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Supermajors Cost Index

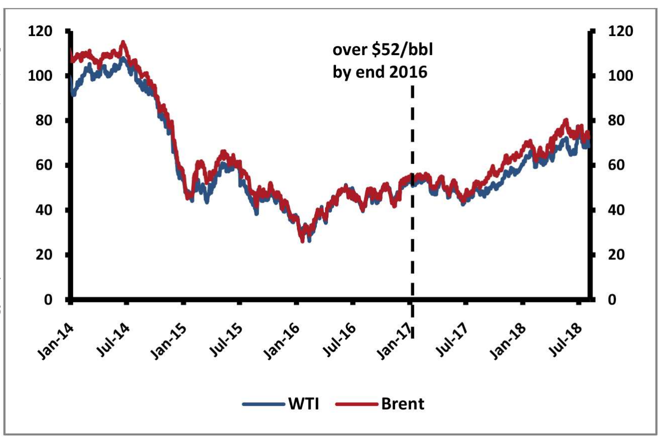
Has Cost Efficiency Peaked?

A combination of rising oil prices, stronger balance sheets and continued significant cost deflation has created a 'sweet spot' for oil and gas companies to start investing in new projects.

Overview of recent developments

The oil and gas industry has experienced some dramatic changes over the last couple of years. Prices collapsed to around $26/bbl in early 2016 (*see chart 1*) as the market became increasingly gloomy about persistent excess supply in the global oil markets and OPEC's ability to reach an agreement among its members to address this worldwide glut.

But bearish sentiments gave way to optimism as robust global economic growth led to higher-than-initially-anticipated demand for oil. This, together with the historic OPEC and non-OPEC alliance to address the oil inventory overhang, resulted in a strong price recovery. As a result, prices more than doubled from their nadir in the first quarter to over $52/bbl by the end of Q4 2016.



Source: U.S. Energy Information Administration (EIA), Apex

Chart 1: Crude Oil Prices since January 2014 (US $ per Bbl)

Other than occasional fluctuations, prices continued to move upwards throughout 2017 and for the most part in 2018 as inventories fell sharply. By the end of April 2018, OECD commercial stocks dropped from 292 million barrels above the five-year average a year ago to 27 million barrels below the five-year average.

Strong, synchronized growth across the major economies, and record-high compliance with the production cuts agreed by OPEC and non-OPEC members, were mainly responsible for this reduction in stocks of approximately 319 million barrels. Geopolitical factors, such as supply outages in Venezuela, also contributed to this earlier-than-expected decline in the OECD commercial inventory level.

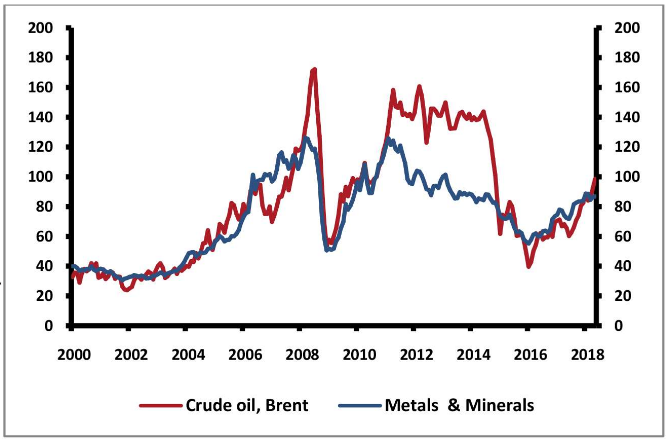
Higher oil prices also helped oil and gas operators to rebuild their financial health. The combination of rising oil prices, stronger balance sheets and an industry still experiencing significant cost deflation created a 'sweet spot' in which oil executives felt confident enough to start investing in new projects. As a result, a number of flagship projects received the go-ahead in 2017. For example, Shell decided to proceed with its Kaikias development in the Gulf of Mexico, which was its first such investment in more than a year and half, while ExxonMobil gave the green light to phase 1 of its Liza field development in offshore Guyana.

As optimism gradually returned to the market and capital spending picked up after years of deep cuts, many industry players and observers became concerned about the sustainability of the cost reductions achieved during the downturn. Citing recent cost inflation in the US shale region as an example, some argued that the industry was moving back to a high cost environment as a wave of new projects reached Final Investment Decision (FID) in 2017.

Given that the number of new projects, including large-scale LNG projects, reaching FID in the coming years is expected to remain high by recent historical standards it is instructive to analyze the industry's latest performance in developing its reserves. We have therefore updated our proprietary Supermajors Cost Index to determine how the industry has performed over recent years, and also investigated the performance of the industry's 'trendsetters', the seven supermajors, in this context.

Supermajors Cost Index: a historical context

In the early 2000s, oil prices entered a 'super cycle' phase alongside other commodities (*see chart 2*). Robust global economic growth, surging demand for commodities from emerging markets and developing economies (EMDEs), such as China, and supply deficit caused by underinvestment in various commodity markets during the previous decade were the main drivers behind this extended and sharp rise in commodity prices.



Source: World Bank, Apex

Chart 2: Nominal Commodity price indices (Sept. 2010 = 100)

In the case of oil, this strong demand coincided with a period in which 'peak oil supply' dominated industry thinking. As a result, the industry expected oil prices to move considerably higher than the previous decade average of $20/bbl. This expectation changed the strategic priorities of oil and gas companies markedly. After more than a decade of retrenchment, the industry moved into a growth phase, and resource and reserves development became the primary focus of oil and gas operators

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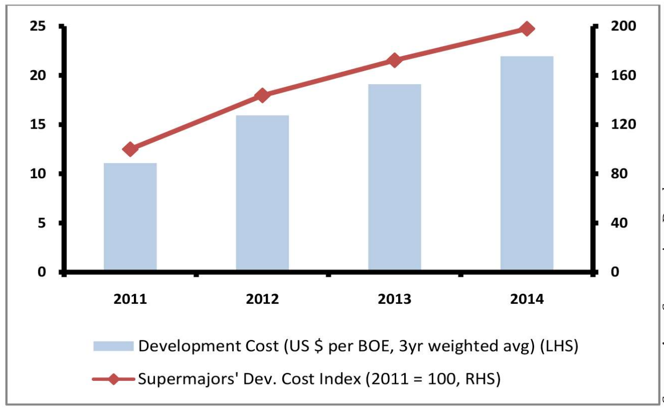
This shift in volume growth encouraged companies to develop shale, deep water, ultra-deep water, and heavy oil resources in more technically challenging and harsher environments. The greater technical risk profile of these resources meant that the costs of developing these assets were higher than for conventional onshore or shallow water developments. Partly because of the development of these inherently riskier resources, global oil and gas capital investment increased almost five-fold, from $160 billion in 2000 to $780 billion in 2014 (in 2015 US $).

Other factors also contributed to the staggering growth in upstream capital investment in this period. Excessive focus on 'volume growth' in many cases resulted in poor planning and flawed project execution. As a result, the industry failed to deal effectively with the myriad of technical and non-technical risks associated with these new sources of supply. Cost overruns and delays became the norm. Indeed, a study conducted by the Oil and Gas Authority in the UK found that between 2011 and 2016, on average, projects in the UK Continental Shelf (UKCS) were costing 35% more than estimates in the FDP (Field Development Plan) and were delivered 10 months late.

Sustained capex growth since 2000 also ushered in a period of significant industry-wide cost escalation. Prolonged ramp-up of upstream capital investment created unprecedented pressure on the supply chain. Therefore, cost of materials (e.g. steel, cement etc.), equipment (e.g. rig rates) and labor increased significantly over the same period. The situation was made worse by the rent-seeking behavior of industry participants, as material suppliers and oil services companies tried to grab their share of the higher oil price dividend, alongside national governments and regulators.

This mix of higher cost resources, industry-wide cost escalation, and cost overruns and delays meant that the productivity of the vast sums of capital employed suffered significantly. As a result, our Supermajors Cost Index almost doubled between 2011 and 2014 (*see chart 3*). We estimate that development cost per BOE (barrels of oil equivalent) for the supermajors as a group went up from just over $11 to almost $22 during this period.



Source: Apex Supermajors Database

Chart 3: Supermajors Cost Index – evolution of development costs (2011 – 2014)

Note:Supermajors group consists of Shell, BP, Total, ENI,Chevron, ExxonMobil and ConocoPhillips.

Supermajors Cost Index: post 2014

Global growth remained sluggish between 2014 and 2016 due to subdued economic activity in the advanced economies as well as in the EMDE regions. This period of weak global growth took place against the backdrop of weakening long-term demand for fossil fuel brought on by a continued increase in energy efficiency and energy productivity, a growth in renewables, and the rise of electric vehicles. While oil demand prospects remained weak, supply continued to increase throughout this period, led by US shale production. In 2014, growth in US shale oil production alone outstripped the rise in global oil demand. The resulting oversupply triggered an almost 18-month long decline in oil prices.

Prior to its collapse in mid-2014, price growth had slowed significantly in response to weak projections of long-term oil demand. This, together with the staggering rise in the cost of developing assets, brought cost reduction back into the spotlight. As a result, by the end of 2013, several projects were delayed or canceled and many companies had cut their capital investment budget for 2014. For example, in 2013, rising costs forced Equinor (previously Statoil) to defer its development plan for the Johan Castberg field, while Shell cut its 2014 upstream investment budget by 20% to improve its financial performance.

At the same time, a number of companies, such as Chevron and Total, were coming out of a major capital investment cycle. The combination of project cancellations and a slowdown in upstream investment eased the pressure on the supply chain which had previously caused service and supply costs to escalate. As a result, service sector cost started to soften as early as 2014.

This trend of project cancellation and cuts in investment accelerated sharply as prices more than halved over the next couple of years. As the industry's attention shifted back firmly to value instead of volume, companies decided to high-grade their portfolios and focus investment activities on their most productive low-cost basins. In addition, operators took a number of steps to reduce the costs of developing assets, as many projects were not commercially viable in this 'lower-for-longer' oil price environment.

Prior to the price collapse, developing large new flagship projects at frontier basins requiring vast upfront capital was the norm for the big players. After prices collapsed, the industry's attention shifted to developing projects with smaller footprints, less capital intensity and shorter payback. Consequently, there was (and still is) a strong focus on developing incremental brownfield projects, developing projects with smaller facilities and fewer wells, and making use of existing infrastructure to reduce upfront capital requirement. Instead of customizations and unique solutions, simplified processes and standardization became the preferred options, enabling companies to achieve manufacturing-like efficiencies through repeated utilization of the same processes and technology. Instead of 'future-proofing' new developments, companies delayed the design of future development phases to exploit the technology available at the time and take account of prevailing market conditions in their investment decisions. These steps generated significant cost savings for the industry. In addition, costs went down further as technological advances reduced drilling times and boosted drilling productivity notably.

The service sector also played its part in reducing the cost of new projects. The collapse in upstream investment which began in 2014 resulted in a significant oversupply of equipment, labor and materials across the board. In response to this supply overhang, oil services companies offered deep rate cuts in order to survive and maintain the utilization of their rigs and equipment. Furthermore, greater collaboration between the operators and service companies improved the industry's ability to manage complex technical challenges and its overall project execution capability.

At the same time, industry-wide job-losses decreased the cost of labor, while lower input costs, such as for steel, reduced the cost of equipment and building appropriate facilities.

The mixture of smaller project footprints, improved efficiency, and lower input and service sector costs raised cost efficiency and capital productivity of the sector significantly. As a result, by 2017, our Supermajors Cost Index had declined by more than 41% compared with the level seen in 2014, when the Index reached its peak (*see chart 4*).

> **Among the seven companies analyzed between 2011 and 2017, we found that Eni's performance improved the most, followed by Chevron and Total**

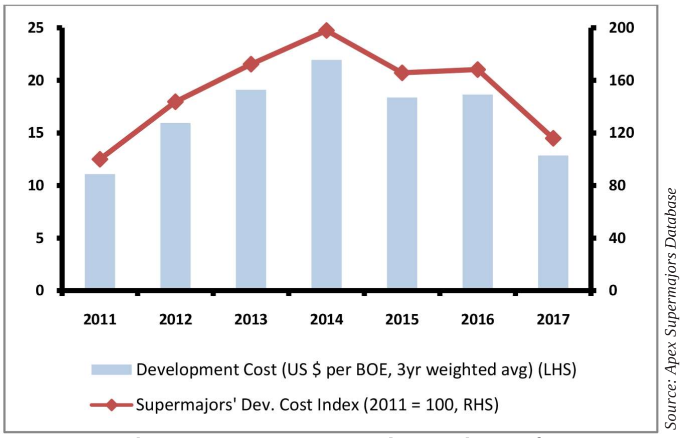


Chart 4: Supermajors Cost Index – evolution of development costs (2011 – 2017)

We estimate that about 35% of this cost reduction took place between 2014 and 2015, which largely reflects the reduction in service sector costs during this period. The remaining 65% took place between 2015 and 2017, reflecting various cost saving measures adopted by the industry, as well as a continued fall in service sector costs.

Despite this impressive reduction, cost was about 16% higher in 2017 than in 2011, when the industry was in the midst of significant cost escalation.

How individual supermajors have performed

The impressive decline in costs over the past few years for supermajors as a group masks considerable differences in the cost reduction achieved by individual supermajors (*see chart 5*). Among the seven companies analyzed between 2011 and 2017, we found that Eni's performance improved the most, followed by Chevron and Total. Although the three-year weighted average development cost per BOE went down for these companies over this period, it increased for the other four companies in line with the wider industry trend.

In our opinion, various actions taken in response to the oil price collapse and falling capital productivity, some as early as 2010, significantly

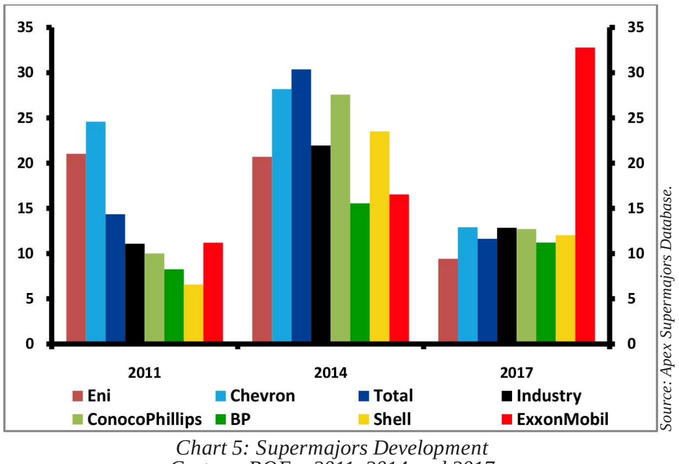


Chart 5: Supermajors Development Cost per BOE – 2011, 2014 and 2017

Note: Three-year weighted average, in US $.

improved Eni's development cost efficiency. For example, in order to manage costs better and negate the impact of sector-specific cost inflation, Eni started high-grading its portfolio, standardizing specifications, applying technologies that reduced drilling and completion times, and focusing on managing risks better and improving its project execution. These steps helped reduce its development cost per BOE by 55% between 2011 and 2017. As a result, by end-2017, Eni's development cost per BOE was 27% lower than that of the supermajors as a group, whereas it was almost twice the peer group average in 2011.

Chevron's development cost efficiency followed the wider industry trend, albeit at a different rate. While development cost per BOE almost doubled between 2011 and 2014 for supermajors as a group, Chevron's cost only went up by 15%. This was mainly due to improvements in capital stewardship and cost discipline, including greater use of technology to manage field performance and complex drilling projects, leveraging of existing infrastructure and facilities, and investing in targeted growth areas.

At the end of 2013, largely due to a number of major projects coming on-stream, Chevron reduced its capital investment budget for 2014. The pace of this reduction increased in 2015 and 2016 in response to declining oil prices.

At the same time, with major projects continuing to come on-stream, a combination of lower investment, portfolio high-grading, cost deflation in the wider industry, and its ongoing focus on capital stewardship, cost efficiency and project execution, enabled Chevron to reduce its development costs significantly. As a result, Chevron's cost efficiency increased by 47% between 2011 and 2017. By end-2017, its development cost per BOE was in line with the supermajors as a group, down from more than twice the peer group average in 2011.

> **"Looking ahead, 2018 may turn out to be the year when development cost deflation bottoms out, leading to a rise in the Index in subsequent years."**

Between 2011 and 2014, the decline in Total's development cost efficiency closely followed its peer group average. During this period, in line with an almost doubling of costs for supermajors as a group, its development cost per BOE increased from $14.3 to $30.4.

At the end of 2013 Total, like Chevron, was coming out of an intensive capital investment phase, which led to it reducing its investment in 2014. This cut in capital investment deepened in the subsequent years as prices began to fall sharply. At the same time, greater cost discipline and improving capital efficiency became key strategic priorities for the company. These priorities – alongside industry-wide cost deflation, a continued focus on portfolio high-grading and a number of major projects coming on-stream – helped Total reduce its development costs per BOE by 62% between 2014 and 2017, compared with 41% for the supermajors as a group. As a result, looking at the period between 2011 and 2017 as a whole, we estimate that Total's cost efficiency improved by 19% during this period. By the end of 2017, its development cost per BOE had decreased from around 30% above the peer group average in 2011 to 10% below the group average.

While these three companies bucked the trend, others have seen their cost efficiency decline during this period. ExxonMobil's development cost efficiency fell significantly following a downward revision of approximately 3.8 billion BOE of reserves, primarily due to low prices in 2016. As a result, ExxonMobil went from having one of the lowest development costs per BOE in 2011 to having the highest among the supermajors in 2017.

Prior to the collapse in oil prices, Shell's development cost efficiency had deteriorated dramatically, due to cost overruns and delays in many of its flagship projects, as well as industry-wide cost escalation. A significant write-down of reserves, particularly in its North American shale operations, also contributed to reducing Shell's cost efficiency. However, since 2014, renewed focus on cost control and capital discipline, portfolio high-grading, important strategic acquisitions, such as that of the BG group, and a number of major projects such as Gorgon (Australia), Lula (Brazil) and Kashagan (Kazakhstan) coming on-stream helped Shell to reverse this trend. As a result, despite the 83% decline in its development cost efficiency between 2011 and 2017, Shell's development cost was around 6% lower than the supermajors as a group in 2017.

Like Eni, having a strategic focus on cost control and capital efficiency long before the oil price slump enabled BP to moderate the impact of sector-specific cost escalations, whilst at the same time developing a portfolio of inherently more expensive resources. As a result, the growth in BP's development cost per BOE between 2011 and 2017 was smaller than that of companies like Shell, helping it maintain its relative cost advantage over some of its peers. During this period, its development cost per BOE went up by 36% compared with 83% for Shell.

In the case of ConocoPhillips, the general industry trend of cost overruns and escalations, along with greater emphasis on debt reduction, production and dividend growth rather than capital efficiency, were largely responsible for the development cost per BOE shooting up from $10.0 in 2011 to $27.6 in 2014. However, like its peers, just as it suffered from the industry-wide cost escalations prior to the fall in oil prices, the company also benefited from the cost deflation that followed the slump in prices. Furthermore, a number of major projects coming on-stream, such as APLNG, and greater focus on cost control and capital discipline helped the company improve its cost efficiency and more than halve its development costs in 2017 compared with 2014 levels.

In our analysis of how companies performed between 2016 and 2017, Shell, ConocoPhillips and Total came out on top (*see chart 6*). This suggests that companies whose development cost per BOE more than doubled between 2011 and 2014 were the ones achieving the greatest improvement in development cost efficiency between 2016 and 2017. While development cost efficiency improved for all supermajors

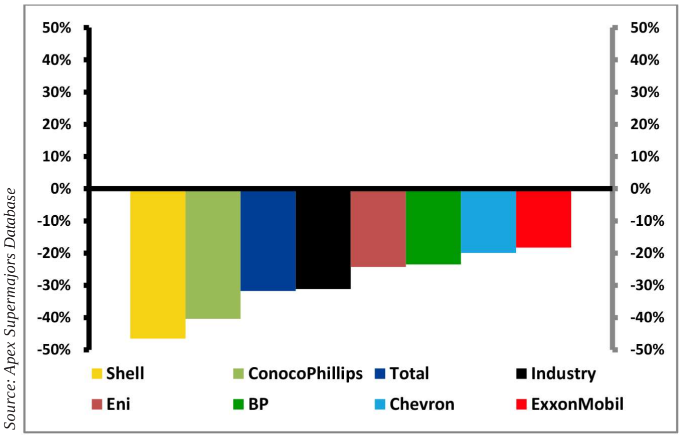


Chart 6: Changes in Development Cost between 2016 and 2017 (%)

Note: Negative percentage reflects reduction in development cost per BOE and therefore,improvement in development cost efficiency.

between 2016 and 2017, it increased by less than the peer group average for Eni, BP, Chevron and ExxonMobil. In the case of ExxonMobil, an 18% improvement in its cost efficiency between 2016 and 2017 helped the company moderate the impact of a significant write-down of reserves in 2016.

The recent revival of deep-water projects provides an initial indication of a broad-based recovery in upstream investment taking place across various sectors of the industry, not just in US shale. The latest reports from several global oil services companies also point to early signs of activity picking up and rates recovering elsewhere in the world. As rates in the service sector continue to improve globally in line with this broad-based uptick in investment, further efficiency and productivity gains – through technological innovation, a continued focus on cost management and structural cost reduction – will be even more crucial to offsetting this emerging inflationary pressure and keeping overall development costs down. While this seems to have been achieved so far in 2018, the industry's ability to continue to do so in 2019 remains to be seen. Therefore, in the absence of additional efficiency gains, 2018 may turn out to be the year when development cost deflation bottoms out, leading to a rise in the Index in subsequent years.

Challenges to sustain this cost reduction

Challenges, therefore, remain, not only in sustaining this cost deflation but also in preventing a recurrence of the cost escalation we have seen in the past.

During the previous growth phase, capital productivity declined significantly, as poor project execution caused cost overruns and delays, and a prolonged ramp-up in investment activities caused industry-wide cost escalation. We might see a repeat of this trend if capital discipline is not maintained as investment greenfield and relatively larger projects increases in 2019 and beyond.

What's more, protectionist measures such as tariffs on coal, steel and other components threaten to raise the cost of manufacturing equipment and building facilities significantly.

This potential upward pressure on costs will be moderated somewhat by cost-saving measures that are not dependent on third-party rates, such as optimizing logistics and production operations, simplifying processes, adopting lower cost drilling techniques, and so on. However, approximately 50-60% of the cost savings achieved by the industry in the last few years could be lost as a result of increased activity, higher rates, tighter labor markets and input tariffs, given that a third of this cost deflation resulted from lower activity and two-thirds from lower costs.

A new approach is therefore needed to mitigate the risk of rising costs and make cost savings more sustainable. Not only do we need greater collaboration between operators and service providers, we also need a more transparent and shared approach to risk allocation so that oil services companies are incentivized appropriately to find innovative ways to cut costs.

Several oil and gas players have already taken steps towards greater collaboration with their suppliers. For example, Equinor (previously Statoil) cited close co-operation with its suppliers as the main reason for the reduction in investment costs of its Johan Sverdrup project. Project owners also identified collaboration as one of the key drivers behind the 60% reduction in BP's Mad Dog phase 2 cost estimates.

Some oil executives believe that two-thirds of the cost savings achieved in the last few years can be sustained, even if upstream investment accelerates. Due to the risks mentioned above, we believe the potential for costs to escalate rapidly is high, especially if the industry tries to manage costs in the same way it has for the last 20 years. However, the threat of rising costs can be managed through greater collaboration and risk-sharing between operators and their suppliers. This new model of collaboration with appropriate incentive structures must be guided by the overarching mantra of '*value accretive volume growth*' to prevent the recurrence of the runaway cost escalations of the past and make the industry's activities more resilient to adverse price movements.

About the Author

Muktadir Ur Rahman is a highly experienced consultant with considerable expertise in project economics, modelling of upstream projects and portfolios, capital raising activities, commercial/contract negotiation strategy, and regulatory compliance. He has worked extensively with major oil and gas companies worldwide on a variety of projects, from undertaking independent reviews of economic models and modeling various fiscal regimes to leading investment appraisal, risk and sensitivity exercises to identify commercial value drivers for clients' commercial teams.