E&P corporate analysis

Value the company, not the asset

September 2016

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Foreword

For at least the last five years, E&P investments have failed to make acceptable returns for many equity investors. High and increasing costs of capital driven by asymmetric cost inflation, a prevalence of increasingly distressed debt and an industry that understandably needs to demonstrate acceptable internal returns from M&A has led to many smaller E&Ps (and E&P equity investors) being uncomfortably squeezed.

At Edison we have been trying to come to grips with the challenge of identifying the right E&P companies, corporate structures and assets that can hopefully be robust enough to face the challenges that both industry and capital markets now throw at them. In this report we assess these challenges by analysing the full cycle economics of up to 140 different E&Ps, looking at the costs associated with doing business, how these evolve through time and how these can ultimately affect equity valuations. At the heart of the analysis is an often misunderstood focus on corporate economics and how these can often be radically different to the standard asset valuation approach.

We believe that this report will be enlightening to all who participate in the funding of E&Ps as well as company management teams, boards and advisers. Edison will be looking to embed the findings from this analysis into all its equity research as we continually seek to make our research robust, accessible and relevant to all.

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Oil & gas

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In preparation for a new oil cycle, we believe investors should re-examine the critical components of the valuation of oil companies to ensure lessons are learnt from the last cycle.

Oil price performance has been a massive driver in lowering share valuations and sentiment in the sector, which had already been compressed by ever-higher costs and falling exploration success among the small caps. In the downturn, costs have moved aggressively, suggesting a rebalancing towards a lower oil price. Unfortunately, so far this has not resulted in a substantial rebalancing of sentiment towards investment, with exploration stocks still in the doldrums and many trading below cash levels.

At some point this sentiment will change, and in preparation we think investors should look at fundamental company valuations (rather than asset values in isolation) to price investment opportunities. By this, we mean take into account all the risks and costs that companies run into when progressing assets that may negatively affect the asset value. We primarily look at examining the costs to equity investors of holding E&P stocks in the last cycle and the associated equity and asset dilutions required to fund operations; we conclude that this effect may be larger than many currently assume.

For example, the CAPM-derived cost of equity for London-listed E&Ps has risen from c 8% in 2000 to over c 11% now – this has a material impact on costs (particularly in an industry that is so reliant on equity funding). We also think returns demanded by industry partners may be higher than some realise and we believe these partners will be even more stringent in their demands given the last cycle's lessons.

The result of this is that we believe un(der)funded exploration and production investors may have to sacrifice over half the value of a project to fund development. This is on top of the dilution seen during the appraisal and exploration phases. Together, our analysis of E&Ps over the last 15 years indicates a material dilution in share count across the sector (of around 20%), affecting companies that have been successful as well as those that have not. We believe investors should bear this effect in mind.

In view of this full-cycle look at exploration, we have also examined factors that should be considered.

Investors have to be careful in analysing the likely full-cycle returns/value (at the company level, not just at the asset level) – and application of higher costs of capital should be seriously contemplated. This will affect the assessment of valuation, force better examination of sources of capital and require scenario planning. The capital intensity of projects will affect the working interest and value companies will be able to retain.

Project risking is a critical part of the process. Lower full-cycle value for exploration companies implies exploration should only take place on lower-risk targets, while the benefit of exposure to multi-well diversified exploration should not be underestimated.

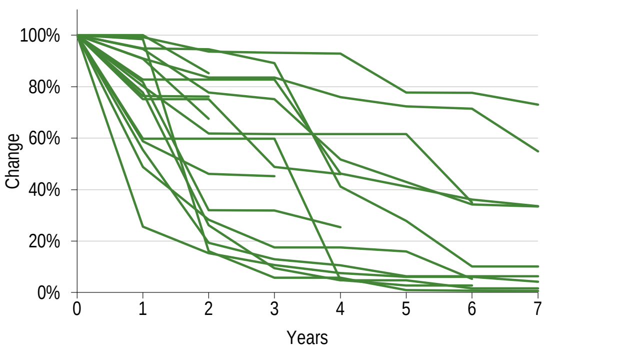
Executive summary

We believe that many equity investors overestimate the value of exploration and development assets because they look at them without considering how each asset should be valued as part of a company that has capital and operational constraints. As a result, equity investors may not fully take into account the toll that funding takes on E&P investor returns. For companies that need to source external funding, we contend that the returns demanded by all investors (be they equity, industry or debt) combine to imply a higher cost of capital for corporates than many use, implying a lower eventual equity value.

Many factors suggest that analysts and investors could approach the valuation of E&Ps in a more systematic way. There seems to be a structural disconnect between share prices and analysts' targets; analyst valuations sometimes decrease at the time of de-risking events (farm-ins, development), while often (target and share) prices fall during development. It is common to see analysts use a discount rate of 10%, despite varying and wildly different funding challenges. This suggests that valuations may not properly price true risks (not that we think it is possible to price in every event). We also believe that investors do not discount the dilutive effect resulting from the full development lifecycle of assets (within the companies), leading to a risk of over-optimistic assumptions on the value of the assets at any given time.

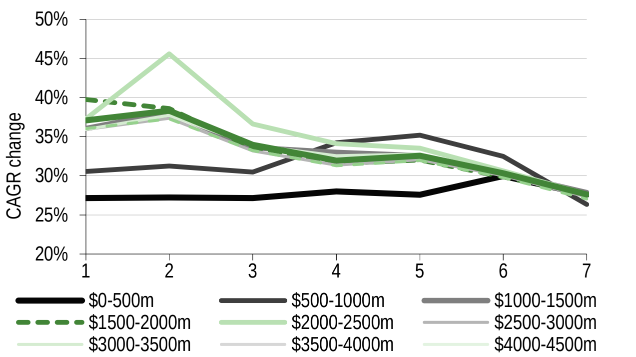
To better understand and quantify the requirements for valuing E&Ps, we have examined the lifecycle of (up to 140, primarily London-listed) E&Ps, looking at equity raises, share count, asset ownership and selected farm-ins. This empirical work suggests a material decline in the share of an asset that equity investors own as the assets are taken through exploration/appraisal and development and funded by equity dilutions or industry farm-ins. If investors do not add to holdings, they see the effective asset ownership (held by their shareholding) – or EAO – fall by 17% per year on average (Exhibit 1). This is simply the effect of having to give up value to buyers in farm-in scenarios or seeing the share count increase as equity raises are executed to fund further work (whether exploration/appraisal or development). **In short, investors in (unfunded) companies will see their share of the value of assets leak away as others are brought in to fund further work. This is both significant and (almost) inevitable.** This may explain the common trend of seeing share value fall after initial exploration success euphoria fades towards funding a development (in the absence of a company or asset sale).

Exhibit 1: Even successful exploration sees material EAO degradation



Source: Edison Investment Research, Bloomberg

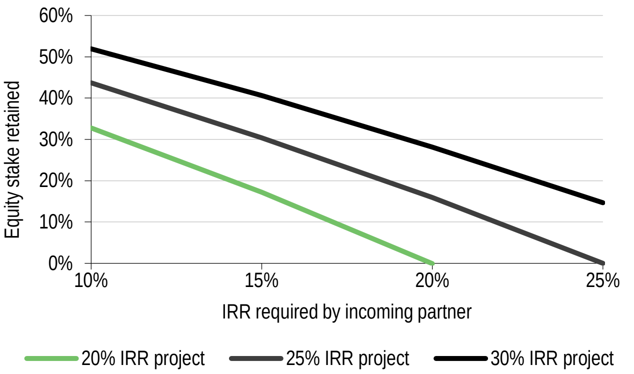
Exhibit 2: Degree of share dilution among E&Ps in the last decade has been consistent and material



Source: Edison Investment Research, Bloomberg Note: x axis represents CAGR dilution over time (years since major discovery).

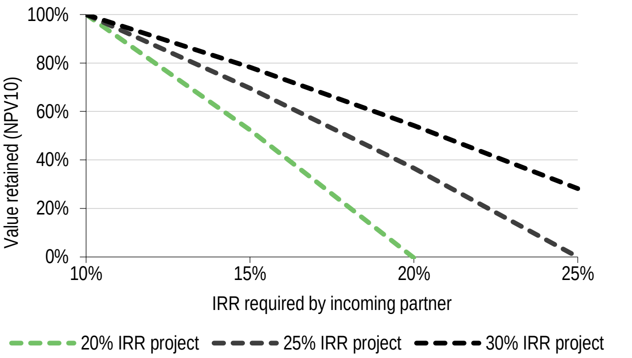
This can be understood from a modelling perspective by replicating varying return/value scenarios. For a project to be funded through development by (in this example) an incoming partner requiring a 10-25% IRR, the incumbent needs to give up a material percentage of working interest (Exhibit 3) and value (Exhibit 4). Taking a large offshore project as an example and using a discount rate of 10% to value resulting cashflows, the incumbent may have to sacrifice 60-80% of working interest (and 40-60% of value) to have projects funded (from FID). **The larger the difference between the discount rate and the IRR demanded/implied by the incoming party, the greater the discrepancy.**

Exhibit 3: Working interest retained by company given different project IRRs and required returns on capital for incoming partner



Source: Edison Investment Research

Exhibit 4: Value retained given different project IRRs and required returns on capital for incoming partner (employing a 10% discount rate for seller)



Source: Edison Investment Research

This does not take into account funding the company during this period and other activities (such as a G&A bill of $5m pa that is almost always paid for by equity investors), or the complexities of geological and commercial risking, something we touch on.

Investment considerations

When investing in E&Ps, investors are seeking access to value added through exploration or development. On balance this means investing in companies that balance the potential reward of oil exploration with the drag of costs and risk. Our work suggests the baseline value of exploration in unfunded E&Ps may be lower than many think and this implies that for creating value, investors need a stronger handle on this potential, but also need to create mechanisms for examining the risks and costs of investing in E&Ps. We would highlight these as:

- **How to best estimate the full-cycle cost of capital for companies**. This is a difficult judgement to make but we believe investors should at least ensure the valuation across a range of higher discount rates is appropriate (above the standard 10%) – third-party costs such as farm-ins are useful (and less subjective) guides. The scale of capital required should be assessed as critical – broad assumptions on ease of access should be dealt with sceptically, given the difficulty many companies have selling assets despite significant effort. Companies can quickly run out of options, and onerous financing structures can become unsustainable.
- **Dilution of ownership either through share or asset dilution should be understood.** This means investors and management should more fully appreciate the costs of doing (or not doing) a deal in the light of possible future scenarios. Investors should seek comfort that management understands and will seek to mitigate dilution and maximise value for investors.
- **Good management of exploration risk.** For investors, this means exposure to enough exploration to reduce the effect of random chance and the balancing benefits of a portfolio approach. High risk and/or expensive wells rarely make sense except within the portfolios of very large companies (and low costs of capital).
- **Pre-/post-discovery assessment needs to be considered.** Assumptions on revenues, costs and schedules need to be flexed. Risking needs to include more than just geological risks, as not all discoveries are developed.

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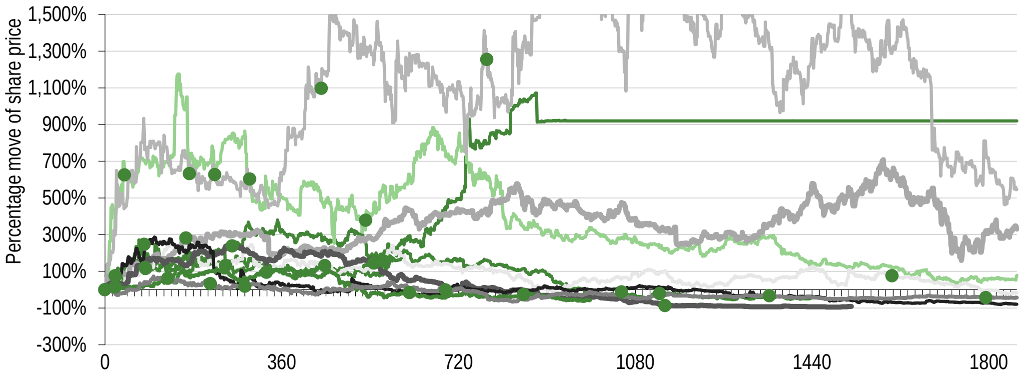
Returns on exploration can be very significant for shareholders. Success stories of Cairn and Tullow, Imperial Energy, Cove (and others) are testament to the value that can be created by a small explorer discovering (and developing) large resources. However, for every exploration success, there are multiple failures and many where successful exploration has not led to the massive value creation hoped for in earlier times.

In the chart below, the share prices for companies that had significant finds are shown. Many see material uplifts in the share prices for the first year or two (from day zero of discovery), but see declines thereafter. While the poor macro environment cannot be ignored, we believe there are several factors indicating that the initial reaction to exploration success was over optimistic.

Exhibit 5: Share prices for successful E&Ps (those that found notable discoveries in recent years)



Source: Edison Investment Research, Bloomberg. Note: Scale restricted to 1,500% for ease of viewing; GKP's price increased by 3,500% at one point (due to takeover speculation we think). Green dots = equity raise. X-axis denotes days since significant success.

In the warm afterglow of exploration success it is easy for investors to forget the impact of future decisions and costs to progress the asset, and naively assume a best-case scenario will materialise. While a few stories (eg, Cove) have seen a bidding war and huge upside, we would argue that, at all times, investors should look at share price potential should the company continue to own the asset to production. This will likely involve multiple equity raises to fund appraisal, while development could be equity, industry or debt fuelled. Of the multiple paths to production, most will involve a material dilution to investors' stakes. Any benefit from intervening bidding should be seen as upside and not a base case, we think.

We classify the major factors that work to degrade investor returns as:

- High cost of capital
- The asset and equity dilution seen over time
- Development issues
- Exploration success

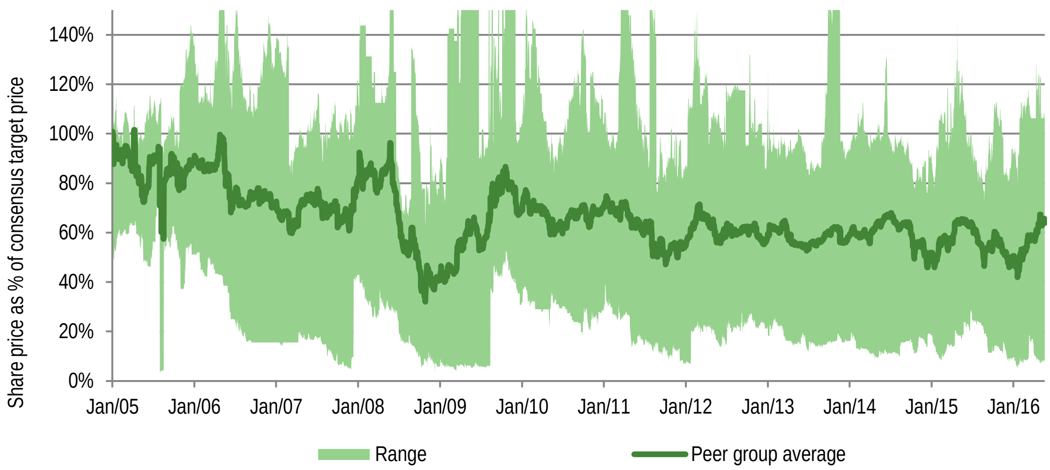
What WACC should be used to value E&P companies? Higher than you think

Although the typical discount rate of 10% used by analysts gives consistency and comparability between companies and projects, our analysis indicates this approach needs refining.

The structural disconnect between consensus target prices and prices that companies actually trade on can be at least partially explained by the market application of higher WACCs. Costs of capital should be materially higher for pre-discovery exploration companies.

There are a number of other factors that could be at play – how do we arrive at a fair assumption on WACCs for E&Ps? After all, WACCs applied by the market may not be correct either, leading to investment opportunities.

Exhibit 6: Material structural discount of share prices to target prices suggests the market is more pessimistic than analysts and could point to WACCs being too low



Source: Edison Investment Research, Bloomberg

Arriving at a single-value WACC to apply to all companies is not possible, given the breadth of company type and changing appetites as markets move. We do think many are missing the key factors that should be taken into account when valuing E&Ps.

Deriving a cost of capital

In an industry as capitally intensive as oil, project NPVs are often much lower than the capital required to fund them (especially offshore). Given this intensity, the cost of this incoming capital is critical to the returns and value that incumbents can retain. For example, if we look at the capex and NPV_{10}s of developments by Cairn and Tullow, we get ratios of 2.1x (Catcher), 5.9x (Kraken), 7.5x (Skarfjell), 5.2x (SNE, 330mmboe), 3.0x (SNE, 560mmboe), 4.6x (Jubilee) and 3.0x (TEN) (although we note that intensity of capex to first oil or NPV is much lower). Given this intensity, the cost of sourcing this capital has a huge effect on the economic and investment viability of projects. Increased cost of equity over the last 15 years is a material compressing factor. Equally, the degree of capital intensity on projects is likely to have a huge impact on the value that companies will be able to retain.

For E&Ps there are three main sources of external capital and examining each should inform the WACC used by analysts and investors to value companies. We would stress that the WACC used should be informed by full-cycle costs of capital, which (should) fall from pre-discovery to production. We can gain insights into true WACCs by examining current trends, point estimates and indications of marginal costs at any point.

There are three main sources of external finance available:

- **Equity funding** – the true cost of equity for E&Ps is hard to determine. Too much reliance on CAPM-implied costs can give misleading results given (recent) market correlations or over-riding macro factors (eg, the global financial crisis). For example, analysis of CAPM results over the last six months implies a low beta given the strong correlation of the market to the oil price (which has been widely commented on and debated). As a result we use other methods to examine costs, such as directly observable discounts required for equity issuances to give a flavour of required returns. In times of stress these can stretch to nearly 20%, well above FTSE 350 averages of 4%. To this data, we can add the fees required by brokers as direct costs, which is not insignificant.
- **Industry deals** – we argue that the cost of capital for a company can be informed by the rate of return demanded by industry players entering projects. Exploration RoR are very difficult to assess, but by examining development IRRs for farm-inees, we see that IRRs can be 15-20%, even in developments where geological risk is low. Given the ambition for majors to achieve larger full ROCEs (which have often dipped below the cost of capital in recent times), the IRRs demanded are unlikely to be less than 10-12%. **If (later-stage) industry partners demand 15%, why would equity investors ask for less by taking more risk (often at an earlier stage)?**
- **Debt funding** is currently in focus given the low oil price reducing cashflows, putting some indebted companies in trouble, with corresponding increases in yield to maturities for listed bonds. Costs for debt vary, with Reserve Based Lending (RBLs) trending in the 4% (over Libor) range in recent years as the cheapest sources of finance. Corporate facilities are typically much higher, while corporate bonds range between 5-15%. Although most of the London-listed companies in the last cycle did not have material debt, a rising proportion of companies have debt (though well below that seen in the early 2000s), with debt making up around 30% of the capital base in those companies on average.

Cost of equity

There are many ways of getting to costs of equity, each with pros and cons.

WACC from current share prices

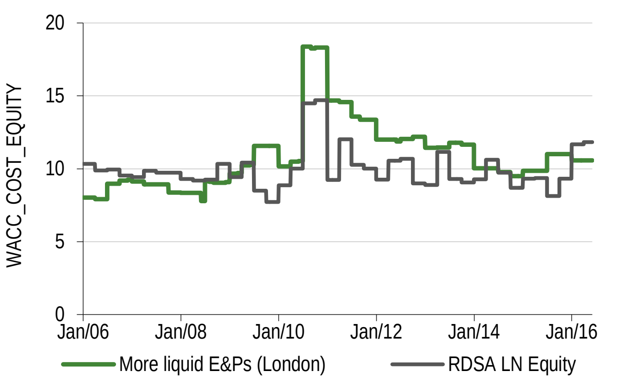
Most of the companies in E&P are primarily equity financed so the we could derive the WACCs from the current share prices of E&Ps. In the cases of our modelled companies (eg Rockhopper, Bowleven and others) analysis implies that the WACC is above 20% (if we assume that our other assumptions on production, timelines and risking are correct). In addition, a large number of companies are trading below cash levels, implying a massive range of WACCs.

However, as we show later in this report, there are other factors that could contribute to this discount, so a straight analysis from share price to inferred WACC may be misleading.

CAPM is not definitive

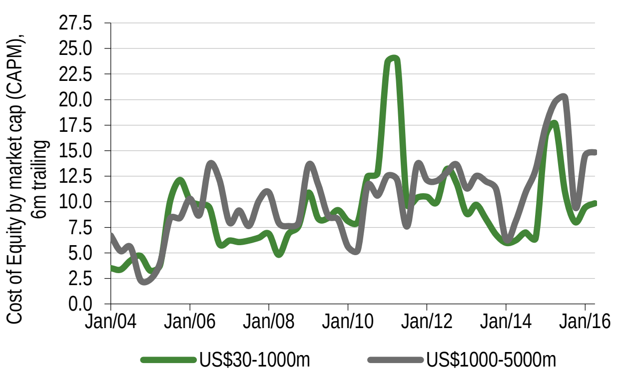
In search for an industry cost of equity, we could employ the CAPM. The calculation derives a beta from trailing 24- or six-month share data, and applies an equity risk premium based on the listing country (not country of operations). We argue that while the data is informative it is not definitive. A large number of E&Ps do not have revenues and company value often jumps in a very discrete way as wells are drilled, meaning that a lagging indicator of implied costs such as CAPM has limitations. Using trailing five- or two-year data cannot adequately capture the changes in perceptions (driven by a massive overhauling of the macro environment), while shorter estimation periods (we have experimented with six months) may also be misleading.

Exhibit 7: Bloomberg-derived cost of equity (%), using a 24-month time period is not instructive. Lower cost of equity than Shell is suspicious…



Source: Bloomberg, Edison Investment Research

Exhibit 8: …and six-month derived data are little better (lines shown are market caps of companies), %



Source: Bloomberg, Edison Investment Research

It also becomes less useful when the general market follows oil sentiment (as happened in Q415-Q116). In this scenario, the betas become depressed, leading to (in our view) a much lower implied cost of equity than is the case. We do not think it is reasonable that the cost of equity for oil companies is this low.

Deriving cost of equity from issuances

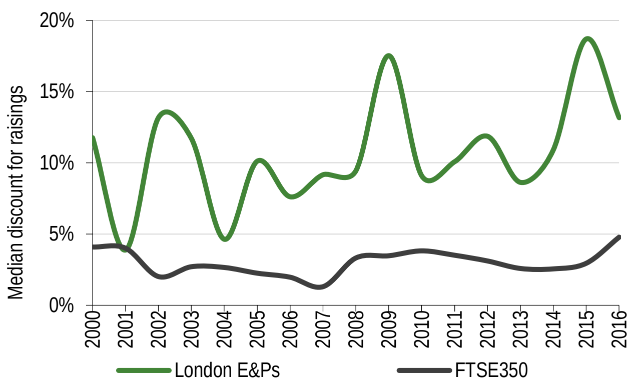
We can get immediate, direct feedback from the market on implied required returns when companies issue shares. Existing and new investors are asked to buy shares on a restricted time basis and the price arrived at should give a view of the returns required. Although the relationship between discounted equity offerings and cost of equity is not clear, it seems fair to assume that higher discounts imply higher costs of equity. We examined all equity issuances for the London listed E&Ps since 2000 (over 400).

It is clear that there is a wide spread of discounts to previous-day closing prices. The median is variable, but averages 11-12% over the time period. We note the vast majority are executed with a discount of 20% or less (40% are executed with a discount of between 0-10% and another 40% with a discount of 10-20%). It is not at all surprising that in times of stress (2008-09 and 2015-16), those costs increased markedly.

Exhibit 9: Equity issuances are executed at large discounts for E&Ps, which is a consistent trend over many years

Source: Bloomberg, Edison Investment Research. Note: Black dots represent the median for the year.

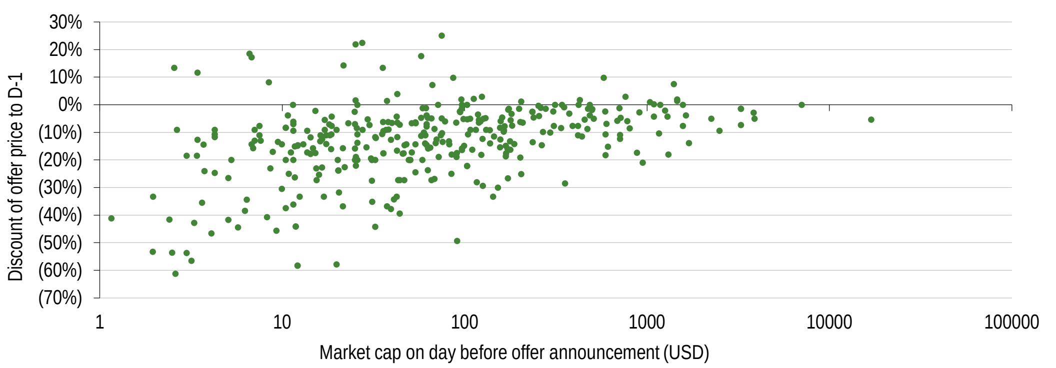
Exhibit 10: Median discount for issuances average 11-12% since 2000, but can touch nearly 20% in stressed times. This is well above the median discounts required by FTSE 350 during the same period



Source: Bloomberg, Edison Investment Research Note: The FTSE 350 line includes companies that have been in the FTSE 350 at some point during the period (they are included for the whole period, even if they were not in for the whole period).

It is worthwhile to compare these trends to those of companies making up the FTSE 350 during the same time period, where median discounts average around 4%. Some of this difference may be due to market cap differences (the smallest member of the FTSE 350, Jimmy Choo, has a market cap of $700m), but we note the discounts seen for non-oil companies in AIM is around 6%.

Exhibit 11: Offer discount is related to market cap (oil companies)



Source: Edison Investment Research, Bloomberg

Deriving the cost of capital from industry buyers

Farm-ins need to provide the incoming party with above cost of capital returns at (presumably) more conservative (planning) prices and costs. If we have enough information on the asset potential, we should be able to derive a cost of capital implied by any deal. This is a fairly direct indication of the capital returns demanded by investors (albeit industry investors). These deals are done by parties that should be extremely well informed of technical/commercial considerations in the projects and have been able to spend significant time and resources to undertake sufficient due diligence.

The IRRs implied by deals should give us indications of the possible floors for costs of capital for these bigger buyers, while giving us an equal view of the implied cost of capital for the seller. If a seller is prepared to accept an IRR for a deal of 15% (for example), it should imply that the cost of capital of the seller's alternative sources are higher than this (at least at the time of the deal and that project). It is arguable therefore that investors should refer to this (higher) cost of capital when appraising investing in the companies.

Of course, once a deal is executed (and especially if all required development capital is secured), the cost of capital for that project should fall materially. How this project cost of capital influences the wider company cost of capital will depend on the diversity of the portfolio and will be a much more direct implication for small companies with little or no internal cashflow generation.

Given the extra information that industry buyers have that the stock market does not, we can never be sure of the exact assumptions and beliefs used by buyers. However, it is considerably easier to derive these costs on development deals (whether carries or cash) than in exploration, given the material uncertainties involved. A small sample of deals is below.

Appraisal/development of the SNE discoveries, offshore Senegal (seller: Conoco ; buyer: Woodside; buyer's IRR: c 16-21%).

Conoco sold its 35%WI in return for cash of $350m in July 2016 (subject to govt approval). Although not a farm-down, we can calculate the return that Woodside expects from the development, assuming the timescale and costs profile publicised by Cairn Energy in August 2016. Assuming the production start-up in 2022, and real long term oil prices of $70/bbl, we model Woodside's IRR to be 21%. If we assume the forward curve at the time of the deal (with 2.5% inflation of prices after the curve stops), the return falls to 16%.

The price paid by Woodside was markedly lower (on a pro-rata basis) than the values ascribed by analysts to the other two partners in the project (Cairn and FAR). We note that the resources given by FAR's CPR are markedly higher than the 473mmbbls given by Cairn – we think it more sensible to use Cairn's lower number at this point.

Appraisal/development of the Etinde asset, Cameroon (seller: Bowleven; buyers: NewAge/Lukoil; buyer IRR: c 20% - this assumes a successful Intra-Isongo appraisal programme and therefore increased contingent resources).

Bowleven disposed of a 40% stake (post government back-in) in return for cash to fund development of Etinde (fertiliser plant option) to first gas. This corresponds to sacrificing 67% of its equity stake for full carry (and more). If we were to assign the cash inflow (and bonus payments) directly to Etinde, the company would have retained over 50% of the NPV.

Appraisal/development of offshore discoveries, Santos basin, Brazil (seller: Karoon Gas; buyers: Pacific Rubiales; buyer IRR: 13-14%).

Karoon Gas sold a 35% stake in four offshore blocks, where two discoveries had been made in previous drilling campaign. Assuming the development concept laid out in a 2012 company presentation (of just below 340mmboe) and the forward curve in 2012, the project would have delivered a 13-14% IRR for PRE after paying $40m in cash and carrying up to $210m drilling costs. The gross project had an IRR of under 20% in 2012 assuming forward curve pricing (2019 pricing of $90/bbl). Under the deal, Karoon would have retained around 85% of the value of the project.

Appraisal/development of the Sea Lion project, Falkland Islands (seller: Rockhopper; buyer: Premier Oil; buyer IRR 15-19%). Many factors have changed since the farm-down was put in place. Although the cash payment remains the same, the equity positions and capital payments structures have changed, while the oil price and development concept and timing have evolved. If we assume the current deal structure, development concept and oil prices, the deal would have implied an IRR for PMO of 15%. Inflating the oil price to $80/bbl long-term (and bringing forward production schedules) would move this to 19%, while a depression of the LR oil price to $60/bbl reduces the IRR to 12%.

Rockhopper disposed of a 60% stake in order to get partially carried (or 60% of its 100% stake). PMO provides a debt facility for funding if required. The current agreement guarantees that the companies will split the NPV 50:50 (as defined at FID).

Albertine Basin, Uganda (seller: Tullow; buyers: CNOOC, Total; buyer IRR: 12.5%). In 2012, Tullow indicated that significant volumes from the Albertine Basin were possible 36 months from sanctions and gave a first oil date of “as early as 2016”. If we move our current model to see first oil in 2017 and a long-term oil price of $85/bbl, the IRR for the entire Uganda portfolio is 12.5%. This has obviously fallen since given oil price declines and production delays. For planning purposes, the buyers may have been using $70/bbl, in which case the implied IRR would have been 9.5%.

Tullow disposed of a 67% stake in return for more cash (pre-tax) than would have been required to fund development to first oil (or 67% of its 100% stake). Rough calculations indicate that if the cash had been retained in the project (and first oil occurred in 2017 as then expected, with $90/bbl long-term oil), Tullow would have retained over 75% of its NPV (assuming a 10% discount rate). Of course this has changed markedly since 2012 given the oil price environment and substantial delays, indicating Tullow’s sale was well timed.

Ain Tsila gas condensate field, Algeria (seller: Petroceltic; buyers: ENEL, Sonatrach; buyer IRR: 14-15%). The two farm-downs executed by PCI to Enel (2012) and Sonatrach (2014) indicate IRRs of around 14-15% for the incoming players. Given the long-term nature of the project (and fixed price gas contracts likely), a relatively low IRR is not unexpected here.

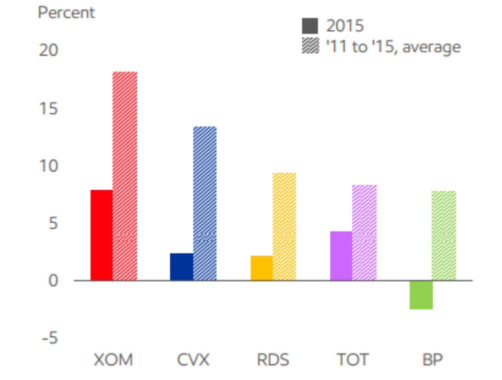
Combined, the two farm-downs (of 18.375%) took PCI equity from 75% to 38.25% (49% of its stake) for carries on appraisal/development that leave the company still needing to find around $400-450m of net capex pre-first gas (in 2019). As a back of the envelope calculation, a further 18.375% would net PCI more than a full carry. If these broad assumptions were true, the company would have sacrificed 75% of its stake for development costs. We explicitly do not assume this for PCI as our understanding (under the terms of the PSC) is that no further reduction in equity is allowed. We also note at the time of writing PCI is subject to take-over rules.

Onshore development, Kenya (seller: Africa Oil; buyer: Maersk; buyer IRR 11-14%). In November 2015, Africa Oil announced the farm-down of half of its 50% stake in a number of its onshore Kenyan blocks to Maersk in return for an upfront cash payment ($440m paid in 2016), a payment contingent on confirmation of resources ($75m) and a development carry once FID is taken. Based on a model of 2C-3C resources of 616-1,291mmboe, we calculate a 2016 IRR for Maersk of 11-14%. The deal effectively allows AOI to retain a 50% equity stake but the carry enables it to retain 55-60% of the NPV. Our modelling evaluates the gross project IRRs range from 21-24% (2C-3C).

The snapshot above is limited, but does show that for modelled projects, the IRRs implied by purchase prices and cost carries is around (or above) 15% for oil projects. This makes sense in a larger context of the returns achieved by majors and US E&Ps where returns for shareholders have been below 10% more often than above 10% since 1993. **If companies are to boost returns, they**

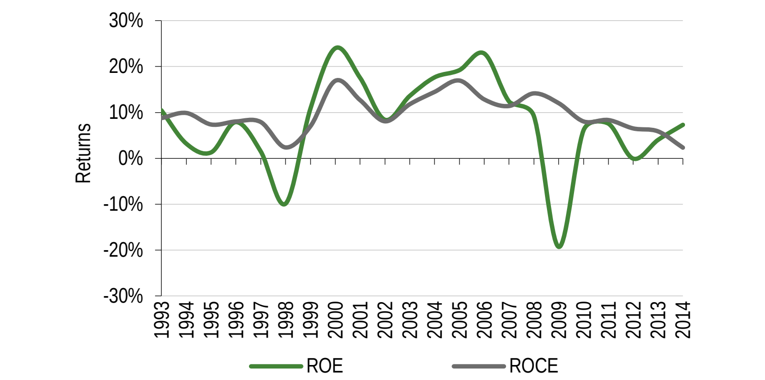
must increase the hurdle rates at which they will invest – effectively increasing the cost of capital of those dependent on their investment. The returns expected will be the lower bound on the seller cost of capital, with buyers trying to maximise their returns (and therefore increasing their returns where a seller has few other options or is distressed, or falling towards its hurdle rate in a bidding war scenario).

Exhibit 12: Majors ROACE



Source: Exxon analyst presentation, March 2016

Exhibit 13: ROE and ROCE for US E&Ps



Source: Edison Investment Research, Bloomberg

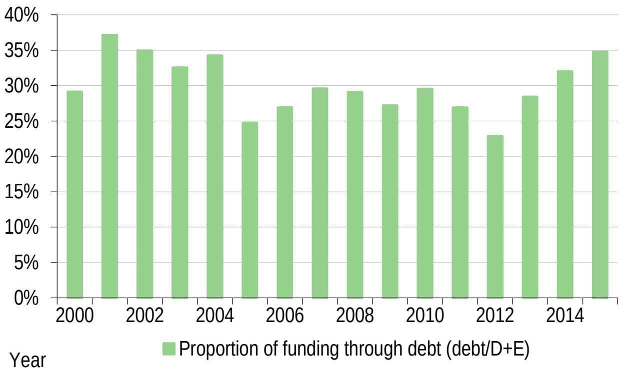
A summary of returns gained historically is shown. While we would like to know the returns targeted by boards, few give specific numbers or hurdle rates. We could not find any upstream targets for ROACE, but in their 2016 updates, Total and Repsol look to generate a ROACE of 13% and “more than 15%” in downstream, respectively. Given the greater risk involved in upstream, we would suppose that this would be higher.

Cost of debt

Although there is a current focus on companies burdened with debt following the oil price slide, it would be wrong to believe there has been a recent spike in London-listed companies taking on debt – since the global financial crisis, a smaller percentage of London-listed companies have used debt. Around 40% of London-listed E&P companies have some level of debt on their balance sheets, falling from 50% in 2008 and much lower than the 60-70% seen in the early 2000s. This lower incidence of debt-laden companies could be a result of them seeing the plight of some in 2008/09 (for London-listed E&Ps), the increased number of pure-explorers, or other factors.

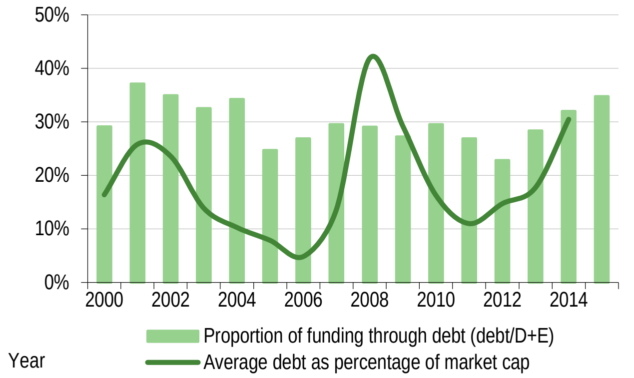
Unfortunately, the companies taking on debt have shown a growing willingness to increase their burden, helped by historically low base rates and easy financing. In this cycle, they have not been caught out by rising interest rates, but by the sliding crude price.

Exhibit 14: Prevalence of debt-laden companies has increased but not outlandishly so…



Source: Edison Investment Research, Bloomberg

Exhibit 15: …but of those with debt, the debt has increased (proportion of funding through debt)

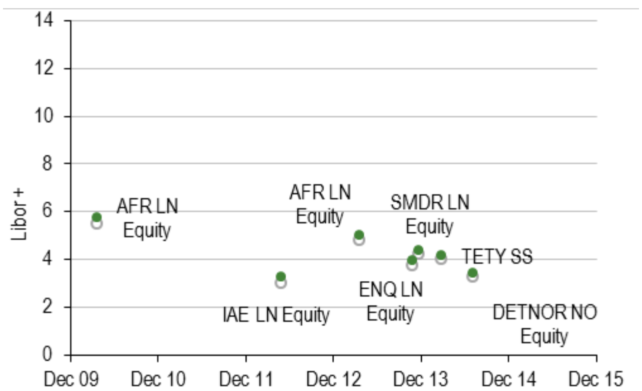


Source: Edison Investment Research, Bloomberg. Note: Based on balance sheet entries of debt and equity (not market values).

Cost of debt is not insignificant for E&Ps

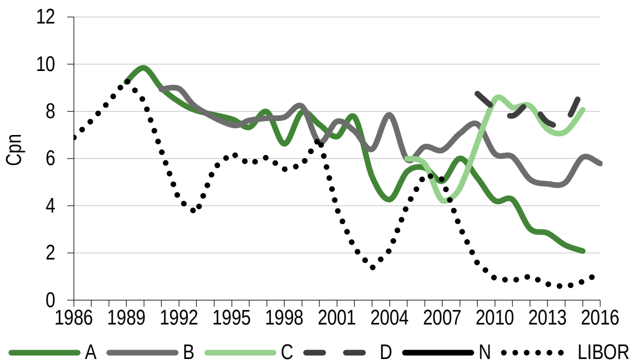
Debt may be cheaper than equity, but is still expensive for E&P companies (even in the world of historically low base rates), with effective interest rates in many cases well above the discount rates applied by analysts. A rarefied few have access to low-interest RBLs, with many looking to corporate credit or bonds for funding.

Exhibit 16: RBLs are the cheapest option, but fewer data points and they can only be accessed late in development



Source: Edison Investment Research

Exhibit 17: Oil company bonds coupon rates broadly track base rate with a variable uplift

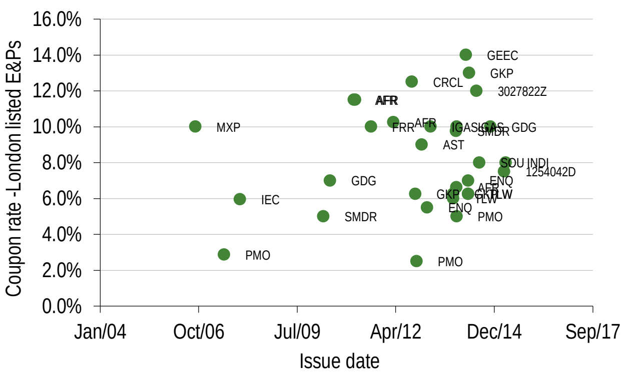


Source: Bloomberg, Edison Investment Research. Note: 'A' relates to A, AA, AAA rated bonds (and so on), N is not rated and # below that. Libor is on 12m Libor rate.

The main sources of debt finance for E&Ps are:

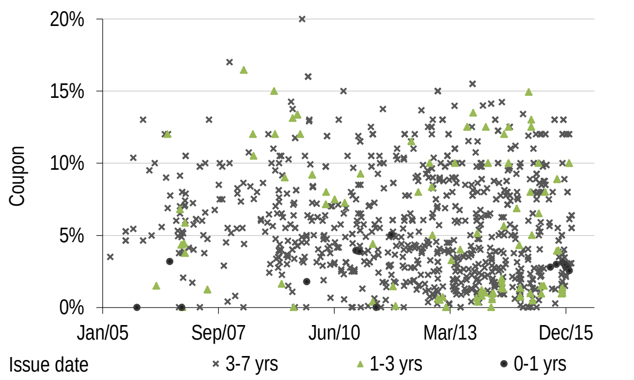
- **RBLs** have the lowest rates, but are only available to those in (or very close to) production.
- **Revolving credit facilities'** costs have increased for the peer group.
- **Bond coupon rates** of around 10% have not been uncommon in the last five years, while bond pricing has collapsed in recent months in concert with oil prices. Every E&P with outstanding debt is under heavy scrutiny over its ability to service and reduce this burden.
  The coupon rates for mid-term maturity bonds in the oil universe (those under seven years) reveal a huge spread, with many bonds having rates of over 10%. Even assuming an (arbitrary) tax rate of 30%, the post-tax cost of debt would be 7%.

Exhibit 18: Bonds costs for E&Ps are not immaterial



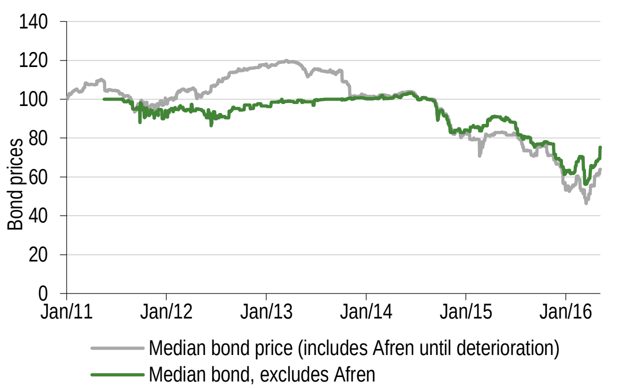
Source: Bloomberg, Edison Investment Research. Note: Many factors will affect coupon rate, from the length of the bond to individual company financial health and risk.

Exhibit 19: For all oil companies



Source: Bloomberg, Edison Investment Research

Exhibit 20: Median prices of bonds for London-listed E&P companies



Source: Bloomberg, Edison Investment Research

Exhibit 21: Yield to maturity for London-listed E&P companies, %

Source: Bloomberg, Edison Investment Research

Conclusion: Cost of capital

Many E&Ps only have equity funding for activities, where it is hard to argue that the cost of capital is 10%, especially when much larger industry partners require much higher returns when developing assets. Layering on debt improves the picture slightly, with post-tax costs of somewhere between 5-10%. This leaves a WACC for the industry above the 10% used by most analysts and investors.

Looking at it another way, if we are to model a project moving from exploration to production, investors either have to assume a material reduction in asset equity along the way or a much higher WACC to get to the values we believe are reflected in full-cycle valuations.

Asset dilution

While E&P companies may hold a large working interest in an exploration block at an early stage, this will in all likelihood fall as exploration, appraisal and development progresses. This reduction in working interest is so likely (if the asset is held) that we believe investors should assume it from the outset. In the absence of an exit event or further investment, investors can expect to see a notable decrease in their interest in a company that itself will see a falling working interest in assets. **As a result, the increase in value that the assets have to achieve for investors to see a return is material**.

How much equity do companies retain?

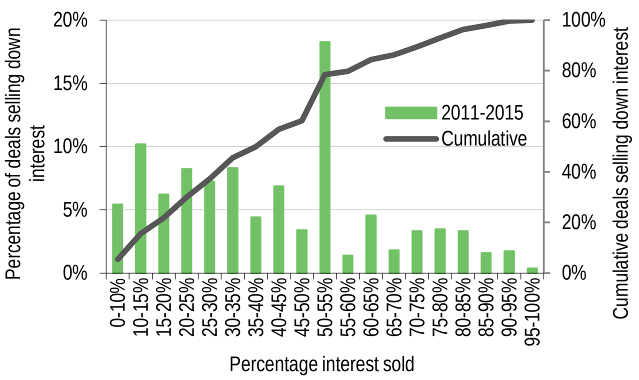
In exploration it is common to see companies reducing working interest stakes by 50% to fund wells (a 'two for one'). The equity given up for a development carry could easily be greater (even if the NPV given up is less).

This seems to be generally borne out by data (from 1Derrick), where exploration block deals see peaks at 10-30% and 50%. Further farm-downs are likely at various milestones and analysis of these steps is made more difficult without knowing the history of these assets in full. However, we can gain a further insight at a later point in the lifecycle.

By the time assets move to production we believe it most likely that entire stakes are sold (rather than the seller retaining a portion). The percentage interest in assets sold should therefore give us a flavour of what equity is typically retained to production by the industry.

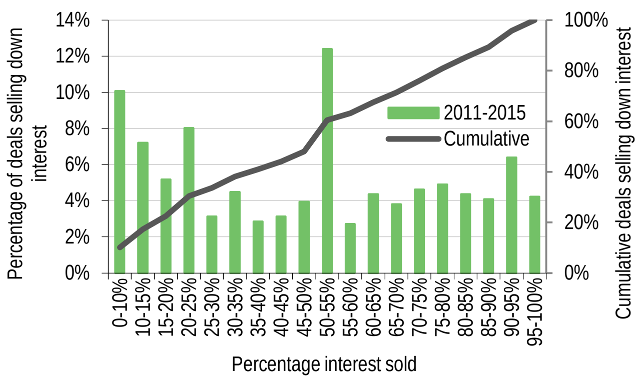
The analysis of this data reveals more than half the time the stake sold is 35% or less, with a further peak at 50-55% (around 13% of the time). Over 80% of deals are executed over working interest of less than 60%. This makes sense in terms of financial and technical exposure to single fields (whatever the company size), and illustrates that oil companies will likely only hold fractional stakes in fields, with that fraction decreasing consistently. While we caution that this data is not absolutely clean, we believe the trends it indicates are fair and agree with our overall impressions.

Exhibit 22: Percentage of assets sold down in exploration blocks (not yet drilled) – median interest sold down 35-40%



Source: 1Derrick, Edison Investment Research

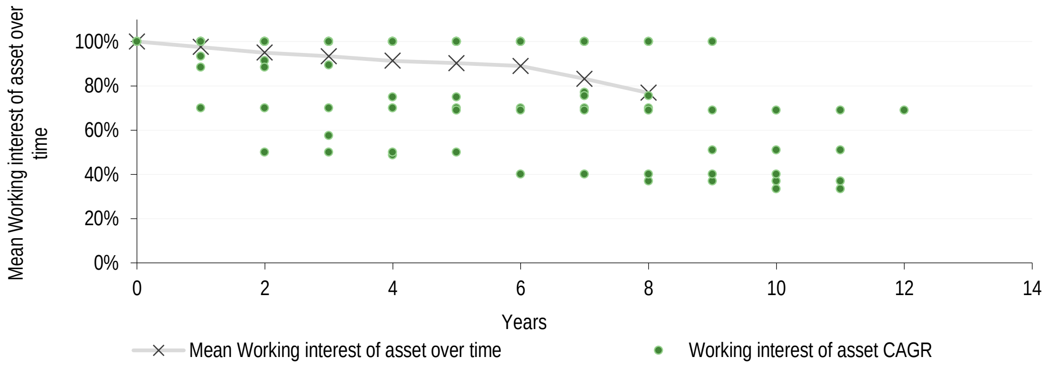
Exhibit 23: Percentage of production assets sold down (global ex-US) – median sold down 50-55% interest



Source: 1Derrick, Edison Investment Research

From another perspective, if we look at our database of E&Ps, we can track the working interest evolving over time.

Exhibit 24: Working interests of assets held by E&Ps in peer group



Source: Edison Investment Research, various. Note: This includes many companies in various stages of the cycle (many of which are still to farm-out for exploration) and is a relatively limited group of companies with concentrated asset portfolios.

We would not advocate applying this trend directly given the different speed at which assets are progressed through exploration, appraisal and beyond. It does, however, give a taste of reduction of asset holding.

Application to investing – For investors, it therefore makes sense to construct a framework whereby project modelling assumes a path suggested by historical data: that companies will not retain large stakes in large discoveries and will suffer from sacrificing returns from a project to get funding (whether this is from equity, the industry or debt).

Our favoured approach is to assume reductions suggested by history in exploration (for example a two for one, or cutting working interest by 50% of existing interest), followed by an IRR approach on reductions in development in return for funded development. How this plays out is dependent on the project; we give a flavour of sensitivities below.

Implications for industry deals

Development cost carries mean companies should sacrifice less value than working interest

It is important to note that although the industry deals require large reductions in equity position, the sellers do not sacrifice this amount in NPV. The value of the carries increases the value of any remaining equity stake as (development) cash outflows are not incurred. Under our oil principles (used when valuing companies), we assume that an unfunded development will see a reduction of equity working interest of 50%. This is an admittedly broad ‘rule of thumb’ but should be indicative of at least the direction of NPV changes given the cost of financing historically in oil. In reality, each project is different (eg onshore/offshore, oil/gas, fiscal rules) so we aim to give an idea of possible reduction only. We aim to refine this approach where applicable.

Effect of cost of capital on development assets held

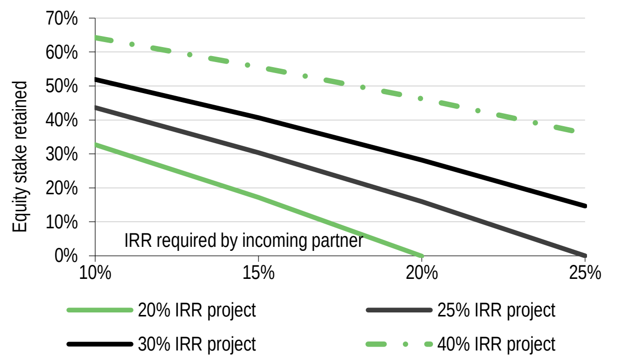
For illustration, we use an indicative project that sees gross cashflows leading to an IRR of 20-30% (from the point of appraisal/FEED), although with the seller incurring some exploration and appraisal expenses beforehand. For simplicity, we assume the seller holds 100% of the assets until a farm-down that leads to a full development carry. In this case, we examine the effect of varying capital demands on the equity interest/NPV retained by the seller.

This effect can be very material, particularly if the returns demanded by the buyer are far from the WACC used to value the project/company. In this case, we compare the post-deal value (after farm-out) with that implied by retaining a 100% stake in a project with a 10% WACC. The difference in value can be very material.

This calculation is project-specific, but the higher the initial IRR of the project the less that a seller will have to sacrifice for a given incoming partner (in this instance requiring a 15% return). For (our) 25% IRR project, a deal will leave the seller with 30% equity but 70% of the value. Reducing the cashflows to get to a 20% IRR project, the seller will only be able to retain 17% of the project equity (and 52% of the value). This still implies that without replicating this analysis, investors could be materially overvaluing the value of projects.

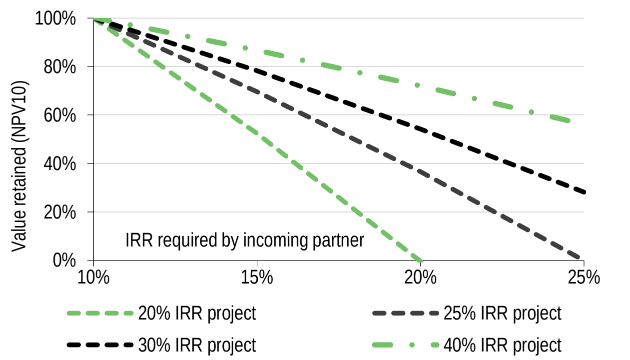
We would caveat this analysis with the observation that this is an illustrative project and results may vary on other types (onshore, phased, gas heavy oil, etc) where capital intensity and cashflow profiles differ.

Exhibit 25: Equity retained by company given different project IRR and required return on capital for incoming partner



Source: Edison Investment Research

Exhibit 26: Value retained by company given different project IRR and required return on capital for incoming partner (employing a 10% discount rate for seller)



Source: Edison Investment Research

Of course, in reality the 'carry' could take the form of a cash settlement, where cash is provided upfront to the company for use as it sees fit. This would skew the data further towards the seller.

Capital cost affecting choice of project concept

In developing a (large) discovery, companies have a number of concepts to analyse. Rockhopper's Sea Lion project started as an FPSO solution, moved to a tension leg platform when Premier farmed-in and has now moved back to an FPSO. Projects such as the Echidna development in Brazil (by Karoon) are starting with an early production system (EPS) before a full field development is progressed, while many companies talk about phased developments. Equally, companies have to deliberate on buying or leasing FPSOs and other items.

There are many technical reasons and uncertainties for a phased development, but this concept also often allows companies to spend less capex upfront, with first production able to pay for (a portion of) full field development. This reduces upfront capex and increases IRR, but may reduce ultimate NPV. For investors in smaller companies, with high costs of capital, the intuitive loss of value from delaying cashflows may be more than compensated for by the higher percentage of project value they may retain in a farm-in deal. To see this, we can look at a project where the choice is between buying or leasing an FPSO.

Exhibit 27: NPV and IRR for an FPSO project

	IRR	NPV ($m)
Lease option	30%	1,300
Buyout immediately	23%	1,550

Source: Edison Investment Research. Note: NPVs are rounded.

In this indicative project, the immediate buying of the FPSO generates an NPV 20% higher than the leasing option, but a much lower IRR. In a case where funding for the development is required, the operator will likely select the development option. Here we assume the third party will provide a full cost carry and negotiate terms based purely on IRR. The resulting value and equity interests retained by the seller (in this case starting with 100% of the project) are below.

Exhibit 28: Farm-in results for

IRR of buyer	Value retained by seller (NPV_{10}), $m		Value % retained		WI retained	
	Buying	Leasing	Buying	Leasing	Buying	Leasing
10%	1,533	1,313	99%	100%	50%	60%
15%	920	1,094	59%	84%	30%	50%
20%	307	657	20%	50%	10%	30%

Source: Edison Investment Research

This shows that for a seller, the value retained in this project is actually greater if the lower NPV project is selected.

This does rely on the buyer seeking to target an IRR in a project rather than NPV. It is arguable that larger companies with a lower cost of capital would look to maximise NPV given the relatively unrestricted capital available, which would change the equation.

This debate also shows the other factors that are worth bearing in mind when looking at projects. Companies with low working interests at the time of development are often beholden to the preferences of the operator. As a result, it is critical that companies retain as much equity and value in the project as possible to have greater impact on development concepts/preferences, given their differing world views, capital access and cost of capital.

Industry farm-ins should give pause for thought on project CoS

For investors, a successful farm-down should be a de-risking event and value should increase. A lower working interest in a project or asset is exchanged for capital and a de-risking of future success. As a result, share valuations should increase when deals are executed. This does not always happen and indicates that analysts' prior expectations are likely to have been too high.

If investors are valuing a company using a WACC or discount rate of 10%, but expect a transaction (where the buyer will almost certainly require a higher IRR), there is a risk that they are over-valuing the asset materially, especially if it is already assigned a high chance of success. While the farm-down will likely increase the CoS of the project, the seller will see a disproportionate percentage of the project go to the buyer. This means that the effective risk employed has to rise meaningfully for an overall rise in value due to the company.

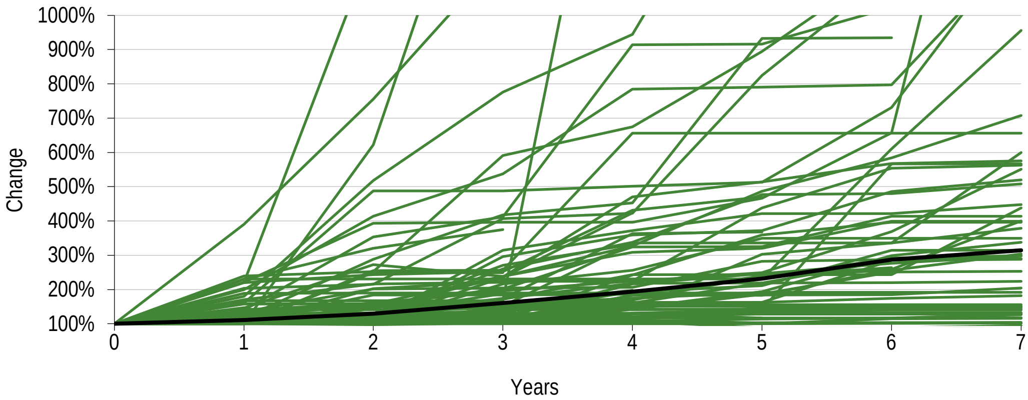
As an example, if we assume a project with initial investment of $100m, followed by free cashflows of $50m for three years, the NPV10 generated is $22m and IRR 23%. If we currently risk this at 65% (typical for a FID project in oil we think), and have an incoming buyer require a 15% return (taking 50% of the project), the project risk would have to increase to 83% in order for the post-deal risked valuation to be the same for the seller. This level of de-risking may make sense in some cases, but we believe that for many E&Ps at the time of FID, an 83% CoS may be too punchy. In retrospect, therefore, investors expecting a farm-down (requiring say 15% IRR) should risk the project at considerably less than 65%, or increase the WACC they use to assess the project.

Share dilution – irrespective of exploration success

As participants in a capital intensive industry, oil companies need large amounts of funding to get projects to production. Unless companies are well funded internally, the cost of sourcing this capital is a material drain on the returns gained from the projects.

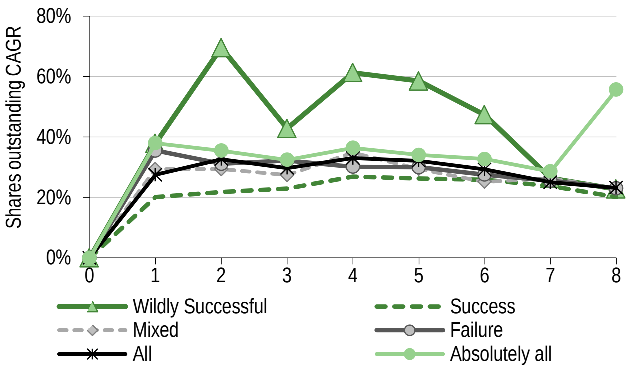
To see this effect, we have summarised the key movements of equity and asset interests of the 140 or so E&Ps listed in London since 2000 (and some internationally focused Canadian E&Ps). We have categorised these into exploration success or failure (or somewhere in between). Although there is significant variation among the groups, the averages are informative, and indicate that E&Ps have a strong tendency to source capital from equity markets to fund activities. While this is not surprising, the extent of this continued share dilution is higher than one might have expected, with shares outstanding increasing across the group by an average of over 20% a year. Included in this are the instances where companies make acquisitions – removing these does not materially alter the analysis.

Exhibit 29: Number of shares grow steadily across the industry



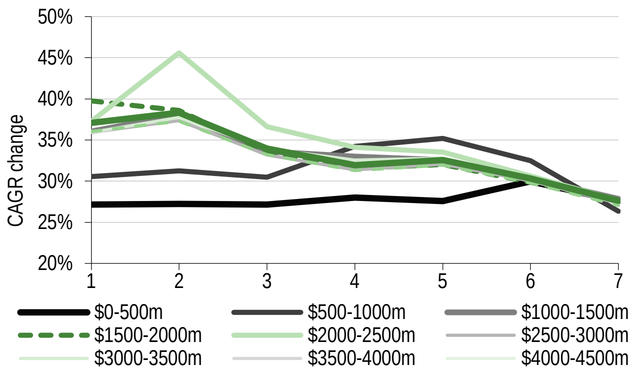
Source: Edison Investment Research, Bloomberg, various. Note: This analysis includes companies with market caps of greater than $150m during their history (in at least one year). Black line is median.

Exhibit 30: Dilution consistent across all categories…



Source: Edison Investment Research, Bloomberg. Note: This analysis includes companies with market caps of greater than $150m during their history (in at least one year) under 'All' classification, with smaller companies under included under 'Absolutely all'. X-axis denotes years since major event

Exhibit 31: …and across market caps



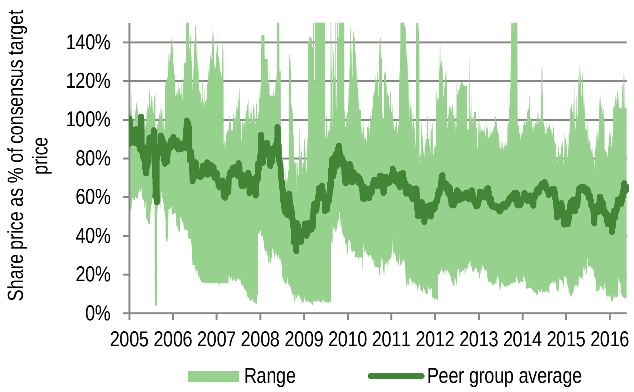
Source: Edison Investment Research, Bloomberg. Note: Market caps given in $m and chosen as peak market cap over period (not analysed year by year). X-axis denotes years since major event

Share dilution can be expensive – 5% per year in value (vs analyst target prices)

The act of raising equity may seem small, but adds up over time. Equity raises involve costs to existing shareholders, from discounts for new capital to broker fees, which we calculate has a material impact on long-term value for existing shareholders' valuation of their holdings.

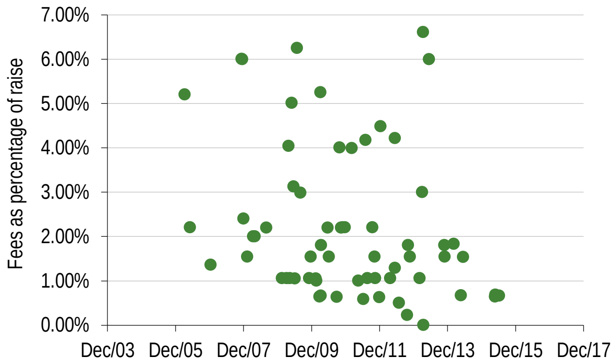
In the vast majority of instances, equity is raised at a discount to the prevailing share price. While this discount can be small, the shares themselves predominantly trade at material discounts to the valuations of analysts. Across the peer group, this discount currently averages more than 40%, but can be as much as 80%.

Exhibit 32: Shares trade below consensus target price



Source: Edison Investment Research, Bloomberg

Exhibit 33: Broker fees average 4-5% to raise capital



Source: Edison Investment Research, Reuters, Bloomberg

The costs of brokers add to the effect. Despite the oft-quoted collapsing margins seen in equity trading revenues by banks, the margins for secondary (and presumably primary) issues seem to have withstood time to a greater extent. According to Reuters data, the average cost of an equity raise by (a selection of) London-listed E&Ps is around 4-5%. In the current environment, these banks have to work harder to find investors, so it is right they should be compensated, although how this balances out with increased competition between banks is not clear.

We look at this in two ways. In the calculations below we assume a 15% share count increase **per year**, with capital raised at a 12% discount to the spot price, which itself is a 30% discount to consensus analyst target price, combining with 4% broker fees:

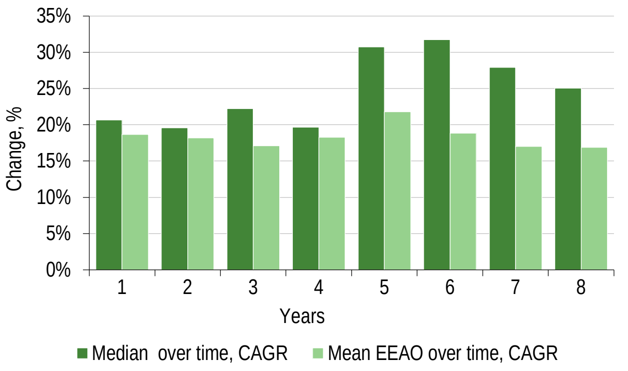
- **Impact on share valuations** – the action dilutes (per share) valuation by 1.1% pa vs previous share price. This is a relatively small effect.
- **Impact on analyst/investor valuations** – if we assume that investors have a similar valuation to analyst target prices, then the action of raising so much capital at such a material discount to 'fair value' reduces the post-money per share valuation by a great deal more; we calculate this as 5.3% pa. This is not immaterial.

Equity asset ownership (EAO)

The combination of falling working interest ownership of assets and equity dilution is a potent mix that reduces potential returns for investors. If indexed to the start of the relevant operations, we can see by how much equity shareholders see their effective ownership of assets reduce – we call this the equity asset ownership (EAO).

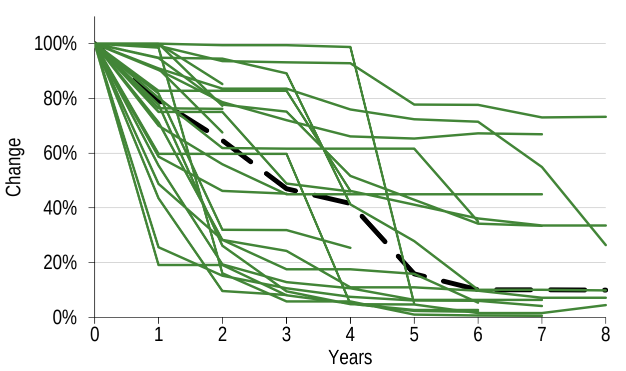
We can see this most clearly in companies with very concentrated asset portfolios (one or two active assets) where the effect is cleanest. We caveat that it is precisely in these smaller companies that dilution risk is highest, so this effect is probably higher than in more diversified companies (especially those with internal cash generation).

Exhibit 34: EAO in concentrated portfolios



Source: Edison Investment Research. Note: This is the EAO that shareholders have, as companies increase share count and decrease working interest in assets. Here we include all companies (regardless of size) where we can track both equity interest and share count. This is a smaller universe than those where we track share count only.

Exhibit 35: EAO by shareholders



Source: Edison Investment Research. Note: This is the EAO that shareholders have, as companies increase share count and decrease working interest in assets. The black line is the median. Here we include all companies (regardless of size) where we can track both equity interest and share count. This is a smaller universe than those where we track share count only.

For most pure-play E&Ps, we can see that unsuccessful exploration has seen EAO fall by 15-20% per year. Even in the event of successful exploration, E&Ps have to fund appraisal and development, meaning further capital raises or farm-downs. In this case, shareholders should see underlying asset value increase (as oil is discovered and moved towards to development), but our analysis indicates that even in the case of success, this increase in value has to be (on average) 17% per year to compensate for the effective loss of asset ownership. This is for developments that are not fully funded.

Success stories are not immune from the EAO impact

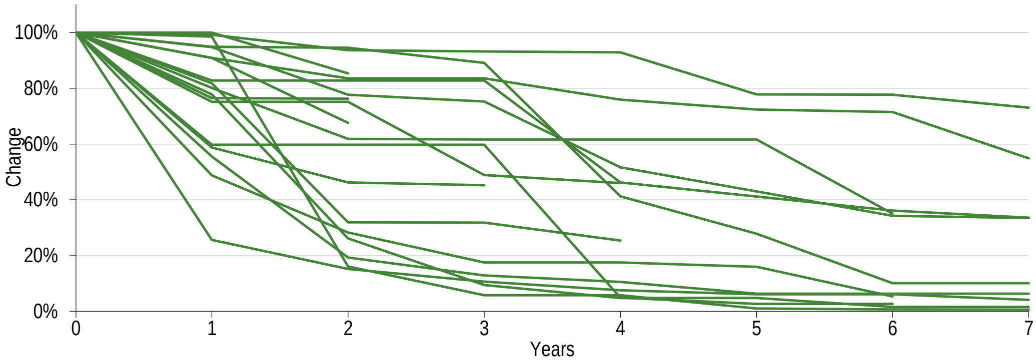
EAO is clearly a big issue for companies that are not successful with their exploration activities. However, even if companies achieve success and can move their assets through development, we believe significant erosion is almost inevitable to progress activities to crystallise value.

As an example, for fully funded developments, Falklands explorer Rockhopper has seen EAO fall to about one-tenth of the level before its flagship Sea Lion field was discovered. This is as a combination of equity raises to fund 100% of the costs of appraisal before a large farm-down and cost carry secured with Premier Oil. This hugely dampens the effect of the value accretion of taking the asset from unproven wildcat status to entering FEED.

Even for the rare, feted examples of companies that have been very successful with the drill bit and crystallised value early, the EAO has to be considered. East African deepwater explorer Cove Energy is a good example of this. Cove equity holders saw a very significant reduction in EAO of 25% per year during the three years it was actively drilling. However, this was massively overshadowed by the stunning exploration success it saw before it was bought and the bidding war that erupted that pushed up its exit price.

Finally, we consider the more development-focused Bridge Energy, which gained additional ownership of assets through deals and swaps, and was ultimately sold with relatively little EAO degradation of 7% CAGR per year.

Exhibit 36: Successful companies still see EAO degradation



Source: Edison Investment Research, Bloomberg. Note: Includes companies that had exploration success. Includes companies that have been bought.

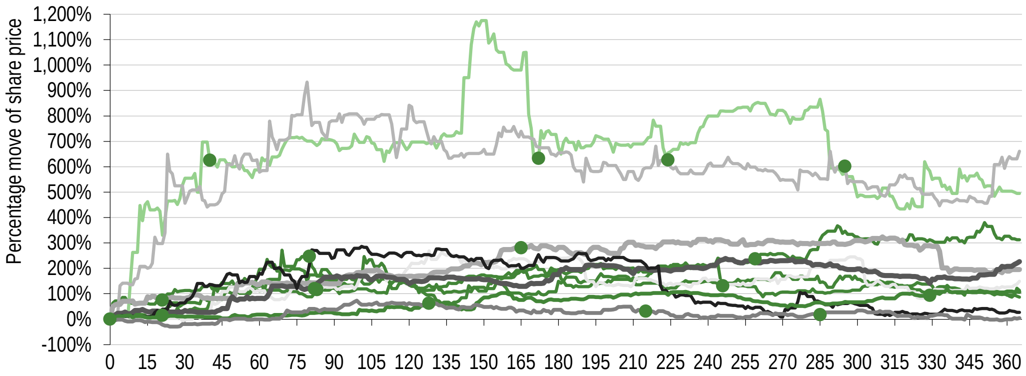
Other considerations

Exploration

Discovery returns can be significant

If an E&P is successful in drilling, it is unsurprising to see large increases in share prices. Below, we look at the price developments of purer-play E&Ps after successful drilling (companies include Cairn, Cove, FAR, Gulf Keystone, Karoon, Lekoil, Petroceltic, Providence, Rockhopper and Xcite after notable successes). Huge returns have been seen by some shareholders in these companies, though the average is around a 2x return over the first 12 months after a well success. We note the understandable tendency of companies to raise equity to pay for exploration or appraisal campaigns.

Exhibit 37: Share price relative return after initial exploration success



Source: Bloomberg, Edison Investment Research. Note: This only examines 365 days after each initial discovery. In many cases prices have fallen since, in some cases very materially. We also note that in some cases, the shares had increased materially in anticipation of success, so did not increase as strongly on the announcement. Green dots represent equity issuances during the period.

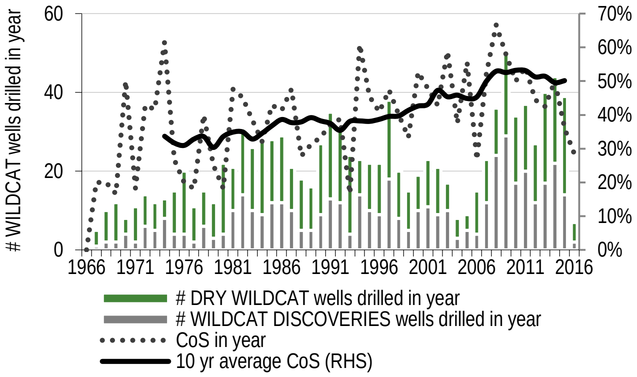
Although exploration success is not sure

Average exploration chances of success are generally seen as 20-25% in wildcats. Progress in geological techniques, including the introduction of ever more complex 3D interpretation, should have increased chances of success as pre-drill understanding of sub-surface improves. On the flipside, advances in these techniques has allowed more complex traps to be seen and explored, which in turn increases the complexity of the prospects explored for.

Chances of success are still high in the industry (despite poor recent success by independents). Data from the Norwegian Petroleum Directorate (NPD) indicates that exploration results in technical success around 50% of the time. This is well above industry accepted norms of 25%, probably due to the mature nature of the basin and the greater understanding of the geology. It is notable, however, that even in a basin that has been explored for 40 years, technical exploration success is around the same level as a coin toss.

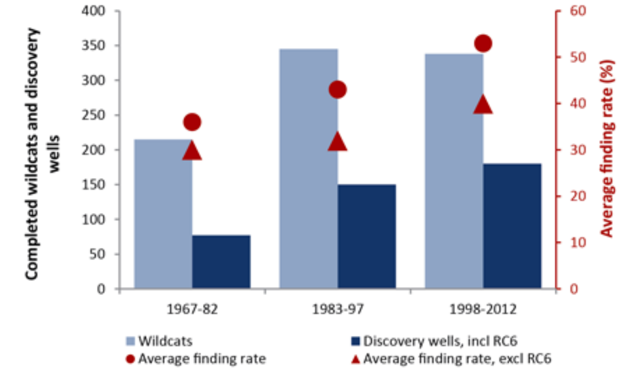
Elsewhere, according to data from Richmond Energy Partners, the commercial success rate was around 75% of the technical rate from 2008-12. According to data from Richmond Energy Partners in 2013, the pre-drill estimates of success rates were broadly accurate predictors of post-drill success rates.

Exhibit 38: Technical geological chance of success in Norway is high



Source: NPD, Edison Investment Research

Exhibit 39: Success rate has improved, but significant number of discoveries are uncommercial



Source: Norwegian Petroleum Directorate

We do not believe that (m)any investors are better able to judge the success of individual wells from company presentations and therefore have to rely on other strategies to improve their chances of making returns from exploration. The best of these is to diversify and be exposed to as many wells as possible.

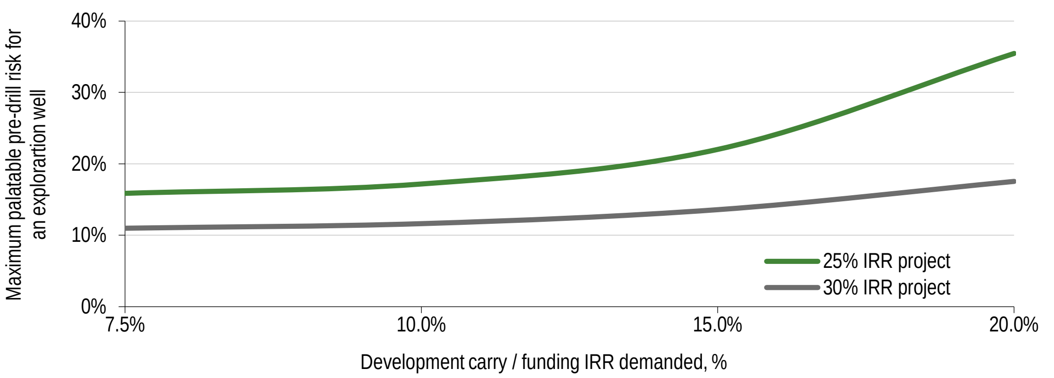
Reading cost of capital through to pre-drill risks

We have modelled a large offshore project to illustrate the effect of varying costs of capital on company value. Here, we assume an industry partner enters at FEED, covering development capex until a year before first oil, at which point another participant enters with a lower cost of capital (which we fix at 10%). If we value the resulting cashflows at a rate of 15% (an approximation of cost of equity), we can see the massive effect these costs have.

We look at two scenarios, the prices and costs producing a project IRR of 25% and a second with higher oil prices producing an IRR of 30%. Assuming an exploration well cost of $50m, we can calculate the pre-drill risk chance of success required to justify an exploration well. This gives us a fundamental basis for expecting that companies should look to drill on lower chances of success. We note that this pre-drill risking is not just made up of GCoS, but should include some level of risking for delays and other uncertainties, in reality making required GCoS even larger.

Of course, every asset is different and will need to be analysed individually.

Exhibit 40: Pre-drill risk of a well required to create a positive EMV for an unfunded exploration company, assuming varying costs of development funding



Source: Bloomberg, Edison Investment Research

Benefits of a portfolio approach and multiple wells

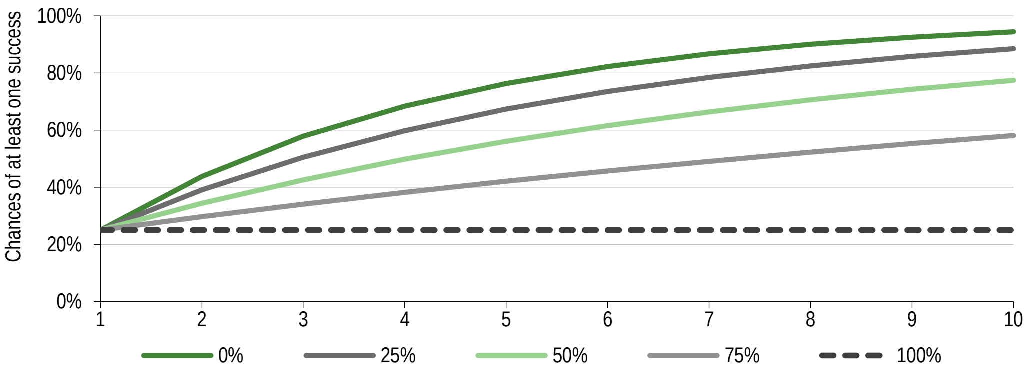
We strongly favour exploration companies with multiple assets. These companies can choose to deploy their capital when it suits them on assets where management believes it has the greatest chance of creating value. For management to justify its existence, it should (on average) add substantially more value each year than it costs shareholders. Given this, there is a clear risk for management with few assets to feel pressured to drill wells with poor(er) prospects. Portfolio players can discontinue working on a licence and maximise effective capital for shareholders, with fewer hang-ups and risks of bruised egos.

A portfolio approach means that a wider range of play types and geologies can be explored by a larger exploration team. Bigger teams should have more diverse experience, reducing the risk of a particular member dominating the debate – teams make better decisions.

A large portfolio of assets gives companies the potential to drill wells regularly. All else being equal, drilling more wells should lead to a higher chance of exploration success. Investing in single wells could be seen as a binary play – a portfolio approach tilts the odds more positively in the long term. If we assume that all wells are independent (which is more likely with a diverse portfolio) and a 25% GCoS, five wells a year will see a probability of at least one success of 76%.

However, investors should also be aware of the impact of dependency of this success curve. There is likely to be some degree of commonality between prospects in the same (or nearby) blocks. A success nearby could de-risk the prospect inventory, but a failure often causes many leads/prospects to be dropped. Numerically, this effect is material – if wells are 50% dependent, five wells would see an average chance of at least one success fall from 76% to 56%.

Exhibit 41: Independence among a prospect inventory sees the chance of (at least one) success from a multiple-well campaign climb quickly. However, dependence quickly reduces this advantage



Source: Edison Investment Research Note: Percentage values for lines correspond to the dependency between wells (0% fully independent, 100% fully dependent). Each well is assumed to have a 25% GCoS.

Once bitten, twice shy

A dry hole generally means the end of exploration in a block or licence

The effects of this dependency can be seen by the actions of companies themselves. If an exploration well is dry, the overwhelming outcome is for companies to walk away from the block. This is not a recent phenomenon, with longer-term evidence that appetite for sustained exploration (and follow-on appraisal) is out of favour with companies.

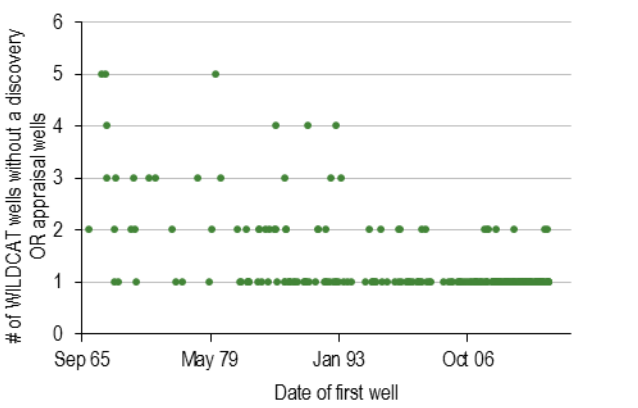
In the early stages of Norwegian exploration, it was common to drill three to five wells in a block before acreage was relinquished. This has now fallen to generally one well and at most two wells being drilled (Exhibit 42). Since 1995, only 8% of Norwegian licences/operators have drilled more than a single (dry) well before relinquishment (Exhibit 43) – and none have drilled more than two wells before walking away. Of course, in Norway the geology is well understood and blocks are relatively small and have very often had wells drilled in them before (however long ago). As a result, more recent exploration techniques may only expose a very small number of potential follow-ups (if at all) within the block, reducing the likelihood that there are any worthwhile second wildcats.

This rule also applies to frontier areas. Our analysis of wells in Africa indicates that only in 7% of cases does a dry wildcat get followed up by another well (admittedly from 2011 onwards so a short timeline). This may be counterintuitive in frontier areas where block or licence areas are larger and where there may be greater prospect diversity to be explored.

There may be far more prospects to drill but much lower knowledge of the underlying geology, and history has proved that past large basins have been proved up only after many wells (UKCS for example). However, the significant risk in frontier basins seems to offset these factors.

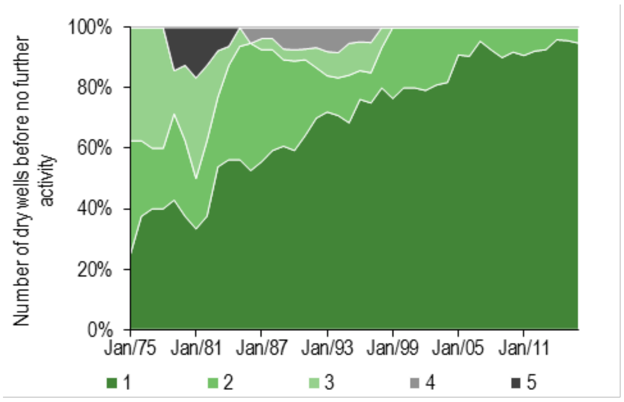
Drilling costs may be considerably higher (given much of frontier work is deep-water), putting off a large number of participants. It is difficult to find more than a handful of instances globally where two or more exploration wells have been drilled in a block or blocks in short succession before the parties have walked away from an unsuccessful campaign. Of course, these blocks could be re-awarded and re-drilled in future, but this can be many years later (and under different ownership).

Exhibit 42: NPD data suggest the norm is now just one dry well before relinquishment



Source: NPD, Edison Investment Research

Exhibit 43: Only 8% of licences are drilled again after a dry well



Source: 1Derrick, Edison Investment Research. Note: Five-year trailing average.

Corollary: Beware 'billions of barrels'

A direct result of this is that an inventory of many millions (or even billions) of barrels across many prospects in a block should be largely discounted. A deep inventory will likely only be unlocked with successful initial exploration. If companies walk away after one failure, this inventory will be discarded at the same time.

However, relevance of a deep inventory is not lost

This should inform the view of E&Ps with many managements presenting long prospect inventories in a few blocks. While this may seem attractive, in our view, this depth essentially acts as an option.

This is not to say that deep inventories within a block are not attractive. A long prospect or lead inventory means companies have a greater choice, probably leading to a greater quality of drilling target (and certainly a lower chance of being forced to drill a poor-quality well). Additionally, if or when a discovery is made, a deep inventory means the follow-up potential could be larger. We believe it is better to think in terms of what *will* be drilled as a value driver, rather than what *might* be drilled. By all means look at what may be opened up after a result is known, but it is difficult to argue that pricing this potential in before a well is pragmatic or fair.

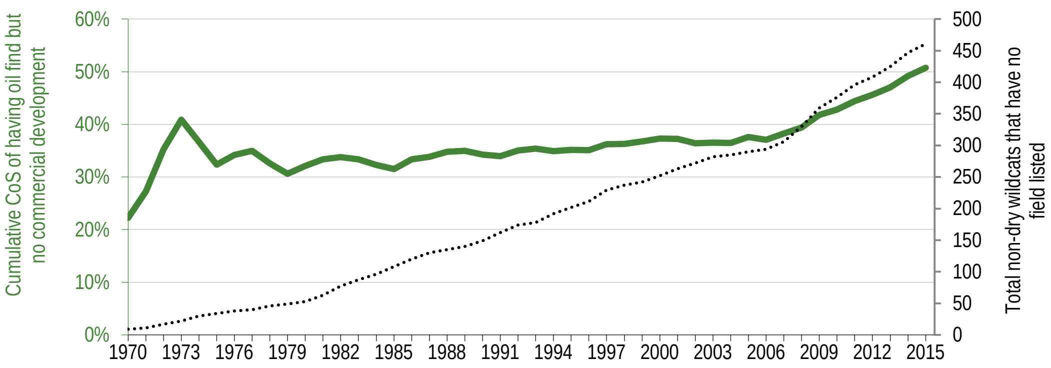
Development: Moving from discovery to development

Likelihood of a development

A successful discovery well does not mean a successful development. NPD data indicates that 65-70% of discoveries are developed. Even once a development has started, there are material risks to the project that mean predicted volumes may not be extracted. Reasons could be:

- Large swings in the oil price (or inflating costs) making production uneconomic sooner than expected (as is very possible in the depths of the current oil price cycle). Oil&Gas UK estimates that 50% of North Sea fields have an opex above $30/bbl.
- Unforeseen problems in the reservoir – examples could include the Athena field (UKCS) or the Durward and Dauntless fields in UKCS (downgraded from 32mmboe to 13mmboe). The compartmentalised Tartan field (UKCS) was only helped by tie-backs after disappointing performance. Kurdistan Genel's Taq Taq field showed water coning leading to a 48% downgrade in 2P resources. Albacora in Peru was poorly developed.
- Other issues – the recent redevelopment of the Yme field (Norway) was abandoned after serious structural faults were found in the mobile offshore production unit.

Exhibit 44: Only 65-70% of 'discoveries' are developed in Norway



Source: NPD, Edison Investment Research. Note: Given that the typical development time is c 10 years, the hockey stick in the line since 2005 is not surprising and not indicative of a large uptick in uncommercial discoveries.

If we generalise using NPD data to obtain a global perspective, we suggest a lack of infrastructure (physical, commercial and governmental) could easily mean a lower number of discoveries are developed. There are plenty of stranded gas fields in Africa that would be developed in other jurisdictions, for example.

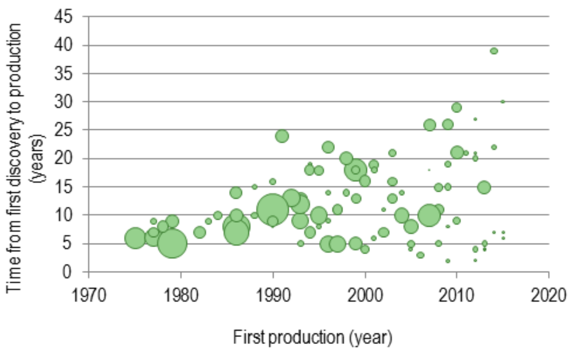
As a result, investors should be aware that the GCoS (typically 20-25%) should also incorporate the development question. Seventy percent is probably a fair approximation for this number, although we lack global data of the quality of NPD disclosure to actually quantify this.

Development time

Despite technological progress, developments do not seem to be getting any quicker. Based on NPD data (again the most complete dataset) development times are very project specific, but lead times of 15 years are not particularly uncommon (from first discovery). Some of this time will be due to previous uneconomic discoveries becoming worthwhile with technology advances or larger discoveries nearby leading to tie-backs, but the trend still indicates an average of 11-12 years (and notably more than that from the first discovery in some cases).

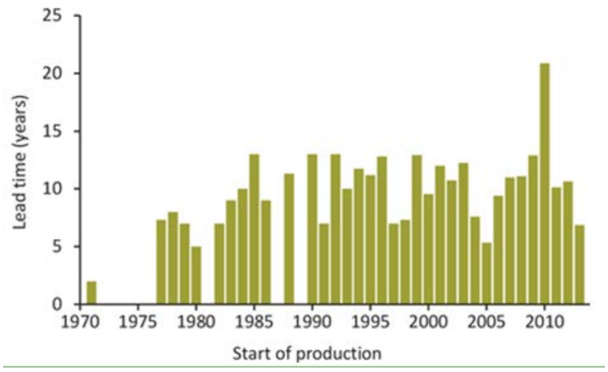
This is a separate issue from companies not delivering on promised timelines for development. The complexity of developments, resulting from wells many kilometres deep (often in deep water), designing and building bespoke production systems, the overlying commercial environment and the optimism of engineers and managers, means it is not uncommon to see first oil months or even years behind schedule. Examples are not hard to come by – Kashagan, Sea Lion and Mangala are of differing sizes and environments but all saw notable delays on management's first estimates. Given the choice between applying a historic trend average or a (possibly more optimistic) management estimate, we would plump for the former.

Exhibit 45: Norwegian data suggests discoveries take time to develop…



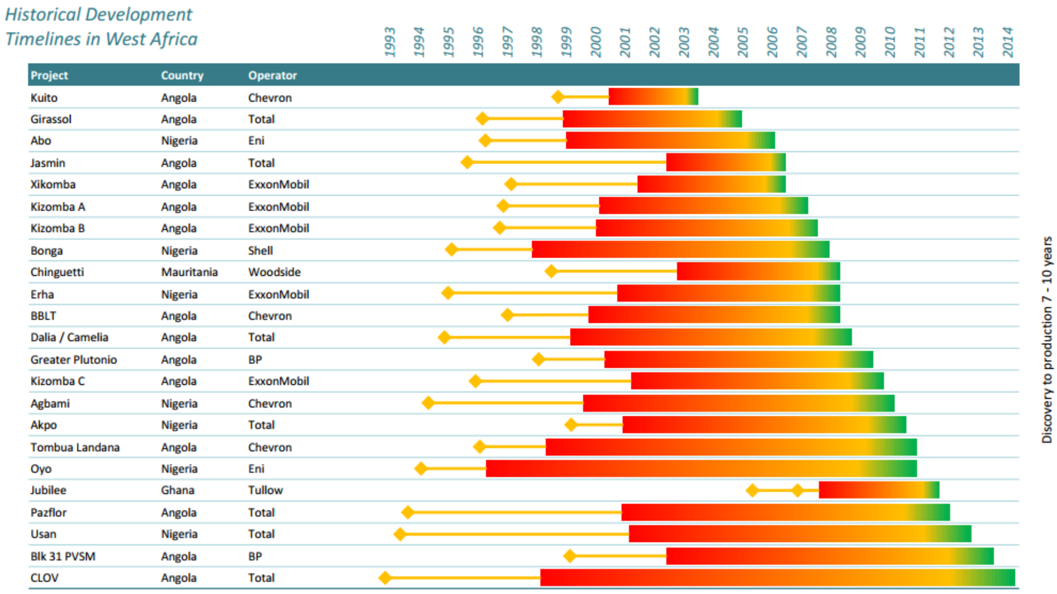
Source: NPD, Edison Investment Research. Note: Data is for offshore Norwegian projects

Exhibit 46: …and this it is rarely substantially lower than eight years for offshore



Source: NPD

Exhibit 47: Africa development timelines range from 3-16 years, median of eight years

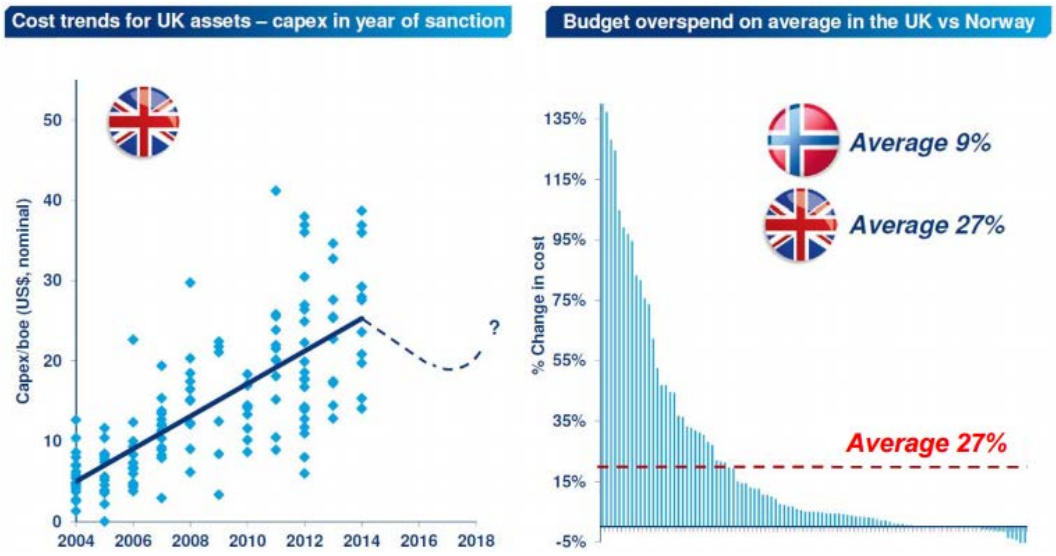


Source: Cairn Energy

Cost inflation

Cost inflation is a natural concern, and profitability has been affected by increased costs.

Exhibit 48: Cost inflation is a real concern and can vary notably between jurisdictions



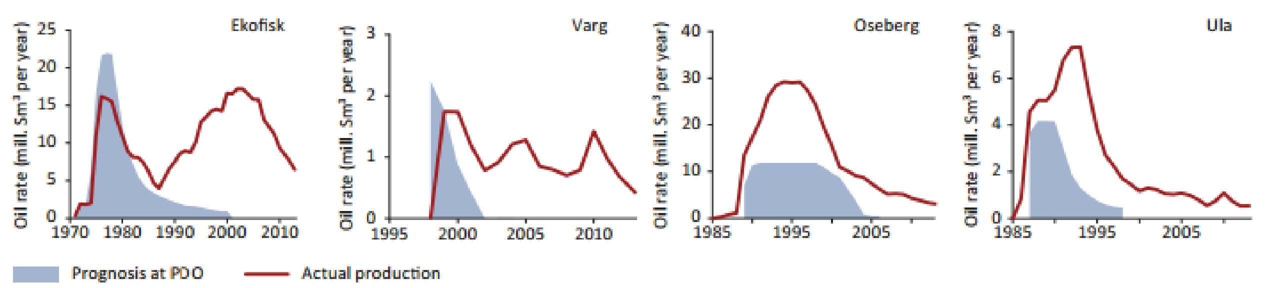
Source: www.gov.uk/government/uploads/system/uploads/attachment_data/file/508749/Topsides_Conference_OGA_Presentation_March_2016_for_website.pdf

Production

Positives: (Big) fields get bigger

It is an oft-repeated maxim (almost an axiom) that 'big fields get bigger'. Given ever-increasing geological and geophysical understanding, increased use of technology and higher oil prices encouraging more extensive secondary and tertiary techniques, this is not altogether surprising.

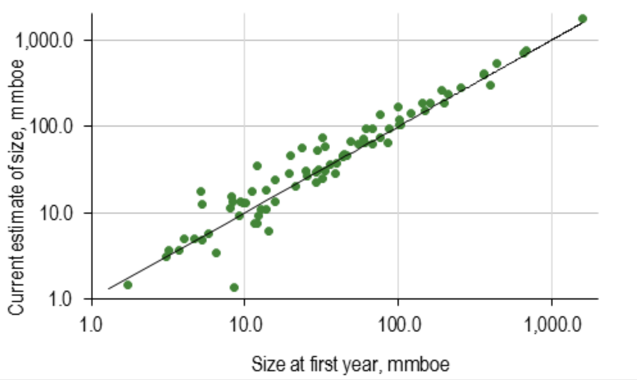
Exhibit 49: Fields get bigger



Source: NPD Facts 2014

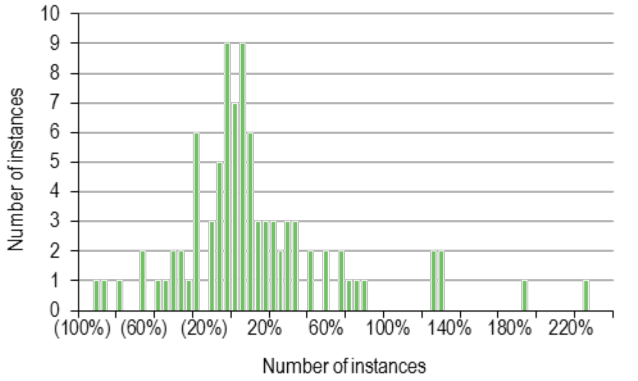
By how much do fields get bigger? Do big fields get bigger to a greater degree than small fields? We examined the data from the NPD, which shows that on average 66% of fields see an increase, although the breakdown of this needs to be carefully understood. There is a clear tendency for larger fields to increase more than the original estimate, but many small fields get smaller.

Exhibit 50: Original field size vs current estimate (total recoverable reserves)



Source: NPD, Edison Investment Research

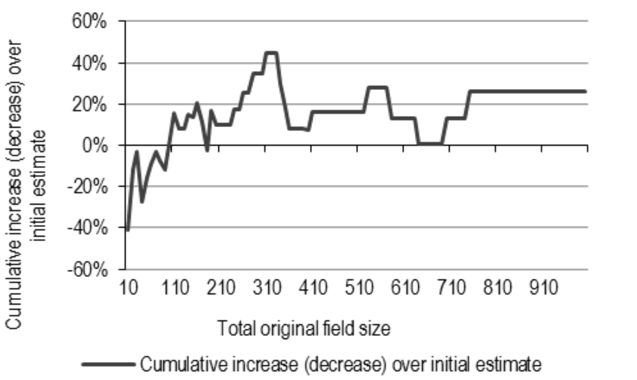
Exhibit 51: Fields are more likely to increase than decrease



Source: NPD, Edison Investment Research

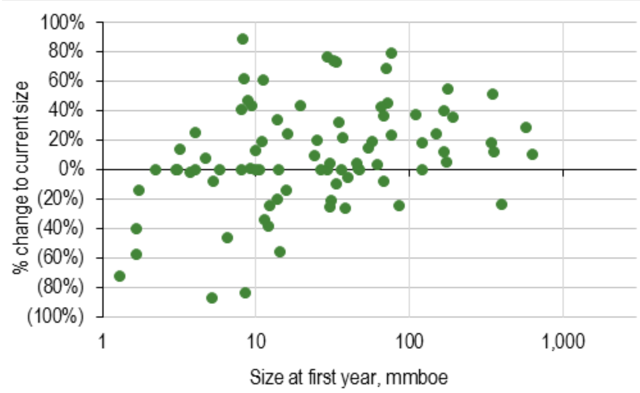
While fields are more likely to grow if they are bigger, the percentage increase falls, so the reserves-weighted average across all fields is an increase of 16%, although we would be cautious as small fields have seen incidences of large percentage reserve downgrades**. Indeed, across our sample of around 80 fields in the NCS, the initial estimate has to be over 100mmboe to be more likely to increase than decrease.**

Exhibit 52: The larger the field, the larger the chances of it getting get bigger, although incidences across the NCS suggest fields need to be more than 100mmboe to be more likely to grow than shrink



Source: NPD, Edison Investment Research

Exhibit 53: Increases in size become more likely as fields get bigger, but percentage increase (if it occurs at all) falls



Source: NPD, Edison Investment Research

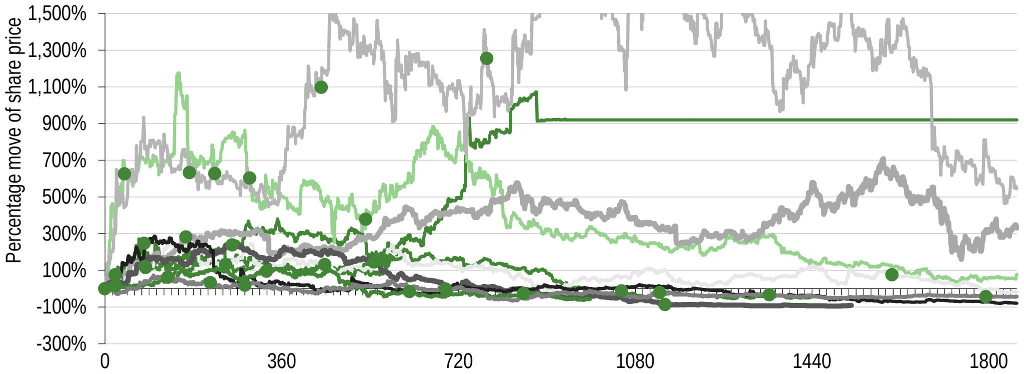
Corporate outcomes

Be prepared to monetise on reasonable terms: The risk of dilution is material

In an earlier section we showed the very strong shareholder returns generated by successful exploration over the following 12 months for success stories (companies include Cairn, Cove, FAR, Gulf Keystone, Karoon, Lekoil, Petroceltic, Providence, Rockhopper and Xcite after notable successes). If we now extend this timeline to current times, the picture looks very different, with most share prices well below the pre-discovery price.

The consideration of what the alternatives are should be paramount to a decision to invest. Our analysis indicates that equity investors that do not sell on see very material dilution or loss in their effective equity ownership, which could offset any value accretion

Exhibit 54: Share prices for successful E&Ps (those with notable discoveries in recent years)



Source: Edison Investment Research, Bloomberg. Note: Scale restricted to 1,500% for ease of viewing; GKP's price increased by 3,500% at one point (due to takeover speculation we think). Every green dot is an equity raise.

In the current environment of hard capital, management teams may be tempted to continue working on a company to extract future value, despite an offer being on the table. However, the effect of this hard capital is to materially undermine this potential future value. In all cases, management should ask how much will it cost investors to make progress, and is this worth the risk and time.

More anecdotally, we have heard of many cases where management has rejected offers on deals/farm-outs only to have to accept far worse terms months or years later. There are many examples of poor judgement (albeit seen in hindsight). Perhaps the most sobering case was Wessex Exploration. After a promising well result at Zaedyus, it was offered c $110m for its 1.25% stake in the block by Total, which it rejected after talks with principal shareholders. Follow-up wells were not so encouraging. Five years later, Hague and London (which includes Wessex's assets) has a market cap of around $2m.

A short checklist for investors

Our work has focused on the costs of capital facing E&Ps over a number of years, revealing that they face higher costs of capital than we believe many attribute. This and the other work outlined in this report leads us to a number of thoughts on investing in E&Ps.

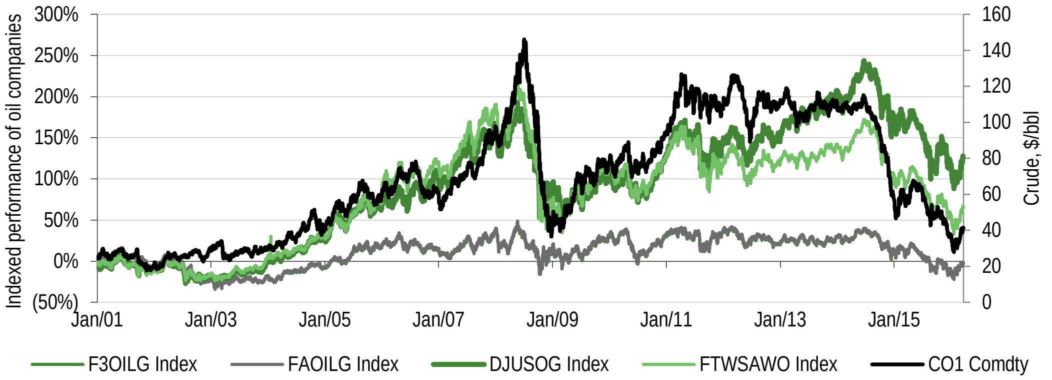
- **Invest with an eye on long-term value**. While companies invested in could be bought for premiums in the future, this is not a given. We argue the baseline value of companies should take into account how the company will seek capital to develop its assets. This cost is likely to be higher for smaller companies than large.
- **Marginal costs of capital (and its visibility) move within a project.** Exploration and appraisal is higher risk than development. Debt and bond rates are often clear and third-party transactions can shine a light on required returns from industry. This leaves estimation of equity returns crucial for many companies. Unfortunately, these costs are both the highest and most opaque – as a result, sensitivities should be run on a wide range.
- **The capital intensity of a project will have wide-ranging effects on the value to an un(der)funded E&P.** Onshore projects will typically require less capital and therefore dilution through the cycle, giving investors more certainty at any given stage on possible value (vs offshore).
- **Asset and share dilution:** Progressing an asset through the next stage of exploration, appraisal or development will have a cost, which is often dilutive to existing holders. The falling asset share that shareholders own over time should be a critical component of management choices. Terms of equity raises/farm-outs and other deals should be viewed through the lens of reducing this risk.

  Empirical work suggests that E&P investors face a sustained challenge to reduce the impact of share dilution. This is a material impact (our work suggests this is over 15% per year for the peer group), either due to funding G&G work, drilling or development or just to pay for management expertise.
- **Exploration risk:** A deep and diverse exploration portfolio allows companies to gain advantage through a large number of wells, enabling exploration success to move beyond the essentially binary result of singular wells. A large inventory of prospects on a limited block gives investors an option value with high upside, but a diverse, independent inventory gives better statistical chance of value, we think.

  In addition, a higher cost of capital lowers project value, requiring higher chances of success to merit a well in the first place.
- **Project economics should be flexed.** It is no surprise that large complex projects can run over-time and over-budget. Additionally, many discoveries do not end up being developed, while reservoir understanding increases. Our analysis of data from Norway indicates that big fields do indeed get bigger, but the opposite (that smaller fields also risk getting smaller) is also true.

Appendix: Depressed sentiment in the sector

Exhibit 55: Performance of oil indices vs crude

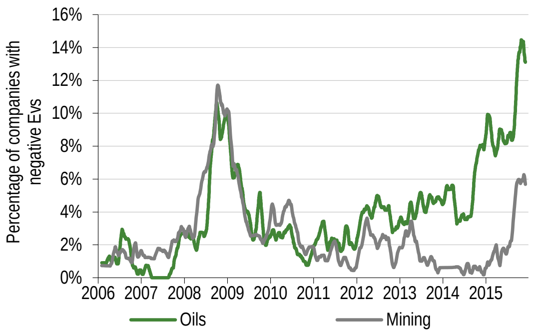


Source: Edison Investment Research, Bloomberg

Performance of E&Ps has been levered to the oil price and sentiment is currently in panic mode. One in seven London-listed E&Ps is trading at a negative EV. Historically, a small minority of companies have traded below cash, but the recent sharp increase implies the market is even more pessimistic about some companies creating any value from their asset base in the short term, while simultaneously burning investors' funds. This is entirely consistent with falling returns from exploration and a lack of wells due in the foreseeable future.

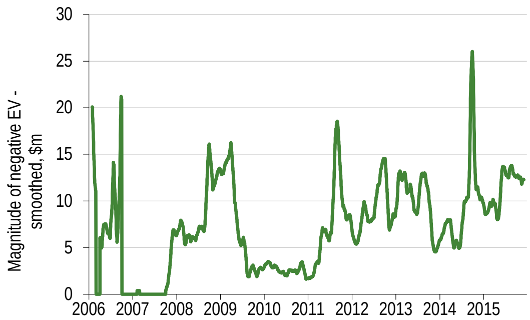
Interestingly, the magnitude of the average negative EV is not wildly out of historical ranges, with an average negative EV of around $12m, or two or three years' worth of G&A costs for small E&Ps. We read this as the market not willing to pay for any (risked value of) exploration in the next two to three years, while fully discounting the need to pay for management costs.

Exhibit 56: More listed exploration cos have negative EVs than at any time this decade (ex-financial crisis)



Source: Bloomberg, Edison Investment Research. Note: London-listed companies only.

Exhibit 57: Average negative value is within historical ranges, indicating broad negative sentiment



Source: Bloomberg. Note: Excludes Cairn (due to India tax) dispute), London-listed oil companies only.

In the current environment, it is difficult to argue that market investors should pay for any activity that is not both material and near-term, given that so much exploration has been put on hold in 2016 and the outlook for 2017 exploration is not looking a great deal better. For example, Exxon's March 2016 presentation does not leave much hope for a meaningful capex increase in 2017 and only small increases beyond. Given exploration is the first sector to be cut and the last to rebound, this leaves many E&Ps (and current shareholders) hanging in limbo.

This does not mean that companies should not explore (if capable). Indeed, given the cost reductions in recent months, brave E&Ps that are willing and able to invest could see good long-term returns, should they believe that the oil price will increase and fuel a rebound in investor sentiment.

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