ABANDONED GULF RESERVOIRS PROVIDE LOW COST, LOW RISK PROSPECTS

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In the Gulf of Mexico, there are hundreds of millions of barrels of oil and trillions of cubic feet of natural gas "forgotten" by lessees in reservoirs shut-in before 2010. A study by Earth Science Associates (ESA), based on decline curve analysis of 59,025 completions and 27,328 reservoirs, located and evaluated all abandoned accumulations and high-graded opportunities that would be attractive today. Additional "data-mining" analyses of well test records and 35 years of independent reserve estimates for all fields and sands in the Gulf, made by the US Minerals Management Service/Bureau of Ocean Energy Management (MMS/BOEM), identified further prospects for new production.

The study generated over 2,000 significant leads – all within the bounds of producing or abandoned fields in the Gulf. These were filtered out of databases with up to 7 million records, identifying five key types of opportunities:

1. Over 500 shut-in oil reservoirs with more than 100,000 barrels (bbls) of recoverable oil remaining and 29 with more than 1 million bbls estimated by decline curve analysis. For gas reservoirs, decline curves show more than 1,400 reservoirs with over 1 billion cubic feet (bcf) remaining and 57 with more than 10 bcf.

2. Hundreds of reservoirs shut-in before production began to decline and whose final production rates were higher than the average for today's on-line reservoirs.

3. Over 100 completions with prospective initial test rates that never produced.

4. Dozens of fields where the MMS/BOEM wrote down large reserve volumes in the past but some of which represent possibly profitable targets at today's prices, costs and technology.

5. A dozen sands booked by the MMS/BOEM when they were discovered, which never produced and were subsequently taken out of the government's inventory of accumulations.

The study required development of automated batch estimation of tens of thousands of decline curves, statistical identification of significant breaks in production data to refine decline curve estimates and machine processing operator-assigned reservoir names to define reservoirs usable in the analysis. These techniques were also applied to finding discovered sands that slipped from inventory and promising completions that never produced. Both time-series and spatial analytic techniques were focused on mining the government's reserve histories of the Gulf's fields and sands.

The heavy computing was done in *R*, a widely respected open-source statistical package; the spatial analysis and integration of input data and outputs was accomplished in ESA's *GOM*^{3} system, which is the industry standard for geographic information systems (GIS) in the GOM and is written on ESRI's *ArcGIS* platform. Only data publically released by MMS/BOEM was used. As the study was of "forgotten" oil and gas, only targets abandoned before 2010 were evaluated.

Batch Decline Curve Analysis

Decline curve analysis of the production from oil and gas wells entered petroleum engineering nearly a century ago. Most of the mathematical foundations and practice were formalized by J.J. Arps in his seminal 1945 article (1). The basic principle is that, after production peaks, future output can be forecasted by the rate at which post-peak production declines. Originally, these estimates were made manually: an engineer plotted production rate versus time (or cumulative production), "eye-balled" a line best fitting the data and drew it in with a straight-edge from the peak through the last production observation. Extending that line predicts future output and remaining producible volumes can be calculated from the predicted production rates (Figure 1).

Eventually, computers replaced graph paper and rulers. Software developed to estimate the four mathematical classes of decline models: exponential and hyperbolic functions of production rate versus time; a linear model of rate versus cumulative production and finally, for gas wells, adjusted pressure (P/Z) versus cumulative production. Because of insufficient quality pressure data for the GOM, the P/Z model could not be run in the study. Typically, estimation is deterministically reported, not including confidence intervals on either future production or remaining resources. Also, decline curve analysis is almost always run by an engineer studying one well or reservoir at a time.

The objective of the *Forgotten Oil and Gas* study, however, was to estimate tens of thousands of decline curves and quantitatively evaluate the statistical confidence in the results of each. The algorithm for batch analysis estimated the three alternative models for each reservoir and then determined which curve was the statistically best fit. It also accommodates a major problem engineers face and solve when performing the analysis on individual wells – breaks in production. Most wells experience occasional unusual drops in output or are temporarily shut-in; sometimes this has little effect on the overall decline. More commonly, an engineer must adjust the decline curve, often starting the analysis after the break in production (i.e., a significant change in slope). Processing tens of thousands of production histories required finding these breaks automatically and adjusting the starting (peak) point of the decline analysis as necessary. A typical run for all GOM reservoirs takes about 48 hours.

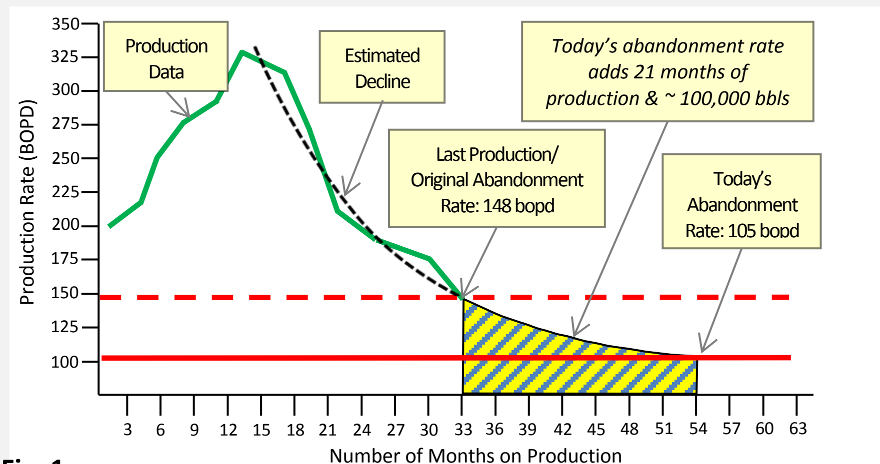

Fig. 1

Preparing Data for Decline Analysis

Before the decline curve algorithm could be run, two preparatory steps were completed: aggregating completions into reservoirs and determining the rate at which each reservoir *abandoned before 2010* would be abandoned under *today's* technical and economic conditions.

Only one completion was required to produce 78% of all GOM reservoirs; the balance needed more than one. For those, the monthly oil, gas and water from each completion must be summed to obtain a production profile for the entire reservoir. If the productive intervals in every well were consistently named, aggregation would be easy. Unfortunately, inconsistencies arise due to different practices between operators, idiosyncratic hand-recording and simple entry errors. In the easiest cases, a completion in the "A1" reservoir needs to be joined to completions labelled "A-1", "A 1" and "A/1". To check the reliability of these re-assignments, all completions grouped into a single reservoir were required to be within specific lateral and vertical distances of each other.

To identify "forgotten" oil and gas worthy of remembering, the production rate at which interesting reservoirs were abandoned many years ago must be *greater* than the rate at which the same reservoir would be abandoned *today*. Abandonment rates for similar reservoirs, on average, have fallen over time (Figure 2 shows abandonment rates for reservoirs with depths <7,000 feet and in <300 feet of water). Some of this change was due to higher prices, some to improved technology that lowered costs and made it profitable to let a well flow to a lower rate. Some was because as infrastructure on the shelf became denser, both production and transport became cheaper. Working in the other direction, water depths have increased, as have reservoir total vertical depths (TVD), raising marginal and average costs of production for those wells, which boosts the minimum flow rate at which they are abandoned.

To estimate "today's" abandonment rates, a separate study was made of the 2,065 GOM reservoirs shut-in between 2010 and 2012. These newly shut-in reservoirs were placed in a matrix based on ranges of gas-oil ratio, water depth and reservoir TVD. This allowed fair comparisons: the final production rate of each reservoir shut-in before 2010 was compared to the final rates from the 2010-2012 set which shared similar gas-oil ratio, water depth and reservoir TVD.

With the best-fitting model of the decline from each reservoir shut-in before 2010 and an estimate of the production rate at which it would be shut-in today, the remaining producible oil and gas was calculated, along with 10%/90% confidence intervals on that estimate. Additionally, for each reservoir analyzed, statistics describing the goodness of fit of the best regression model were reported for assessment of the *quality* of the forecasts.

Results of Decline Curve Analysis

Ignoring statistical confidence and minimum volumes remaining in each of 27,328 reservoirs, the decline curve analysis found 2.81 billion barrels of oil equivalent (BOE) of remaining producible oil and gas. That number, however, must be immediately cut to eliminate estimates made by statistically unreliable regression models of decline. Using a common measure for statistical goodness of fit, called R^2, to eliminate bad regressions (i.e., $R^2 < 0.6$), a smaller but still impressive volume of forgotten resources remained: 304 million bbls of oil and 6.6 trillion cubic feet (tcf) of gas (or a total of 1.47 billion BOE). In the analysis that follows, only decline curves with statistical fits carrying $R^2 \geq 0.6$ are included.

Although these are large volumes in aggregate, what is attractive to producers are the very largest accumulations in these distributions. On the oil side, setting minimum interesting reservoir size at 100,000 bbls recoverable, 556 oil accumulations were found; with the minimum raised to 1 million bbls, 29 reservoirs made the grade, the largest of which was 10.2 million bbls. For gas, setting the minimum size to 1 bcf, 1,417 reservoirs met that threshold and 57 contained at least 10 bcf, the largest of which was 67.4 bcf.

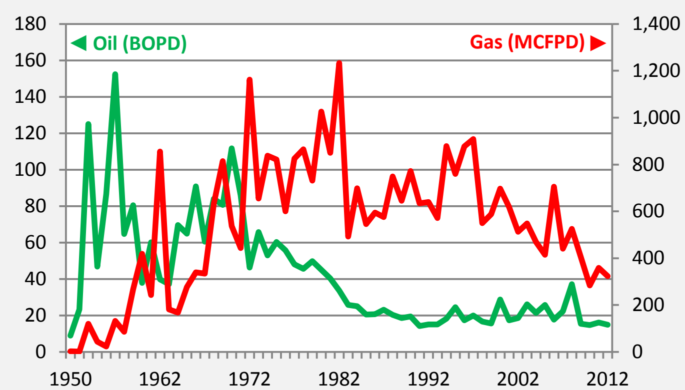

Fig. 2

While 100,000 bbls of oil and 1 bcf of gas may seem low thresholds, these equal the decadal median sizes of new oil and gas reservoirs brought on-line in the GOM over the last 40 years (Figure 3). It is true that the "anchoring" (i.e., largest) reservoirs of *new field discoveries* are larger than these medians. However, over the last 40 years, half of the *new reservoir* additions within *discovered fields*, have fallen between 10,000 and 226,000 bbls of oil and 500 mmcf and 6 bcf for gas. These are comparable to the ranges of most remaining recoverable volumes of the 556 oil and 1,417 gas reservoirs highlighted in the *Forgotten Oil and Gas* study. The reservoirs assessed in the study between 100,000 and 1 million bbls contain 127 million bbls collectively; for gas reservoirs between 1 and 10 bcf, 3.1 tcf was found. At the richest ends of both distributions, the 29 oil accumulations > 1 million bbls hold 65.9 million bbls collectively and the 57 gas reservoirs with remaining recoverable >10 bcf have 1.1 tcf.

By joining the reservoirs identified in the study with the leases in which they are contained and allocating the volumes to lessees by their percent ownership of those leases, the companies holding the greatest volumes of forgotten oil and gas were determined (Table 1). Approximately 30% of the resources in reservoirs > 100,000 bbls and > 1 bcf are under currently open lease blocks.

Reservoirs Shut-In Before Decline

Considering all reservoirs shut-in before 2010, about 7% of oil reservoirs and 6% of gas reservoirs were abandoned before their production began to decline. To be fair, most of them were not *increasing* when turned off. These reservoirs made small volumes monthly and at some point, operators judged them uneconomic and abandoned them.

Some did, however, exhibit positive production profiles. More importantly, hundreds had final output (averaging the final two months) higher than the average daily rate for reservoirs on-line in the 2010-2012 control period (representing "today's" rates). Of those equal or exceeding today's average output, 75 oil reservoirs had final production of ≥ 435 barrels of oil per day (bopd) and 478 gas reservoirs had final production ≥ 1.6 million cubic feet per day (mmcfpd).

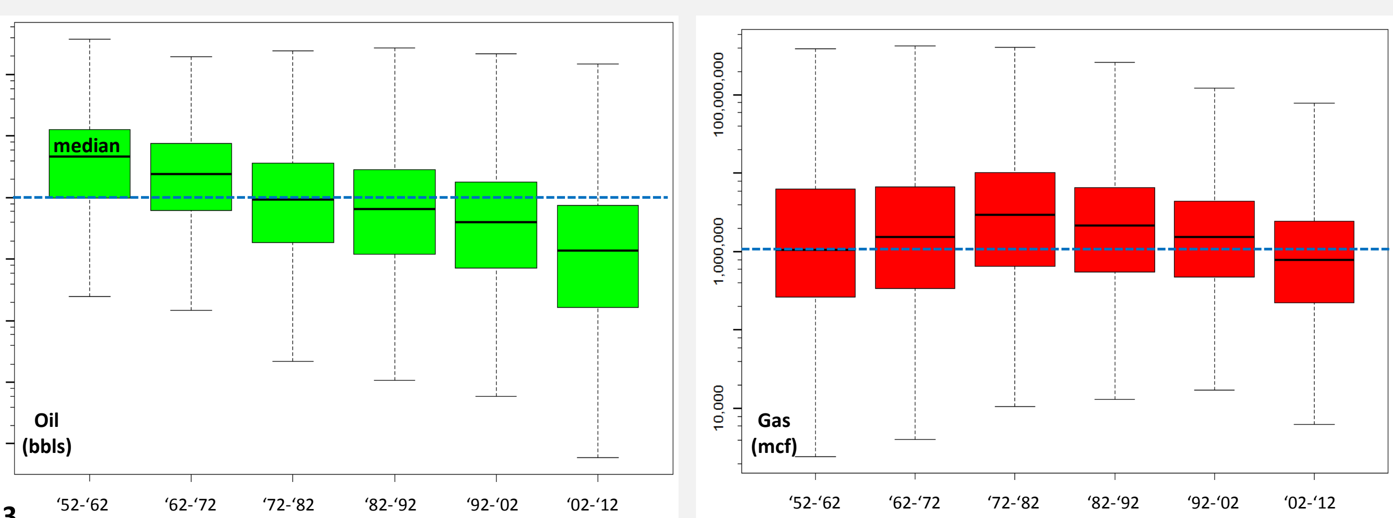

Fig. 3

Company	Recoverable Volume Threshold		Recoverable Volume Threshold	
Leasee	> 100,000 bbls	> 1 bcf	1 million bbls	10 bcf
	(million bbls)	(bcf)	(million bbls)	(bcf)
Fieldwood	28	509	5	130
Chevron	20	341	0	91
Energy XXI	20	254	1	69
Arena	3	169	0	39
McMoRan	4	163	2	40
W&T	9	118	6	41
Stone	10	112	6	23
Black Elk	3	142	< 1	24
Talos	14	45	10	0
Shell	8	57	5	0

Table 1. Companies whose current lease interests in the Gulf of Mexico cover oil and gas resources identified as "forgotten" in the study (as determined by decline curve analysis); volumes allocated by fractional interests held as of April, 2014. (Due to a lack of new BOEM data on record title assignments, only Apache resources in water depths less than 580 feet were assigned to Fieldwood).

Focusing on the 553 reservoirs with high final production rates, 11 were associated with storm-damaged platforms, requiring facilities as well as completion/reservoir performance analysis. For the balance of 542, why apparently strong producers were shut-in is not known. However, *if* all these 553 high-rate abandoned reservoirs could all be turned back on at their final rates, it would result in 76,525 bopd and 2.7 bcfpd of gas.

Reserve History Analysis

Each year from 1975 through 2010, the MMS published its annual independent estimates of the reserves in all fields in the Gulf of Mexico. Starting in 1995, they also estimated reserves at the sand level. Each year's report gives cumulative production, estimated reserves and their sum, estimated ultimate recovery (EUR). In theory, EUR should never fall unless remaining reserves are explicitly written down. This could happen because of a change in economics (e.g., drop in price) or realization that earlier technical assessments were optimistic (e.g., effective thickness found to be thinner or permeability lower than originally estimated). EUR can also fall for regulatory reasons (e.g., a reservoir assigned to one field is later reassigned to a neighboring field).

Closely examining all 1,296 fields and 14,288 sands evaluated by the MMS, three classes emerged: 1) fields/sands with EURs that were never revised downward by the time they were depleted (or by 2010 for still-producing fields); 2) fields/sands that had insignificant negative revisions, indicating correction of entry errors or random fluctuations in the MMS analyses and 3) fields/sands for which there were large reductions in the MMS assessments of EUR. The study focused on this last class, for example, the Ship Shoal 28 field, where approximately 305 bcf (54 million BOE) of gas reserves were booked in 1978 and written down in 1984 (Figure 4).

For all fields with large negative revisions, spatial checks were made to ensure that the resources subtracted from one field or sand were not simply credited to a neighboring field or sand. The relationship between revisions and lease holdings was also examined. From the reserve history analysis, 74 fields were identified with write-downs of greater than 10 million BOE and 79 sands where the negative changes in EUR exceeded 5 million BOE. Collectively, these negative revisions sum to 2.9 billion BOE.

In all of these cases the presence of producible hydrocarbons is not in question; so, their geologic risk is minimal. In many cases, further engineering and geoscience work will show that the negative revisions were appropriate and would not be revised today – even in light of different economic and technical conditions. However, among these 153 fields and sands are hydrocarbon volumes that were appropriate to write down 5-10-25 years ago for technical or economic reasons but under today's conditions, could be profitable.

Lost Completions and Sands

Two final study components mined databases on well tests and production and the MMS/BOEM *Sand Atlas* series (2) to find anomalies that might be prospective.

In the first case, all 59,025 completions were checked for initial tests and those results compared to subsequent production. Of these, 9% never produced but the rest did. The interesting subset was those completions with good flow rates on initial tests that were never put on line. In some cases, further analysis showed that the oil and gas that would have come from these completions were produced out of neighboring wells and additional potential from the unproduced completions was unlikely.

The core finding of this search was the set of 125 completions that were never produced but had initial tests that were higher than the today's average rates of completion-level production: 350 bopd for oil and 1.2 mmcfpd for gas. The sum of the test rates of these 125 completions was 28,659 bopd and 526 mmcfpd. Using a general (and high variance) relationship between completion EUR and initial potential tests, together, these completions represent a mean of 58 million BOE of producible oil and gas.

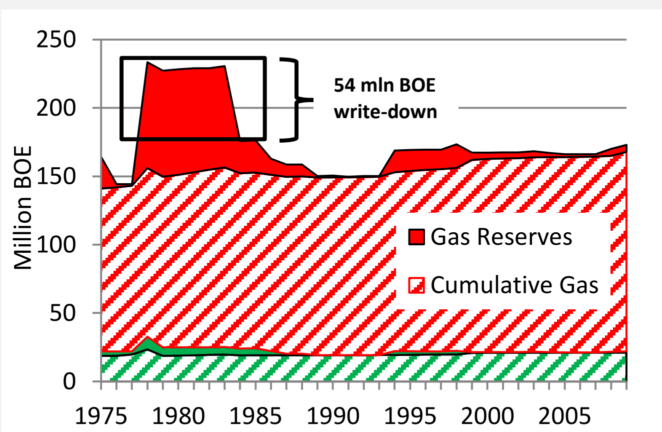

Fig. 4

The search for "lost" sands centered on the *Sand Atlas*. It gives rock and fluid/gas properties and assessment of each sand's oil and gas resources. When the first *Atlas* document was published by MMS, it was a comprehensive list of all sands in all GOM fields that either had produced or had qualifying production but were not yet on-line (e.g., they were waiting on a pipeline connection or a platform). Every year, the MMS/BOEM added the sands of newly discovered fields and newly discovered sands in discovered fields to the *Sand Atlas*.

As the *Sand Atlas* is a cumulative document, once a sand enters, it should stay. Some sands ultimately get reassigned to other sands as additional drilling and geophysical information indicates that what was earlier judged to be a separate accumulation was simply an extension of another sand. However, examination of drilling and completion histories within a field and spatial analysis of its sands can usually identify such reassignments.

Eliminating reassignments, 12 sands with EURs greater than 1 million bbls or 10 bcf simply disappeared from the *Sand Atlas*. As being added to the *Sand Atlas* requires detailed geologic and engineering data, it is unlikely that these represent simply *postulated* hydrocarbon accumulations. They collectively constitute about 43 million BOE of recoverable resources; they were included in the *Forgotten Oil and Gas* study because some may constitute low-risk and profitable extension exploration/development opportunities.

Conclusions

Two valuable results came from the study of resources remaining in abandoned reservoirs and wells in the Gulf of Mexico. First were the empirical findings of the *Forgotten Oil and Gas* study: that there are hundreds of millions of barrels of oil and trillions of cubic feet of gas producible but left behind in discovered GOM fields. Most of the remaining accumulations found in the study are too small to economically produce. However, from tens of thousands of reservoirs, hundreds of the accumulations identified are as large as or larger than the sizes of new reservoirs brought on-line in the last 40 years.

These opportunities are very diverse: from completions, to reservoirs, to sands and to fields themselves. All these volumes are associated with fields that produced - most with fields that are currently under production. This minimizes geologic risk and reduces costs through exploiting existing production and transportation infrastructure.

The second outcome of the study was a detailed demonstration that mathematical and statistical methods for "mining" massive volumes of data – so widely and successfully applied in other industries – can be usefully employed in oil and gas. This is enabled by the existence and organization of comprehensive electronic data bases on geology, drilling, testing, production and reserves. Invested in all of the study components, where possible, were explicit evaluations of the statistical certainty underlying individual results.

While the growth of onshore unconventional oil and gas production and deep water oil have headlined the fundamental change in U.S. hydrocarbon supply in the last half dozen years, both sources have met cost and regulatory obstacles to output continuing to increase at recent rates. New resources in established fields can provide a low-cost/lower-regulation complement to those supplies and profitable opportunities for nimble niche producers and particularly for the companies that own the leases under which most of these accumulations are located.

References

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