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New Fossil Energy Resources push the E&P Industry toward faster Innovation Rates

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The changing realities facing the oil and gas industry include challenging operational and strategic changes. Easy oil is gone and new resources are complex and involve more risk in their development. Can oil companies of the future maintain their operational integrity, meet global energy demand, and satisfy the normative expectations of the general public?

Fossil fuels still needed

Normative expectations for the energy business are incredibly high: consumers expect security of energy supply at low cost and with no adverse environmental impact, and investors want a steady stream of positive earnings. Meanwhile, rapid de-carbonization is not a viable option, because renewable energy technology cannot displace fossil fuels faster than the most optimistic renewable energy innovation rates allow (Kramer & Haigh, 2009). The most promising renewable energy sources of the 20th Century were characterized by a scale-up rate of one order of magnitude per decade, and leveled off to linear growth when reaching about 1% of our primary energy mix supply (Fig. 1).

The projected transition rate to renewable energy sources, based on the best trend extrapolations (BP, 2011; Exxon, 2012), is as follows. In 2010, fossil fuels still (oil, gas and coal) accounted for 82% of world energy supply, 5% came from nuclear power and 13% from renewable energy. In 2040, fossil fuels will still account for 77% of our primary energy supply (Exxon, 2012). The relative share of renewable energy will then have grown to 18% (Exxon, 2012). Shell thinks renewable sources can grow further and will supply up to 30% of global energy by 2050 (Voser, 2012). The expectation is that the share of renewable energy will by 2050 have more than doubled, and quadrupled in absolute terms as compared to 2010, and replace some of coal's share in power generation.

To meet the growing demand for all energy supply systems (oil, coal, gas, nuclear, bio-fuels, solar and wind), the world needs to invest heavily in their development - as much as $38 trillion will be needed between now and 2035 (IEA/OECD, 2011). That means industry spends on average about $30 billion/week to maintain and develop our global energy supply infrastructure (Voser, 2012). The lion share of this amount is spent in the upstream oil and gas business.

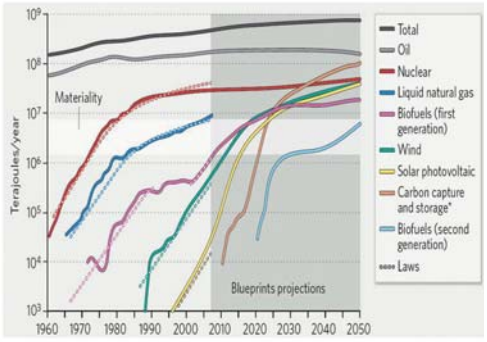

Figure 1: Global energy production technology evolves and new energy technologies nestle into our primary energy sources after extensive in pilot project. When the new technology produces 1,000 teraJoules a year (equivalent to 500 barrels of oil a day), the technology is 'available', but it commonly takes 30 years to reach materiality (~1% of world energy mix). [After Kramer & Haigh, 2009, based on Shell's 2007 Blueprints scenarios].

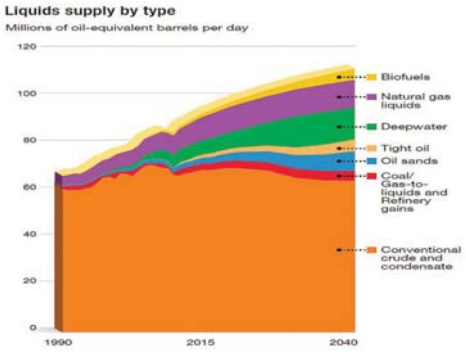

Figure 2: Future oil supply is from conventional supplies, but the production growth required to meet overall growth in energy demand by emerging economies must mainly come from non-conventional resources (after Exxon, 2012).

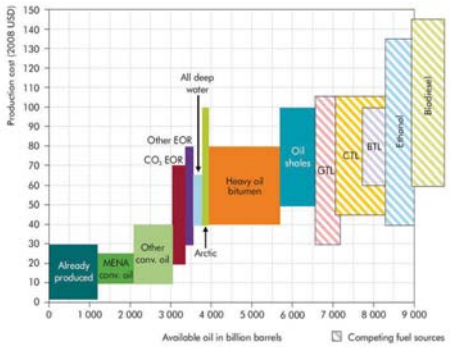

Figure 3: The cheaper-to-produce oil resources in the left of the diagram are in legacy fields and often require costly EOR treatment. New production comes from even costlier produced heavy oil, tar sands (bitumen) and oil shale, complemented with GTL, CTL, and biomass to liquids (BTL) (after IEA, 2011).

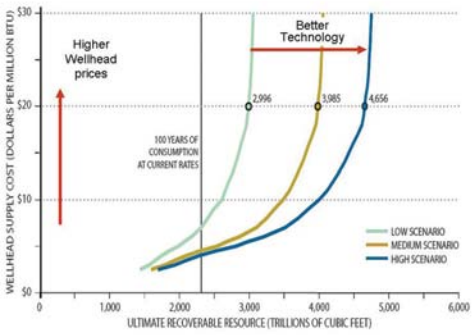

Figure 4: New fossil fuel resources can be developed when wellhead prices go up and/or when the recovery technology improves (preferably at lower cost). The example shows the ultimate recoverable gas resources in North America and sensitivity to gas prices (NPC, 2011), using ICF Global Hydrocarbon Supply Model (MIT, 2011). Further growth of economic producible resources at a given gas price is possible by optimization of technology and better control on subsurface uncertainties (geology & geophysics).

Oil Industry Resource Base

The pressure on the petroleum industry to deliver more energy is still mounting: oil and gas already account for 55% of the energy mix in 2010, but this portion must grow to 60% in 2040. The E&P industry faces faster innovation rates due to the accelerating shift toward more complex hydrocarbon resources. Figure 2 shows where the oil liquids are expected to come from (Exxon, 2012). Clearly, conventional oil supply sources have peaked. The growth in future oil supplies must entirely come from unconventional sources [tight oil, oil sands, coal to liquids (CTL), gas to liquids (GTL), natural gas liquids (NGL)], deep-water plays and bio-fuels.

Figure 3 shows how the cost of future oil supplies from the new plays becomes higher and higher as the more challenging resources need to be tapped into (IEA/OECD, 2011). As the 'new' oil fields are developed, the production cost of oil goes up – and thereby enables their development as long as world markets remain tightly supplied.

The project portfolios of today's oil company's upstream activities are characterized by field asset development opportunities in mainly four categories:

- Aging and declining fields that need EOR to extend their production lifecycle
- Small satellite fields in mature areas fields
- New conventional fields, invariably located in challenging high-risk frontier areas
- Unconventional resources with very volatile reserve basis and uncertain economics

These developments mean that the business environment in which petroleum companies are operating has become distinctly more challenging. Proactive portfolio strategies, economic management, and technology innovation have now become more critical than ever before for the prolonged success and optimization of today's and future petroleum business operations.

Large companies typically have access to the technology array, innovation mechanisms, and capital resources required to develop the best and the biggest assets, while the smaller companies play their niche role and develop the smaller assets, commonly with less favorable financing access (Weijermars, 2010, 2011a).

Figure 4 highlights the generic principle of fossil fuel resource growth. The example used is gas but the principle equally applies to oil. Margins only stay high when prices stay high, and this is a prerequisite for the growth of a company's proved hydrocarbon reserves. For global oil prices the condition of rising prices is met (Fig. 5a), but US natural gas prices have shrunk (Fig. 5b). The insular US gas market

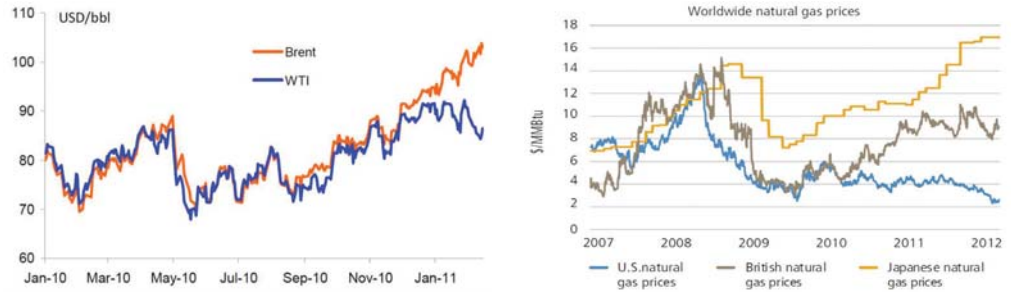

Figure 5: (a) The US crude benchmark (West Texas Intermediate, WTI) and the EU benchmark (Brent Blend) have both risen over the period June 2010 till the completion date of this study (March 2012). However, WTI trades at a discount relative to Brent due to the lack of physical transport capacity at Cushing, the principal US crude oil trading hub. (b): Natural gas prices are lowest in the US, higher in Europe and highest in Japan (Bloomberg).

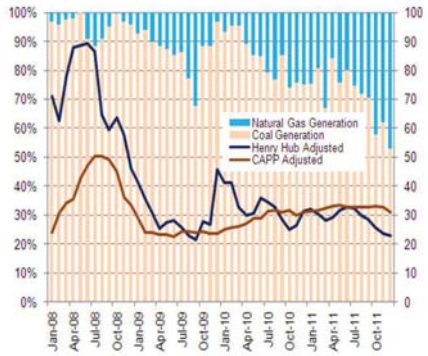

Figure 6: US power stations have massively shifted to gas firings as gas is now cheaper than coal on the basis of calorific adjusted price parity (CAPP) (data from EIA, 2012).

suffers from a structural oversupply for which there is no alternative outlet and natural gas prices will remain depressed until LNG export capacity links the US to gas prices on the world gas market. US natural gas reserves are expected to be downgraded when steep declines of natural gas prices render previously booked reserves structurally sub-economic (Weijermars and McCredie, 2011a, Weijermars, 2012a).

Gas prices outside the US, which are commonly oil-indexed, have become detached from the US gas pricing mechanism (Fig. 5b). The reason is that EU gas demand and supply elasticity is limited by long-term contracts still dominating the EU gas trades (McCredie & Weijermars, 2011).

Meanwhile, gas has displaced coal for power supply in many US States (Fig. 6). In Ohio, natural gas generation went from 3% of total sample plant generation in January 2008 to 47% in December 2011. Three highly efficient natural gas combined cycle plants (the Hanging Rock, Waterford, and Washington power plants) with a combined capacity of 2,698 megawatts, have increased their generation significantly since 2008, from a 1% share of the electricity generation in Ohio in 2008 to 13% last December. At the same time, seven less efficient coal plants in Ohio, with a combined capacity of 7,113 megawatts, have also shifted to cheaper gas firing during peak loads. Meanwhile, natural gas in Ohio power generation is used for 50% of the total capacity generated Fig. 6).

Gas is now produced at a loss by most US shale gas suppliers. They need to fetch wellhead prices of $6-7 for break-even (Banc of America), and only get a third of that price on the 2012 spot market. Liquidity problems may impound the performance of shale gas operators that have no more room for financial gearing. The price advantage of natural gas over coal will

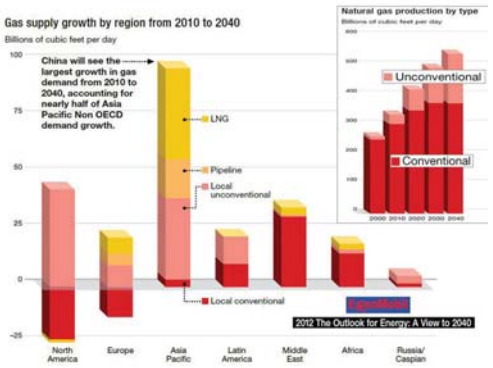

Figure 7: Natural gas supplies in 2040 will for one third come from unconventional sources. Each world region sees net growth in LNG and pipeline gas supplied (after Exxon, 2012).

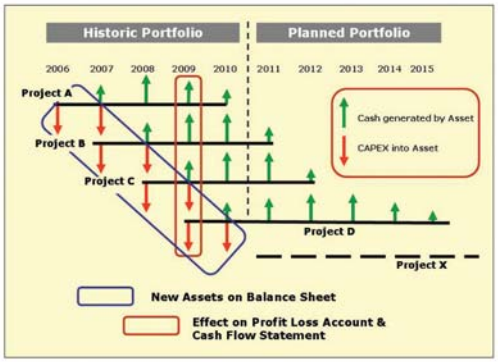

Figure 8: Balanced project phasing in the corporate portfolio is important. If operational cash flow from the new assets kicks-in too slowly or with interruptions, cash flow shortfalls may occur. Ultimately, this may lead to illiquidity and possibly insolvency.

likely reverse when tight supply is triggered by the US gas industry's liquidity ailments, a process likely to begin unfolding in 2012 and 2013.

Figure 7 shows where the future gas supplies in the rest of the world will come from. The share of natural gas in the world's primary energy mix will expand from 22% in 2010 to 27% in 2040 (Exxon, 2012). One third of the 2040 gas supply will come from unconventional sources (CBM, tight gas, shale gas). In 2010, already half of Europe's gas came from overseas. In 2030 it will be 75%, and Exxon projects Europe will have 30% of its gas supplied from shale, 30% will be long-distance pipeline importation and another 30% will be LNG imports. Only 10% will be catered for by conventional gas production from European reservoirs. In the coming decades, LNG will continue its head-on competition with pipeline imports. Australia will by 2020 have taken over Qatar's domination as the world's leading LNG shipper (from shale, coal and conventional sources).

Technology Innovation Role

Figure 4 showed that fossil fuel reserves can grow not only by higher fuel prices, but also by technology innovation. The key issue is to bring down cost while making the technology more effective in bringing the resources to the surface. The portfolio of oil companies must be continually fed by new, profitable projects to maintain their cash flow as illustrated in the principle diagram of Figure 8.

Research in the E&P business runs a risk of lagging behind in bringing the new resources to the market. The CEOs of major companies like Bob Dudley (BP) and Christophe de Margerie (TOTAL) have now openly stated their data show that global oil production cannot be raised much further. Lee Raymond, former CEO of ExxonMobil thinks the R&D required to bring down the cost of tight gas development is not going to happen in the US but China.

What is causing the problem of sluggish oil and gas technology innovation?

Some would argue that the major oil operators are still trapped in technology and workflow processes that have worked well for conventional fields, but now need to accelerate technology innovation for unlocking slim margin resources such as tight oil and gas shale. The E&P clockspeed settings (Weijermars, 2009) are adjusted too slowly to adapt to the changing realities of the oil and gas industry. If the upstream industry does not succeed in accelerating its innovation rates, the superb retained earnings of the past may become affected by the pattern of retained losses that is characteristic for many US shale gas operators (see later).

Outside the US, the learning opportunities for better shale gas technology are few and far. Slow and complex decision-making systems in Europe will continue to delay shale gas development (Weijermars and McCredie,

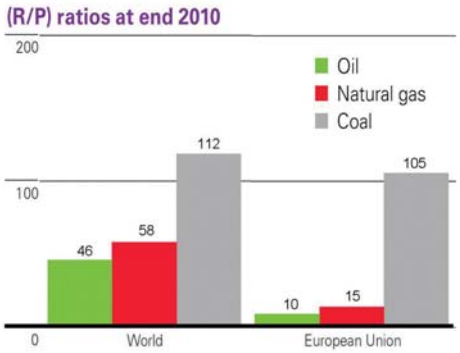

Figure 9: Europe's reserves to production ratios (R/P) for both oil and gas are lowest of all continents: 10 years for oil and 15 years for gas before depletion at current production rates (after BP, 2011).

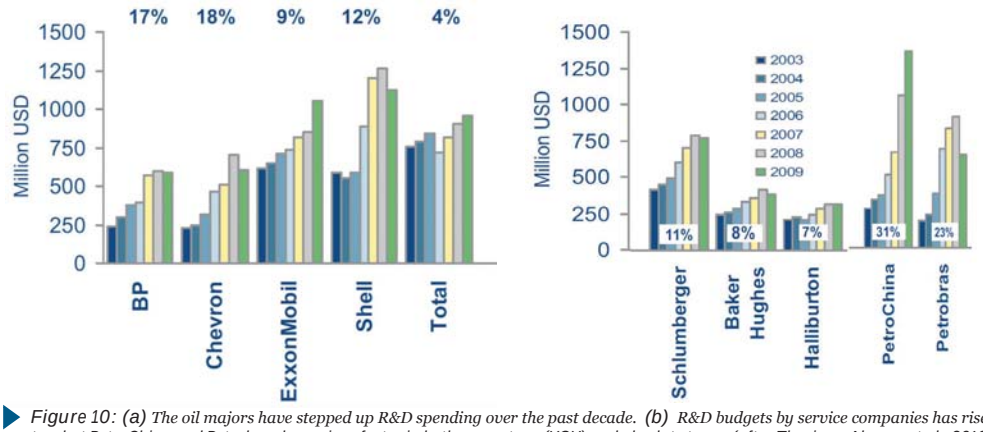

Figure 10: (a) The oil majors have stepped up R&D spending over the past decade. (b) R&D budgets by service companies has risen too, but PetroChina and Petrobras have risen faster in both percentage (YOY) and absolute terms (after Thuriaux-Aleman et al., 2010).

2011b). Ironically, R/P ratios for indigenous oil and gas are lower for Europe than any other continent (Fig. 9). Due to its dependency on fossil fuel importation, Europe runs a severe risk of being economically adversely impacted by cartelization, which may result for gas alone in a lost consumer surplus of $91.4 billion US dollars by 2030 (Gabriel et al., 2011). In 2010, Europe imported 50% of its gas and 70% of its oil (Weijermars, 2011a), which amounts to about 10.6 Tcf (~300 bcm) gas imports and 3.64 billion barrels per year (~10 million barrels per day) oil imports. Using average European market prices of $100 bbl for oil and $10/Mcf for gas, one can conclude that Europe annually transfers ~$470 billion dollars to oil and gas exporters.

In western economies, the pressure of lost consumer surplus has already risen due to the progressively rising oil prices. A 2005 RAND study calculated that daily, $2.2 billion US dollars flow toward oil exporters (Bartis et al., 2005). At 2011 global oil trade volumes and prices, oil importers transferred $5 billion US dollars per day to oil exporters. This means a staggering $1.8 trillion US dollars a year – equivalent to nearly 3% of the world's GDP ($63.1 trillion US in 2010, Worldbank) flows out of western economies into oil exporting nations. Further rises in the cost of oil will further adversely impact consumer surplus and hurt western economies.

What have oil companies done so far to bring about the technology innovations needed to run their future business, open up new resources and keep fossil fuel prices still attractive for consumers?

Oil majors increased their R&D spending between 4 and 18% year on year (Thuriaux-Aleman et al., 2010), with Shell and Exxon as leading spenders and Chevron showing the fastest growth in absolute R&D budget (Fig. 10a). Arguably, this is not nearly enough when fast access to resources in extreme environments needs to become economically attractive. The rise if oil prices already flags a growing mismatch between cost reductions achieved by effective technology innovation and rising cost due to increased complexity of the new oil resources. Large organizations historically are ineffective in bringing new solutions to market via complex and sluggish corporate knowledge silos. Meanwhile, NOCs like PetroChina and Petrobras have expanded their R&D budgets by 31% and 23% (YOY; Fig. 10b). The service industry is lead by Schlumberger with an R&D budget equal to the R&D budgets of Halliburton and Baker Hughes combined (Fig. 10b).

Financing Sources and Retained Earnings

Innovative firms have been analyzed to make selective use of five principal financing sources (Baldwin and Gellatly, 2003):

- Retained earnings
- New share capital
- Short-term-debt
- Long-term debt

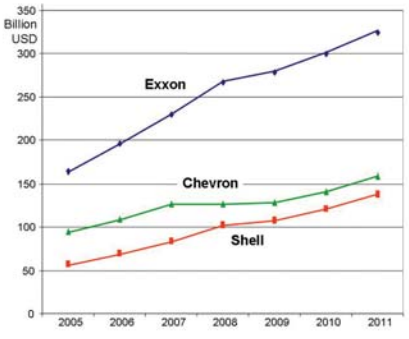

Figure 11: Retained earnings amassed by Exxon, Chevron, and Shell since the start of their operations. Shown is only the cumulative growth over the past 7 years (Alboran analysis and company reports).

• Other instruments (asset sales, government grants, tax credits, contract financing, volumetric production payments)

Major upstream oil and gas companies typically have ROCEs of 20% (Weijermars, 2012b), and their retained earnings are more than enough to maintain investments in new Capex projects and serve dividend payouts to shareholders (Fig. 11). Retained earnings are reported in the shareholders' equity section of a company's balance sheet. Retained earnings refer to the portion of the company's net income retained by the corporation rather than distributed to its owners as dividends.

Historically, the safest investments are interest income from bank deposits and rental income from property. The earnings retained will continue to grow as long as interest and rental proceeds flow in, without much need for Capex expenditure. Oil and gas business opportunities with higher risk must continue to yield higher returns than such relatively risk free investments. In fact, retained earnings are not necessarily a cash reserve, as most companies will chose to invest part of the retained earnings in Capex intensive projects. The use of retained earnings leads to increasing sales and using this as working capital may lead to reduction or retirement of debt-financing.

Companies may chose not to retain operational profits, when there is no need for reinvestment in Capex projects in any particular year. The excess cash may then be fully distributed as free cash flow to the company owners and shareholders.

Companies that do not succeed in generating operational profits do not retain earnings but instead accumulate losses. This translates to negative shareholder equity - a shareholder deficit. If the corporation takes a loss, then that loss is retained and called variously: retained losses, accumulated losses or accumulated deficit. Retained earnings and losses are cumulative from year to year, with losses off-setting earnings. A complete report of the retained earnings or retained losses is presented in the Statement of Retained Earnings or Statement of Retained Losses

As oil and gas companies move into more challenging oil and gas plays, their retained earnings will come under pressure as operational margins are slimmer and capital requirements are rising. For example, the newly emerging US shale gas operators have been struggling to make a profit (Fig. 12). Companies like Petrohawk and Chesapeake have not been able to generate any retained earnings, in spite of their business model that

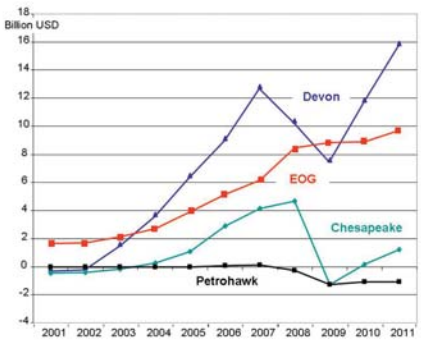

Figure 12: Retained earnings for peer group of US unconventional gas operators (Alboran analysis and company reports).

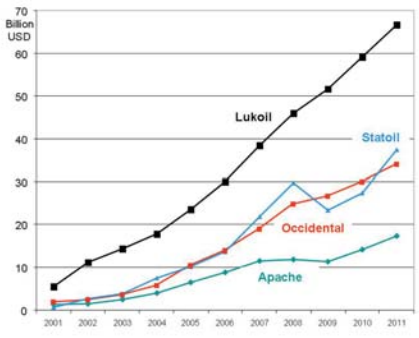

Figure 13: Retained earnings for peer group of US unconventional gas operators (Alboran analysis and company reports).

distributes no dividends to shareholders. New projects have typically been financed by new share issues and new debt acquisition. Devon and EOG have outperformed their peers (Fig. 12), partly because their portfolios include not primarily gas only but also significant oil assets, which generate higher profits than US gas assets.

There is a new league of US companies that continues to seek for profitable, global opportunities. Examples are the internationalizing US independents (Occidental and Apache). Their retained earnings demonstrate successful growth strategies. Even faster growth is reported by the internationalizing privatized NOCs. Statoil and Lukoil collect a steady stream of retained earnings (Fig. 13) and arguably are good at innovation of their business operations. Some of these operators have a regional cost advantage. For example, Lukoil has still access to low-wage, high skills engineers.

Innovation rates and retained earnings

The question is whether one could reverse the argument: Are low or diminishing retained earnings a sign of lagging innovation rates?

To explore this supposition, the retained earnings of three US software based technology companies are compared in Figure 14. Apple is the retained earnings leader, and Microsoft is the laggard. In July 2004, Microsoft issued a one time dividend payout of $32 billion. Bill Gates share in the dividend receipts of $3.6 billion went straight into his Bill and Melinda Gates Charity. Large shareholder dividend payments continue to suppress the retained earnings of Microsoft.

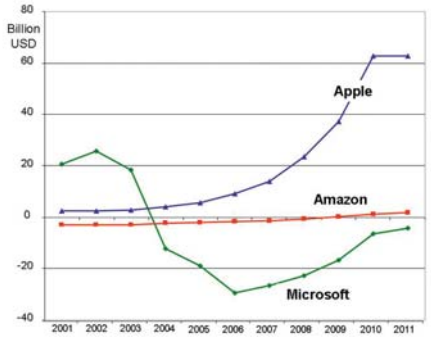

Figure 14: Retained earnings of the three major US based internet business providers (Alboran analysis and company reports).

In contrast, Apple pays little dividend and uses the retained earnings (Fig. 14) to fund new Capex projects that continue to generate operational profits to feed into next years retained earnings. The company also uses the retained earnings to build up a war chest filled with cash to acquire profitable companies and spend on huge R&D projects.

Amazon's follows and intermediate path (Fig. 14) and is in an early life cycle business stage, which forces the company to expenditure capital faster than operational profits can generate. Investor expectations have been satisfied by capital growth of the share price rather than dividend pay-outs. As the online business comes of age and capital gains slow down, Amazon - as the innovator of the online business model – will have to grow its operational profits in order to maintain the interest of its shareholders.

The conclusion drawn here is that all three companies examined have innovation drive. Apple leads the way when it comes to generating operational profits and retained earnings, and uses the excess cash earned for new projects, R&D and acquisitions. Amazon is moving into that direction too. Microsoft seems to be used as an instant cash provider for its shareholders rather than going for investment in future growth projects.

Lessons for the oil business

As we move forward into a new era of the oil and gas life-cycle, entrepreneurial companies are needed to open new avenues. The internationalizing US independents and privatized NOCs are clearly successful in their business operations. The US shale gas operators are less successful as they are marred by low gas prices and a locked regional gas market. Opening up LNG export facilities in the US could effectively link US gas prices to other world gas markets.

However, continued reliance on equity-financing and debt-financing sources is risky

for any oil company. Rigid repayment or tough re-negotiation conditions are associated with the debt capital. Sliding share prices may adversely impact the debt to equity capital ratio. Any (re-)financing strategy is affected by the type of assets held by the company, and US shale gas operators are suffering from a deadly spiral of debt burden and deteriorating acreage collateral value.

Reliance on operational profits to generate retained earnings is by far the more patient capital source for any stable oil business development, especially when innovation is needed. Debt service places restrictions on R&D budgets, which explains why shale gas companies have been relatively slow in developing the innovation required to keep their shale gas operations profitable. This vicious circle has trapped them into lower retained earnings, insufficient for raising the vigorous R&D efforts needed to improve their operational margins. Arguably, US natural gas prices have declined so rapidly between 2008 and 2012 that no technology innovation rate cold possibly keep up and compensate for income loss due to the wellhead price decline rate.

In order not to land in the cash flow trap outlined, the rate of technology innovation in the upstream oil and gas business must keep pace with the fast clockspeed changes in the industry. That requires increased R&D expenditure before the mismatch grows so large that operational income of the major oil companies starts to decline and preclude a rise in R&D activity as seen in the case of US shale gas operators. NOCs are already catching up, and will play an increasingly larger role in global energy technology innovation.

Conclusions

The oil company of the future must fulfill a number of expectations in order to keep the support of the general pubic, policy makers and the investor community. Some of the topics that require attention are listed below:

Communication issues:
• Repeat the message about the realistic speed of de-carbonization
• Engage the public at large in the energy debate
• Work closely with policy makers and regulators to gain political support and project approval
• Engage local communities when drilling plans are perceived by them to affect their daily lives

Performance issues:
• Communicate both the risk and importance of learning opportunities of new fossil fuel plays (shale etc.)
• Mitigate reserve volatility that comes when market prices are unstable – keep safe margins
• Inform the investor community properly about the operational uncertainties
• Accelerate the innovation rate to bring down the FD&A cost of reserve growth
• Innovate technology fast enough to secure access to new oil and gas resources at affordable consumer prices

Clearly, innovation goes beyond technology issues alone. The most important elements remain: generating creative solutions utilizing human's intellectual genius to look at problems in unconventional ways, analyzing which ideas are worthwhile, and excelling at the articulation of the most promising ideas in order to convince others that these ideas are truly worthwhile and should be pursued.

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