MMO: Means, Motive and Opportunity; the outlook for offshore upstream 2019-2020 with a particular emphasis on seismic demand

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Summary

Oil price drops and turbulence at the end of Q4, 2018, make demand predictions developed earlier in the quarter less certain for 2019 planning.

This white paper uses a well-tested complementary method of predicting forward activity to provide an outlook based on a combination of operational criteria to determine what the industry will be *forced* to do, rather than what it might *want* to do. The approach has proven to be very accurate for upstream demand generally but in this case specifically for seismic demand. It uses a sample of ~110 energy companies with a generally offshore bias.

The low activity levels during this past/current downturn have stripped away a lot of the comfort from the situation existing at the onset of the downturn in late 2014. The outlook for seismic demand on the face of it continues to be neutral and recovery is unlikely to be frontier-exploration led. However, the underlying situation for offshore producing fields is very different and paints a different story. Unless there is a return to wholesale reliance on growing onshore unconventional production, there is an urgent need for the industry to change gear for brownfield exploration and re-development projects.

I trust this provides a useful high-level overview for friends and colleagues past and present as background to their own analysis. It is an overall picture of course; within it, there are “winners and losers”. The representative sample includes some that are comfortable but some whose future will be severely constrained if they do not resume upstream spending in 2019, almost regardless of oil price. These represent a solid range of opportunities for seismic and other services.

Introduction

As the volatility in oil prices returned at the end of 2018, the upstream services industry will have an even greater challenge in attempting to figure out what is going to happen in 2019 and 2020. Early Q4 discussions with key customers about next year's plans may now be obsolete; proposed projects (which in any case are contingent on selection) won't necessarily survive the controller's cull.

There are grounds for some optimism and industry comment (based on high level interviews) has not been completely negative, for good reason.

A complementary approach, which has gradually been refined over the years, is to look at a representative sample of ~110 energy companies, who all have an offshore bias to their upstream operations, and which constitute a bellweather grouping.

Forced Move: the MMO approach.

Over the last 15 years or so, a range of indicators, including acreage and upstream earnings have been considered together to give an overall forward activity indicator and it has proven very resilient in good times and bad. This is studied as an entity (i.e. treated as a single company) and determines what *has to* happen – whether it is comfortable or not. This gives a reliable forward indicator of *overall* demand. Further divisions (such as geographical, or individual company performance) are beyond the scope, though they have also proven reliable historically.

The approach has been refined significantly since setting up No2ndPrize and has been used as part of multiple consultancy projects.

Upstream activity is considered in the context of absolute necessity. The approach is the three steps of Means, Motive and Opportunity; can I do something, must I do something, do I have anything to exploit?

Sample Size and Reliability

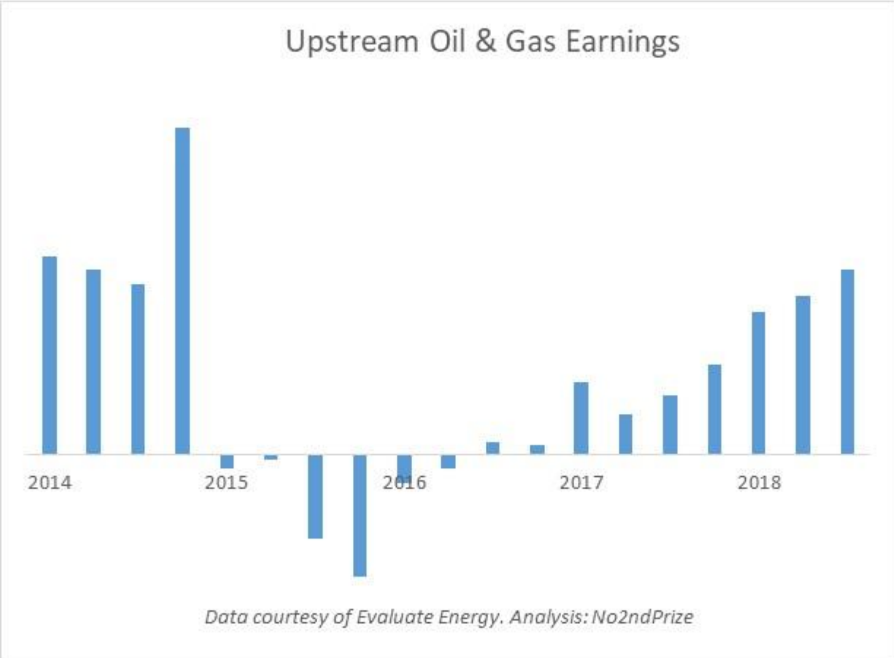
The sample is sizeable: a "bellweather" group of ~110 energy companies, small and large, which have proven an accurate indicator for the whole industry over the years. There is a general offshore focus, though many also work the unconventional space to an extent. This group was chosen in part for its very tight correlation with overall forward offshore upstream activity. The actions of individual companies will of course vary; some will be quite comfortable and their metrics very different from the overall; others will be in a very difficult situation. Note that these companies all report publicly, and the data consolidated by Evaluate Energy (http://www.evaluateenergy.com/). The advantage is accuracy, the constraint is that some of the large NOCs which do not report are excluded (though many are there). However, many countries' NOCs operate via PSC and this data is visible even if the NOC itself it not. I make no apology for this being "seismic centric". This approach has been applied successfully for overall upstream services, but it is particularly well calibrated for seismic.

Naturally, service pricing will also fluctuate with supply, which is not evaluated here.

I am very happy to do a deeper dive as an individual project, but the very high-level outlook is below.

Means

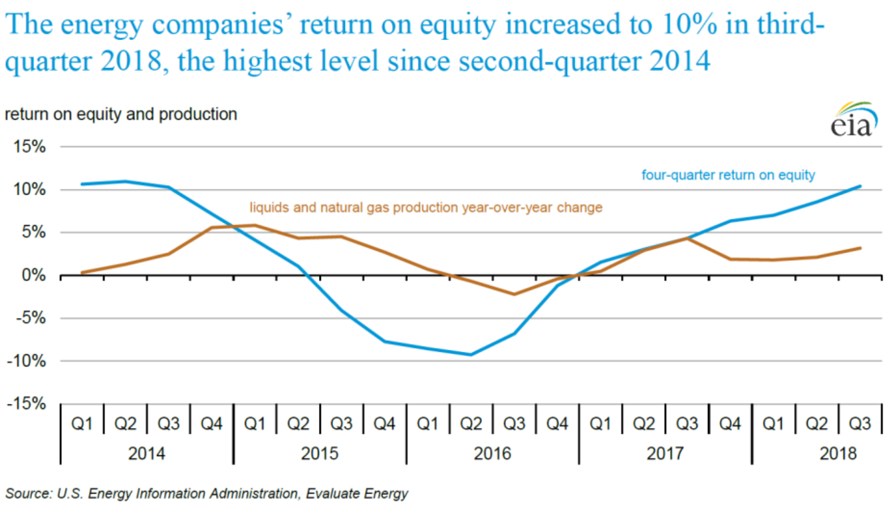
Exploration spending – and seismic in particular – has always been highly dependent on upstream earnings – the "Means". It is hard to continue upstream investment without this. A graph of total upstream earnings for the group (i.e. if it were one company) to the end of Q3 2018, (the latest public information at time of writing) looks like this:



The vertical axis is dollars – the actual numbers aren't useful but the trend is. Since returning to profit during 2016, there has been solid earnings recovery per quarter and at end Q3 2018 in absolute $$ terms it was equal to mid-2014.

This implies energy companies learnt to break even with sub $50 oil (in Brent terms) by the end of 2016, and recovery since has provided positive earnings, though it is happening on the back of continuing service company losses so is unsustainable without process and technology change.

This is perfectly aligned with the quarterly EIA summary (https://www.eia.gov/finance/review/)



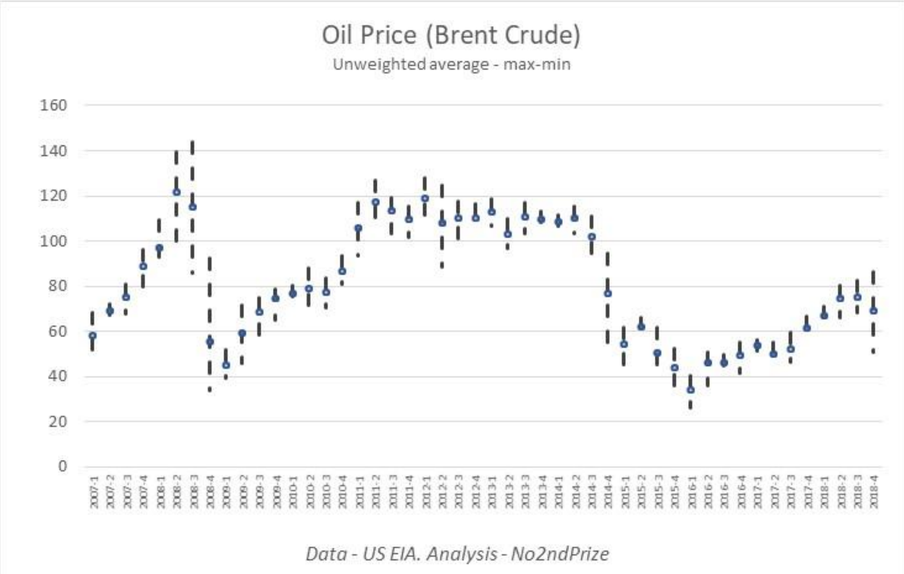
Data sources as indicated. Evaluate Energy normalizes and consolidates publicly available data.

who also pull data form Evaluate Energy using a similar sized, but somewhat different sample. These findings include cash from operations of $144Bn for the 3 months ending 30th June – along with eight quarters of continuous debt reduction.

Oil Price Volatility Impact on Planning

The data above demonstrate that energy companies have adjusted their operations to break even on ~$50/boe oil equivalent.

The volatility in recent weeks is very unwelcome, not only because of the level, but the timing: – it tends to have a disproportionate impact on the next year's plans when it is year-end. Consider the price of oil over the past decade, expressed in a stock (high-low-average) quarterly basis:



Q4 2018 saw not only a drop, but a higher than recent level of i*nstability*. Once prices started to pick up after the trough of Q1-2016, if the overall level was not what was wanted, at least it was reliable. Q4 saw a return to instability not seen since Q4-2014 – and in that case the following year's pricing continued to slide. At least when the same thing happened in Q4-2008, prices largely recovered by the end of 2010. A year-end drop is of course significant as it may also impact the proven (P1) reserves quantity under SFAS 69, in extreme cases weakening balance sheets.

Even factoring in the Q4 drop, upstream profitability will not be wiped out; there is no over-riding logical reason for energy companies to continue to defer the activity they *need*; even if oil prices stay where they are – but there is certainly no scope for "nice to haves" and service pricing will remain under pressure. The positive thing (from a seismic perspective) is that technology changes (the rise of OBN, effort moving from receiver to source side in acquisition, and wider use of full wavefield imaging in processing) offer the potential for radical data value improvements. The upcoming demands will force faster acceptance of these techniques.

Of course, there are winners and losers within this population and not everyone has the "Means". Overall, though, the upstream sector will still prove to be profitable – with upstream providing 2018 returns better than 2017, even taking recent falls into account, and continued profit in 2019 even at $50 oil.

Conclusions: Means.

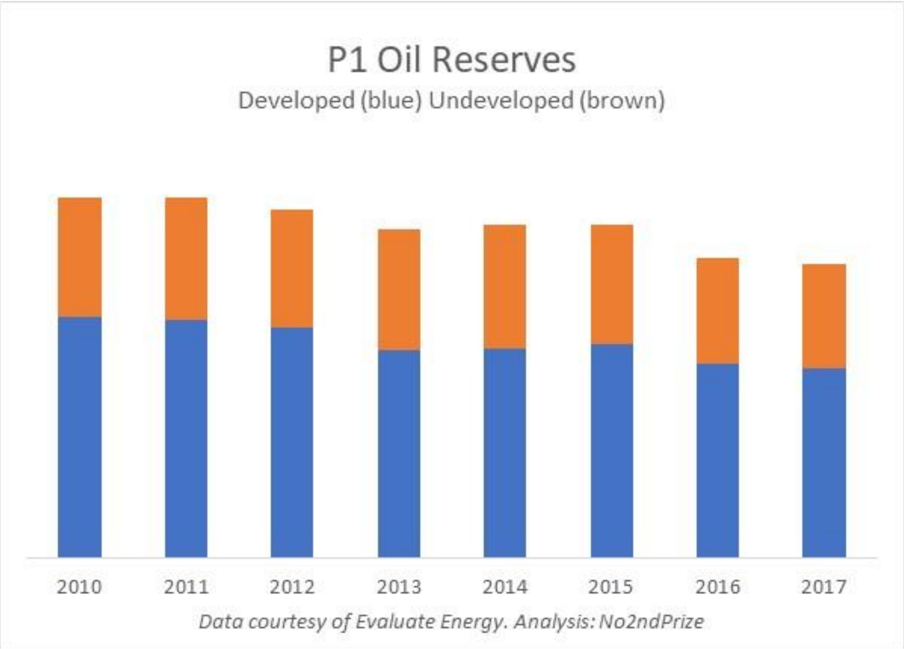
- The energy industry upstream profitability turned positive in 2016 and continues to improve sequentially
- The impact of the late Q4 oil price drop will not wipe out upstream profitability, though its impact will likely be magnified due to timing
- The drive for greater cost-efficiency will not diminish. On the flip side, it may force faster technology adoption.

Motive

No industry spends money without purpose. Upstream spending is about proving up more reserves and managing production to get the product to market at lowest lifting cost. Whilst seismic doesn't generate proved (P1) reserves directly, it does provide the structural framework and helps define reservoir attributes, so it is vital.

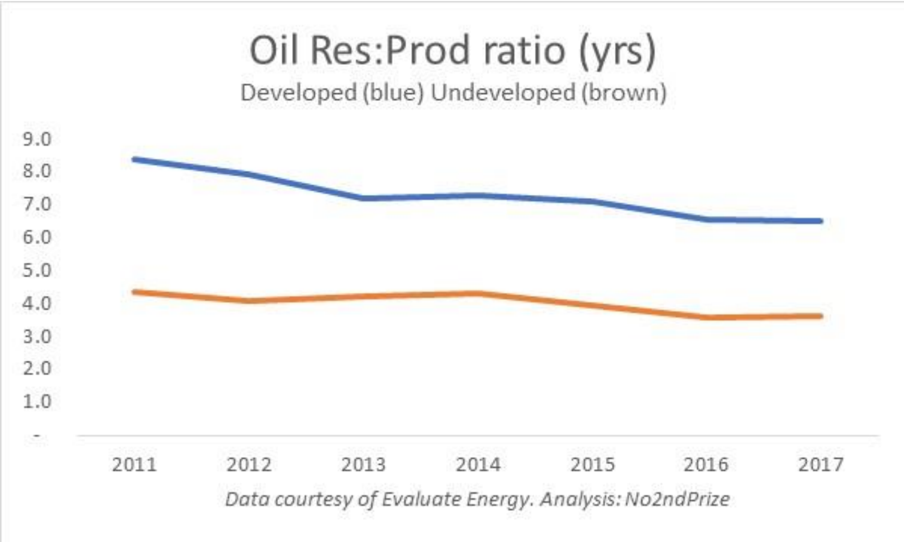
Total Proven Reserves and Reserves:Production Cover

Note that Proven (P1) reserves are the focus here as they must pass both a statistical probability and economic test. A summary of the total overall reserves over time, split by developed and undeveloped, for our bellweather group gives the result below:



That *overall* proven (P1) reserves are declining is hardly a surprise – production has been maintained but upstream spending slashed, reflected in the drop being mostly in developed reserves (i.e. which have infrastructure in place and can be produced without significant further CAPEX). Since it does not make good economic (time value of money) sense to prove up and develop more reserves than are needed, there are P2 (probable reserves) in addition; these are imperfectly reported and at the global level are not considered reliable. The overall solid position going into the recent downturn enabled CAPEX deferment with little risk. Several years on, though, the situation is far less comfortable. This is worrying; proving up new undeveloped reserves via exploration drilling is one thing, turning it into production revenue is quite another. It is testament to the lack of upstream investment in the last few years.

This feeds into reserves cover (reserves:production ratio, measured in years). This presents the reserves as a multiple of annual production.



The resulting ratio in simplistic terms gives the number of years' production "in hand". For our bellweather group, this shows an inevitable and steady decline; note these are not cumulative.

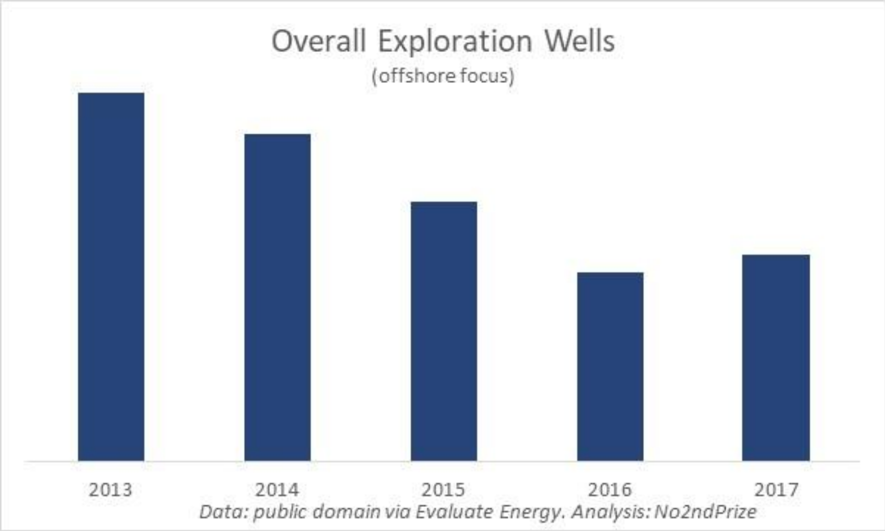
Accelerated field development timelines in the past decade have somewhat reduced the emphasis on reserves to production cover. However, there is real cause for concern here, from an energy company perspective. For developed reserves this was historically around 10 years – now down to 6.5. Whilst field development timelines are now shorter this is hardly adequate. It is now only supported by somewhat over three years' proven, but still to be developed, reserves, though note this has decayed less since 2013.

Drilling and Proving.

New reserves are only proven by drilling and testing (or starting production, of course). So the trend in both exploration and development drilling is important. In the graphs below, I have attempted where possible to eliminate onshore unconventional wells, as the well count is significant but generally not linked to much seismic demand.

Exploration Drilling – from prospect to asset

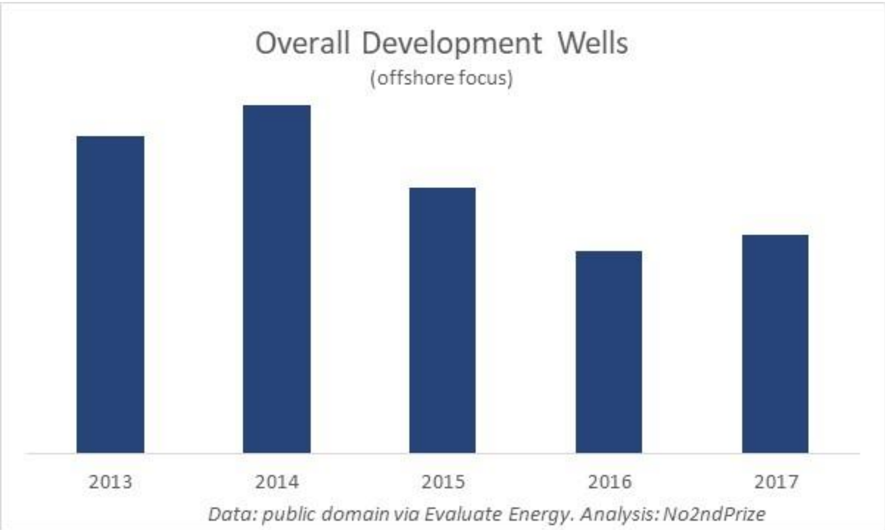
A look at our bellweather group's overall net exploration wells shows the expected trend. 2017 finally shows a long-awaited and welcome (if limited) recovery. It is too early to confirm that 2018 continued this. The graph below shows total net wells (this metric avoids double counting on partnership wells), both discoveries and unsuccessful. Overall exploration success ratios have remained static, at around 70-73% over this period, implying a continuation of focus on low risk and brownfield exploration.



We know that 2018 saw some significant new discoveries, which is long overdue.

Development Drilling – from asset to cashflow

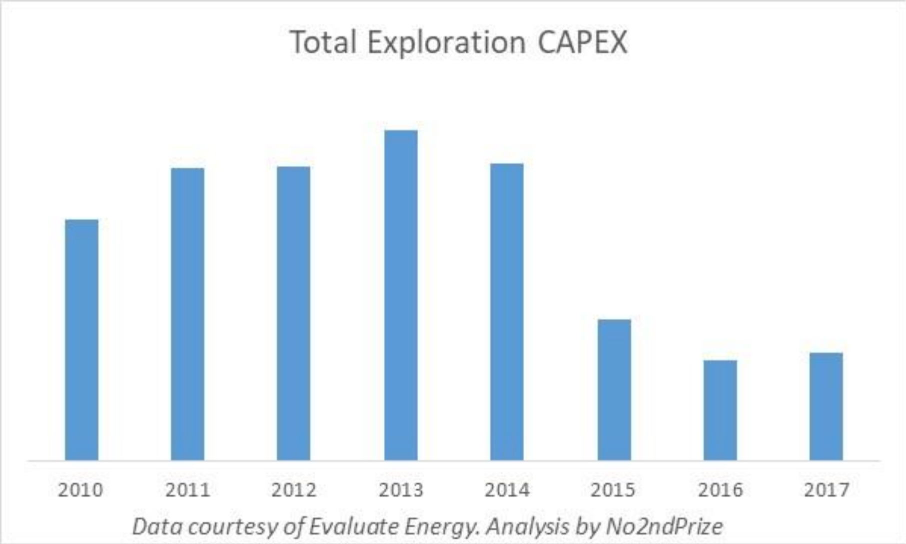
For comparison, development wells (on the same basis) over the same period have the following trend:



The 2013-14 growth dropped back sharply already in 2015 and, as with exploration, only began to recover in 2017, corresponding to a major shutdown of development activity. This, as we shall see, is concerning.

Resulting Exploration CAPEX

From industry activity, it is unlikely that 2018 will go beyond some limited, but steady, growth once the comparable reporting is in – either for exploration or development drilling. In absolute terms, exploration CAPEX (which is mainly drilling and new acreage but is also seismic) for the same group looks like this:



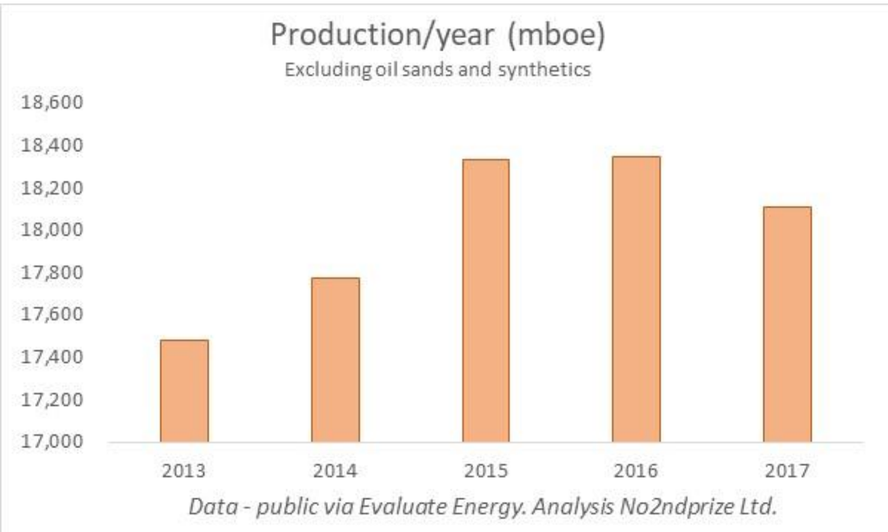
The level of drop-off is hardly surprising, encapsulating as it does both activity drop-off and the impact of rig rate and service price reductions.

The Production – Oriented Market Outlook

Reserves Cover – which is one driver for drilling activity – only tells the front-end part of the story. All fields in production have a limited life (and a decline curve that demands greater intervention and consequently higher lifting costs as they age). That 4D seismic (usually a continuing need in a downturn, given the short cycle time to achieve solid ROI) dropped off so much in the current/last downturn, is not that surprising: 4D seismic only has value if it impacts the planned field activity. If the plan is for no activity beyond continuing production and to only carry out minimal necessary safety-related maintenance, then there is nothing to impact.

Production Profile

Overall, hydrocarbon production for the bellweather group has remained remarkably flat in recent years, considering the lack of investment. The graph below excludes unconventional production as far as possible.



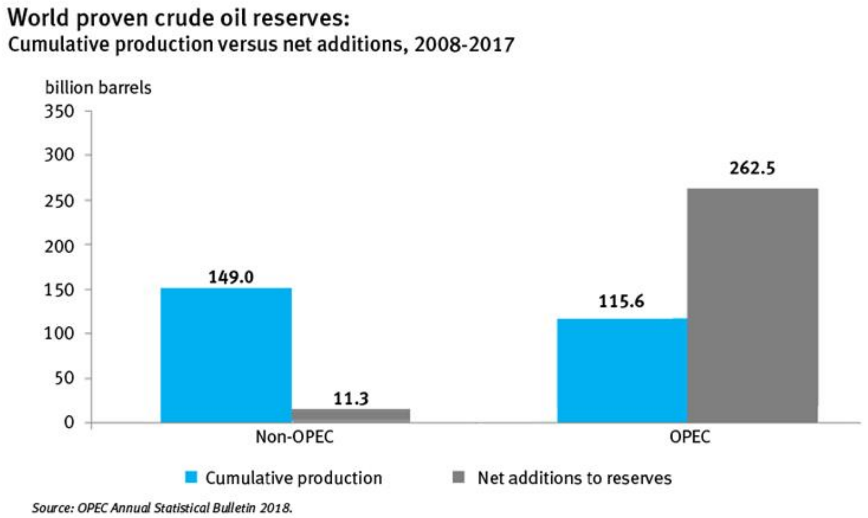
Note this graph does not start at zero: the trend is slightly down but overall remarkably flat. It is plotted this way to highlight what may prove to be the beginning of a downward trend after 2016. Certainly, 2018 national reporting suggests non-OPEC production in 2018 may prove to be lower than 2017.

A quick look at OPEC

No discussion of either reserves or production can be considered without looking briefly at OPEC. The OPEC statistical bulletin for 2018 includes the graph blow.

At face value, the overall "Non-OPEC" result gives major cause for concern, whilst the OPEC story is very comforting – especially with OPEC production increasing during 2018. It should not be forgotten that many of OPEC's members rely on PSC relationships (i.e. companies such as those in the bellweather group) to renew these reserves, so the two are not entirely separate.

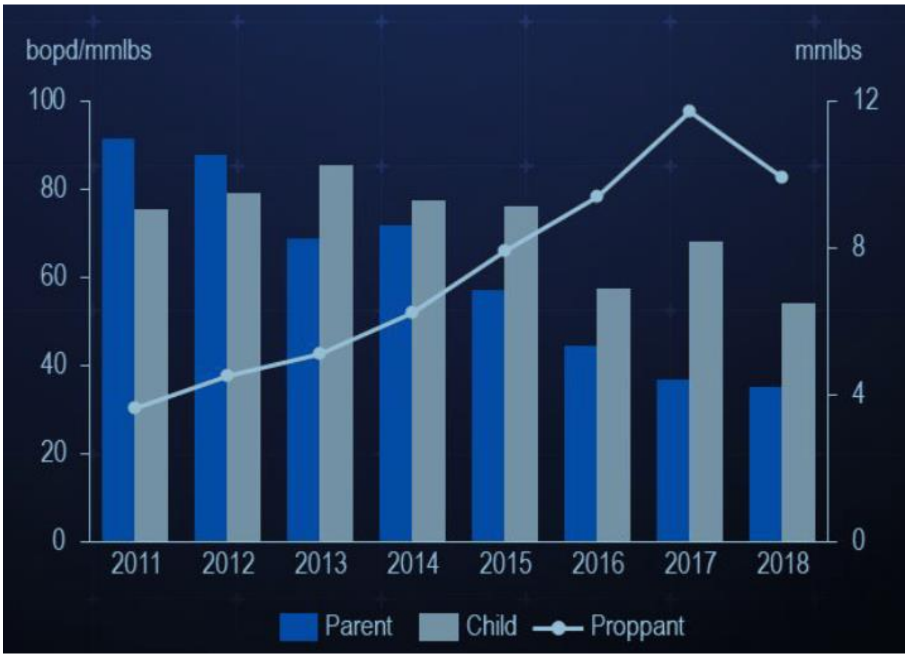
To what extent the international energy industry is willing to rely on OPEC production to feed its refineries is not a topic for this white paper.



Is industry likely to return to an "onshore unconventionals will save us" mindset?

What the trend will be over the next few years is the question; onshore (principally unconventionals outside of the Middle East) are high Opex and require constant drilling to maintain production profile. Whilst the US has proven to be both prolific and resilient, the potential environmental concerns (I don't want to go into whether perceived or real here) associated with repeated "Fracking" is very likely to prove a significant barrier to new areas of onshore unconventional production – Europe is a classic example.

Thus, there are signs that relying on unconventional supply to "plug any gaps" may be beginning to have run its course. Note the Schlumberger analysis of IHS data presented at Barclay CEO Energy conference by Paal Kibsgaard in September 2018 included this analysis of well productivity from the Eagleford onshore US:



Source: *Kibsgaard Speaks at Barclays CEO Energy-Power Conference, September, 2018. Schlumberger analysis of HIS Markit data*

If the industry starts to consider this level of effort is not cost-effective in a $50 oil environment, is the offshore ready to fill the gap?

There is good reason to conclude this is far from the case (see Opportunity, below). The lack of investment in offshore in the last five years has turned a fairly comfortable outlook in 2010-11 into a very discomforting one for many at the beginning of 2019.

Conclusions: Motive.

- Exploration has finally begun to pick up late in 2017; flat drilling success rates imply a focus on brownfield.
- Overall industry offshore reserves to production ratios entered this downturn in a reasonably comfortable place. Now, however, the industry is facing a need to add developed reserves at an accelerated level
- Production has remained fairly buoyant but there is a high likelihood of a slowdown in the near future, unless upstream efforts are accelerated considerably.
- If the general industry sentiment that onshore unconventionals have peaked is correct, then the shortfall will have to come from offshore, and this will require a significant effort.

Opportunity

We have reviewed the ability of the industry to make sustainable profits, (even after recent price falls, though it is tight) and begin to increase offshore upstream activity -whether that is exploration (greenfield or brownfield) or optimizing and extending current production.

We have noted that the overall challenge of maintaining offshore production and thus maintaining that positive free cashflow has increased during (and primarily as a result of) the recent (current) downturn, such that the relatively comfortably situation that prevailed in 2013 no longer applies.

We must therefore look at Opportunity; does the industry have the acreage to exploit quickly? Does it really *need* to act?

Can the industry shift gears – and does it have to?

The overall result for the bellweather group gives a very reliable predictor of future activity and therefore "need to act". There are two elements: the overall outlook (i.e. the group as a single entity) shows overall demand – industry outlook "Opportunity".

The overall outlook demands either a return to reliance on OPEC, or unconventionals, or a major gear change to identify, in particular, additional offshore reserves as well as a re-invigorated greenfield exploration activity to identify those sizeable new fields which will "move the needle on the dial".

This does not reflect individual energy company realities (before some of my friends in particular energy companies shout at me!). Some will still be in a good place, others now facing a need for urgent action. This method can also be used at company level to identify specific opportunities – which would require a much deeper analysis of the deconsolidated data.

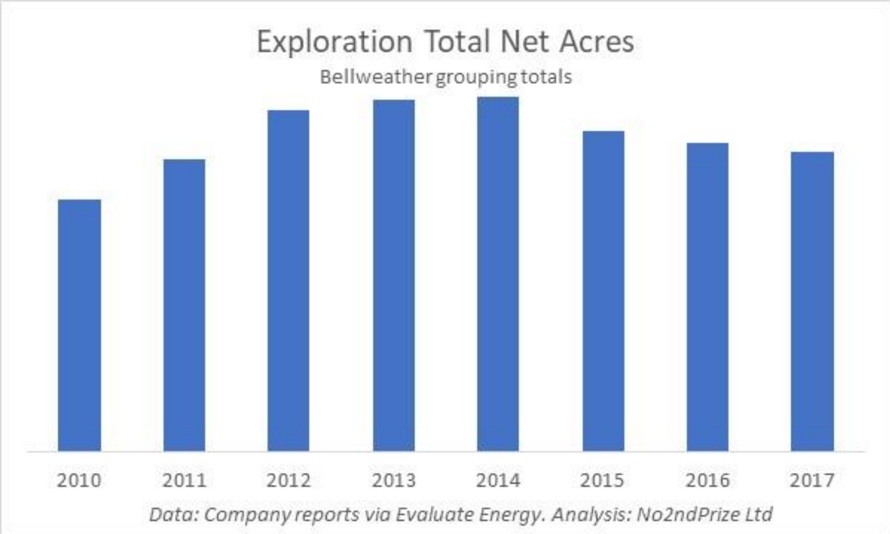
Using Net Acres as a predictive indicator of future seismic demand

A detailed study carried out by No2ndPrize early in 2016 showed exploration acreage was being relinquished significantly faster than it was being acquired. It is beyond the scope to look in that level of detail here. However overall net acres held is a high-level result and the strong correlation between overall changes in acreage held and the level of subsequent upstream activity is very clear. It has been demonstrated to correlate particularly well with subsequent seismic activity as described. This makes empirical sense (increases in acreage lead to increased demand for seismic data). In the graphs below, we look at total net acres held, which removes duplication on partnerships (i.e. 1 acre held * 50% equity interest = 0.5 acres; equity changes within the group do not impact totals). It is split into exploration and production net acres

Note the information is extracted from individual company annual reports; therefore, the latest data available at time of writing is as of December 2017.

Exploration Acreage: Upstream Opportunity space

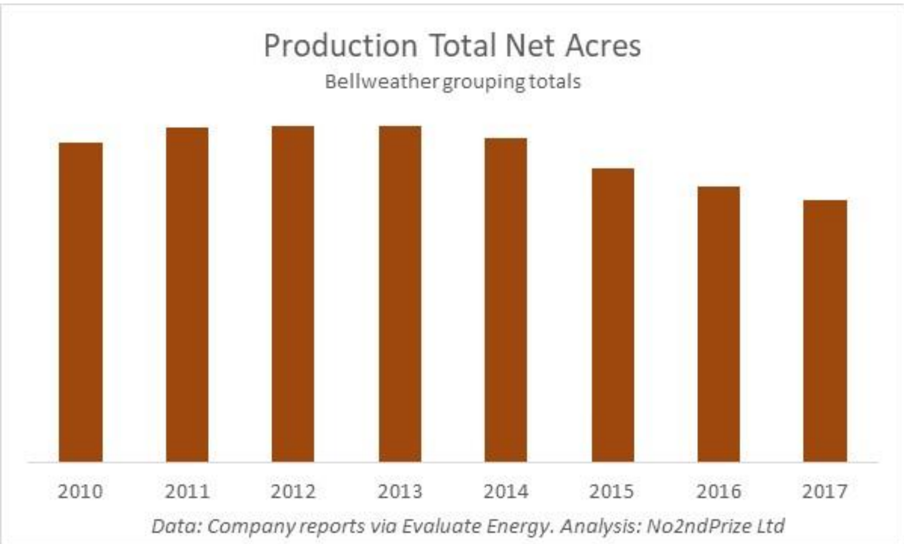
The graph below shows that overall, Exploration acreage continued to decline from the peak in 2014. Despite some resurgence of licensing rounds in 2017, which continued in 2018, the total is still falling, though the pace of fall has reduced and it may well be that 2018 data, when available, will show a levelling off; new licensing activity in 2018 certainly continued to grow, but it is disappointing and not at all a positive indicator that, despite license rounds in 2017, the net result was still a drop, albeit smaller.



Changes in net exploration acres correlates very well with upstream exploration activity (especially Multi-client seismic) in the next 12-18 months. It would be nice to suggest a significant recovery, but the data shows this is still a way away. Part of the reason for this was an unusually long acreage/reserves purchase phase in late 2016 - mid 2018; purchasing reserves is the standard herald to the end of a downturn but usually lasts ~ 9 months. It does generate Multiclient late sales but is considered an alternative to field exploration. There has been significant interest in OBN-based multi-client seismic in 2018 and this is likely to continue in 2019. This is more a function of either addressing intractable 3D imaging challenges (in the Gulf of Mexico, for example), or it is related to brownfield exploration (the need to provide new feed into pre-existing platforms, covered below).

Production Net Acres: assessing the production base

There is a very real possibility that the continuing slide in exploration acreage reflects maturity in a static market, in which case the production acreage would be expected to increase as exploration acreage is converted to production but not renewed.



This is clearly not the case. Total net acres held by production (i.e. developed), has shown an even steeper decline (down 22% from the peak in 2013, versus Exploration down 16% from a 2014 peak).

Changes in developed net actress held accurately predict development and reservoir seismic demand 3-4 years hence. This explains much of the drop in development seismic, exacerbated by the severity of the oil price drop that also impacted the infield activities for which 4D seismic provides the essential data.

What does this mean for both Exploration and Production/4D seismic?

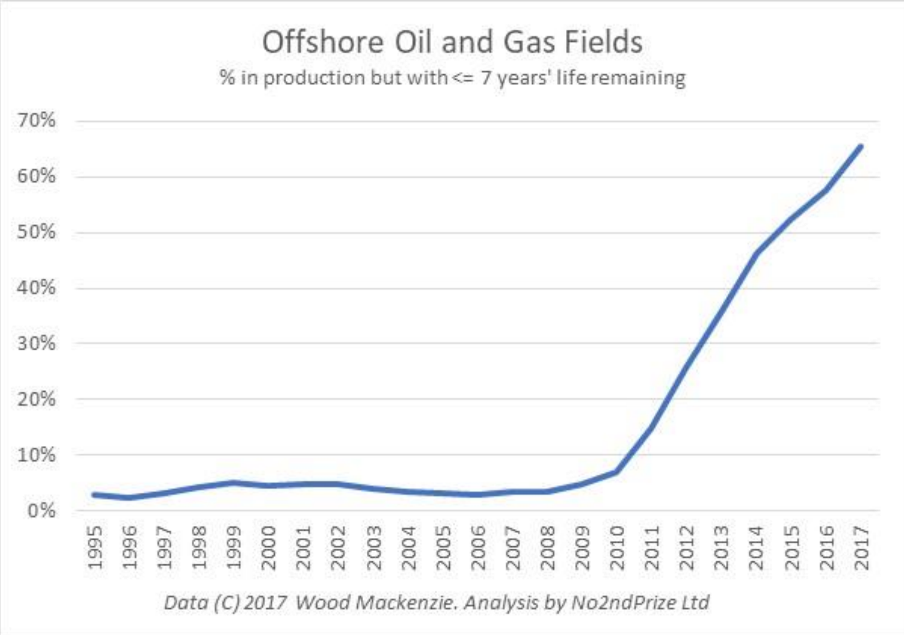
For anyone in the seismic industry, this does not look to be a comforting picture. With both exploration and production acreage still falling in 2017, what does this mean? Before anyone slashes their wrists, there are three points to make:

1. This sample is sizeable and reliable, but it is not "whole industry". Acreage sold on to companies not in the sample is lost but is still active; it would need a full analysis of the complete relinquishment picture to determine whether this is relevant or not.
2. A "glass half full" interpretation is that, with upstream acreage now overall 16% down, what remains has been high graded, and is ripe for development (we have seen how, whilst overall P1 reserves have remained amazingly flat, the developed reserves total is down 9% since 2013). Therefore, to rebuild the reserves opportunity pipeline, new exploration acreage is required; we have seen indicators of this, such as a resumption of license rounds in Brazil and the positive outcome of the Norwegian APA 2018 – though note this is mainly in mature areas and there is less appetite for frontier.
3. The impact of the drop of production acreage strongly implies a looming shortage of producing assets. This proved to be the case – see Abandonment, below.

Before looking at the seismic outlook, one vital component of the overall picture has not yet been explored. The usual cycle of new fields passing FID, being developed and coming online has been disrupted, certainly since 2014. From an offshore perspective, with the rush to onshore unconventionals in the period before that, this pattern may have been disrupted before this.

Offshore Field Abandonment

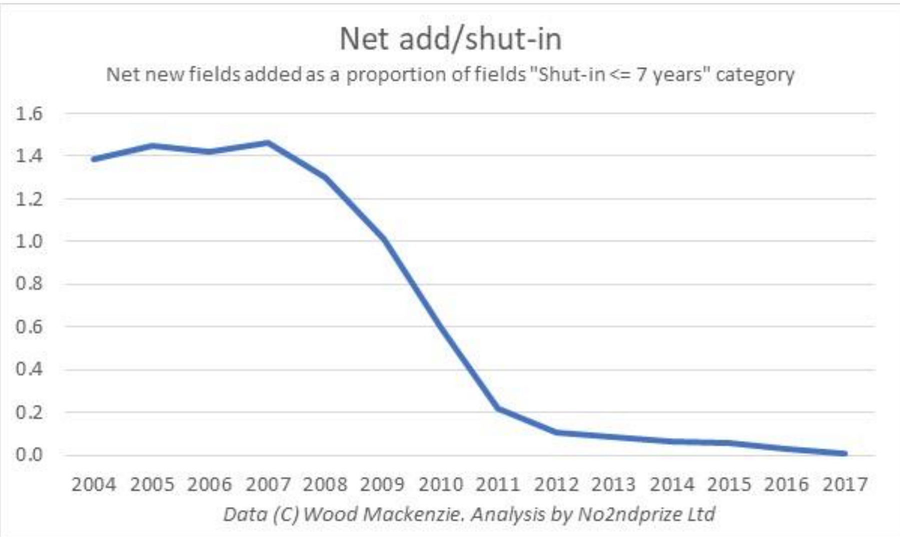
Data for all offshore fields was re-worked from information previously studied for other purposes (courtesy Wood Mackenzie) to look only at the "first production" and "shut-in" dates for all fields back to 1995. For each year, the total fields in production in that year was extracted, and the proportion of those fields that were planned to (and did) cease production within 7 years plotted. Then the process was repeated for each year, from 1995 up to 2017 (latest data available). 7 years was selected as it corresponds to the bellweather group industry average developed production:reserves cover, and broadly reflects "optimal" time to first offshore production in the current environment.



We can see a very well-established pattern for the first 13 years: each year, around 5% of the fields in production in that year, fall into the category of "these fields will shut-in in the visible timeline". Note this does NOT necessarily represent the same proportion of production. This is important – larger fields have longer lives. Also, the Wood Mackenzie definition of a "field" is a legally separate accumulation – so, for example, Gullfaks and Gullfaks Sor are counted as two fields.

Then, around 2009-2011, there was an uptick such that by 2011, that annual total increased to 10%, not too much to worry about. The surprise is that this proportion has continued to rise – rapidly -so by 2017, *two thirds of all* offshore producing fields were due to be abandoned within 7 years.

It could be argued that newer discoveries are (typically) smaller and therefore will have shorter planned field lives – all expected, all planned for and not to worry. There are for sure new fields (and especially extensions to pre-existing fields, which are much more cost-effective to develop/produce into pre-existing facilities) continually coming on line, renewing the population. So if the above data are presented a different way – *the ratio* of net additional fields (increase in total fields in production) to the number of fields in the "<=7 year shut-in", we get the graph below.



Data sources as indicated. Evaluate Energy normalizes and consolidates publicly available data.

Just as reserve replacement ratios ought to hover around 100% to ensure a healthy business going forward, then this ratio should logically hover around 1.0 – sufficient new fields coming into production to offset those that will soon shut in. As can be seen, for the offshore industry overall, this plummeted in the same 2008 – 2011 period (broadly corresponding to the period when the onshore unconventionals were going to save everyone). Again, note this is number of fields, NOT total production; translated to production and reserves, the flow on new fields is always better, and it is possible (though unlikely) the new fields are larger than those approaching shut-in. The high-level picture is inescapable, though; *field shut-ins are set to increase many-fold over the next few years, and they have not been even partially replaced by new fields coming on stream*.

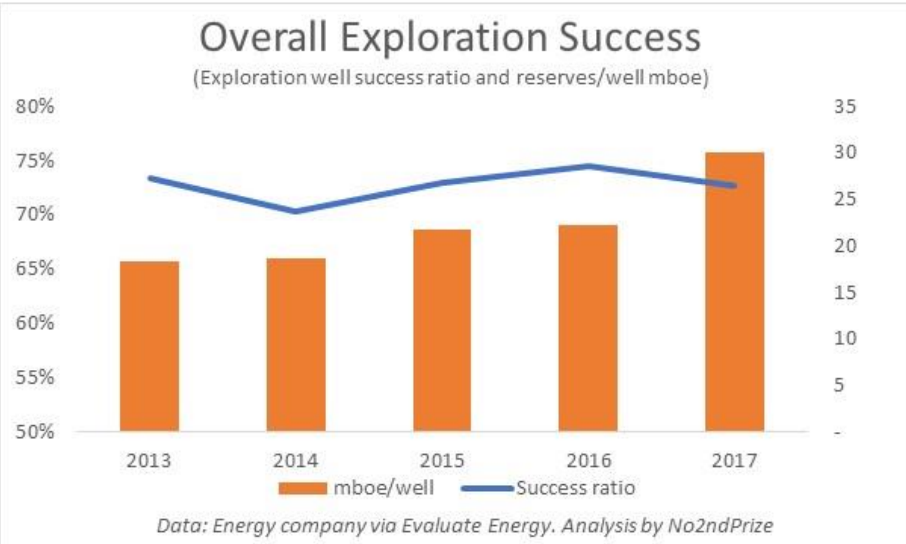
The situation (at a global level) therefore started to decay before the onset of the most recent downturn, which has exacerbated it. This may help explain why the "buy rather than explore" phase, always the herald of an ending downturn, has lasted much longer than usual; companies wanted to secure more developed reserves, fast. This will help "fix the roof" for the purchasers; globally, though, whoever operates the fields, this is simply rearranging the deckchairs on the Titanic.

The global picture above must make uncomfortable reviewing for some: just as for any other element of this analysis, the status of individual energy companies will not necessarily follow this pattern; some may be an a very good position, whilst others may be facing a crisis. In the current environment, almost regardless of oil prices, those companies in the latter category will be forced to act.

Is Exploration drilling worth it?

The final – critical – part of the analysis is to determine whether the offshore-oriented activity is worth it. The welcome uptick in 2017 suggests that it is, but it is also possible to look at this objectively.

We have seen that P1 reserves have diminished – but the undeveloped reserves have not dropped as much as might have been expected, given that conventional exploration well counts have tumbled. Something is going right, then. If we look at drilling outcome in terms of boe added reserves per successful well, we get the graph below:



Whilst the number of wells has dropped significantly, as noted above, and success ratios (discoveries/total exploration wells) have remained stubbornly flat at what is probably the efficient frontier of 70-73%, the reserves (mboe/well) added to the Extensions and Discoveries reserves pot per successful well has increased over 60% since 2013. The industry is significantly more successful per exploration well. It may be brownfield oriented but it is a great success story and suggests exploration is a worthwhile activity. This, in terms of opportunity, is strongly indicative of confidence to re-invigorate exploration.

What does this mean for the seismic industry?

The recent activity levels on frontier exploration (effectively, now, Multi-client) have clearly been inadequate but also reflect the overall drop in net acres held. This cannot be reversed by acreage trades. The industry is still risk-averse (in concentrating on brownfield versus frontier) and this is likely to be insufficient.

Whilst the "around production facilities" prognosis below includes some brownfield exploration, this is unlikely to provide the level of long-term reserves needed to service what continues to be an inexorable rise in oil and gas demand, despite legitimate concerns over global warming and economic headwinds. Without a re-boot on unconventionals, the offshore industry must fill the gap, and greenfield exploration, essentially out of favour for a decade, must return.

However, this will be the second priority. For 2019 and 2020 we will see a continuation of the trend visible in 2018; there is a looming abandonment crisis in offshore and the only viable way of addressing that is to find more feed for the production facilities that are already in place. It is a virtuous circle; not only does it help defer abandonment (thus giving time to re-build compromised balance sheets to enable those costs to be borne), it adds reserves that can be moved to "developed" very quickly and cheaply by connecting to pre-existing infrastructure and pipelines to shore. It is a forced move and thus likely to continue even if oil prices are also facing headwinds at present.

The rise of OBN has been mentioned before; even with recent operational and technical developments lowering the cost (and, given that ~80% of today's producing fields have surface production facilities, it is often easier than towed), it is still more expensive than towed marine, so for this battered industry sector, there are opportunities to be found.

Conclusions: Opportunity

- Greenfield exploration efforts, severely curtailed in recent years, have left the overall international energy industry woefully short of potential to replace current field areas.
- Net acres held have continued to fall, both for exploration and production, implying a level of maturity that may mean limited "unfound" opportunities remain. Major new greenfield discoveries (despite some good results in 2017/18) may in general demand new acreage.
- The offshore industry is facing an incipient shut-in and abandonment crisis unless it can identify new reserves produced via current infrastructure and brought to market within a few years.
- The outlook for offshore seismic, derived from the above, implies a short-term focus on brownfield exploration and re-development, especially around current infrastructure. This is already showing up in the beginnings of mature basin multiclient around facilities. Longer

term, there is going to be renewed interest in re-working new plays in current acreage and pursuing what new frontier opportunities arise.
- The continuing improvement in overall exploration success (reserves/well) is a strongly positive indicator and bodes well for confidence in the success of upstream activity.

Conclusions

By necessity, this study uses a known accurately representative but incomplete sample for the "Means and Motive" analysis, as well as the acreage side of "Opportunity". The data is complete in terms of field populations. A "deep dive" would reveal interesting geographical and individual energy company variations but is well beyond scope.

The overall outlook for the upstream – from this analysis, can be split up and summarized as below:

Exploration Oriented

Greenfield exploration will flat-line in 2019 as the longer time to first production of frontier acreage is less attractive than brownfield exploration and satellite development. However, there will be a focus on continuing to maximise the potential of the acreage already held and this will create opportunities for re-analysis of pre-existing data and the addition of new data in highly prospective areas where the interpretation is unclear or ambiguous.

Brownfield exploration will increase, as it offers a much shorter (and cheaper) route to first production. We are seeing the rise of high fidelity (reservoir towed and OBN) Multiclient surveys in these areas and a hesitant return of contract data. Issues such as the suitability of such data for future 4D has to be confirmed. The continued overall success of exploration in terms of reserves/well is a strongly positive indicator. Brownfield volumes (probably often combined with production, below) will continue to increase to shore up "cheap to convert to developed" reserves.

Production Oriented

That production drilling dropped off just as sharply as exploration, and that production acreage fell even more than exploration (for our representative sample) points to a "harvest only" mindset that was inescapable given the drop in oil prices but has left an industry badly in need of feedstock for current facilities. This is confirmed by the rise and rise of the proportion of offshore fields facing fairly imminent shut-in. This will drive a significant increase in this type of seismic, which will be very much a "forced move" by those companies which are most at risk from the consequences of the sharply reduced activity in the past four years.

The objective of this white paper has been to look purely at data and facts rather than "industry sentiment". This is important, of course. The logic of treating all companies as if they were a single entity uncovers what that single company would have to do. However, each energy company will be looking at the situation it finds itself in and will be forced to plan accordingly. At the top level, though, 2019 could shape up to be very uncomfortable for some.

I trust this is a useful adjunct to individual marketing activities. Please feel free to comment back to me.

Robin Walker

No2ndPrize Ltd. 20th January, 2019