly traded oil and gas companies on field-by-field reserves. Partners owning parts of the same field often do not know even the amount the other partners estimate as the OOIP, let alone the URR, the P1 or Proven Reserves.

The only fact that does stand out as an indicator that many companies could have been too aggressive at booking proven reserves is the fact that companies booked far more proven reserve additions over the past five to seven years while their daily production of oil and gas steadily either declined or showed little growth. When a company has multiple years of high proven reserve growth AND production declines, then one of the two numbers is probably wrong.

Over time, any company that books a realistic amount of proven reserves and adds 125% more each year than it produces should start to see daily production volumes rise. It only takes four years of 125% proven reserve growth over current production for a company to theoretically double future production. If the daily production barely grows, a smell test suggests that the proven reserve additions could be too optimistic.

The whole area is confusing, but contributing to the problem is the complete lack of quality data for anyone to analyze.

There is a simple in-concept solution that will produce the additional data needed to assess the overall quality of a producing E&P company's asset base and defuse the whole P1 "proven reserve" issue. The concept is more difficult to implement, but it is better than today's system.

THE 13 POINT PROGRAM

My suggestion for the reform of reserve and production data reporting would begin by requiring all oil and gas companies to define their oil and gas asset base by key production units. For companies with interests in key fields, it is simple to then report each as a significant production unit. For companies holding scattered interests in many different areas, the selection of what constitutes key production units becomes slightly more complex though perhaps this is even more important for a shareholder or prospective shareholder to know.

A company with varied interests in the Gulf of Mexico Shelf could list the GOM Shelf as a production unit, but the shelf should not be co-mingled with deepwater interests. The two areas are quite different.

Once a list of all key production units is presented, 13 pieces of data would then be reported for each unit. The first five pieces would be the past five years' production history and the next five would be the cumulative number of well penetrations for each of the five years.

If the only data reform was merely the disclosure of these 10 items, the energy world will be far better off because analysts and prospective shareholders can then divide total annual production into the number of producing wells and get a trend line of well productivity. If this ever gets widely adopted as a standard reporting procedure, analysts following the E&P industry could begin to grasp the power of depletion.

The last three pieces of information are more subtle, but just as important. The first two are simply estimates and should be clearly noted as such. These are the production unit's most recent updated OOIP, and the second is the most recent estimate of the gross EUR/URR. Finally, the cumulative barrels produced from each production unit should be disclosed.

This new disclosure standard would not answer reserve and field productivity questions - the topic is far too complex for that. But providing these 13 data points by each key production unit will quickly highlight fields now into decline. The three sets of reserve data also provides solid clues of how far into decline each key field is.

This new disclosure can be summed up in three words: Simple, Available and Analyzable. All companies have this data and it is easy to analyze. If it is not readily at hand, this signals far greater problems for the company in question.

If all the key oil and gas providers in the world embraced this new form of reporting, it would trigger a massive re-evaluation of global resource adequacy. It would also give partners in shared oil and gas fields a glimpse at what their partners think the asset is all about. It would quickly highlight a company's asset quality. Those with highest quality would shine and those with old, depleting assets would also be revealed.

Is this data reform possible? Unless the stakeholders involved in owning these companies and the public policy groups that should worry about global resource adequacy press for a change, nothing will happen. But the need for a change is becoming urgent.