Competing and partnering for resources and profits: Strategic shifts of oil Majors during the past quarter of a century

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ABSTRACT

This article analyzes the change over the past 25 years in selected financial and operational performance indicators of US and EU based peer groups of oil Majors. After the Millennium’s turn, all peer group companies experienced steep rises in their unit cost of production. Until 2000, oil Majors could replace reserves depleted by production, typically by splitting capital employed equally between upstream and downstream activities. Upstream assets include progressively more deepwater fields and unconventional resources, resulting in increased reserve replacement costs. This means the share of capital employed on upstream projects has risen to 70% in 2013. Capital expenditure (Capex) in the upstream segment for oil Majors is nearly 80% of the total, and for downstream (and other activities) Capex has been reduced accordingly (partly by asset divestures). In spite of sharply increased Capex on upstream projects, production output of the peer group has declined 6% since 2006. The profitability of upstream projects peaked in 2008, then declined and subsequently steadied at returns on capital employed (ROCEs) of about 20% in the period 2010–2012. US Majors have returned a greater proportion of cash generated from operations to shareholders than their EU counterparts, consistently so over the past 6 years. US companies achieved this better outcome in part by rapidly decreasing capital employed in downstream assets when these became less profitable. Downstream ROCEs have been weak over the past decade, but a modest recovery has begun. Downstream ROCEs of 15% in 2012 are sharply up from a low of 5% in 2009. For the coming decade, we expect fierce competition for technology leadership. To meet rising demand, oil and gas companies must increasingly produce from very complex fields, development cost of which will inevitably require high oil and gas prices. The rising cost of hydrocarbon extraction creates a strong incentive to accelerate the energy transition away from costly hydrocarbons toward progressively more affordable renewable energy resources.

1. Introduction

This article analyses time-series of 25 years of past performance to abstract the major changes that have been achieved by the world’s leading vertically integrated international oil and gas companies. Steering oil and gas companies in the right direction from the present state toward a future business state requires continual adaption by these companies to meet the challenges and opportunities offered by the changing business environment. The choices made by the companies have resulted in a very clear pattern of shifts in the upstream asset portfolios, which now include progressively more offshore, deepwater assets and unconventional resources. Changes in the upstream segment have been accompanied by larger Capex allocations at the expense of downstream and other asset investments. In the past decade, asset divestures by the traditional, western Majors mostly outpaced acquisitions, reflecting the fact that organic growth, in spite of rising cost, still remains less costly per barrel than the acquisition of acreage developed by others.
Conclusions reported in this article are supported by detailed financial and operational analyses. These analyses of the integrated oil companies clearly reveal that capital requirements are intensifying and profit margins are under duress. The observed trends provide a solid basis to predict which strategic issues will be crucial for the future success and development of international oil and gas companies.

Fostering constructive partnerships with key stakeholders, including investors and national hydrocarbon resource owners, is becoming ever more important for securing access to capital markets and to develop new hydrocarbon resources under reasonable taxation regimes, which are required to develop new high risk projects. Informed dialogue with resource holders includes finding and securing a proper balance with the local taxation regimes. These developments imply that the demands on the professional performance of top management and operational experts alike are rising. Such demands can be met in the future by competitive recruitment as long as oil and gas prices stay firm and market conditions remain favourable to facilitate continuous investments in both new talent and innovation of technology for the effective exploration and development of new resources [1–3].

2. Shifts in the upstream asset base

Proved reserves of the oil and gas Majors are typically held at reserve/production (R/P) ratios of about 10 years [4]. Acquisition or organic development of reserves at substantially higher R/P ratios would result in underutilization of tangible assets. Additionally, reserves definitions and evaluation practices affect nominal R/P ratios [5]. Stocklisted companies that report reserves compliant to SEC [6], FASB [7] and PRMS [8], generally have R/P ratios that are an order of magnitude smaller than of major national oil companies. The latter companies do not need to comply with SEC and FASB reporting rules. Also, unconventional resources with slim or negative operational margins provide for volatile reserves. These new resources have lead to situations where stocklisted oil and gas companies adopted a new business driver: speculative acreage leasehold values rather than positive production margins. Rising leasehold values have been the principal source of capital gains in the development of North American shale gas and oil resources by independents. Major oil companies which bought such assets at the height of the shale bonanza when acreage values crested in 2012 have not been able to prolong the speculative sales spiral. Shale acreage values have declined since, leading to massive write downs of unconventional reserves and asset values (see Appendix A).

In spite of an element of speculation entering into reserves booking [5, 9], proved reserves of the oil Majors have grown from 82 Bn boe in 2000 to 96 Bn boe in 2012 by a combination of mergers, acquisitions and organic growth (Fig. 1). Over the same period, the world’s total proved oil and gas resources, including assets of non-SEC reporting reserves of

![Fig. 1](image_url)
national oil companies have grown from 2100 Bn boe in 1987 to about 3000 Bn boe in 2012 [4]. Only 10% of these reserves are located in OECD nations, although the number of exploration wells drilled in the OECD regions still make up 25% of the total wells drilled globally [10]. The majority of these OECD wells is comprised of relatively low-cost, land-based drill holes for shale gas and liquids extraction in the US.

Production output of the world’s traditional US and EU based oil Majors has declined by 6% over the 7-year period between 2006 and 2012 (Fig. 2). A modest recovery in production growth of 2.2% CAGR is expected to occur between 2012 and 2020. The proportion of production from offshore assets has increased over the past 30 years and currently half of total oil production by EU Majors comes from offshore wells (Fig. 3). However, the ratio of onshore/offshore production is highly variable for individual companies, with Galp having 100% of its production from offshore assets and Repsol only a mere 30% (Fig. 3).

The trend within the offshore segment has been a steady progression from shallow waters toward deepwater and ultra-deep water assets (Fig. 4). The development of ultra-deep water assets has been supported by rising oil prices and the rapid development of suitable technology, both for exploration and development of such assets. However, the uncertainty in resource development times and costing have risen as Upstream developments have become more complex. Although the US Gulf of Mexico provides one of the world’s most attractive and stable fiscal policy environments, drilling the remaining assets in ultra-deep water is technically challenging and field development is costly due to very high pressure, high temperature and complex salt dynamics [11–13]. The ultradeep water pre-salt plays in the Gulf of Mexico, and Brazilian Santos and Campos basins all have development costs ranging from several billion to tens of billion dollars (industry reports). Even in shallow water, development costs have risen, exacerbated by cost

![Fig. 2. Consolidated oil and gas production output of US and EU peer group companies shows cresting in 2006, followed by a 6% decline from 2006 to 2012. Outlook is a gentle growth in production from 2012 to 2020 mostly by US peer group. Source: EU peer group output are estimates by Bernstein Research; US peer group output from company forecasts.](image)

![Fig. 3. Increasingly production of European Majors comes from off-shore fields. Galp assets are primarily giant oil fields in the Brazilian pre-salt. Statoil produces from a mix of UK and Norwegian off-shore assets, as well as offshore field elsewhere (Gulf of Mexico, Brazil). The 9% onshore assets are mainly unconventional oil and gas assets in North America. Not included are Statoil’s production in Angola and Azerbaijan as a non-operating partner. BP portfolio includes TNK/BP assets. Based on 2012 corporate reports and data compiled by Bernstein Research.](image)
overruns and delays, such as illustrated by Kazakhstan’s Kashagan field in the Caspian Sea, with over a decade delay in first oil and multiples of the original cost estimate for field development. High acidity mean the gas produced is lethal to life should it escape and the extreme environmental conditions include ice blocking access or water too shallow for any standard marine vessels to operate effectively. Added to this is a complex partnership and a highly demanding policy framework for natural resource development, all driving up cost and efficiency down. Such issues are now germane to the global oil and gas industry, which is why technology innovation must accelerate [14] and partnerships must be structured to improve operational efficiency.

A further trend is that the share of gas in the total production output has been steadily climbing: The EU Majors have moved from a gas to total production ratio of 30% in 1980 to nearly 50% in 2012 (Fig. 5). This has resulted in realized sales revenue per barrel as a percentage of actual oil price declining since 2000. In absolute terms, the realized oil and gas sales price grew from about $14/boe of production in 1987 to about $74/boe of production in 2012 [10]. The spread between the realized sale price on total production of oil and gas against the Brent benchmark for oil has been widening due to the increased proportion of gas as well as weak prices for natural gas and WTI in North America in recent years. The trend may reverse in the next few years when and if...

Fig. 5. Percentage of gas of total production output has moved to 50% in 2012, but our outlook predicts gas share will cease to rise and may slightly shrink instead. Gas Percentage right scale. Revenue per boe as a percentage of the underlying Brent price, left scale. Source: corporate reports and Bernstein Research.
US natural gas prices recover; WTI prices will firm up when pipeline bottlenecks near Cushing are resolved.

Another long-term trend in the upstream asset portfolios has been a shift toward land-based, unconventional oil and gas projects (Fig. 6). The proportion of unconventional resources in the portfolios has doubled from a mere 12.5% of production share in 2000 to 25% in 2012. Within the unconventional assets, production will continue to shift from gas to oil or oil-linked LNG to reduce the spread in differential income from total production sale per barrel realized and the oil price benchmark.

3. Trends in upstream spending and operational profitability

Unlocking new resources by predominantly organic growth (exploration and development of new fields) and additional, resource acquisitions have resulted in ever increasing upstream capital expenditure (Fig. 7). Annual Capex multiplied 4.5 times after the Millennium turn from about $40 billion in 1999 to $180 billion in 2012. The cost escalation is mostly on development cost and to a lesser extent due to rising exploration expenditure. Organic F&D spend per barrel of proved reserves averaged $4.45/boe from 1987 to 2003, but increased to $21.38/boe in 2012. Acquisitions from 2001 to 2012 accounted for $275 billion, a sharp increase from $80 billion in the preceding epoch (1987–1999) [10]. The numbers quoted are for the Majors studied as a subset of global energy acquisitions, which overall represent much larger value when including NOCs and US independents.

The European Majors account for a large proportion of the total Capex spent by the peer group included in this study (Fig. 8). Organic Capex has vastly outsized acquisition Capex, and grew ~16% in 2011 and ~26% in 2012 [10]. Development spending has doubled from $40 billion in 2006 to over $80 billion in 2012. Shell and BP spent the largest amounts on exploration in the European peer group of companies (BG, BP, ENI, RDS, REP, STL and TOT). The increased Capex for upstream projects was supported by the rise in annually averaged oil price, which has now been at all-time highs above $100/barrel for the annual average price of Brent benchmark oil since 2011 (Fig. 8).

The increased Capex over the past decade has neither lead to increased production output nor any significant increase in proved reserves, but is needed to replace production from older legacy fields that are depleted or nearing depletion. Another effect of ageing fields is that some investment goes into re-development and facilities modification in the tail-end of the field production life-cycle. These...
Investments are time-critical in the sense that if recovery is not achieved before the facilities of the field are decommissioned and abandoned, the resources are lost. Such tail-end production generates recoverable quantities and maintains jobs, but low production rates lead to marginal revenues close to operating costs. Such fields no longer generate excess economic rent for the owners of the magnitude seen when production was higher. Added to this is that newly developed assets are on average more technically challenging and require larger investments for organic resource maturation than ever before. The unit cost per barrel produced has therefore risen steeply between 2000 and 2012 (Fig. 9, left-hand scale). The dip in oil price in June 2008 more than halved income tax payments in the following year (2009), due to lowered net income by a combination of lower realizations and tactical write down of reserves no longer economic at the lower oil and gas prices. But since then, unit cost ($/boe) has resumed its ascent albeit faster than the rise in oil price (Fig. 9). Unit cost rose due to increases in production cost, DD&A, exploration expense and income tax with only SG&A expenditure staying relatively stable. Inflated unit cost has outpaced the rise in oil price so that net income per barrel has steadily eroded since 2005 (Fig. 10). Net income was $15/boe in 2005, but declined to $12/boe in 2012 and is expected to steady on $10/boe in the coming years. The profit margin for upstream activities for the peer group of oil Majors peaked at 31% in 2005, and declined to 23% in 2012.

The upstream profit margin has also been burdened by higher tax payments as is apparent from a comparison of the tax payment per barrel, which in absolute terms increased five-fold within the decade lapsed between 2002 and 2012 (Fig. 11). Tax payments appear to track before tax profits very closely and the hike in the tax payments is largely due to an increase in absolute size of the profits, lifted by the price of oil [15]. Nonetheless, the implied tax rate rose from 49% in 2002 to 60% in 2012. Income tax has become by far the largest cost for

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**Fig. 9.** Unit cost for production by European Majors. Taxation cost is rapidly rising (left-hand scale). Realisation spread refers to the difference between realised revenue per barrel and the benchmark Brent price (right-hand scale). Source: corporate reports and Bernstein Research.

**Fig. 10.** Net income per boe (left-hand scale) peaked in 2008 and again in 2011 due to rising oil prices, but margins as a percentage of revenue (right-hand scale) are under pressure due to the rising cost of unit production. Source: corporate reports and Bernstein Research.
European integrated operators (Fig. 11). There is nothing unusual about tax being the largest expense of a natural resource development business [16], but oil and gas companies with a portfolio of assets across different tax regimes must make sure their tax burden remains competitive. Company results depend on asset performance with respect to costs and revenues and share of costs and revenues accruing to the company. Fiscal and contractual regimes determine this relationship. For example, the tax take in OECD countries with a concessionaire system of royalty and income tax payments is generally lower than in non-OECD countries with production sharing agreements [17]. For definition of tax take and review of contractual regimes see Appendix B.

The rising trend in oil price (Fig. 12, right-hand scale) was in the first half of the past decade faster than the rise in unit cost of production, which means net income as a percentage of total revenue increased (Fig. 12, left-hand scale). However, unit cost per barrel continued to rise faster than the oil price from 2005 onward, which is why net income peaked in absolute terms at $15/bbls in 2005 (Fig. 10). This is consistent with a rise in development cost for organic F&D from $5—7/boe until 2005 to $22/boe in 2012 (Fig. 7).

4. Sources and uses of cash

For investors, oil Majors are mostly cash machines that generate cash through oil and gas production and use it either for investment in growth or for cash returned to shareholders in form of dividends (or share buybacks), or both. The industry must generate a profit that continues to attract financial support from the prudent investor. The cash flow sources and uses by major oil companies (US plus EU) have been compiled (Fig. 13). The sharp increase in upstream Capex (for
organic growth and acquisitions) since year 2000 was fuelled by the rise in oil price, which in turn has led to a boost in operational cash flow. The cash flows in excess of those retained for reinvestment were redistributed to shareholders as dividends and share repurchases, and in the most profitable years (2003–2005) to retire long-term debt (Fig. 13). Assumption of new long-term debt since 2005 (Fig. 13) has slightly increased the debt to equity ratio for the peer group. The gearing ratio averaged for all companies in the peer groups reached an historic low in 2005 but is still a modest 13% at the end of 2012 – which is a very low gearing ratio compared to the corresponding gearing ratio of 32% of 1987 [10].

Cash flow from operations (CFO) relative to Capex spending steeply improved in the period from 2000 to 2008 (Fig. 14). There is always a lag between new investments and generation of new profits as investments precede production growth and revenue generation. Growth portfolios therefore may have lower ROCEs than steady state or declining portfolios. Such transient effects in periods of change could potentially obscure indicators (e.g. CFO/Capex) used in our analysis. However, total production for the peer group of oil Majors in our study did barely change over the past decade (in fact, a 6% contraction occurred, see Section 2, Fig. 2). For these companies with steady-state portfolios, CFO and Capex are generated by and tied up in a more or less stable asset volume. The ratio of CFO to Organic Capex between 2000 and 2008 was 182%, sharply up from 126% in the preceding decade. From 2008 to 2012 the ratio CFO/Organic Capex deteriorated again to a mean value of 125%. The explanation being that costs for reserve replacement have risen even faster than oil and gas prices. It is also worth noting that the operational returns on Capex since 2005 have been markedly better for US Majors as compared to EU Majors (Fig. 14). The competitive difference had disappeared in the period 2000–2005, but also prevailed in
the preceding decade (1990–1999), and reappeared after 2005 (Fig. 14). The explanation for the better performance of US companies is given in Section 5 of our study.

Cash flow from operations used for shareholder returns and for retained earnings to fund new Capex projects was supported by net asset sales in at least some companies over the period (2000–2013), while others were net acquirers of assets rather than net disposers of assets (Fig. 15). Many of the traditional Majors (Exxon, Chevron, Conoco, Shell, BP, BG, and Repsol) were net sellers of assets. A balance between acquisitions and sales of assets by M&A strategies is seen for others (Statoil), while another group comprises net asset buyers (TOTAL and Eni; Fig. 15). In contrast to the net asset sales by most western Majors, the emerging Majors (Gazprom, Sinopec, CNOOC, Petrochina and Petrobras) typically acquired more assets than divested.

5. Shifts in vertical assets

Over the past decade, most integrated oil Majors have progressively shifted the bulk of their capital employed toward the upstream segment (Fig. 16a–f). Chevron and Exxon were first to start and then accelerated this re-allocation pattern since 2004/2005. Upstream projects would typically represent about half of the total capital employed until 2004/2005, when the emphasis on capital spending shifted away from the downstream segment due to the increased cost of reserve replacement. Larger capital expenditure for organic growth projects in the upstream segment resulted in the upstream segment accounting for over 70% of total capital employed in 2012 (Fig. 16a and b). European Majors were not merely as responsive as their US counterparts in mitigating the deteriorating margins in the downstream segment. For example, ENI still had only 55% of capital employed in the upstream segment in 2012, Shell 60%, and BP 65%. It seems that EU Majors were relatively slow to respond to declining profits in the downstream segment. Only TOTAL mimics the trend of US Majors shifting more capital to upstream activities, with over 70% capital employed in 2012 as compared to 40% in 2000 (Fig. 16c and d).

Shifting more Capex to the upstream segment was not only required by rising reserve replacement cost. Another reason why the upstream segment employed more capital relative to the downstream and other activities was a better return on investment for upstream projects (Fig. 17). The return on capital employed (ROCE) for downstream assets varied between a 1/2 and 1/3rd of upstream ROCEs over the past decade. Good resource management practice required companies to increase their economic rent upstream. Meanwhile, downstream ROCEs have recovered since 2009 and are now edging back toward returns realized in the upstream segment (Fig. 17). The 2012 performance gap between upstream and downstream assets is reduced to 4.2% and may close or downstream may outperform upstream assets in the coming years as only the best downstream assets have been retained. Capital employed, which is book value of fixed plus current assets less current liabilities, in the downstream segment quickly depreciates as refineries and other activities will lose book value and require little or no capital expenditure (Capex) during their life cycle. But downstream consumes considerable operating expenditure (Opex) due to relatively large number of people employed as compared to the upstream segment. For example, TOTAL has 17% of its personnel in upstream (E&P) activities, while 53% are in downstream (refining and petrochemicals) and the remaining 39% in other services (gas & power, marketing, trading, research and corporate affairs; 2012 company reports). In summary, Opex requirement is high in downstream with only modest Capex requirement. It is worth noting that ROCE comparisons across segments are impacted by different asset life cycle stages and ageing assets. In spite of such differences, companies striving for optimization of operational profits and shareholder value should promptly reduce exposure to underperforming business assets.

Whereas Opex requirements are high in the downstream segment with only modest Capex requirements, the reverse holds for the upstream segment. Capital employed in the upstream assets like proved reserves will rapidly deplete by production, which corresponds to high cost for replacement of reserves produced; the depreciation matches diminished value of assets developed and acquired through past FD&A. That is why upstream Capex intensity is high, as rejuvenation and growth of upstream assets by organic growth and/or acquisition requires continuous investments. When the cost of FD&A rises, this will be reflected in the Capex allocation (Section 3). As the number of people employed in the upstream segment is much lower than the downstream segment, Opex requirements will remain modest as compared to those of the downstream segment.

6. Overall profitability and shareholder returns

The rising Capex requirements for the maintenance of the upstream asset base have been facilitated by rising oil prices. Net

![Figure 15](image-url) For the traditional, western Majors inorganic growth has been very modest over the past decade. Western Majors have been mostly disposing of assets rather than acquiring, except for TOTAL and Eni. Emerging Majors (Gazprom, Sinopec, CNOOC, Petrochina and Petrobras) are net acquirers of assets. Source: Bloomberg and Bernstein Research.
Income has also risen, albeit held back somewhat by the rising costs of field development which continue to outpace the increases seen in global oil prices. A 25 year time-series of ROCEs for the combined peer groups of US and EU based oil Majors shows excellent returns for the past decade (Fig. 18). US Majors have earned higher ROCEs of 18.1% averaged for 2010–2012, while EU based Majors only realized 9.3% in the same period. There is a potential blurring effect when combining steady state and growth portfolios. The latter should see reduced ROCE but enhanced share values provided the capital built through investments is communicated properly. However, in the case of US and EU Majors only Statoil has seen significant growth in both reserves and production output over the past decade. The explanation for the performance gap between US and EU Majors is a faster shift toward more profitable upstream projects by US companies. In the period before year 2000, ROCEs typically hovered between 5 and 10% (Fig. 18).

The higher profitability realized in certain years by US Majors has translated to handsome cash returned to shareholders as percentage of CFO, which typically outperformed EU Majors before the Millennium turn and also after 2006 (Fig. 19). The timely shift of US Majors away from downstream assets in favour of upstream projects has resulted in returns of the CFO percentage to shareholders at about 40% for 2011 and 2012, which is twice the CFO percentage returned to shareholders of EU based companies.

7. Discussion

7.1. Emerging majors

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.

Fig. 16. Time series showing vertical shifts in capital employed for selected US (a and b) and EU majors (c–f). US companies moved more capital employed toward upstream since 2004/2005. Source: corporate reports and Bernstein Research.
Fig. 17. Profitability of vertical assets (upstream, downstream, and other assets) in terms of ROCE. Upstream activities return higher profits as compared to downstream and other activities. Even upstream ROCEs have come down from 2008 peak due to rising cost of field development, increased realisation spreads and higher operating costs. ROCEs will only resume their 2005–2008 levels when oil and gas prices go up, and Capex rises for new field development can be contained. Source: corporate reports and Bernstein Research.

Fig. 18. Overall profitability for peer groups. ROACE is under pressure for EU Majors (left-hand scale), which have been outperformed by their US counterparts. Source: corporate reports and Bernstein Research.

Fig. 19. US companies typically return more cash to shareholders (as a percentage of operational cash flow) than their European counterparts. Source: Bloomberg, corporate reports and Bernstein Research.
Some may argue easy oil and gas are coming on stream again by production from land-based unconventional source rocks. However, for shale resources the uncertainties are high, societal acceptance is still low, and steep technology improvements are needed to render such field projects profitable, all of which is far from simple or easy [18].

Can oil companies of the future maintain their operational profits and meet global energy demand? Our analysis covered US and EU based Majors, because transparent reporting is available for the past 25 year period covered in our analysis. New Majors are emerging in Russia (Lukoil, Rosneft, Novatek), South America (Petrobras, YPF) and Asia (PetroChina, Sinopec). Although technology leadership has traditionally resided in US and EU based Majors, research spending by both Petrochina and Petrobras has risen faster and exceeds that of many traditional Majors for a sample panel between 2003 and 2009 (Fig. 20). This means technology leadership is no longer a competitive privilege held only by the select peer group of traditional Majors. The fierce competition for technology leadership puts additional pressure on the future strategy of traditional Majors to generate profitable resource extraction opportunities. The emergence of a new league of oil Majors from the fast growing economies will help these nations to secure the much needed fossil energy resources to fuel their rapid economic growth.

7.2. Innovation rates and retained earnings

Some would argue that the major oil operators are still trapped in technology and workflow processes that work well for conventional fields, but now need to accelerate the technology innovation required for unlocking lower margin resources such as tight oil and gas shale. As oil and gas companies move into more challenging oil and gas plays, their retained earnings will come under pressure as operational margins are lower and capital requirements are rising. For example, the newly emerged US shale gas operators have been struggling to generate any retained earnings (Fig. 21a). These US shale gas operators are less successful in generating cash flow from operations, marred by low gas prices in a land-locked regional gas market. Companies that do not succeed in generating operational profits do not retain earnings but instead accumulate losses, unless compensated for by financing activities. Both Chesapeake and Petrohawk have typically financed new projects by issuing new shares, new debt acquisition, or asset sales (by either volumetric production payments or leasehold sales, or both) [20]. Devon and EOG have outperformed their peers on retained earnings (Fig. 21a), partly because their portfolios include not only gas but also significant oil assets, which generate higher profits than US gas assets. Although cash flow from US shale gas operations has been largely negative over the past decade (see also Appendix A), opening up LNG export facilities could create some linkage between US gas prices and world gas markets [21] and thus restore profits.

If the upstream oil and gas industry does not succeed in accelerating innovation rates, the superb retained earnings growth of the past (Fig. 21b) may become affected by the effects of a pattern of retained losses that has been characteristic for the operational performance of many US shale gas operators. Retained earnings and losses are cumulative from year to year, with losses off-setting earnings. As for now, the E&P clockspeed settings need to adjust ever faster to adapt to the changing realities of the oil and gas industry [22]. As we move forward into a new era of the oil and gas extraction challenges, entrepreneurial companies are needed to open new avenues. Actualizing dynamic capabilities [1–3] becomes a key issue for oil and gas companies to retain and gain competitive industry leadership positions.

Fig. 20. a: The oil Majors have stepped up R&D spending during the past decade. b: R&D budgets by service companies has risen too, but PetroChina and Petrobras have risen faster in both percentage (Y/Y) and absolute terms. Source: Thuriaux-Aleman et al. [19].

Fig. 21. a: Retained earnings for peer group of US unconventional gas operators. b: Retained earnings amassed by Exxon, Chevron, and Shell since the start of their operations. The cumulative growth of retained earning (or cumulative losses) are for (a) 12 year period (2001–2011) and (b) 7 year period (2005–2011). Source: Alboran Research and company reports.
7.3. Energy transition

The rising cost of hydrocarbon extraction creates a strong incentive to accelerate the energy transition and move away from costly hydrocarbons toward progressively more affordable renewable energy resources. However, renewable energy technology cannot displace fossil fuels faster than the most successful renewable energy innovation rates allow [23]. 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 levelled off to linear growth when reaching about 1% of our primary energy mix supply (Fig. 22).

The projected transition rate to renewable energy sources, based on the best trend extrapolations [4,24], 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 about 77% of our primary energy supply [24]. The relative share of renewable energy will then have grown to 18% according to Exxon [24]. Shell projected further growth of renewable sources which may supply up to 30% of global energy by 2050 [25]. 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, mostly displacing some of coal’s share in power generation.

To meet the growing energy demand that is driven by the emerging economies and accelerating urbanization and rural electrification programs, our future energy supply systems will be reliant on coal, oil, gas, nuclear, bio-fuels, and solar, wind and hydro power. The world needs to invest heavily in their development – as much as $38 trillion will be needed between now and 2035 [26]. That means industry spends on average about $30 billion/week to maintain and develop our global energy supply infrastructure [25]. The lion’s share of this amount is spent in the upstream oil and gas business. Although very large investments are needed in the power sector, the continued production of fossil fuels will also need significant and growing investments due to the accelerating depletion rates of existing fields.

8. Conclusions

8.1. Conclusions related to tactical choices and key performance indicators

Although unit cost of producing new barrels is rising, organic asset growth has remained more profitable than acquisitions, which explains why net sales of assets is presently the prevailing trend for the global Majors. The rising cost for assets can be afforded only because the price of oil is rising, and net income remains competitive but lags behind the growth in the oil price. The rising unit cost of production is due to ever deeper and costlier ultra-deep water projects, dear unconventional projects and inflation of industry cost (supplies, energy cost and wages) that have outpaced oil price rises. The ultra-deep water projects have still better margins than unconventional projects, which are also capital intensive over the life-cycle of the field but less profitable [5,26]. The current low cost of natural gas in North America due to an over-supplied market, does suppress net income for North American gas producers [20], but exports may provide a lift [21]. Gas from other continents still commands steady prices due to oil-indexed contracts still being the norm [27]. Cash flow from operations versus organic Capex was highest in the first decade of the 21st Century (Fig. 14), but now deteriorated due to lower margins per barrel and heavy investments in the maintenance of production capacity due to depletion of legacy fields.

Apart from shifts within the upstream portfolios, oil Majors also increased the capital allocation in upstream projects at the expense of downstream activities (Fig. 16). The reason being that margins on upstream production are still higher than on refining and other downstream activities. Overall profitability (ROCEs) of major operators is excellent but declining, due to capital intensive E&P activities and is further eroded by the rising burden of taxation. Growth portfolios could cause an apparent deterioration of performance indicators, but asset and production growth are only apparent for Statoil, most other EU and US majors have a steady asset base and a more or less stable production output.

The leverage of oil and gas companies on tax regimes is weakening which partly may explain their higher tax burden (see also Appendix B). Shareholders in oil Majors still enjoy high returns on investments (based on total shareholder return) but receipts are declining since 2006 (Fig. 19). US companies have better return for shareholders due to profitability staying relatively firm by a prompt shift to upstream away from the downstream activities when profitability of that segment declined. Oil Majors perform well but can only maintain their production output and asset base as long as oil and gas prices stay firm. Return to lower oil prices therefore is unlikely to occur, unless OPEC producers will undercut prices by increasing their production share in the global market. Such an OPEC move seems unlikely and oil prices therefore are likely to stabilise in the next few years before continuing their ascent.

8.2. Recommendations related to strategic directions and corporate alignment

As the demand on Capex is growing in all oil companies, investor relations become more important and so are government lobbying to keep the tax burden from escalating. The management of external stakeholder relations requires ever increasing attention from corporate managers (CEO, CFO). At the same time there is increasing complexity and rising challenges to successfully develop deep water fields and unconventional assets on time, safely and within budget. This means the demand on operational staff and expertise is rising in step with the challenges in the upstream development of new resources (deep water, unconventional resources). Attracting leading experts and training engineers in newly developed operational procedures remains key in the quest for access to new streams of profitable oil and gas resources [1–3].

Rapid response to changes in the business environment remains important to maintain profitability of operations as has been highlighted by the quick move of US based oil Majors toward disposal of upstream and other assets. European operators were slower to recognize these changes or did choose to adapt at a slower pace, which led to a decline in their cash flow from operations. Rapid strategic
realignment is key and requires swift organizational changes and Corporate IQ awareness to implement the required changes fast and successfully [28–30].

8.3. Key findings

The principal conclusions from our performance analyses based on the benchmarking of US and EU peer groups of oil Majors can be highlighted as follows:

- Upstream capital expenditure by oil Majors rose 450% in period 2000–2012.
- Production has not risen but declined 6% between 2006 and 2012.
- Upstream ROCE and cash flow have declined since peaking in 2008.
- Downstream ROCE bottomed out over past decade and trend is sharply up.
- Shareholder returns of US Majors were twice that for EU Majors (2007–2012).
- High upstream development costs require high oil prices for sustained oil supply.
- Transition away from costly hydrocarbons to renewable energy will likely accelerate.

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Appendix A. Shale-lease price correction

Many of the signing bonuses paid as North America’s unconventional sector boomed were not supported by economic fundamentals. A price correction is on its way.

The large number of US shale assets up for sale suggests vendors do not see positive cash flow coming out of these plays anytime soon. A number of major North American shale acreage acquisitions have been hit by large impairments within one or two years of the deals closing. For example, BHP Billiton and BG Group in 2012 impaired freshly acquired US shale assets by more than one-third of the acquisition price, translating to multibillion dollar write-downs. Shell is the latest major to concede that North American shale assets are worth less than previously thought. The company had been quietly but aggressively acquiring shale assets, particularly in North America, but in its second quarter results of 2013 took a pre-tax charge of about $3 billion on its North American shale portfolio, valued at about $24 billion. Shell emphasized it faced difficulty in capitalising on these shale assets, adding they hold less oil than hoped for even after moving from the gas to the liquids maturity windows.

According to chief financial officer Simon Henry (investor presentation, 2013), half of Shell’s main nine unconventional oil and gas assets in North America will be divested. Shell holds shale acreage in Texas, Ohio, Pennsylvania, Wyoming, Kansas, Colorado and California; it also has shale assets in the Canadian province of British Columbia. The location of the impaired shale assets has not been disclosed, as the Securities and Exchange Commission (SEC) does not require that companies report more than aggregated asset impairments. Shell signalled that further write-downs are likely to follow and a strategic review of its portfolio is under way.

Asset volatility

The wave of shale asset value impairments highlights the broader problem industry faces: volatility of shale asset values. What are the causes of this volatility? Was the rhetoric about shale’s cheap energy potential unwarranted as a handful of critics have been signalling all along? Indeed, it is no longer disputed by industry that Henry Hub gas prices have collapsed to far below the cost of production. Shale margins have evaporated due to oversupply in an isolated North American market. The tangible worth of shale acreage resides in the net present value of gas reserves. Due to the slim margins on shale-gas production [20], reserves have become as volatile as the gas price itself [5, 9]. Positive net present value has shrunk across the US’ shale plays as gas prices collapsed.

As a result, we are nowhere near realising the 50% margins on conventional legacy oil and gas fields. It is arguable that the prices paid for shale acreage were speculative and not supported by any certainty about economic recoverable resources. Proved reserves that were previously thought to exist provided unreliable asset values. Fewer proved reserves can be booked when depressed gas prices make the production sub-economic. These proved reserves need to be technically downgraded and instead must be classified as contingent resources. That is the real message we must read in the impairment of asset values reported by BHP, BG, Shell, and other shale operators. Speculative future value remains, but when the contingent resources can be upgraded into proved reserves again is wholly uncertain. Advanced drilling technology has already slashed drilling time in half, improved well productivity and drilling and completion costs has been halved within less than a decade. But gas prices fell faster than the financial gains from technological advances.

Future technologies and gas prices may reverse this trend, but there is currently no cheap shale-gas production method. Gas producers have effectively been subsidising the gas bills of US gas consumers over the past few years. Shale may provide long-term profit potential, but we can now conclude that the acreage has been overvalued. The rise and fall of Utica shale lease bonuses provide an interesting case study of the speculative rush into shale acreage (see below).

Utica signing bonuses

Farmers owning land in the Ohio sector of the Utica play still pay no more than $5000/acre (2012 Farm Real Estate Values) in what already is an historic price boom. Leasing acreage to oil and gas companies has traditionally earned landowners in Ohio only modest additional income: $2/acre in 2000 and $30/acre in 2005. In 2008, leasehold signing bonuses shot up to $2400/acre. Chesapeake Energy — an early entrant into the Utica — played a major role in the creation of the shale pricing bubble. Former chief executive Aubrey McClendon said during an investor call for its third-quarter results in 2011: “We continue to be very pleased with our Utica well results to date, but are not releasing any additional results because last time we did leasehold prices doubled within weeks”. Announcements such as these helped send lease prices higher. A joint venture agreement struck between Chesapeake and French Major Total in January 2012 valued the leasehold at $15,000/acre, sharply higher than any other Utica acreage. At the time, Utica lease prices were valued at $5000 to $8000/acre; the median land sales price remained $5000/acre.

As of 2013, the median Utica lease bonus prices are nearer to $4000/acre, with a spread ranging between $1000 and $8000/acre. Meanwhile, Chesapeake itself is seeking to divest 94,200 acres of Utica leasehold. The current wave of impairment charges — basically reserves no longer supported by economic fundamentals — is likely to herald a move toward more realistic signing bonuses throughout the industry. That will reduce the risk of volatility in shale asset values as future operators will no longer need to balance the lease prices paid with inflated reserves collateral.

Appendix B. Total tax take and brief outline of contractual regimes

Companies already face ever rising E&P expenditure and any shift to higher taxation of hydrocarbon assets may cause distortion and could
slow new field development. Taxation of hydrocarbon production varies considerably from country to country. The fiscal burden for oil producers can be as low as 45% for offshore production in the US, yet twice as high in Algeria. With the fiscal burden being so different across the globe, companies must work hard to contain a potential rise in their overall tax burden by skillful portfolio management. For example, Shell produces from 37 different countries, which exposes it to government tax taking ranging from 32% in Ireland to 97% in the UAE. Indeed, there is a huge range of variants on licences costs, royalties, production sharing agreements and corporation tax (a see below).

In this study, the total tax take or Fiscal Entitlement Payment (FEP) is defined as the percentage of revenue from production sales after subtraction of resource development cost (DD&A) and operating expenses (Opex). This can be calculated as follows: FEP = (Revenue per unit production – Operating Costs – DD&A – Net Income). Operating costs includes production expenses, SG&A and exploration expense, but not royalties or other production taxes. Equity production is the company’s share of production prior to any government share under any PSA. Expressed as a percentage, FEP = 1 – [(Equity Production × Revenue per unit production) – Operating Costs – DD&A – Net Income]. For the operator remains cash from operations after FEP.

FEP is made up of income tax, plus royalty charges, plus the government share of production under any production sharing agreement (PSA). FEP includes equivalent to the effective tax rate (ETR), which is defined as the percentage of revenue from production sales after subtraction of resource development cost (DD&A) and operating expenses (Opex). This can be calculated as follows: FEP = (Equity Production × Revenue per unit production – Operating Costs – DD&A – Net Income). Operating costs includes production expenses, SG&A and exploration expense, but not royalties or other production taxes. Equity production is the company’s share of production prior to any government share under any PSA. Expressed as a percentage, FEP = 1 – [(Equity Production × Revenue per unit production) – Operating Costs – DD&A]. For the operator remains cash from operations after FEP.

The government entitlement payment (FEP) can be termed total fiscal take, government take, or effective tax rate. The IMF also distinguishes the incremental effective tax rate (IETR), which may differ from the AETR by using a specific realized net income from operations in a specific year which may be affected by special circumstances.

The right to exploit a country’s natural resources is generally granted by the responsible sovereign authority in return for an agreement that details how the various project taxes plus corporate income tax add up to a total fiscal entitlement payment (FEP). The three following types of agreements are commonly used.

### B1. Royalty and Taxation Agreement (RTA)

The majority of OECD countries tax oil and gas production using a concessionaire system comprised of a royalty and income tax payments, sometimes accompanied by an upfront auction bonus payment. Royalties are charged as a percentage of revenue earned from production, and income taxes are then charged as a percentage of operating profit. The deeper water part of the US Gulf of Mexico is now one of the most challenging drilling environments, but companies are attracted by a stable fiscal regime on which to calculate their return on investment. The bonus for concessions tends to become costlier over the years. For example, the US Interior Department held a record-setting 2012 sale of oil and gas drilling rights in the central Gulf of Mexico. Companies submitted $1.7 billion to win bids for 454 offshore tracts, with Statoil establishing a new high-water mark with its $157 million offering for a single lease. However, since bidding bonuses may be subtracted from corporate income tax and in essence are an advance tax payment rather than an extra cost.

Table B1 includes a simplified example of the government entitlement under RTA. Under a royalty and tax regime, the tax rate is not sensitive to the oil price, making the net income of operating companies more sensitive to the oil price than under other tax regimes. This can be a relatively simple tax system: The income tax rate charged will often be the country’s standard corporate tax rate plus an additional resource tax, as is the case in Norway. Brazil is another example of a royalty and tax regime, but one that’s more complex. Royalties are charged at 10% and Brazilian corporate tax is charged at 34%. However, there is also an additional Special Participation Tax (SPT) charged on the pre-salt fields of 40% prior to corporate tax, making the income tax charged on oil and gas production actually 61.4%. The SPT and royalties are reported under production cost and just the corporate tax is shown as income tax.

### B2. Production Sharing Agreement (PSA)

Most non-OECD nations opt for so-called production sharing agreements (PSAs) where the state demands an unpaid equity stake in the field asset and production revenues are further levered back to the state via corporation tax. A simplified PSA is schematized in Fig. B1. When oil or gas is produced, the operating company can recover costs of production (this portion of production is termed Cost Oil), before any additional volumes (Profit Oil) is split between the government and the contractor. The ratio of the Profit Oil split is determined by a sliding scale, which is based on complicated formulas generally established by the IRR for the project to date. Table B1 includes an example of government entitlements under PSA. The tax take also varies significantly through the life of the project. In the early stages, while the operator is still recovering Capex, the IRR up to that point is low and therefore the government’s share of Profit Oil is low; in later years, Capex spend slows and the IRR likely moves above a threshold, meaning the government share of Profit Oil increases, often to a proportion of around 80%. PSA tax regimes tend to be sensitive to the oil price. A high oil price means that operators earn costs back quickly and have higher returns, resulting in the government taking an increased share of production. There is a distinct trend where the highest tax rates are applied in non-OECD countries.

| Table B1 | Simplified project economics and government FEP for the taxation regimes under the three different main types of contract. Source: Bernstein Research |
|---|---|---|
| RTA | PSA | SCA |
| Equity production × price | 100 | 100 | 100 |
| Government share | 0% | 30% | 100% |
| Entitlement production × price | 100 | 70 | 0 |
| Royalty rate | 10% | 0% | 0% |
| Royalty | 10 | 0 | 0 |
| Operating costs | 30 | 21 | 0 |
| DD&A | 15 | 11 | 0 |
| Operating profit | 45 | 39 | 0 |
| Operating margin | 45% | 55% | n.a. |
| Income tax rate | 60% | 53% | 0% |
| Income tax | 27 | 21 | 0 |
| Service fee | 0 | 0 | 2 |
| Net income | 18 | 18 | 2 |
| Government entitlement (FEP) | 67% | 74% | 98% |

Many emerging oil-rich nations have been successful in their struggle for progressively bigger profit shares from their geological endowments. Where there exist weak institutions, unstable governments or state-controlled judiciary systems, earlier fiscal agreements may be easily replaced by new terms less favourable to the operators and more favourable to the resource owner.

### B3. Service Contract Agreement (SCA)

The third type of tax regime is a service contract agreement, which is much less common than tax rates or PSAs. The Integrateds have some exposure due to SCAs being used in the UAE and Iraq for contracts awarded after the second Gulf War. Under the service agreements, the operators receive a fixed fee for each barrel of oil produced above a fixed level. The fees in Iraq range from as little as $1.15/bbl (for West Qurna-2, operated by Lukoil) to $6/bbl (for Najmah, operated by...
Sonangol). Under the agreements, the income of the operators remains insensitive to any oil price windfall or loss. Table B1 includes an example of the government FEP under SCAs.

References


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