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THE EFFECT OF THE OIL PRICE DECLINE ON INTERNATIONAL OIL COMPANIES AND THEIR BUSINESS STRATEGIES

Author: **Maja Lojanica**

Supervisor: **Dr. Marie-Claire Aoun**

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Master's Thesis Presentation Authorization

THE STUDENT:

Maja Lojanica

....

THE SUPERVISOR

Dr. Marie-Claire Aoun, French Institute for International Relations (IFRI)

Signed: .... Date: 03/07/2015

THE CO-SUPERVISOR

Dr. Yannick Perez

Signed: .... Date: 09/07/2015

Authorization of the Master's Thesis Coordinator

Dr. Javier García González

Signed: .... Date: ....../ ....../ ......

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Executive Summary

In light of the oil price fall that began in June 2014, this master's thesis assesses the resulting impacts on the top six international oil companies (IOCs): ExxonMobil, Chevron, ConocoPhillips, Shell, BP and Total. The report presents the key drivers and the role of the oil price decline in the business strategies of the IOCs from the economic, environmental and regulatory perspective and how they affect their position in the global energy landscape. Within each segment the thesis evaluates the comprising indicators to answer key questions related to: market power, business models, portfolios, reserves and environmental and regulatory policies.

First, the report reviews the literature on the fundamental concepts of the petroleum industry. It then goes on to analyze the available financial and operational data of the companies and identifies the trends in the key financial indicators in the historical oil price cycles. Lastly, it demonstrates the subsequent actions taken by the companies.

Through a qualitative and quantitative analysis of the available literature on the IOCs, the study concludes that the downturn in the price of oil has financially weakened the IOCs and created the following domino effect: with a negative impact on the income, lower revenues resulted in market devaluations, decreasing the operating cash flow, thus reducing the funds needed to cover dividends and capital expenditures (capex), ultimately limiting the long-term investment. To optimize their financial resources, the IOCs cut capex but continued to distribute dividends to maintain shareholder value. However, to fund current operations, they issued extensive amount of debt and began divesting downstream assets. Comparable to previous oil price decline environments, divestment activity increased coupled with a fast trend of mergers and acquisitions. Moreover, despite record capital spending, their reserves and production levels are decreasing overtime. Consequently, the pressure to improve their resource base has shifted their strategies by developing a competitive advantage in large scale and capital intensive projects like LNG, the Arctic, and Deepwater.

In a world increasingly concerned with climate change, the IOCs' high dependence on oil exposes their current assets to development risk. One way forward is a large shift towards natural gas production. Increasing production of gas has also become part of the IOCs' role in the fight against climate change, as evidenced by the recent announcement of EU companies (Shell, Total, BP) in support of a global carbon pricing system. However, there is a rift between the six majors, as the US companies (ExxonMobil, Chevron, ConocoPhillips) hold the opposing view, which can be explained by examining their production portfolios. Their EU counterparts produce more gas than crude oil; meanwhile, the portfolios of the US companies show a predominant production of crude.

From regulatory perspective, deteriorating contract formulas reflect the weakened negotiating power of the IOCs with the producing countries, as the "government take" has increased over the years. However, the fluctuation in government take policies follows the trend of oil prices. In a downturn, governments are prompted to reduce requirements to attract more investment, and for the majors, this presents an opportunity to secure future reserves consistent with their newly reduced budgets. Furthermore, a lift on the ban of US oil and gas exports would close the gap between the WTI and the Brent, and increase the profitability of the IOCs with operations in the US, but the current status only deepens the effect of low oil prices.

In sum, this thesis exposes the vulnerability of the six major oil companies and recommends a more conservative risk assessment approach for investment decisions involving the IOCs. A weak financial and operational performance, increasing environmental and regulatory risks coupled with depressed oil prices with weak prospects of rapid recovery question the future sustainability of the IOCs.

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1 Introduction

Just as a $100 barrel of oil was becoming the norm, in June 2014, the price of crude oil started to fall. By January 2015, Brent crude was traded at $47 per barrel (bbl), down from $110. Similarly, on the West Texas Intermediate, the price fell from around $100 to $45/bbl. The significant drop in price began to reflect the robust non-OPEC supply, mainly attributed to the US unconventional production, weak demand and OPEC's decision to maintain its production ceiling. In this cycle, it was the excess supply that shifted the balance, as The Economist described it, "The contest between the shalemen and the sheikhs has tipped the world from a shortage of oil to a surplus."(Economist, 2014).

The balance between the demand and supply has shifted. Expectations of continued growth in emerging markets such as China did not realize. A decline in energy consumption and increased energy efficiency has made the demand the key factor and questions of limited supply a distant debate. The US has surpassed Saudi Arabia as the world's largest oil producer, reducing its dependency on imports, thus flooding the market with excess supply. In the short-run, supply disruptions due to conflicts among large producers such as Iraq and Libya did not realize as anticipated, thus having less effect on the markets. OPEC's change in objectives from price balancing to maintaining market share, suppressed the prices even further. Lastly, the US dollar appreciation by 10% against major currencies also contributed to the fall of oil the price, as it negatively affects the demand in countries whose purchasing power is reduced.[1]

As of early March 2015, the WTI and Brent prices were $50/bbl and $60/bbl, respectively: a slight recovery from record lows, but leaving a high uncertainty over future expectations. Low oil price cycles have different implications on various stakeholders and result in diverse strategies being applied to mitigate risks and seize opportunities. The oil markets have entered a new era, and the behavior or the key players has begun to reflect this transition.

1.1 Research Question and Methodology

This paper will focus on assessing the impacts of the oil price drop on the top six international oil companies (IOCs) and their evolving role in the global energy landscape. It also strives to shed light on rising uncertainties bound to affect the IOCs in the long term, and provide insight on possible future implications. To determine the effects, the paper will examine the three key aspects of the business strategies of the IOCs: economic, environmental and regulatory. Within each segment it will assess the comprising indicators to answer the following questions:

- Are the oil price cycles diminishing the market power of the IOCs? What is the impact on the crude oil reserves and production?
- Is the most recent oil price decline changing the business models and portfolios of the IOCs? Does this impact vary across the operating regions and the types of resources?

[1]Empirical estimates of the size of the U.S. dollar effect cover a wide range: high estimates suggest a 10% appreciation is associated with a decline of about 10% in the oil price, and low estimates suggest 3 % or less (Baffes, et al., 2015)

- How are the IOCs weathering out the price decline? What are their short-term strategies and what will be the impact on future investment?
- What are the possible implications of the environmental and regulatory policies in general and in the context of low oil prices?

The first section of the report will provide an overview of the available literature on the IOCs, the key players, reserves, global oil markets and oil prices to set the context of the petroleum industry. The second section will focus on the business strategies of the IOCs from the economic, environmental and regulatory perspective as well as the role of the oil price within each. Lastly, chapter three will summarize the analysis of the underlining elements impacted by the oil price decline by answering the questions stated above, discuss the resulting recommendations and provide insight on further research.

In addition to the academic documentation on the international oil companies, alternative resources have been prevalent in conducting this research. The resources used include: companies' annual reports, corporate websites, reports from consulting firms and companies in the petroleum industry and press articles from specialized institutions.

2 Literature Review

2.1 Historical Evolution of International Oil Companies

The oil industry of the 21st century began with John D. Rockefeller's Standard Oil empire. Formed in 1870, the Standard Oil Company held the largest refining capacity of any single firm in the world (ExxonMobil, 2015). At the start of the twentieth century, the most famous monopoly controlled 87% of the production, 82% of refining and 85% of all petroleum marketing operations in the U.S (Rudolph, 2013). However, in 1911, the application of the Sherman Antitrust Act led to the breakup of Standard Oil into four regional components: Standard Oil of New York (later Mobil), Standard Oil of New Jersey (Jersey Oil, later Exxon), and Standard Oil of California (later Chevron). The breakup of the largest petroleum company at the time created a more competitive industry and left a lasting effect on the international oil market. Standard Oil of New York and Jersey Oil, with strong refining and marketing operations, were forced to look abroad for their oil supply, quickly establishing themselves as the world's first multinational corporations (Rudolph, 2013). As oil discoveries around the world rose, market power of international competitors was increasing. Global operations were run by the Nobel Brothers, the Rothschilds and other Russian producers out of the Baku region (Azerbaijan), and later by Royal Dutch from discoveries in Sumatra (Indonesia) in 1885 (Llewellyn et al., 2013). As the global competition emerged, the oil industry evolved into an oligopoly, consisting of the seven largest companies.

Oil became a strategic asset during the two World Wars and its growing importance continued to rise. Spurred by rising demand for oil and new discoveries, the international oil companies started to dominate the industry. By the end of WWII, the IOCs, also referred to as the *majors*, led the global production of oil. Through vertical integration, technological innovation, and established relationships with local governments, they controlled the market and maintained high barriers to entry (Llewellyn et al., 2013). Coined as the "Seven Sisters" by ENI's founder Enrico Mattei, the companies included:

- Standard Oil of New York (Mobil)
- Anglo Persian Oil Company (BP)
- Royal Dutch Shell
- Standard Oil of California (Chevron)
- Gulf Oil
- Texaco
- Standard Oil of New Jersey (Exxon)

The power of this cartel slowly started to erode in the 1960s. Increased consumption and diminished barriers to entry fueled the competition. With government incentives, smaller US oil companies became involved in foreign oil exploration. As the oil market was becoming constrained between 1968-1973, host governments received better compensation deals from the individual producers than from the IOCs, slowly eroding their market share. As a result, the IOCs had no choice but to renegotiate similar terms as the independents, the alternative being forced out completely.

Although founded in 1960, the power of the Organization of Petroleum Exporting Countries (OPEC)[2] became prominent in the 1970s with a series of nationalizations. The aim of the organization was to

[2] Founded by Iran, Iraq, Venezuela, Kuwait and Saudi Arabia.

coordinate and unify petroleum policies among Member Countries, in order to secure fair and stable prices for petroleum producers, an efficient, economic and regular supply of petroleum to consuming nations, and a fair return on capital to those investing in the industry. Effectively, it allowed member countries to exercise permanent sovereignty over their natural resources in the interest of their national development (OPEC, 2015).

From 1948-1970 the price of oil was set by the Seven Sisters within a stable range. However, during the Arab oil embargo of 1973 led by OPEC's production cuts, the spot price of oil went from $3 per barrel in September to $11 in December. By 1981 the oil price more than doubled, reaching $34 per barrel. With the IOCs unable to meet supply, shortages and price hikes swept Western nations. Now in a weaker position than in the previous decade, with lower profits and less control over reserves, the IOCs began to invest to develop their own resources. With growing demand, their exploration led to several discoveries in the North Sea, Alaska, Latin America and Canada.[3]

The oil crisis of the 1970s restructured the market, leading to an increase in trading on public exchanges. With more competition in upstream and downstream activities, the power of the IOCs was diminishing. Still dominant in the upstream, together with newly founded National Oil Companies (NOCs), downstream competition was decreasing their market share. By 1980s, the oil traded through IOCs dropped to 50% from the previous 90% in 1973 (Llewellyn et al., 2013).

Entering the 1990s with the collapse of the Soviet Union, the end of the Gulf War, and growing demand in developing countries, the IOCs faced even greater competition. Former soviet states opened new opportunities for investment, stability in the Middle East increased production in the region, and the emerging markets in Asia increased demand for oil. To secure supply, the Seven Sisters merged and became known as the "supermajors"- Chevron, British Petroleum, ConocoPhillips, Royal Dutch Shell, Total and ExxonMobil. The wave of consolidation increased their size, efficiency and capacity to embark on larger and more complex projects (Yergin, 2011). However, even with a significant role in the industry, the power had shifted from the IOCs to the NOCs, the so called "new seven sisters" (Hoyos, C. 2007). In 2007, the Financial Times published a list of the most influential energy companies outside the OECD circle. The emerging players included Saudi Aramco, Russia's Gazprom, CNPC of China, NIOC of Iran, Venezuela's PDVSA, Brazil's Petrobras and Petronas of Malaysia. Each wave of high prices amplified the power of the NOCs and in the process diminished the role of the IOCs. When the price recedes, the IOCs' expertise and efficiency is in high demand and their role in the oil supply chain improves, but after every cycle, never to the extent it once was.

2.2 Key Players

The current oil market consists of various stakeholders forming a complex petroleum supply chain. However, the industry is dominated by five types of companies involved in global oil supply. The Energy Information Administration (EIA) defines companies in the following categories (EIA, 2014):

- **International oil companies (IOCs):** vertically integrated companies with global operations spanning the entire oil and gas value chain. The companies are entirely investor-owned and primarily seek to increase their shareholder value, hence, basing investment decisions on economic factors. They develop and produce oil resources to sell in the global market. Although

[3] North Sea in 1968 and Alaska in 1969. North Sea oil did not begin adding to world supply until 1975; North Slope Alaskan oil did not come to market until 1977.

subject to regulations in countries where they operate, the decisions are made in the interest of the company and its shareholders, not a government. The companies rank among the world's largest corporations in terms of revenue and include the majors: ExxonMobil, BP, and Royal Dutch Shell, Total, Chevron, and ConocoPhillips. In addition to being referred to as the "IOCs", they are known as the "supermajors", "majors" and "Big Oil".

- **National oil companies (NOCs):** companies with majority ownership by the government. In the OPEC countries[4] and in some non-OPEC countries, national oil companies have exclusive or near exclusive control of oil production. The companies support the government programs and provide fuels to domestic consumers at discount compared to the international market. These companies include: Aramco (Saudi Arabia), Pemex (Mexico), the China National Petroleum Corporation (CNPC) and PdVSA (Venezuela) among others. With diverse objectives of their countries' governments, NOCs pursue goals that are not necessarily market-oriented. Such goals often include employing citizens, furthering the government's domestic or foreign policies, generating long-term revenue to pay for government programs, and supplying inexpensive domestic energy.

- **NOCs with strategic and operational autonomy:** these NOCs function as corporate entities and do not operate as an extension of the government of their country. This third category includes Petrobras (Brazil) and Statoil (Norway). These companies often balance profit-oriented concerns and the objectives of their country with the development of their corporate strategy. While these companies may support their country's goals, they are primarily commercially driven.

- **Independents:** independent companies that operate in a specific region or country, or even internationally. These producers are typically involved in the exploration and production segment of the industry and generally, with no marketing, transportation or refining operations. Also known as a non-integrated producing company in the oil industry.

- **Oilfield Service Companies (OSCs):** companies such as Schlumberger, Halliburton, Baker Hughes, and Weatherford that provide exploration and production services to oil companies. They deliver specific technical expertise, including but not limited to: geophysical surveys, drilling and equipment leases.

2.3 Reserves

The Energy Information Administration (EIA) defines "*proved reserves"* as the amount of oil in a given area, known with reasonable certainty, that today's technology can recover cost-effectively. Another category often described is "*probable reserves".* These are reserves that have been identified with a 50% or greater chance of being proved. Both categories are ultimately estimates and are bound to change. The IOCs follow the Security and Exchange Commission (SEC) definition of reserves for reporting. Often deemed the most restrictive characterization, it states that:

[4] Algeria, Angola, Ecuador, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, United Arab Emirates, Venezuela

> “*Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations— prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.”*[5]

It further categorizes the reserves into two segments, developed and undeveloped. Developed being those reserves expected to be recovered, while undeveloped refers to reserves expected to be recovered from new wells or from existing wells that require large investment for extraction. For the purpose of this report, references to “reserves” will follow the SEC definition.

In this paper, the terms: resources, resource base, and recoverable resources, will refer to the total remaining estimated quantities of oil and gas that are expected to be ultimately recoverable. IOCs refer to new discoveries and acquisitions of discovered resources as resource additions. The resource base includes quantities of oil and gas that have not yet been classified as proved reserves, but which the companies believe will likely be part of the proved reserves category and produced in the future (ExxonMobil, 2015a).

By the end of 2014 worldwide proved oil reserves were estimated at about 1700.1 billion barrels, sufficient to meet 52.5 years of global production (BP, 2015). Global oil production averaged at 93.16 million barrels a day (b/d) while consumption was at 92 million b/d (EIA, 2015b).

Out of the total global proved oil reserves, the majority is found in the Middle East. In 1980, the second largest source was Europe & Eurasia, however by 2014, South and Central America became the second largest oil reserve region. By country, in 2014 Venezuela held the largest reserves, followed by Saudi Arabia (BP, 2015). In contrast to Venezuela, with primarily heavy oil from the Orinoco Belt, Saudi Arabia’s oil is the least expensive to extract, making it the key player in the industry. Saudi Arabia’s dominance is also in part due to its spare capacity[6] used to manage the market, usually between 1.5 - 2 million barrels per day (EIA, 2015).

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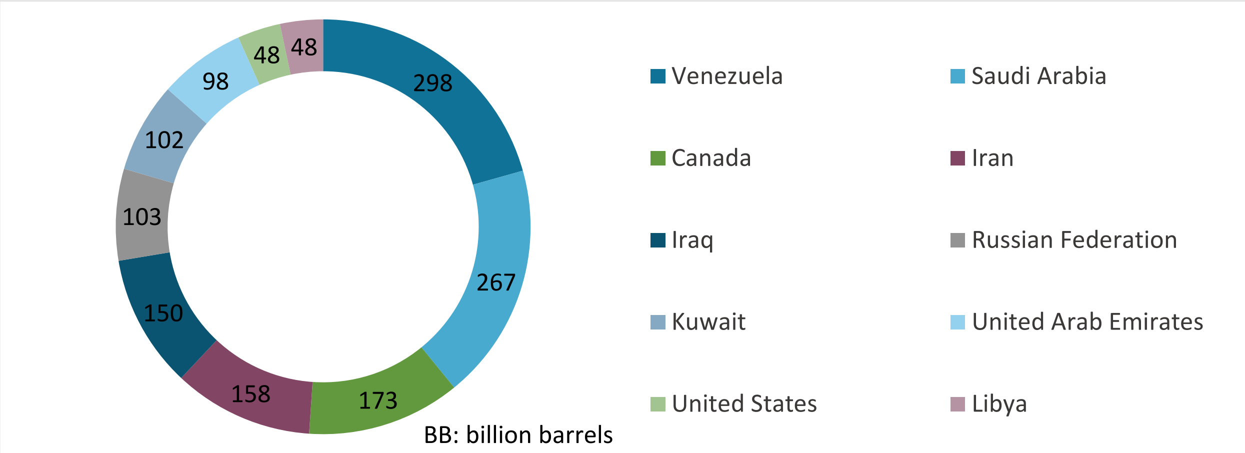
[5] Refer to CFR 210.4-10 Financial accounting and reporting for oil and gas producing activities pursuant to the Federal securities laws and the Energy Policy and Conservation Act of 1975.

[6] EIA defines spare capacity as the volume of production that can be brought on within 30 days and sustained for at least 90 days.

Figure 1: 2014 Oil Reserves by Country –Top 10



Source: BP Statistical Review of World Energy 2015

2.3.1 Reserve Ownership and Models of Cooperation

The ownership of reserves is another aspect of the industry that plays an important role in development of hydrocarbon resources. In general, mineral resources belong to the government. However, the United States is an anomaly in this respect, as the property owners have a complete private ownership of these resources, known as the "mineral rights". In most countries around the world, subsoil minerals are categorized into "social ownership", property of the state. In some cases, where the indigenous communities have the claim over land, they are the governing body of the land rather than the state. In subsea resources, the treaties that founded the Law of the Sea (UNCLOS) are the standard for some governments, and others rely on established agreements for exploration and development rights (Mitchell et al., 2012).

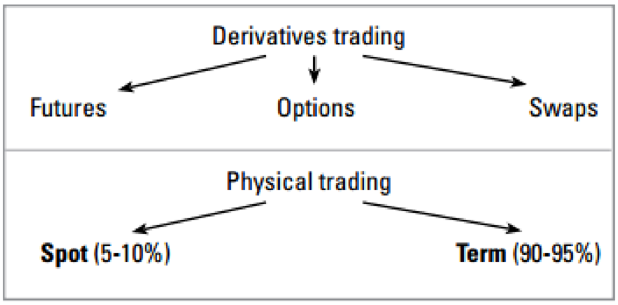
Cooperation among the different players in resource exploration and development takes different forms. In present day concession agreements, the government takes the portion of the revenue in form of a tax, fees, or royalties. The oil company, the concession holder, has the exclusive right to explore the area and owns the infrastructure it has established for its operations. It pays royalties and income and other taxes to the national company according to the amount of oil it produces.

In a joint-venture partnership, state and private companies share the costs and profits depending on the interest in the project. Another form of agreement is the, risk contract, in which a private company assumes the full risk of development, and its revenues are based on production through a fixed per barrel fee. Lastly, the most common type of agreement today is known as production-sharing agreements (PSAs) or contracts (PSCs). Under a PSA, the NOC retains the control of the reserves, in some cases also the infrastructure that the private company invests. It defines, typically under a determined formula, a percentage of production granted to the private company, where the profitability is shared with the NOC. Income tax is also a mandatory payment for the private companies. PSAs, for various historical and political reasons are the predominant types of agreements, further reflecting the extent to which oil producing nations are willing to maintain sovereignty over their reserves. At the same time, finding new reserves is a key priority for an E&P company since reserves are typically used to value companies and are the basis of future revenue and earnings. Through exploration, the companies replace the depleting quantity of reserves, and can sustain their growth.

2.4 Global Oil Markets

Once produced, oil feeds into refineries for processing in end-use products. Within large companies, like the supermajors, this is part of the fully integrated systems in place. When the upstream and downstream are separated activities, refiners are participants in oil trades to procure supplies for their facilities or sell their excess. Oil trading is either done through term contracts or on the spot market. To reduce risk exposure, refineries and end users such as airlines enter into contracts instead. Contracts are the most common form of arrangements (Platts, 2010). Another form of trading is through futures markets. With a standardized contract and a various derivative instruments, buyers and sellers can hedge the price of oil for future delivery.

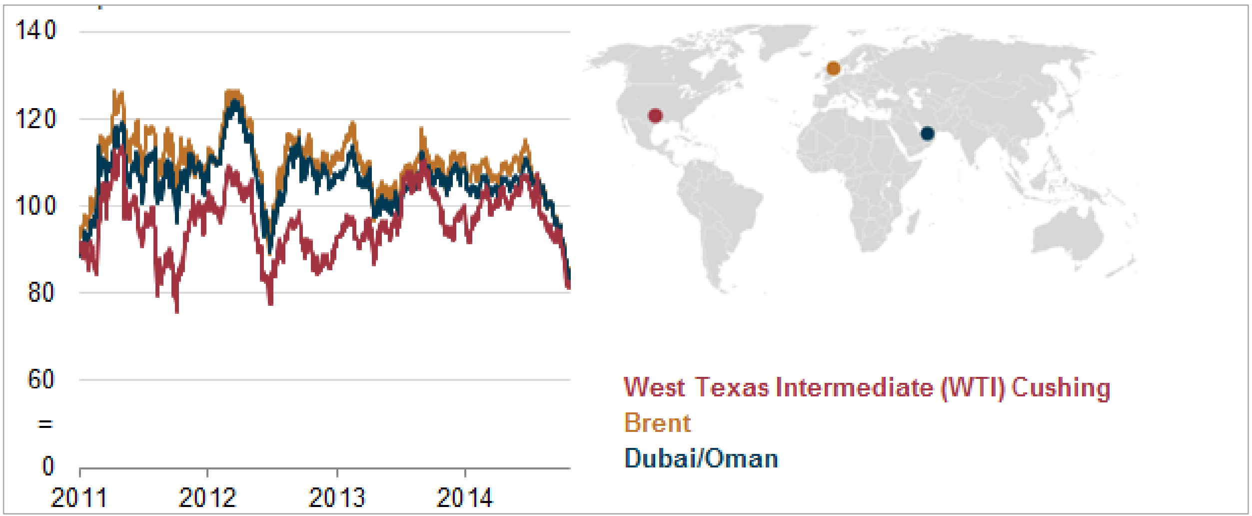
Figure 2: Oil Trading



Source: Platts

The most common benchmarks for oil are Brent Crude and the West Texas Intermediate (WTI). Brent is traded on the International Petroleum Exchange, now ICE Futures, and the WTI at the New York Mercantile Exchange (NYMEX). Brent is the leading global benchmark, and it includes four separate light, sweet crude streams that are produced in the North Sea. WTI is a light, sweet crude oil produced in the US that is priced at the crude oil trading hub of Cushing, Oklahoma. WTI is used as a benchmark for other types of crude oil produced in the United States and for imported crude oil produced in Canada, Mexico, and South America. Dubai/Oman is the third crude benchmark used to price crudes produced in the Middle East and exported to Asia. Lastly, there is the OPEC basket price. This is the average price of fifteen different types of crudes from OPEC countries like Algeria, Ecuador, and etc. In general oil prices tend to correlate closely, but the spread between WTI and Brent started to increase from 2011 forward. Increased US light sweet crude oil production, limited infrastructure capacity to move the oil to processing and the market, lowered the WTI crude oil prices. Now WTI trades at a discount compared to the Brent (EIA, 2013).

Figure 3: Spot Prices for Selected Benchmark Crude Oils (US$/bbl)



Source: US Energy Information Administration

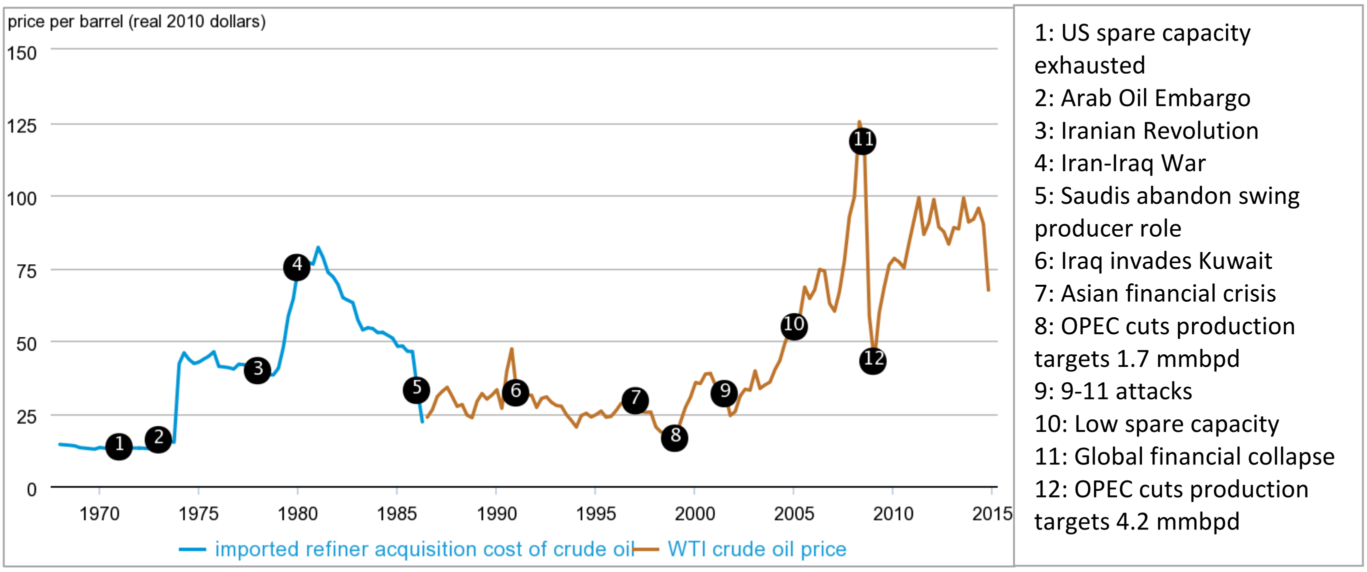
2.5 Oil Price Cycles

Various factors affect crude oil prices. They can be divided into external, meaning general economic, political, meteorological factors, and technical, referring to technologies, position of major exchange players and price volatility. The key drivers are considered to be the state and growth rate of the global economy, technological progress, and the availability and forecast of proven and probable reserves. Other factors include, OPEC production, changes in the sector, and legislation (Braginskii, 2009).

OPEC's production can significantly affect the oil prices. The member countries produce about 40% of the global crude oil, similarly OPEC's exports account for 60% of the petroleum traded internationally (EIA, 2015). The organization manages production by setting targets, and periods of high prices are traditionally associated with the reduction of these targets. Saudi Arabia, as OPEC's largest producer, has a predominant role due to its spare capacity and fluctuations in this capacity can affect the oil prices. From 2003-2008, OPEC's spare capacity was low, limiting the response to demand, thus resulting in the increase of oil price.

Geopolitical and economic events are another driver of crude prices. Figure 4 shows the events that correlated to the crude price drops and spikes. Additionally, there is evidence of a strong correlation between high spikes in oil prices and the arrival of economic information, indicating that oil prices respond to new economic data (Elder, 2013). Other research focuses on examining the effect of speculation on the price of oil. Some argue that speculation does not play a key role in oil prices, specifically in the period after 2003, rather that, the movement of spot and future prices reflects the common economic fundamentals rather than financialization of oil future markets (Fattouh et al., 2013).

Figure 4: Crude Oil Prices and Key Geopolitical and Economic Events



Source: US Energy Information Administration

A combination of methods is employed in forecasting oil prices, however due to the specificities of the crude oil market, a precise forecast is has yet to be developed. Many industry stakeholders try to predict the future energy landscape and use this outlook as a base for developing their strategies. The most widely used reference is the International Energy Agency (IEA) *World Energy Outlook.* Similarly, with a focus on the US, is the EIA *Annual Energy Outlook.* OPEC also publishes its own *World Oil Outlook.* Reports among the international oil companies include BP's *Energy Outlook 2035,* ExxonMobil's *2015 Outlook for Energy: A View to 2040* and Shell's *New Lens Scenarios.*

From the 1970s until present day, the world oil market experienced four significant oil price drops: 1986, 1998, 2008 and 2014[7]. With record prices in the 1970, due to the Arab Oil Embargo, followed by the Iranian Revolution and then the Iran-Iraq War, exploration efforts by oil companies moved towards unconventional oil supply from the North Sea and Mexico. Moreover, demand for oil decreased. The US legislation implemented energy efficiency standards for cars, and the use of oil as a primary fuel for electricity generation declined. As non-OPEC supply rose, OPEC's output increased as well. As a result, the following decade saw record low oil prices.

When the prices started to fall, OPEC cut production in attempt to stabilize the market. Saudi Arabia, as the swing producer, had cut production the most, from 10 million barrels per day in 1980 to 2.3 million barrels per day by 1985 (EIA, 2002). By the end of the year, Saudi Arabia changed its course and increased production to gain market share and OPEC followed suit, causing the price to fall from $27 ($58.60-real) in August of 1985 to $10 ($23.47-real) per barrel by July 1986 (EIA, 2002). The oil companies reacted by shifting exploration efforts abroad. With lower production costs, foreign fields were deemed an attractive investment option.[8]

In the following years, prices increased as a result of the Iraq-Kuwait war, followed by the Asian financial crisis in 1997. But with lower levels than the previous decade, inventories increased. Asia was

[7] See Annex F

[8] Changes in policy in the former Soviet Union since 1991 have increased U.S. production investment there, and recent moves toward foreign investments in Mexico have attracted American exploration and production companies.

the highest growing market for oil. From 1990 to 1997 Asia/Pacific accounted for 86% of the world oil consumption, by 1998 that number dropped to 75% (BP, 2015). The weak demand, from the highest growing region, depressed prices leading the collapse of 1998 (Mabro, 1998). Other suggested contributing factors include the increase in OPEC production half way through 1998 (Lichtblau, 1999). In 2000, OPEC implemented a price band mechanism, setting the target range for the OPEC basket price between $22 and $28 per barrel of oil. If the price fell below the floor, OPEC was to cut production and increase it when it reached the ceiling (Fattouh, 2007). However, in 2004, following unprecedented demand growth, the organization abandoned this strategy.

The global economy experienced a slow recovery from 1998 forward. In 2001, the September 11 attacks further destabilized the recovery process and growing uncertainty around the event, suppressed the oil prices. As the growth in Europe, the US and large developing economies was rebounding during this period, the Federal Reserve's implementation of aggressive monetary policy easing helped accelerate the recovery (Baffes et al., 2015). Oil prices continued an upward trend as demand was outpacing supply. At the same time, OPEC's spare capacity from 2003-2008 was low (less than 2.5 million barrels per day) (EIA, 2015), further putting upward pressure on price of oil. However, this reversed in 2008, as a sharp decrease in demand caused commodity prices to fall, leading to a global recession. Unlike the slow economic recovery constrained by the financial sector restructuring, among other ramifications of the recession, the price drop did not last for long.

The most recent price drop started in June 2014. Brent crude went from trading at $110/bbl to $47 in January 2015. According to a World Bank report, the reasons behind this trend in prices are underlined in the demand and supply conditions in the long-run, and fluctuations in the markets and expectations in the short-run. Demand is lower than expected due to weak economic activity, excess supply from the US production flooded the market and Saudi Arabia abandoned its role as a swing producer, causing the prices to further decrease. The next chapter analyzes the business strategies of the majors in this new context.

3 Business Strategies

3.1 Economic

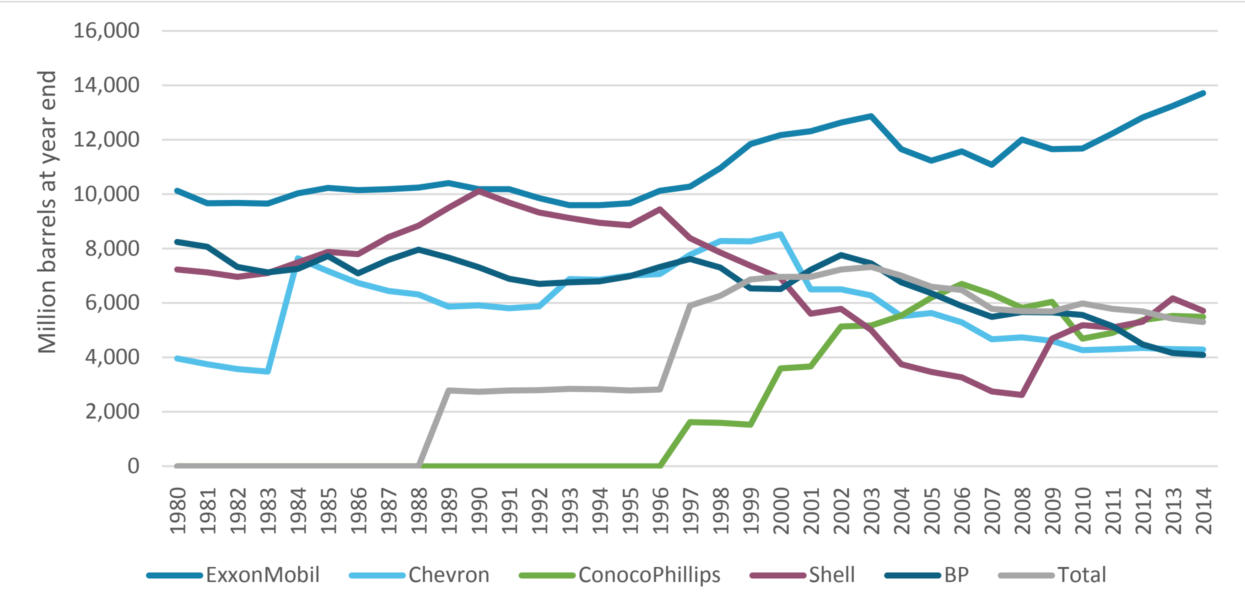
3.1.1 Financial and Operational Standing

3.1.1.1 Historical Reserves and Production Volumes

Historically, the IOCs were the dominant players in the oil market with the majority control of the world oil and gas reserves. However, from 1970 to present day, that control shifted to the NOCs. The NOCs went from controlling about 10% of the reserves in 1970 to more than 90% today (Leis et al., 2012). In 2009, IOCs owned only 9% of the world oil reserves and 12% of gas reserves (Thurber, 2012). The wave of nationalizations in Venezuela, Saudi Arabia, Libya and Iran, additionally cut the production of crude oil of majors. For example, ExxonMobil's production decreased from 6.8 million barrels per day in 1973 to 1.7 million in 1985 (3% of global supply) (Pratt, 2012). The supermajors went from operating under leasing agreements to serving as primary contractors and buyers of crude oil.

From the 1980s the oil reserves of the majors had remained relatively constant up to 2000, where they began to decrease for the majority of companies. From 2002-2011, the reserve replacement ratio (RRR) for the majors averaged at 75% (Leis et al., 2012), demonstrating greater pressure and challenge to replenish natural decline rate of their reserves. Out of the six oil companies, ExxonMobil proved to be an exception, with a reserve replacement consistently above 100% for the past twenty-one years (World Oil, 2015).

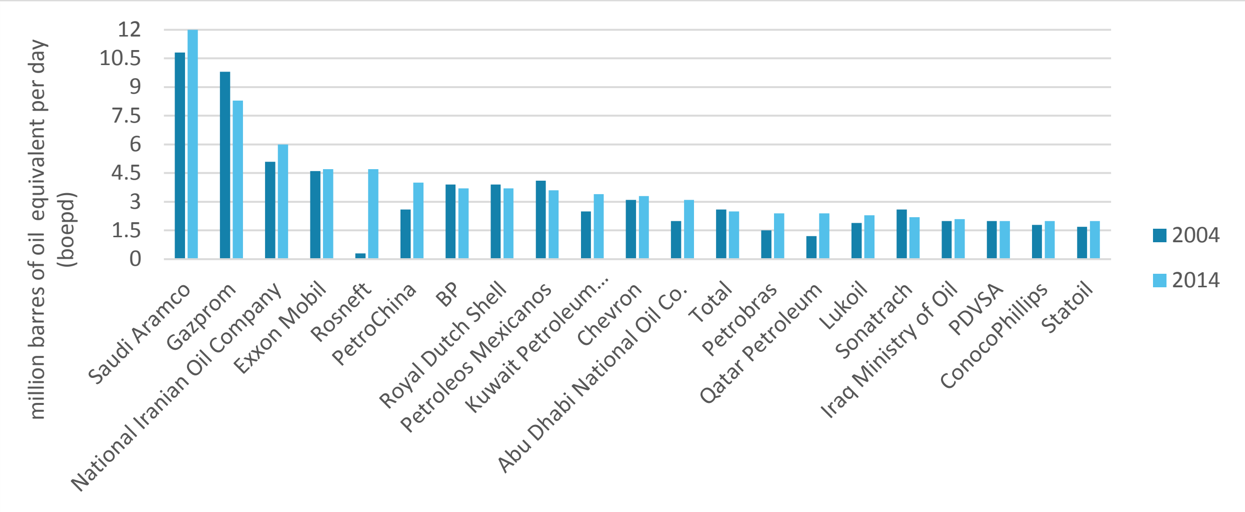
Figure 5: IOCs - Crude Oil & NGL Reserves 1980-2014



Source: OPEC Annual Statistical Bulletin 2014; Company Annual Reports and SEC Filings from 1997-2014

From 2004 forward, the majority of the growth in production of oil and gas has emerged from the state-owned companies like Saudi Aramco, Rosneft, PetroChina, among others. The majors' production, like the reserves, has been stagnant. From 2004 to 2014 ExxonMobil's saw an increase of 2% in volumes -4.6 to 4.7 million barrels of oil equivalent per day (boepd), Chevron managed to obtain 6%, and ConocoPhillips 10%, while the others (BP, Total and Shell) decreased by an average of 5%. Overall, for the past decade, the majors grew on average by 1% compared to the NOCs at 19%.

Figure 6: Oil & Gas Production of Top 21 Oil Companies



Source: Forbes and WoodMackenzie

Over the years, the portfolios of the IOCs have seen an increase in gas reserves and production. In 2011 the natural gas production of Shell and Total outpaced oil. Similarly the share of natural gas reserves of BP, Chevron and Total surpassed those of oil. ExxonMobil's reserve and production of natural gas has been increasing but still trails behind oil. For most companies, the oil production levels drop during a period of low prices, and slightly recover thereafter. However, overtime the recovery is much smaller, as gas production begins to dominate. With the decrease in oil price in the last two quarters of 2014, the IOCs saw a decrease in production levels of oil and gas for the year.[9]

3.1.1.2 Earnings

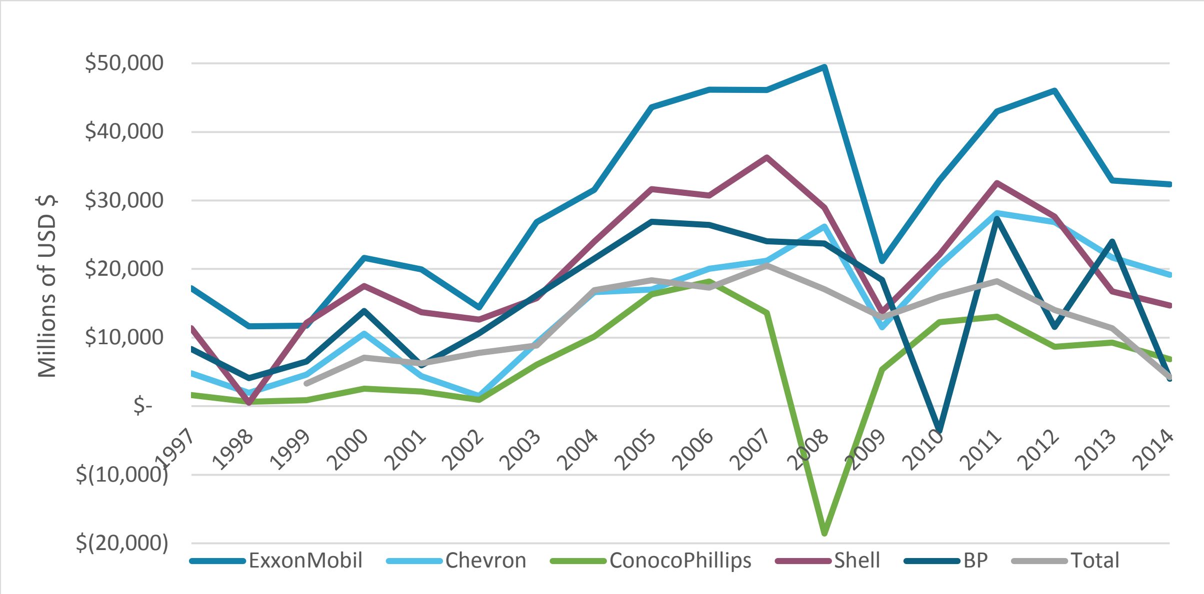
One of the main indicators and most observed by investors is the net income. The company's earnings are a strong indicator of its long-term profitability and a determinant of its market value or share price. In the petroleum industry the price of oil strongly correlates with the earnings of the IOCs.

From 1997 to 2014, the earnings of the six major oil companies followed the same pattern as price of oil. Figure 7 shows that from 1997 to 1998 the average earnings among the IOCs decreased by 55%, when oil prices declined by about 36%. Similarly during the financial crisis in 2008, the net income of the all supermajors decreased by 57% when oil price fell by 37%. ConocoPhillips experienced the most significant drop due to large impairments linked to their market capitalization-a write down of $25.4 billion in the E&P segment and $7.4 billon decrease in value of company's LUKOIL investment (ConocoPhillips, 2008). BP's income decreased on par with its competitors, but the most significant drop occurred in 2010 due the Deepwater Horizon oil spill in the Gulf of Mexico. However, the

[9] See Annex A - Company Profiles

adjusted income for both companies was $16.4 billion for ConocoPhillips in 2008 and $20.5 billion for BP in 2010.

Figure 7: IOCs - Annual Net Income 1997-2014



Source: Company Annual Reports and SEC Filings from 1997-2014

The poor financial performance of the IOCs in the first quarter of 2015 further exposed the impact of the oil price drop on the profits. On April 30, 2015, Shell, Europe's largest oil company, results showed a 56% decrease in earnings ($3.2 billion) compared to the same period in 2014. ExxonMobil followed a similar pattern, with a 46% drop ($4.94 billion compared to $9.1 billion in Q1 of 2014).

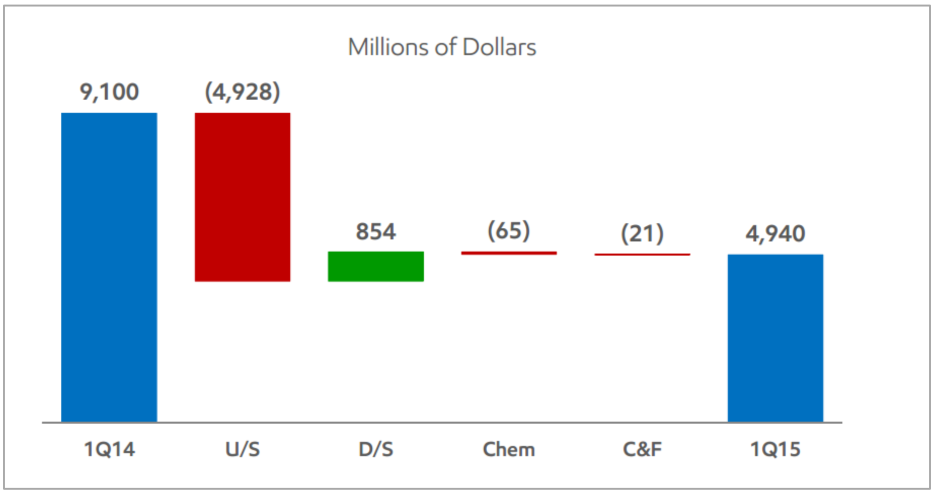
Even though, the companies are fully integrated firms, with the exception of ConocoPhillips from 2010 forward, the majority of their net income can be attributed to the upstream segment. In 2014, ExxonMobil E&P sector accounted for 85% of the total earnings for the year. The value of IOC's downstream activities emerges with the finished refined product. Although an important aspect of their business model, the earnings attained from the downstream segment are much lower than from upstream. In 2014, the refining and marketing profits of ExxonMobil and Shell made up about 9% and 18% respectively of the total income.

3.1.1.2.1 Downstream Effect on Income

When oil price falls, the downstream activities can either boost the profit for the company or can simply contribute to the decrease. Even though the price of crude oil is accounted as a cost for the refining segment, when prices are high, the cost can be passed on through an increase in the price of final products if the petroleum markets are expected to grow. However, if both the price and demand follow a downward trend or demand becomes stagnant, the cost pass through option becomes limited.

Although the most recent drop in oil prices continued to cut the profit of the majors, the declines were offset by strong performance of the downstream segment. The refining and marketing business aided the most recent earnings of the IOCs. Chevron reported a net income of $2.5 billion for the first quarter of 2015, down from $4.5 billion a year ago. While the company's overall earnings fell, its profit from refining more than doubled ($1,423 vs. $710 million in Q1 of 2014), as overall production grew by about 3% compared to the same period last year. Figure 8 below reflects ExxonMobil's decline in upstream earnings and a partial offset by an increase in downstream results.

Figure 8: ExxonMobil - 2014 Earnings by Segment



Source: ExxonMobil 1Q2015 Earnings Presentation

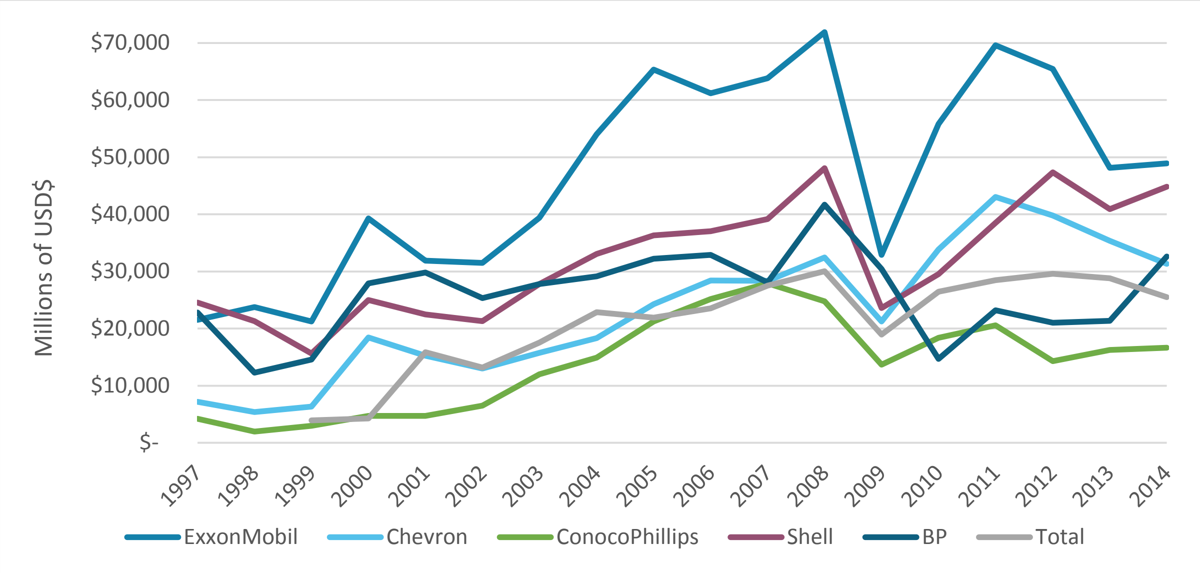
A similar trend can be observed with BP and Total. For the two European majors, refining margins are smaller during periods of high prices due to high crude acquisition costs and the oversupply of refineries. In 2013, North America and Europe had the largest refining capacity, with 20.8 thousand barrels oil per day (mb/d) and 16.8 mb/d respectively. By 2040, the largest decrease in refinery runs is expected in Europe (-7.8 mb/d) primarily due to decreasing local demand. For the same time period, China will account for one third of the net capacity growth. As the global refining capacity outpaces refinery runs, oversupply will put pressure on margins and capacity cuts, most likely on Europe. European refiners cannot compete as the oil demand shifts to Asian markets. Russia and the US, on the other hand, are expected to increase exports and profit margins mainly due to the local crude oil (IEA, 2014).

In the current context, both BP and Total benefit from low price and stable demand for their refining and marketing segments. Even though the downstream segment is a small part of the integrated operations, it provides some hedge against the volatility of oil prices, as seen in the last couple of months. However, future expectations from the downstream segment are bleak for companies with assets in Europe.

3.1.1.3 Cash Flow

In addition to the net income, during periods of low oil prices, operating cash flow (OCF) is another key indicator used to evaluate performance of IOCs and their resilience to weather out the downturn. OCF is a measure of cash generated by the company's operations. If the majors are not able to generate enough cash to maintain and grow future operations, they may resort to external financing, either through equity, by issuing more shares, or via debt financing. The evolution of the OCF among the majors since 1997 demonstrates that when the price of crude drops, cash flow follows a similar pattern.

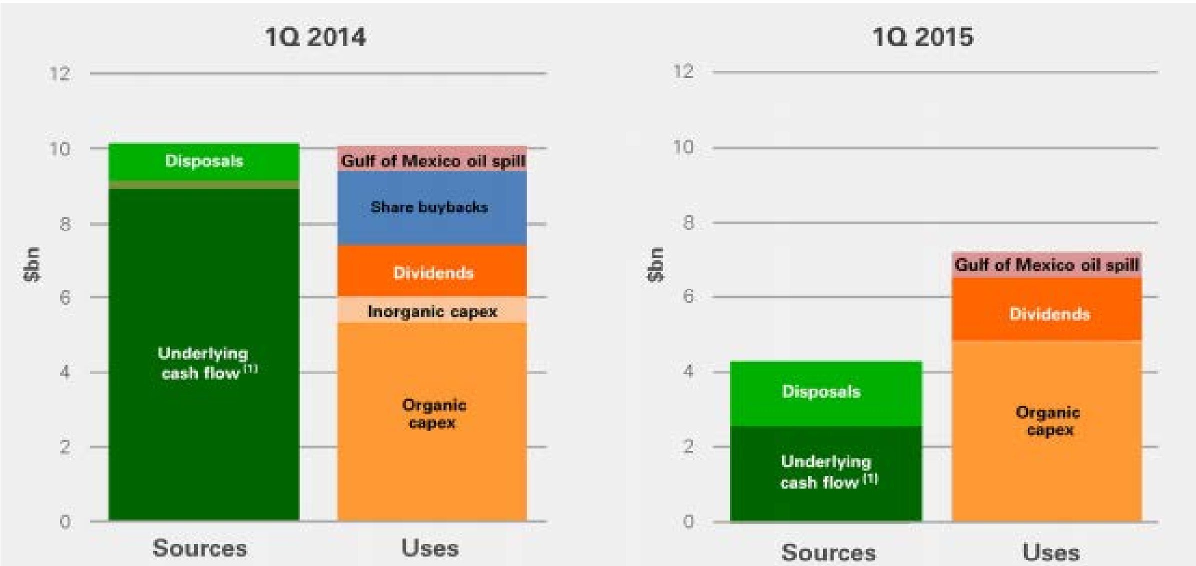
Figure 9: IOCs - Cash Flow from Operations 1997-2014



Source: Company Annual Reports and SEC Filings from 1997-2014

In the most recent published results by the IOCs, the OCF decreased significantly. Figure 10 below illustrates the case for BP. The operating cash flows, even after adjusting for Macondo payouts for the quarter, were not sufficient to cover the company's capital expenditures and dividend distributions. Chevron's quarter one results also showed a similar effect. Its OCF fell by close to 73% from $8.4 billion in Q1-2014 to $2.3 billion for Q1-2015 (Yarrington et al., 2014; Yarrington et al., 2015).

Figure 10: BP - Sources and Uses of Cash 1Q 2014 & 1Q 2015

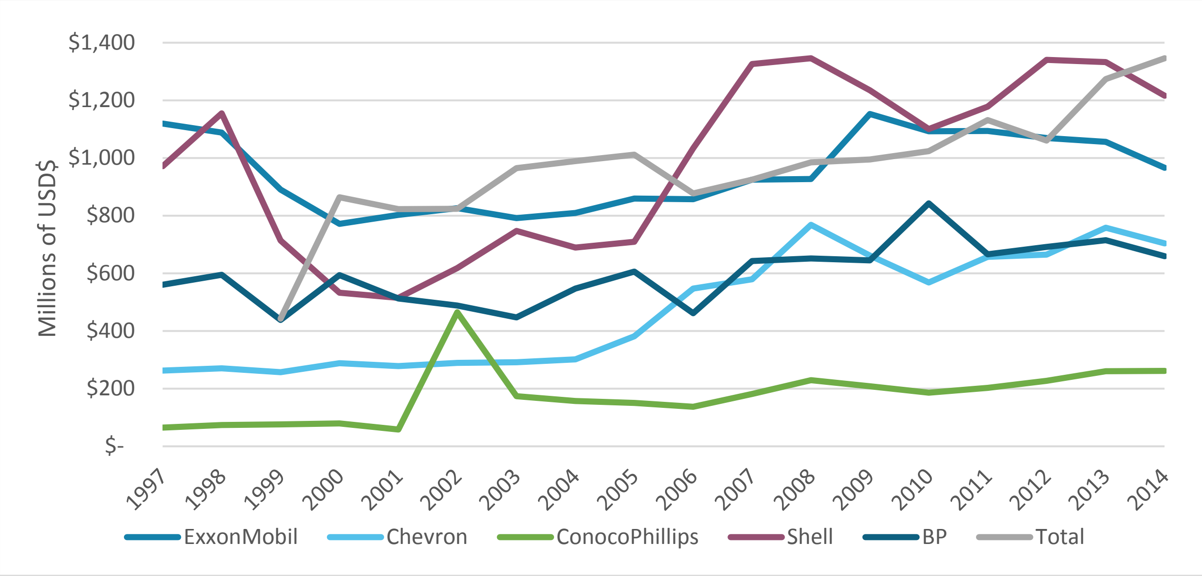


Source: BP 1Q2015 Results Presentation

3.1.1.4 R&D Expenditure

Traditionally IOCs have been the leaders in research and development (R&D), but their expenditure in R&D over the past thirty years has not changed significantly. R&D also corresponds to the price cycles; as price of oil tumbles, spending in R&D decreases as well. Figure 11 illustrates the R&D spending trends for the IOCs.

Figure 11: IOCs - R&D Expenditure 1997-2014

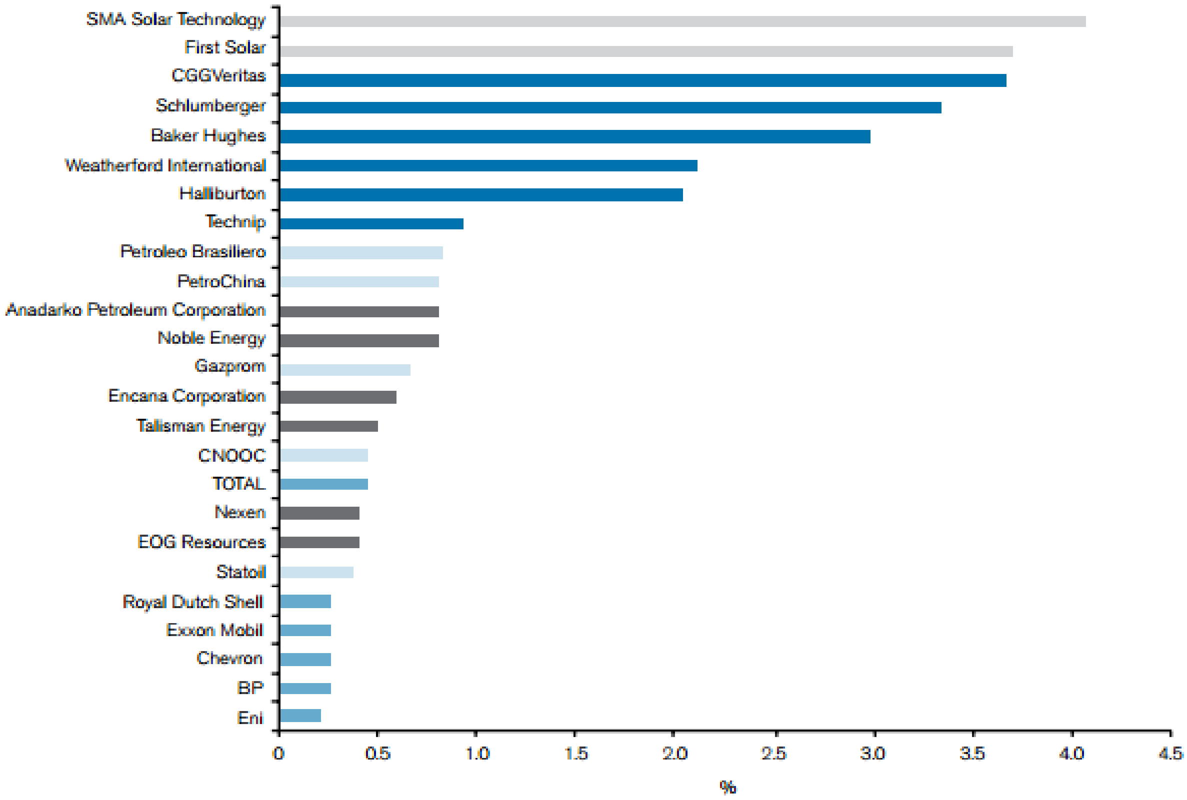


Source: Company Annual Reports and SEC Filings from 1997-2014

Furthermore, a 2012 report by Schlumberger showed that in 2011, the top three NOCs invested more than the top three supermajors. NOCs have acquired more technical expertise through partnerships with IOCs and the OSCs. [10] A comparison of the 2010 R&D expenditures for various companies as a ratio of their net sales indicates that the OSCs are the leading firms in R&D followed by NOCs, while the IOCs remain the lowest ranking among the group (Mitchell et al., 2012).

[10] See Annex E

Figure 12: R&D Expenditure for Various Types of Companies as a Ratio of Net Sales - 2010



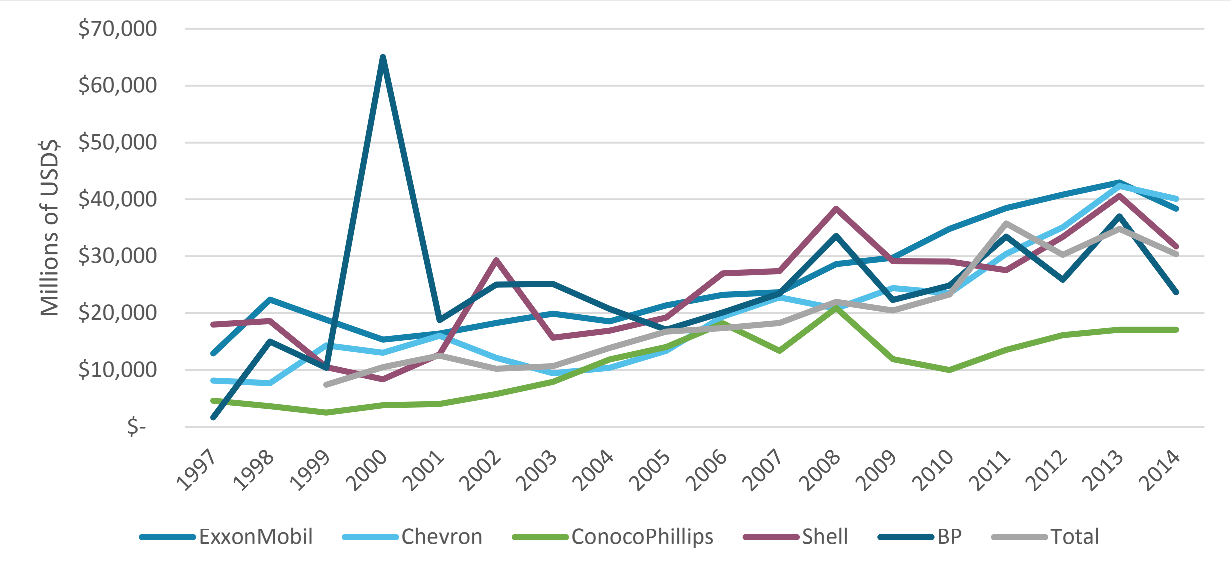
Source: (Mitchel et al., 2012) - (European Commission; Zacks; Research Infosource Inc)

One argument for this shift is that supermajors are also becoming more reliant on OSCs for providing the technology in E&P. They have been increasing their capital expenditures and reducing R&D, to pave the way for the short-term technical support from the OSCs. From 1997 to 2014, the R&D budget of the IOCs has increased by 37%, for some, it even decreased; meanwhile, the financial resources put into capital expenditures increased by about 72% for the same time frame. However, now that the capex has been downsized, and the R&D budget along with it, the majors are putting at risk the remaining strength over the NOCs and the OSCs, which has opened up the debate of their future competitive advantage.

3.1.1.5 Capital Expenditures

Over the last two decades capital investments by the oil majors have increased at a stable pace, and at a certain point tend to follow the trends in the price of crude. However, the impact is not as sharp as evidenced in earnings and cash flows. Instead, capital expenditures (capex) are better hedged in low price environments.

Figure 13: IOCs – Capital Expenditures 1997-2014



Source: OPEC Annual Statistical Bulletin 2014 and Company Annual Reports and SEC Filings from 1997-2014

Since capital projects in the industry are long-term commitments, the projects most likely to experience cuts are start-ups; those already in progress might experience delays but are more economically feasible to reach completion despite the market conditions. This lag effect results in relatively stable capital budgets.

BP's capital expenditure in 1999 reflects a significantly lower investment due to the merger between BP and Amoco. In 2000, the expenditure spiked due to the acquisition of the Atlantic Richfield Company (ARCO) through a share transaction, as compared to prior financing which has been done through cash flow from operations, disposals, and external financing.

In 2008, when the price of oil was over $100 per barrel, the capital expenditure for all the majors reached an all-time high. Up to that point, it was steadily growing. From 2008 through 2011, the supermajors' upstream capex increased by 21%, falling behind the NOCs with 31%, but outpacing the independents, who saw a decline by 8%.[11]

By 2009, the prices plummeted by almost 40%, and the cuts in capex did the same. ExxonMobil and Chevron were the only majors that maintained their budgets in place. Capex recovered for the following four years for most majors, in the same path as the oil price surge, with the exception of ConocoPhillips. After 2008, the company's capex further decreased before slightly recovering in 2011. In this period, ConocoPhillips also moved away from the "integrated" business model, to focus only on E&P, and its capex remained far below its counter parts.

When the 2014 fourth quarter results were issued, all the majors announced cuts for the capital and exploratory investment programs. Excluding, ConocoPhillips, Table 1 shows that the reduction in capex for 2015 averaged at about 12% for five of the major oil companies.

[11] See Annex B

Table 1: 2015 IOC Capital Expenditure Reductions

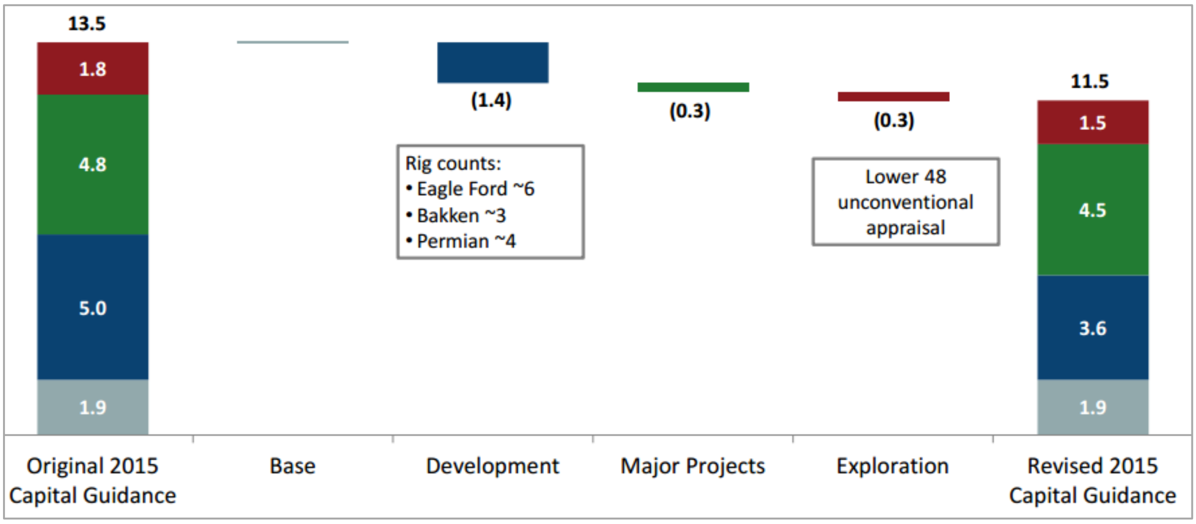
	ExxonMobil	Chevron	ConocoPhillips	BP	Shell	Total
2015 CAPEX Reduction *(percent from 2014 level)*	**12%**	**13%**	**33%**	**13%**	**14%**	**10%**
2015 CAPEX Budget *(USD$ billions)*	**$34**	**$35**	**$11.5**	**$20**	**$33**	**$24**

Source: Company Press Release Statements and SEC Filings – 2015

Chevron's $35 billion budget for year 2015 includes a $12 billion[12] of planned upstream capital spending for existing base producing assets (includes shale and tight resource investments). Roughly $14 billion will be allocated for major capital projects already underway such as LNG and deepwater developments with the remaining amount going towards the downstream segment and other efforts.

ConocoPhillips announced the largest reduction among its peers as a result of low price environment. The company initially announced it would reduce capex by 20% to $13.5 billion, but in December 2014, with the release of the fourth quarter results it announced an additional reduction to $11.5 billion due to low expectations of commodity prices. The cuts will be applied to major projects, several of which are close to completion, and in the North American unconventional plays.

Figure 14: ConocoPhillips - 2015 Original and Revised Capital Guidance



Source: ConocoPhillips Q4-2014 Earnings Presentation

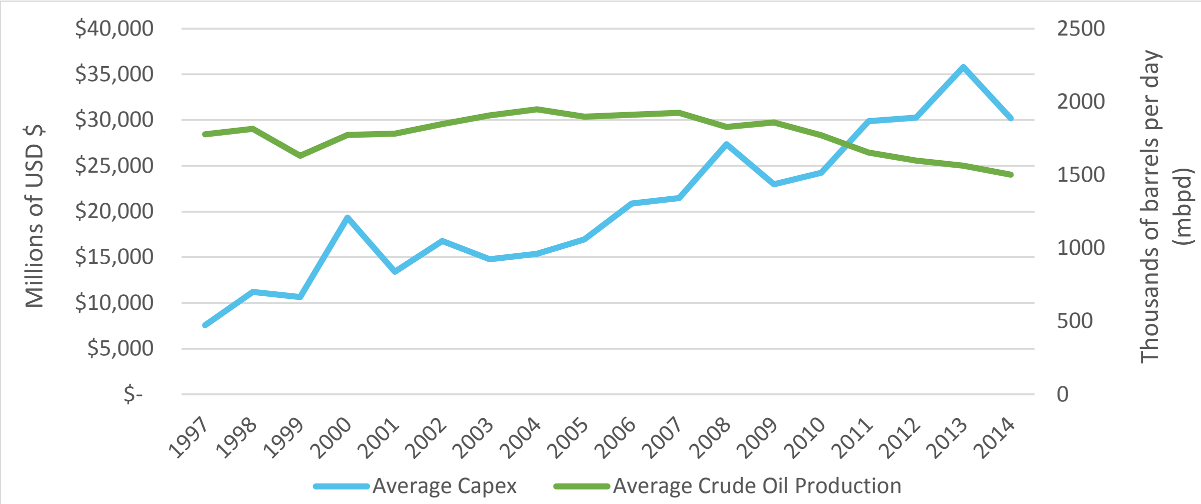
In a commodity down cycle, such as this one, integrated companies tend to fare better than independents. With the sole focus on exploration and production, a decrease in operating cash flows of the independents significantly impacts the available resources for capex, making their plans highly dependent on the short-term outlook for global crude oil prices.

Despite the hedge capital budgets have in oil price cycles, the return on investment has a more negative trend. In 2013 and 2014, the supermajors had spent a cumulative of about $214 billon and $180 billion respectively, on exploration and production. Although the level of spending has hit a

[12] See Annex C

record high, all companies are producing far less oil than before, with the overall output has falling by 15% since 1997.

Figure 15: IOCs - Capex and Crude Oil Production 1997-2014

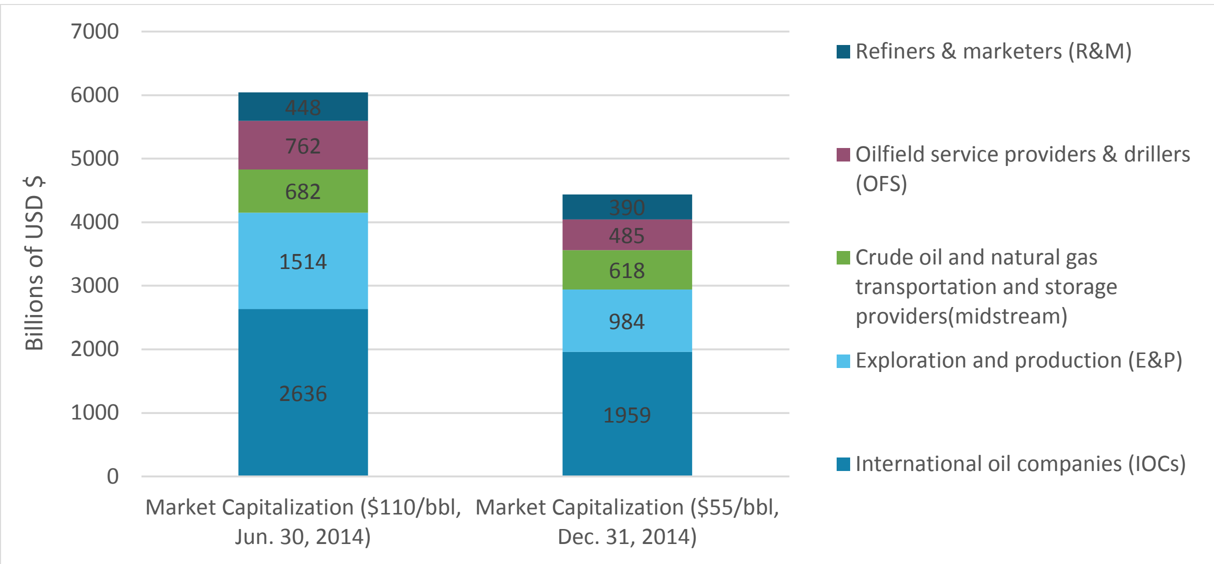


Source: OPEC Annual Statistical Bulletin 2014; Company Annual Reports and SEC Filings from 1997-2014

3.1.1.6 Market Capitalization

The variation in company valuations is mainly explained by the oil price, oil and gas production, and to some extent reserve replacement (Osmundsen, 2006). Thus the fall in revenues contributed to substantial devaluation in market capitalization. The EIA projects that oil prices will remain below $76/bbl until 2018 (EIA, 2015c). With lower market values, low expectations for the price recovery, the IOCs face a new challenge of secure financing. The IOCs experienced devaluation by about 15%, compared to the E&P and OSFs with 21% and 22% respectively.

Figure 16: Market Capitalization of O&G Segments (before and after oil price decline)



Source: Deloitte – (England et al., 2015)

3.1.1.7 Dividends

The first announced changes by the supermajors were the cuts in capital expenditures across the board. In addition to downsizing capex, companies are delaying projects and selling assets, and some are pressing suppliers to cut costs. However, despite all the reductions in effort to optimize portfolios, one area that seems to be untouchable is the dividend.

ExxonMobil's dividends have increased by an average rate of 6.4% (ExxonMobil, 2015b) annually for the past 32 years and the company has issued a dividend consistently for more than a 100 years (ExxonMobil, 2015c). Similarly, Royal Dutch Shell has had a consistent dividend payment since 1945. BP has had a less consistent history. For the past two decades it has cut dividends during difficult times, such as the Macondo oil spill. Compared to its peers, it also trails behind. BP's dividends have increased by about 12% in the past twenty years compared to ExxonMobil with about 400% change (Crowe, 2015). Since January 2014, the majors either increased or maintained the same dividend payout, with the exception of Total which regularly decreased.

Table 2: Dividend Cash Payments for 2014 and Q1 & Q2 of 2015

	ExxonMobil	Chevron	ConocoPhillips	BP	Shell	Total
Q1-2014	0.63	1.00	0.69	0.57	0.94	0.81
Q2-2014	0.69	1.07	0.69	0.58	0.94	0.83
Q3-2014	0.69	1.07	0.73	0.58	0.94	0.77
Q4-2014	0.69	1.07	0.73	0.60	0.94	0.75
Q1-2015	0.69	1.07	0.73	0.60	0.94	0.68
Q2-2015	0.73	1.07	0.73	0.60	0.94	0.67

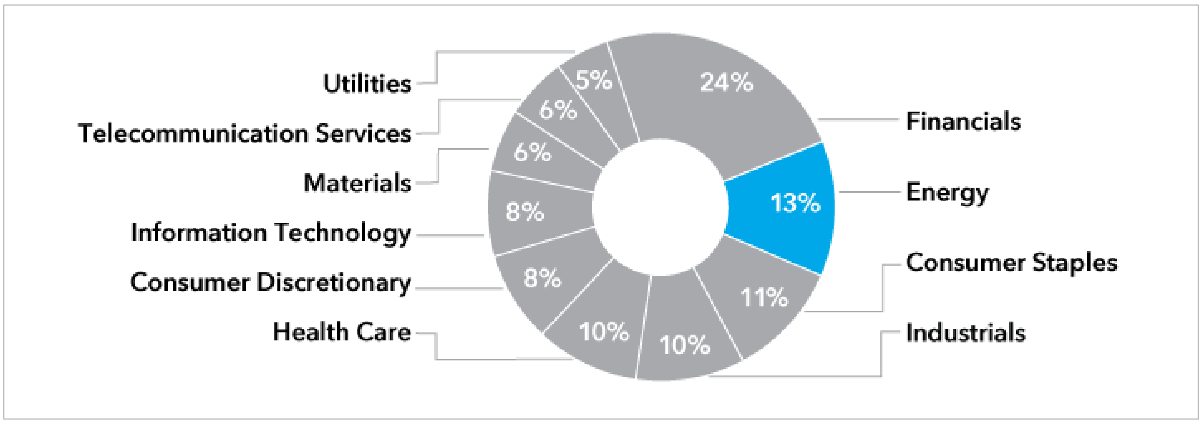
The oil industry has always been seen as a safe investment with consistent and generous returns. This is also reflected in the stock ownership distribution. A study conducted by the American Petroleum Institute (API) on the ownership of oil and natural gas industry in the US revealed that the majority owners of oil and gas companies are individual investors, through their pension funds (Shapiro et al., 2014)[13].

At the beginning of June 2015, the three European majors were leaders in dividend yields. Shell's dividend yield averaged at 6.5%, BP at 5.93% and Total with 5.46% (CNN Money, 2015). However, the dividend yield measures the income distributed in proportion to the share price. The US majors have lower divided yields. This, however, can either reflect their higher share price (market capitalization) or the speculation that the company is not performing well, therefore the dividends it pays are below par. On the other hand, high dividend yields, as seen with the EU majors, can also reflect a lower share price. As the IOCs are considered to be mature and profitable companies, the shareholders expect higher dividends, as oppose to companies that are considered to be in the "growth" stage of development. But, even though not much growth is expected, IOCs still need to retain some of the cash flow to fund future business activities. If they reduce dividends or refrain from distributing for a certain period, investors can see this as a sign of weak performance and sell the stock, eventually reducing their market value and profitability.

[13] See Annex D

In 2014, the energy industry was the second largest dividend payer, after financials, it accounted for 13% of dividends paid by companies in the MSCI All Country World Index (Hu, 2015).

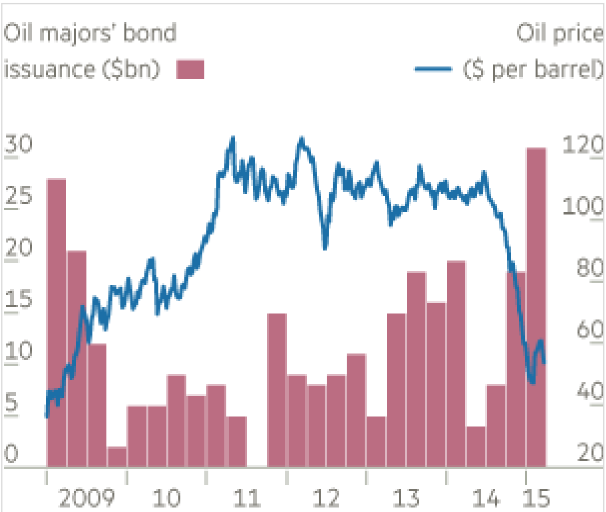
Figure 17: Dividend Payers by Industry



Source: FactSet, as of December 31, 2014

With this aspect strongly protected by the companies, analysts predict that the cuts in shareholder dividends will be the last resort to weather out the price decline. However, to fund this payment, most are beginning to sell assets, increase their borrowing or a combination of the two. The devaluation of their market values limits equity financing as an option. With low interest rates, some majors were able to increase their debt and fund the dividends. If interest rates spike, this may become an unviable option. For 2015, the IOCs were able to raise a record amount of debt through bond issuance, which reflects the optimistic outlook by investors that the companies are financially strong to sustain the period of low prices.

Figure 18: Oil Majors' Bond Issuance 2009-2015



Source: Financial Times (Adams, 2015) - Dealogic, Morgan Stanley, Thomson Reuters Datastream

3.1.2 Strategies

3.1.2.1 Divestments

A common trend observed during low price cycles is an increase in divestments. For the past two quarters, the price of oil has resulted in more asset sales by the majors. In April, Shell announced its plans to sell 185 company-owned service stations (Shell, 2015). As oil prices and high costs cut the profit margins, Chevron decided to sell its stake of the Caltex Australia Ltd refinery (Reuters, 2015). Similarly, BP announced a sale of its equity in the Central Area Transmission System (CATS), a natural gas pipeline business in the UK North Sea (BP Press, 2015). Total presented a plan to restructure its French refineries to withstand the low oil price environment. Even though the company is investing to improve the efficiency of the refineries, it plans to cut more than half of the jobs. Divestments are also being realized in the upstream segments for some companies. In March 2015, ConocoPhillips put up 20% of its production in Western Canada for sale as oil prices made the operations in the country less attractive (Scotia Waterous, 2015).

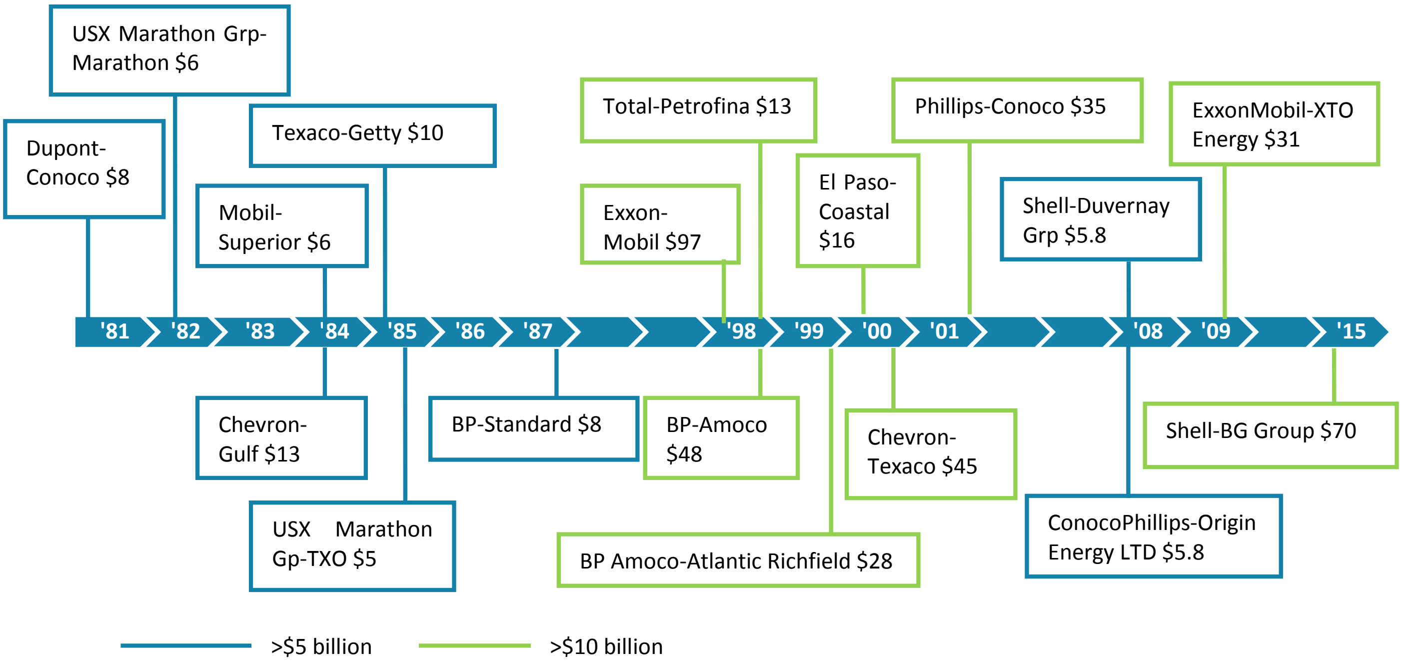
Over the years, IOCs have shifted their strategy to focus more on upstream activities due to the higher profit margins. However, when the price of oil drops, there is greater pressure on the companies to optimize their portfolios. In this effort, IOCs begin to divest non-core assets, particularly downstream activities to generate cash flow in order to finance upstream investments. In the past decade, the downstream segment has become less profitable and less attractive for the IOCs. Although refining activities are more hedged against crude price volatility, they tend to be more exposed regulatory risks. Expansions in the downstream segment are more likely to realize in other parts of the world, as environmental regulations in Europe and the US have become more restrictive.

3.1.2.2 Mergers & Acquisitions

The infamous energy crisis of 1970s restructured the industry and started a new trend among the oil majors. With high prices, the companies saw a large increase in profits, but with limited supply, they rushed to adapt new strategies and purse alternative energy options. Exxon moved towards exploration in non-OPEC regions, while others started to diversify their portfolios. The diversification strategies varied across the board as well. Some shifted away from oil, to food, microelectronics, even biotechnology. Majors like Chevron invested in uranium and geothermal sources. Texaco also moved towards uranium mining, in addition to electronics and coal gasification (Johnston et al., 2006). In the following decade, the price crash halted these projects and generated a wave of consolidation. From 1981 to 1984, oil company mergers alone accounted for 25% of all merger and acquisition (M&A) activity. The two largest were Chevron's purchase of Gulf Oil ($13 billion) followed by Texaco's merger with Getty Oil for $10 billion (Johnston et al., 2006).

In the oil price collapse of 1998, the industry saw a new wave of mergers once again. However, the consolidations that followed are often characterized by efforts in optimization and achieving economies of scale. At the end of the year, BP acquired Amoco, Total merged with Petrofina, followed by a merger between Exxon and Mobil in November of 1999, creating ExxonMobil, the largest corporation in the world (Rudolph, 2013). The M&A activity continued through the early 2002, with a merger between Chevron and Texaco for $45 billion, and Philips and Conoco for $34 billion.

Figure 19: Major Mergers and Acquisitions from 1980-2015



Source: Data from 1980-2002 (Johnston et al., 2006); Data from 2008-2015 - Company Press Releases

The consolidation that emerged from the price collapse, particularly Exxon and Mobil, and BP and Amoco, ushered an era of the "majors". The companies that formed had the economic advantage because of size and scale over to the oil companies located in regions with few competitors and limited access to financial markets and reserve access.

When oil prices fell in 2008, six of the top ten largest deals in the industry were acquisitions of natural gas assets. The majority were unconventional resources, all located either in Australia or North America (PwC, 2008). With the shale gas revolution in the US, the majors shifted their focus to natural gas. In 2010 ExxonMobil acquired XTO Energy, to create a new organization focused on global development and production of unconventional resources. The purchase made the company the largest natural gas producer in the US (Kahn, 2011).

3.1.2.2.1 Current M&A Activity

The most recent price drop is expected to be a repeat of the M&A activity from the 1980s and the 1990s. The decreasing oil prices have already triggered a wave of restructuring in an effort to cut costs and generate cash flow. The oil and gas industry M&A activity was at record high in 2014, both in terms of value and volume. The value of the 49 largest deals was $266.1 billion, compared to 24 worth $71 billion the previous year (PwC US, 2015).

After eight months of low oil prices, the first IOC merger announcement was made by Shell. On April 7, 2015, the company announced the acquisition of BG Group for $70 billion. The takeover will make Shell the largest global producer and seller of LNG, with the potential to increase its oil and gas reserves by 20% (Kaufman, 2015). Other speculations over mergers include ExxonMobil and BP. After the Deepwater Horizon disaster in the Gulf of Mexico in April 2010, BP's share prices never fully recovered. Five years later the company is still engulfed by lawsuits and the oil price collapse further increased the pressure on future performance. Its weak position sparked rumors of a takeover. However, BP's CEO, Bob Dudley, dismissed the potential megamerger during the IHS CERA Week conference in April 2015, arguing that unless prices stay low for a longer period of time, the company's portfolio is unlikely to change (Adams, 2015b).

With the price collapse, many independents prominent in tight oil are exposed to higher debt and risk of bankruptcy. A takeover by big oil is a plausible as their scale and financial resources enable such endeavors. Yet whether it would strengthen their position is uncertain. The success of the independents can be attributed to business models. The companies embrace a different organizational culture compared to that of a large IOC. Their size and agility increased their pace in developments. If the IOCs move towards acquisition of these players, in effort to expand their resources and diversify portfolios, they run risk of purchasing the low-end plays, as prime fields are more likely to be faring well in the downturn. The alternative is to start their own tight oil operations as independents, but this would require disintegration and a shift to a new business model.

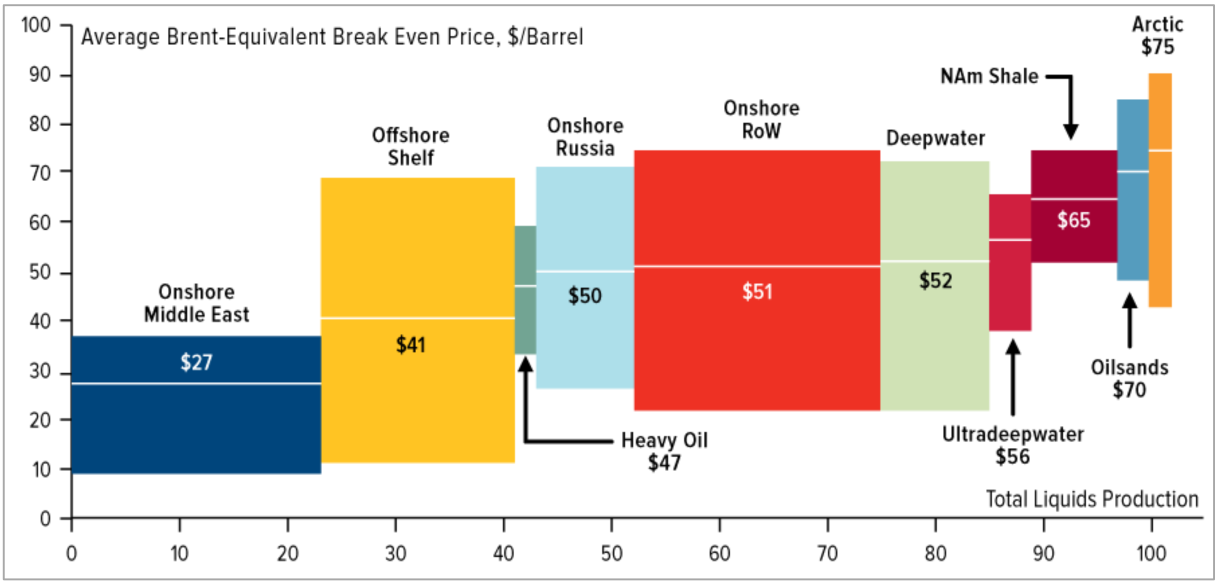
The US majors were too late for the US tight oil and gas revolution. ExxonMobil's acquisition of XTO Energy in 2010 illustrated that the major didn't pursue this opportunity from the start, and when it did, analysts argued that it overpaid. As the takeover seemed like the best choice and gateway to gas resources, the gas price collapse suddenly made the assets less valuable. However, the bet was part of the long term strategy that has yet to play out, as price of gas in the US is low and has followed a downward trend with the oil price. Further liberalization of LNG exports laws may ease the pressure for the companies. This price cycle may resemble that of the 1990s, a consolidation of the large players, more than a takeover of the 'smaller fish in the pond'.

3.1.2.3 E&P Focus Areas and Status of Current Projects

A sustained period of low oil prices has the potential to create a domino effect for the IOCs. With the price of oil in April averaging at $60/bbl (Brent) and $54/bbl (WTI), it may reduce the expected returns from future production. With lower expectations, companies are less likely to invest in E&P, which can lead to project delays and cancelations, ultimately hindering the production growth. Some of these trends are already evident in the announcements by the IOCs to cut capex.

To optimize portfolios, the majors have begun to cancel or delay ongoing projects. The projects that are being set aside also depend on the type source the hydrocarbons are to be derived from. A study conducted by Rystad Energy showed a rise in production costs as the demand for crude increases in the future and the average breakeven price of each crude source.

Figure 20: Crude Cost of Production Rises as Demand Grows



Source: Rystad Energy, Morgan Stanely, U.S. Global Investors

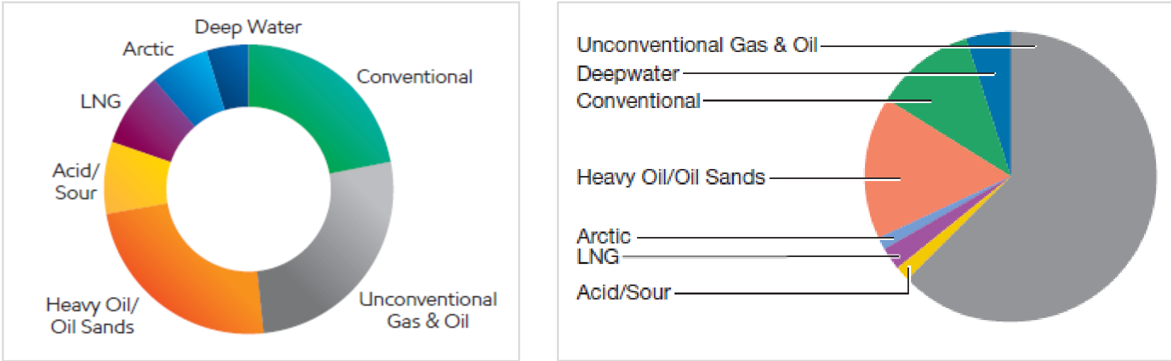
Over the years the resource distribution of the majors has shifted to a new frontier. A large portion of undiscovered conventional resources either lies in technologically challenging areas like the Arctic or under the borders of countries with political instability, rending the exploitation high risk endeavor. The 2012 U.S. Geological Survey (Schenk, 2012) assessment of global undiscovered conventional oil and gas resources indicate that about 75% of the undiscovered and technically recoverable conventional oil of the world is in four regions: South America and the Caribbean with 126 billion barrels of oil (bbo); sub-Saharan Africa (115 bbo); the Middle East and North Africa (111 bbo); and the Arctic provinces portion of North America (61 bbo).

To ensure sustainability in the long run, the IOCs have begun to expand their operations in unchartered territories such as the Arctic, towards unconventional sources like the North American shale and Deepwater production. Currently, one-third of the global oil production comes from offshore wells - shallow and deep waters (Yergin, 2011a). Similarly, the U.S. Geological Survey assessment of the area north of the Arctic Circle holds 13% of the world's undiscovered oil and 30% of the world's undiscovered gas (Gautier et al., 2009). However, unconventional sources require continuous large investments and technological breakthroughs to ensure an increasing recovery rate, and drilling in the Arctic has its own unique and expensive challenges. In 2014 a large portion of ExxonMobil's resources came from oil sands and unconventional fields. From 2008 to 2012, unconventional gas and oil and oil sands made up the majority of the resource additions.

Figure 21: ExxonMobil - Resource Base Distribution and Resource Additions/Acquisitions

Resource Base Distribution
By Resource Type
(percent, oil-equivalent barrels, 2014)

Resource Additions/Acquisitions
By Resource Type
(percent, oil-equivalent barrels added, 2009-2012)



Source: 2014 ExxonMobil Operating Review; 2012 ExxonMobil Annual Report Summary

In May 2015, Shell announced that it will resume its drilling in the Arctic Ocean, after receiving a conditional approval from the U.S. government. Shell's activity in the Chukchi and Beaufort Seas began in the 1970s and 1980s but the company abandoned all plans due to the fall of oil prices in the mid-1980s. In 2010 Shell estimated that new discoveries could produce of 1.2 million barrels of oil per day (mmbpd) in the Chukchi Sea and 600,000 barrels per day (bpd) in the Beaufort Sea, and paved the way for another wave of large investments for licenses. However, by 2012 Shell encountered various legal issues and regulatory hurdles, officially halting operations (Henderson et al., 2014). Its current plans include an investment of $1 billion, adding to the previous $6 billion spent on such projects in the Arctic (Harder et al., 2015). Other companies, ConocoPhillips and the Statoil, also own leases in the US Arctic, but with high costs and risks, neither has plans to pursue the projects at this time.

A recent report by Carbon Tracker demonstrated the high exposure of the IOCs to the various types of undeveloped projects, unconventional in particular. The study evaluated the company's risk in terms of potential production and capex expenditures from 2014-2025. The ranking assessed the projects that would require a price above $75/bbl and $95/bbl.[14] Out of the majors, ConocoPhillips has the highest proportions of production projects requiring the price of oil to be $75/bbl and above (56%), and 36% of the projects would require a price of at least $95/bbl. BP on the other hand, has the lowest oil market price requirements (40%) for $75/bbl and (21%) $95/bbl. In terms of potential capital spending, Total and ExxonMobil's capital budgets have some of the highest oil price requirements, with 60% and 68% respectively on projects requiring a market price of at least $75/bbl for sanction and 40% and 39% requiring at least $95/bbl (Carbon Tracker Initiative, 2014).

[14] This note examines the IOCs' potential future project portfolios looking at production and capex using Rystad Energy's UCube Upstream database (as at July 2014). "Capex" and "production" in this note are thus based on Rystad's analysis and expectations of the company's potential projects.

Table 3: Potential 2014-2025 Production (%) Market Price Requirement

	ExxonMobil	Chevron	ConocoPhillips	BP	Shell	Total
$75/bbl+	44%	46%	**56%**	40%	45%	44%
$95/bbl+	29%	26%	**36%**	21%	30%	29%

Source: Oil & Gas Majors: Fact Sheets, Carbon Tracker Initiative 2014

Additionally, the report outlined the specific projects of the oil majors that would not be feasible unless the price of crude is above $95/bbl. All these face cancelation unless the oil price rebounds. In the current price context, projects in the Arctic and oil sands in general are at high risk, as the cost of production averages at $75/bbl and $70/bbl respectively. However, the average price could change pending the response of the oil companies to the cost cutting pressure. In the meantime, obtaining a profit from such investments and at the same time meeting shareholder expectations could prove to be difficult path ahead.

As their control over reserves has diminished over the years, the majors have shifted their strategy towards harder to reach sources of oil, finding a competitive advantage in large scale and capital intensive projects-LNG, the Arctic, and deepwater. With record high crude prices, investment in these regions was justified. Taking advantage of their integration and sheer size, the IOCs saw this as an opportunity to specialize and dominate the market in intensive exploration and development projects. However, the riskier projects come with longer lead times resulting in longer periods required for a realized return on capital invested. When proposed, the projects are planned with much higher price of oil than the current value to be economically feasible.

3.2 Environmental

With increasing efforts to fight climate change, the majors' dependence on oil has emerged in the debate. Investor groups are putting pressure for greater transparency and risk assessment in fossil fuel investments, in particular those concerning the international oil companies. Many are starting to reconsider their future strategies in an environment shifting away from fossil fuels.

3.2.1 Climate Change and Carbon Risk

In 1970s oil crisis, many of the majors invested in alternative sources of energy, but as soon as the prices recovered, most of these projects were abandoned. In 1997, BP became to first oil major to take measures against global warming. In 2000, the company rebranded its self by adopting a slogan "BP: Beyond Petroleum" and changing its logo to the present day sunburst, in an effort to reflect its commitment to the environment. In the next decade it spent $8.3 billion (Downing, 2014) in renewable energy, but after the Gulf of Mexico oil spill, it disposed all renewable assets, only retaining the biofuels business. Most of its peers followed a similar path with the exception of Total. In addition to developing biofuels since the 1990s, in 2011, Total became a majority owner (66%) of SunPower Corporation, a designer and manufacturer of PV cells, with the aim to become a leader in solar energy.

The environmental policies of the IOCs in general focus on development of biofuels, energy efficiency, and in some cases R&D in carbon capture and sequestration (CCS) [15]. The majority emphasizes their gas production as sustainability and diversification factors. However, the wide diversification of portfolios seems unlikely in the future for most majors. Despite being the largest producer of natural gas in the US, ExxonMobil's stance on the economic viability of its proved reserves resulting from reducing greenhouse gas (GHG) emissions 80% by 2050, as outlined by the "low carbon scenario," is skeptical. The company believes that it is highly unlikely, and does not fall under the suggested category "reasonably likely to occur" in its planning assumptions (ExxonMobil, 2014). Even in this scenario, hydrocarbon sources will still be needed, therefore their exposure to the climate change risk is minimal.

As the Road to Paris culminates this December ahead of the 21st Session of the Conference of the Parties to the United Nations Framework Convention on Climate Change (COP21), ambitions for a global climate agreement are intense as ever. In 2013, the Carbon Tracker Initiative (CTI) and Ceres introduced the Carbon Risk Initiative, the idea to pressure the global fossil fuel companies to address the financial and physical risks associated with climate change. The idea behind the "stranded assets" is that a many global fossil fuel reserves cannot be produced because of the climate risks. The key stakeholders in this debate are the investors. Even if climate change may not be a priority for many, they will respond for purely economic reasons, for their return on investment.

A sustained low oil price environment may have to significant impacts on the IOCs. It may further discourage investment in renewable sources as evidenced in previous periods, and if the global oil demand continues to decline due to evolving policy, technology, or consumer responses to address climate change, the risk of stranded assets may be more likely than the majors currently consider.

[15] ExxonMobil operates the LaBarge plant in Wyoming, one of the world's largest CCS plants and it is a co-venturer in the Gorgon natural gas development in Australia, expected to have the largest saline reservoir CO2 injection facility in the world.

Investor resolutions for oil companies to take action have intensified and most recently, proposals for ExxonMobil and Chevron have emerged to nominate directors with environment expertise to address their high carbon assets among other resolutions. However, a vote for this proposal in May only gathered 4% of the investors for Chevron and ExxonMobil was able to remove it from the ballot all together. Furthermore, in a report on managing carbon risk, ExxonMobil issued the following statement:

> *"Based on this analysis, we are confident that none of our hydrocarbon reserves are now or will become "stranded." We believe producing these assets is essential to meeting growing energy demand worldwide…"* (ExxonMobil, 2014)

On the other hand, Shell and BP took another approach, and urged their investors to adopt a resolution mandating a disclosure of "stranded asset" risks. Shell called for a transition to a new cleaner and less carbon intensive model that incorporates a greater share of natural gas and renewables and a significant role for CCS (Critchlow, A., 2015).

With increasing pressure from investor groups some companies are starting to reconsider their future strategies in an environment shifting from fossil fuels. A recent announcement showed a rift between the US and the European IOCs. On June 1, 2015 Europe's major oil and gas companies (BG Group plc, BP plc, Eni S.p.A., Royal Dutch Shell plc, Statoil ASA and Total SA) announced their support for governments to establish carbon pricing systems.

> "*Our industry faces a challenge: we need to meet greater energy demand with less CO2. We are ready to meet that challenge and we are prepared to play our part. We firmly believe that carbon pricing will discourage high carbon options and reduce uncertainty that will help stimulate investments in the right low carbon technologies and the right resources at the right pace. We now need governments around the world to provide us with this framework and we believe our presence at the table will be helpful in designing an approach that will be both practical and deliverable."* (Helge Lund, BG Group Plc; Bob Dudley, BP plc; Claudio Descalzi, Eni S.p.A.; Ben van Beurden, Royal Dutch Shell plc; Eldar Sætre, Statoil ASA; Patrick Pouyanné, Total SA)(BP, 2015b).

Their peers, ExxonMobil, Chevron and ConocoPhillips, declined to join the coalition. Chevron argued a carbon price was not manageable, ConocoPhillips stated that the policy is ineffective because customers ultimately want low prices (Macalister, 2015), and ExxonMobil claimed the European counterparts were not sincere in their statements, and that they (ExxonMobil) tend to urge policies that have merit (Carroll, 2015). The news was received with mixed views. Some see it as a progressive step forward and a historical break from the US majors, while others as a strategic move in the growing debate over fossil fuel divestment.

The decision by the EU companies could also be a strategic move based on their existing portfolios. The gas production of Shell, BP and Total has is greater than oil, therefore the interest in supporting a carbon price would make them more competitive against coal in the future. The opposite scenario is true for the US companies. A carbon price would decrease their profitability since their production of oil outweighs that of natural gas.

According to CTI, even though current proven reserves may not be exposed to the carbon risk, future development of reserves on the other hand is not excluded. Market valuations of IOCs based on historical return on capital assume that future profit margins can be maintained but this will be tested if demand continues to contract and the price of crude with it. If the low oil prices are sustained for a longer period of time, the concept of stranded assets may become a reality for the majors.

3.3 Regulatory

3.3.1 Contract Formulas

Once the dominant players, controlling the majority of reserves and production, the IOCs have taken a back seat in the recent history of the petroleum industry. In the second phase, the roles are reversed, with the NOCs emerging as the leaders. Rather than being viewed as opposing sides, the two have embraced a cooperative model, with different kinds of partnerships that reflect the synergies among their distinct capabilities. However, in the past decade, the bargaining power of the IOCs has diminished (Vivoda, 2009). NOCs have acquired the 'know how' that once made the IOCs an irreplaceable partner. Further impacted by the increased competition from independents and oil service companies, and with the uncertain political and stringent fiscal policies of the oil exporting countries, the sustainability of the IOCs business model is in question.

Host governments have developed and implemented a range of arrangements for IOCs operations. The most common types include concessions, production sharing contracts or agreements (PSCs)/(PSAs) and risk service contracts. In Africa, about half of the countries use production sharing contracts, while the other half relies on a mix of a tax/royalty regime. In Asia, PSAs are the most common, while in the Western hemisphere PSAs are rare (with the exception of the Caribbean) and royalties are predominant (Davis et al., 2003).

However, the complexity of these systems expands with the varying fiscal policies in each country, also known as the "government take". For individual petroleum projects, the government take can vary between 25% and 98% (van Meurs, 2008). For example, in low-cost oil development fields, like Abu Dhabi (concessions), or Kuwait (operating service contract) and Libya (PSCs), the government take can be between 95-99%. For fields with average conditions like the Norwegian North Sea (concession) or in Egypt deep water offshore (PSC), the government take is lower (60-85%). Lastly, with difficult fields, like the British North Sea(concession) or marginal gas fields in Mexico (service contracts), the government take is the lowest, ranging from 40-60%.

The various fiscal instruments implemented by producing countries limit the profits the IOCs. For its hydrocarbon industry, Algeria only implements PSCs. In 2006, the country passed a new law –Law No. 05-07- that introduced a Tax on extraordinary profits (TEP)(EY, 2014) or windfall tax to all the contracts signed under the previous law (Law No. 86-14) dating back to 1986. The TEP, ranging from 5% to 50%, is applied to the output share of foreign partners of the NOC when the average price of oil exceeds $30 per barrel. In the new law, the tax regime was revised to include a petroleum income tax (PIT) - 30-70% and an additional profit tax (APT) -30% and 15% for reinvested profits.

In a case study of four countries (Norway, Kazakhstan, Indonesia and Angola), Sunley, E. M et al. (2002) identifies the evolution features of their respective fiscal regimes. There is a correlation between the price of oil and the fiscal terms. As the price declines, the terms become more favorable, in turn lower, and the opposite during price booms. When the oil prices drastically increased between 1973 and 1984, the governments take increased as well, along with sweeping nationalizations at the time. However, from 1986 to the early 2000s, it decreased as price declined. In 2003 and forward, the government take has been on a rise, following a similar pattern as oil prices (van Meurs, 2008). The second observation is that the tax policies of the IOCs origin countries influence the regimes of the producing countries. Lastly, over the years these schemes become more progressive as the petroleum sector of the respective country matures.

These principles are also evidenced in the case of Algeria. Similarly, even with favorable market conditions for the IOCs, their profits are in some cases capped. In periods of high oil prices, the government take is likely to increase, along with the expectations of higher profits for the IOC. These expectations may not be realized as they once use to be, as IOCs face more competition from oil companies in China and elsewhere, willing to accept smaller earnings in exchange for access to exploration and development areas (van Meurs, 2008). Moreover, the new price context is not a guarantee that the fiscal regimes of host countries will adjust, hence the majors face this risk and profit loss in the future.

However, the low oil prices may bring new opportunities for the majors in the case of new projects. Countries trying to attract foreign investment in their petroleum industry are easing the requirements and offering better deals as evidenced by Mexico's recent energy law reform. Mexico enacted a new law legislation to open its oil and natural gas markets to foreign direct investment, ending the 75-year-old monopoly of state-owned Petróleos Mexicanos (Pemex). By offering new types of contracts, the country hopes to boost investment and increase its production. Contracts being offered include: production-sharing contracts and licenses, that would enable foreign companies to account for reserves, and others would be applied based on the risk profile of the projects (Doman et al., 2014). Although the reform was met with high interest from the majors, the depressed oil prices changed the landscape. As IOCs scaled back investment budgets, their interest in bidding became questionable. As a result, Mexico rushed to offer more competitive terms by adjusting the pre-tax profit margin to 20% from the previous 15% (Webber, 2015). Furthermore, its strategy is the auction the less risky shallow offshore projects first, due to the lower development costs, and to hold the tenders for unconventional assets for next year, as their viability at current prices is uncertain (Webber, 2015).

3.3.2 The US Crude and LNG Regulation

With the technological innovation, the US oil and gas industry in particular, has seen a rapid increase in production and reserves. When the US production surpassed that of Russia and Saudi Arabia in 2013, the US majors began to push for a lift on the export ban on oil and LNG.

In 1975, the US Congress banned the export of domestic crude oil without a license. The legislation was meant to spur conservation of domestic reserves and discourage foreign imports. The US majors and independent producers are pushing for a lift on the ban, while refiners take the other side. US oil (WTI) trades at a discount compared to the international (Brent). The distortion is primarily due to the bottleneck created with the growing production and limited transport capacity and US refining capacity for light crude oil produced in the US. Refineries in the US are able to purchase the lower domestic crude and sell the refined products based on the global price. However, US producers are limited and cannot export their product and face suppressed prices, which can decrease their production and thus profitability. The US majors take the side of the producers, despite also having refining segments.

Similarly, the US Natural Gas Act of 1938 stipulates the regulations for the import and export of natural gas to or from a foreign country, which is being revisited as the "shale gas revolution" took off. Notably due to technology advances (horizontal drilling and hydraulic fracturing), and coupled with high oil and gas prices, the production of shale gas increased, by 2008 it accounted for more than half of total US gas output **(**Aguilera et al.,2013). The developed global LNG capacity was aimed at fulfilling US imports, but the shale boom made the US self-sufficient in natural gas and provided a considerable export potential instead. The decrease in imports shifted the excess LNG capacity and collapsed the prices in Europe and Asia. Similarly, the increased production significantly reduced the price of gas in the US. In 2014 the price of gas decreased globally, but the spread between the different markets is still large; the US (Henry Hub) - $4.35/Mmbtu, UK (Heren NBP Index)-$8.22/Mmbtu, Germany (AGIP)-$9.11/Mmbtu, and Japan cif (LNG)-16.33/Mmbtu (BP, 2015).

To export this abundant gas, interested parties must receive the authorization of the US Department of Energy (DOE). Currently, only five LNG export projects have received government approval and are under construction; with one, Cheniere Energy, expected to begin exports in 2015(FERC, 2015). In 2003, Golden Pass LNG, a joint venture company -Qatar Petroleum (70%), ExxonMobil (17.6%) and ConocoPhillips (12.4%)-, formed to develop an LNG terminal in Sabine Pass, Texas. It was completed in 2010 and envisioned as an import facility originally. However, when the price of gas dropped, the companies filed for an export authorization. The company already received an authorization for export to countries that are part of the Free Trade Agreement and is awaiting DOE approval to export to non-FTA nations. The investment decision is expected in 2015.

As the recent fall of oil prices also suppressed the price of natural gas, the US IOCs have an even greater interest in the lift of the export ban on crude and faster approval of LNG export authorizations. The argument put forward is that with the American oil flow in the international markets, domestic production would increase and untimely decrease the price for consumers. Opponents foresee the opposite reaction. Prices for the domestic industry will increase, may discourage innovation among energy companies and are harmful for the environment. Despite the prospects for the natural gas industry in the US, the low oil price environment is testing the economics of the many US projects. As global gas prices are tied to oil, previously lucrative markets like Asia now look bleak. Furthermore, as the majors are developing more gas, the risks are now twofold.

4 Conclusion

The landscape of the petroleum industry looks very different than it has decades ago. In 1980, the world's proven oil reserves were at 643 billion barrels. At the end of 2014 that number had reached 1700 billion barrels. Since 1980, global consumption totaled 914 billion barrels.[16] Oil's role in the global economy, in particular as part of the fuel mix, and its demand are in a transmission process.

From the supply aspect, non-OPEC production has hit record growth. US light, tight oil (LTO) output has changed the relationship between OPEC and non-OPEC supply. The fracking boom had placed the US as the world's leading oil producer. Saudi Arabia has abandoned its role as a swing producer, maintaining production despite the changing market dynamics.

In the Medium Term Oil Market Report, the IEA indicates a strong contraction in demand. Coupled with a technological revolution, growth in general has been less fuel intensive compared previous periods. Emerging economies have shifted toward less oil intensive development and the natural gas market is slowly eroding the oil market share in the global economy. Lastly, with COP21 approaching, concerns over climate change are reshaping the way nations enact future energy policies.

The most recent price collapse is shedding light on the ever-changing roles of the key players and questions the resilience of some. As stated in the introductory note, based on the available literature and data sources, this study assessed the comprising indicators to answer several key questions. The findings are given as follows:

- **Are the oil price cycles diminishing the market power of the IOCs*?* What is the impact on the crude oil reserves and production?**

  For the past thirty years, the oil majors have witnessed a significant change in operations and the industry as a whole and the decline in oil prices has further amplified these changes. The companies face decreasing earnings, lower operating cash flows, reduced Capex and R&D expenditures. The reserves currently in place are depleted at a faster rate than ever, but replenishing them has proven to be a difficult venture. Only few companies have been able to achieve an above 100% reserve replacement ratio. For the past decade, the major growth in reserves has come from NOCs instead. Similarly, the production volumes have leveled and most recently decreased in response to the price of oil. Overall, the IOCs face dwindling oil reserves, lower production levels but an increase in capital expenditures; record spending is yielding far less than before. Consequently, the oil price cycles are financially weakening the companies, impacting their operations, thus diminishing their competitiveness and power in the global oil market.

- **Is the most recent oil price decline changing the business models and portfolios of the IOCs? Does this impact vary across the operating regions and the types of resources?**

  As their control over reserves has diminished over the years, the majors have shifted their strategy towards harder to reach sources of oil, finding a competitive advantage in large scale and capital intensive projects-LNG, the Arctic, and Deepwater. Moreover, another key change observed is the move towards greater natural gas production. For many, gas production accounts for more than 40% of the total production. The drive to improve production levels has prompted mergers

[16] IEA International Statistics

like the most recent bid by Shell to buy BG Group. But, natural gas, a lower valued commodity, cannot boost profits on the same scale as crude oil.

With record high crude prices, investment in these regions was justified. Taking advantage of their integration and sheer size, the IOCs saw this as an opportunity to specialize and dominate the market in intensive exploration and development projects. However, the riskier projects come with longer lead times resulting in longer periods required for a realized return on capital invested. When proposed, the projects are planned with much higher price of oil than the current value to be economically feasible. As a result, many of the unconventional projects are at risk for cancelation and delays. Finding a competitive advantage as 'high end developers' does not align in the current price environment, and can only be exacerbated if a carbon price is established.

- **How are the IOCs weathering out the price decline? What are their short-term strategies and what will be the impact on future investment?**

In an effort to optimize their financial resources, IOCs reduced capital spending. Although they cut Capex, dividends have remained in place. Creating and maintaining shareholder value is a priority, and reducing the dividend payout has never been done in previous cycles. To fund dividends and optimize operations, the IOCs have issued large amounts of debt and have begun to dispose of downstream assets. The increase in debt is a liability if prices do not rebound in the mid to long term horizon.

Comparable to previous low price environments, divestment activity increased along with a fast trend of mergers and acquisitions. In the past mergers enabled the companies to reduce operational costs and increase reserves without incurring the exploration costs. With large resources, the majors have the opportunity to assume the role of acquirers as smaller underperforming companies in the current price context become potential targets. The M&A activity in this down cycle for the IOCs started with Shell's acquisition of BG Group. Further M&A activity is expected, largely involving small and medium size independent companies in the US.

Similar to the impact on resources, the oil price also weakened the financial situation of the IOCs creating a domino effect. With a negative impact on the income, lower revenues also resulted in market devaluations, decreasing the operating cash flow, thus reducing the funding sources necessary to cover dividends and Capex, ultimately limiting the long-term investment plans of the IOCs.

Moreover, when the price of oil was high, some majors moved towards alternative sources of energy to increase the supply. A low price environment has the opposite effect. A sustained period of low prices may lead to lack of investment in the industry and higher prices in the future, as demand increases, but the supply becomes limited.

- **What are the possible implications of the environmental and regulatory policies in general and in the context of low oil prices?**

Environmental

With increasing global efforts to fight climate change, the IOCs' high dependence on oil of the puts their current assets at risk of simply not being developed and future exploration out of reach. With high pressure from investors, many are reconsidering their long-term strategies. One avenue is a large shift towards natural gas production, as evidenced across all the companies in the past few years. The natural gas market is expanding as LNG becomes more integrated, and it's expected to be the fastest growing fossil fuel by 2035. The larger production of gas has become part of the IOCs' role in the fight against climate change, due to the lower emissions than crude oil. More recently, the EU majors, have announced their support for the governments to establish a carbon pricing system to better incentivize investments consistent with the low carbon scenario.

The shift to natural gas is also part their traditional business. The IOCs' move to gas is more strategic than just the result of environmental concerns. Becoming the next LNG and gas majors does not require a whole new business model. It fits well with their current capabilities, as gas production can be more capital intensive than oil and their size and financial resources make the IOCs the perfect fit for these projects. Similarly, the rift between the EU and US companies may be due to the higher natural gas production compared to crude oil evidenced in the portfolios of Shell, BP and Total, while the ExxonMobil, Chevron and ConocoPhillips are still predominately producing oil. A push for a carbon price would make the natural gas producers far more competitive than coal in the future.

Regulatory

Overtime, the IOCs ceased to be the leaders in the industry. To ensure their sustainability, many adopted new cooperative models with their competitors. Deteriorating contract formulas reflect the weakened negotiating power of the IOCs with the producing countries. Through various mechanisms, taxes, royalties, etc., the "government take" on contracts has increased over the years. The overall government take pattern follows the trend in oil prices. In the current context, governments may be prompted to adjust the requirements to attract more investment, especially in new exploration and development projects, as seen in the case of Mexico. For the majors this it's an opportunity to secure future reserves consistent with newly reduced budgets.

Furthermore, developments in US oil and gas export regulations, can affect the profitability of the IOCs, in particular those with operations in the US. With the increasing share of natural gas in the companies' portfolios, coupled with the price decline, interests in lifting bans on exports are at an all-time high. The case is similar for oil. ExxonMobil and ConocoPhillips, with interests in US shale oil, are pushing for a change in legislation that would effectively boost their profit margins. From the IOCs perspective, exports would close the gap between the WTI and Brent and incentivize further production in the US. Even though, ExxonMobil, as an integrated company has stakes in the downstream segment, the majority of revenues come from the upstream, therefore, it not surprising that its willing to forgo the beneficial refining margin to bolster production.

4.1 Recommendations

The BP Energy Outlook 2035 estimates that global demand for energy will rise by 37% from 2013 to 2035, an average of 1.4% per year, with much of the growth coming from Asia, China and India specifically. Demand for oil is expected to grow 0.8% per year, while gas is expected to be the fastest growing fossil fuel (1.9% per year). The report outlines three key features changing the shape of the industry. Starting with shifting trade patterns, as a result of the US tight oil production, oil trade is moving from West to East. Natural gas market is expanding as LNG becomes more integrated. The energy mix is also changing. The report predicts that the majority (2/3) of the global energy demand will be met by fossil fuels up to 2035. Furthermore, renewables and unconventional fossil fuels will play a larger role and gas will be the fastest growing fossil fuel. Lastly, the environmental challenge is another key topic of focus. With current policies, the carbon emissions are not sustainable and policy-makers are critical drivers towards a global price for carbon to incentivize all the stakeholders to act accordingly.

With this outlook in mind, investors should also consider the impact of sustained low oil prices and the implications it may have on the IOCs in the short and long term. This study has evaluated the direct and immediate effect on the majors, and in the process it has highlighted some of the underlying issues confronting the IOCs and their future business models.

Investors should try and envision the future version of the "supermajor", specifically the approach of each company towards addressing uncertainty. The current strengths of the IOCs include their vertical integration, with the exception of ConocoPhillips, and their global presence. The expectation of rising demand of LNG may prove to be boost for their operations and weak financial performance and for Total in particular, the focus on solar energy may be seen as a new opportunity. On the other hand, their recent poor financial results, coupled with major emerging litigations brought against them - for BP the 2010 oil spill in the Gulf of Mexico, and for ConocoPhillips the 2011 Yellow Sea in northeast China - maybe a threat and source of high operational risk. Moreover, political instability in country of operations such as Nigeria, could have a future implications for IOCs, in addition to the commodity price.

Lastly, investors should also take into account the development of environmental regulations. In search of new sources in difficult to reach areas with sensitive ecosystems, such as the Arctic, risk management has become a critical part of the upstream operations for the IOCs. The environment is closely tied to risk management, but instead, in form of carbon risk. Companies are pressured to minimize their carbon footprint in operations, while reducing greenhouse gas emissions and the prospect of a carbon price may put their future reserves in question. If the prices stay low, investors should further analyze the viability of the proposed projects by the IOCs, in particular those in regions associated with high risks. Reserve replacement ratios as a metric for valuation, for example, should be adjusted to reflect a carbon constrained environment.

The equity values of the international oil companies include various sources of risk, including economic (financial and operational), political, and environmental. The expectations arising from changes in the industry will affect the companies based on their activities. Investors should have a complete view and analysis of the companies determine the specificities of their individual risk profiles.

This report has been limited to analyzing the immediate impact of the 2014 oil price drop on the IOCs. It thus recommends further analysis on the individual companies, the role of low oil prices on the specific projects and their strategic decisions. Additional research could expand on the impact on the energy sector as a whole, i.e. natural gas and power sectors in the US, Europe and Asia. Moreover, future analysis could revolve around the outcomes of COP21 and the response of the IOCs in terms of future investments and current assets, in particular if the price of oil stays suppressed.

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Appendix A – Company Profiles

ExxonMobil

Profile:	**Stock Forecast:**
Founded: 1999 *Headquarters: Texas, United States* *Type: Integrated Oil Company* *CEO: Rex W. Tillerson* *No of employees (2014): Approximately 75300.* *Revenue (2014): $364.8 billion (-7.35% change from last year)* *Profit (2014): $32.5 billion* *Net Profit Margin: 8.92%* *Market Capitalization(June 29, 2015): $350.6 billion*	

Source: CNN Money

History:

ExxonMobil's history dates back to the John D. Rockefeller's Standard Oil Trust. In 1911, when the Standard Oil Trust was dissolved, 34 companies were created. Standard Oil of New Jersey (Jersey Standard) and Standard Oil of New York (Socony), emerged as the chief predecessors of Exxon and Mobil. In 1931, Socony merged with Vacuum Oil Company. By 1955, Socony-Vacuum became known as the Socony Mobil Oil Company and in 1966, it was named Mobil Oil Corporation. On the other end, Jersey Standard was renamed Exxon Corporation in 1972 and the two officially merged in 1999 creating the present day ExxonMobil Corporation.

Currently, ExxonMobil is one of the largest publically traded international oil and gas companies. It holds the position as the largest global integrated refiner and lube basestock manufacturer. As of fourth quarter, 2014, the company held a resource base of about 91 billion oil-equivalent barrels. As an integrated oil and gas company it operates through three segments: upstream, downstream, and chemicals. With global operations, it is involved in oil and gas exploration, production, marketing, distribution, transportation and storage. It produces refined products such as gasoline, and aviation fuel, lubricants, and manufactures various petrochemicals. On the service side, ExxonMobil also operates service stations and convenience stores and is involved in technical advisory services. ExxonMobil's upstream portfolio includes operations in the US, Canada, South America, Europe, the Asia-Pacific, Australia, the Middle East, Russia, the Caspian region, and Africa (ExxonMobil Corporation, 2015).

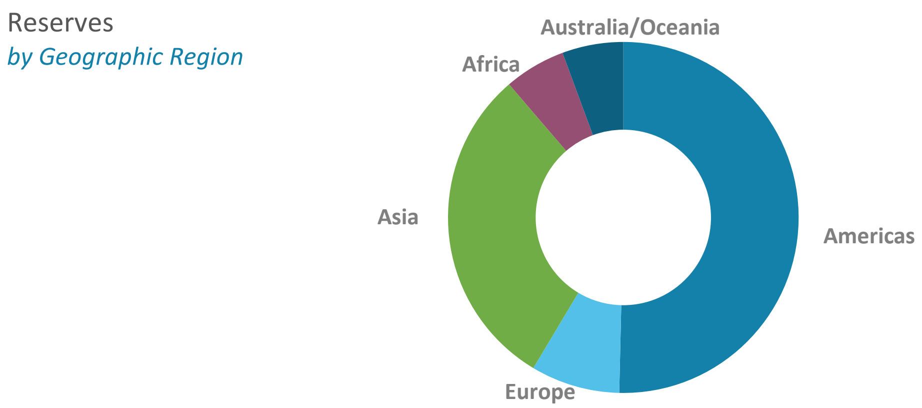
Financial Performance:

CORPORATE RESULTS FINANCIAL HIGHLIGHTS 2014	Earnings after Income Taxes	Average Capital Employed	Return on Average Capital Employed (%)	Capital & Exploration Expenditures
(millions of dollars)				
Upstream	27,548	164,965	16.7	32,727
Downstream	3,045	23,977	12.7	3,034
Chemical	4,315	22,197	19.4	2,741
Corporate and Financing	(2,388)	(8,029)	N.A.	35
Total	**32,520**	**203,110**	**16.2**	**38,537**

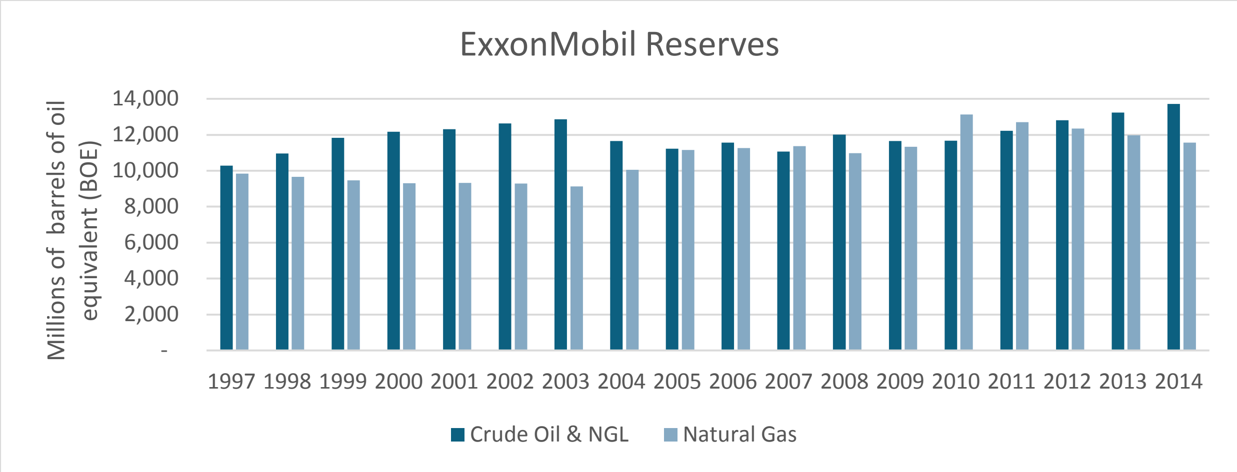
CORPORATE RESULTS HISTORICAL FINANCIAL HIGHLIGHTS	**2014**	2013	2012	2011	2010
(millions of dollars)					
Net income attributable to ExxonMobil	**32,520**	32,580	44,880	41,060	30,460
Cash flow from operations and asset sales(1)	**49,151**	47,621	63,825	66,478	51,674
Capital and exploration expenditures(1)	**38,537**	42,489	39,799	36,766	32,226
Research and development costs	**971**	1,044	1,042	1,044	1,012
Total debt at year end	**29,121**	22,699	11,581	17,033	15,014
Market valuation at year end	**388,398**	438,684	389,680	401,249	364,035

Source: Company Annual Reports and SEC Filings 1997-2014

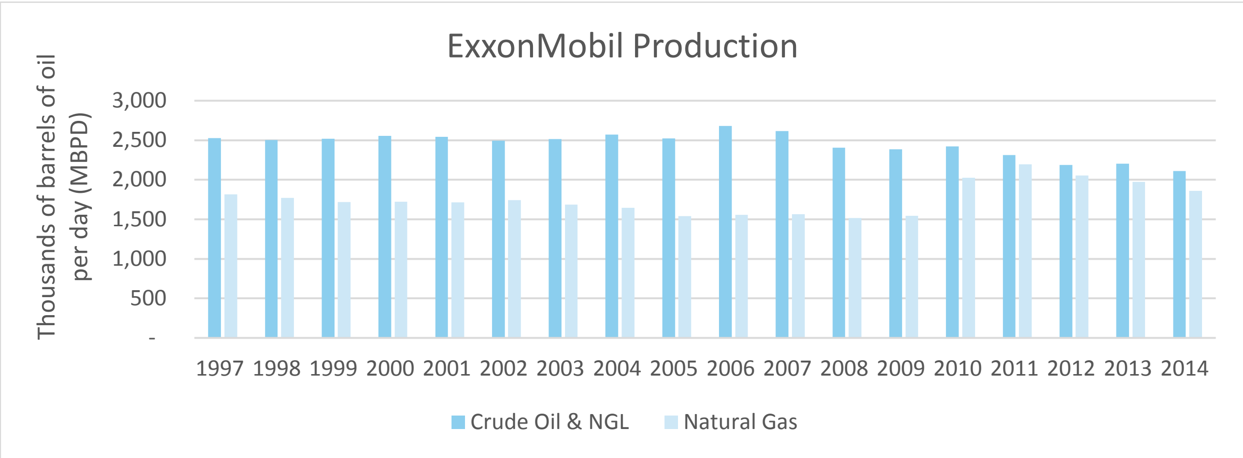
Operations:



Source: 2014 ExxonMobil Financial and Operating Review

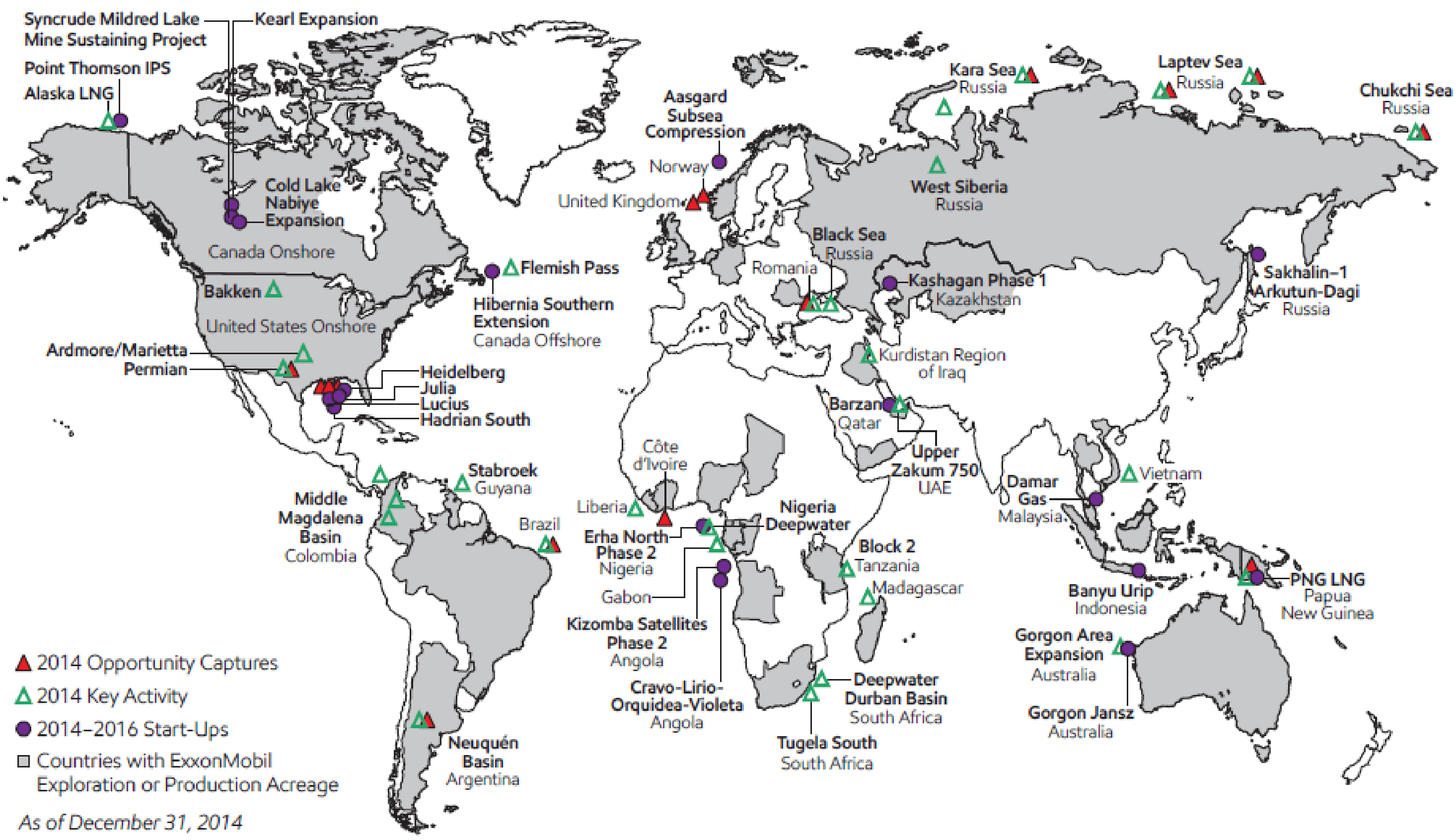


Source: OPEC Annual Statistical Bulletin 2014; Company Annual Reports and SEC Filings 1997-2014



Source: OPEC Annual Statistical Bulletin 2014; Company Annual Reports and SEC Filings 1997-2014

Global Upstream Portfolio:



Source: 2014 ExxonMobil Financial and Operating Review

Major Project Start-Ups[1]

	Project	Facility Capacity (Gross) Liquids (KBD)	Facility Capacity (Gross) Gas (MCFD)	ExxonMobil Working Interest (%)	
2012–2014 (Actual)					
Angola	Cravo-Lirio-Orquidea-Violeta (CLOV)	160	–	20	●
	Kizomba Satellites Phase 1	100	–	40	■
Australia	Kipper-Tuna	15	175	40	■
	Turrum	20	200	50	■
Canada	Cold Lake Nabiye Expansion[2]	50	–	100	■
	Hibernia Southern Extension	55	–	27	■
	Kearl Initial Development	110	–	100	■
	Syncrude Aurora North Mine Sustaining Project	215	–	25	▲
	Syncrude Mildred Lake Mine Sustaining Project	180	–	25	▲
Malaysia	Damar Gas	5	200	50	■
	Telok	–	430	50	■
Nigeria	Satellite Field Development Phase 1	70	–	40	■
	Usan	180	–	30	■
Papua New Guinea	PNG LNG	30	1,000	33	■
Russia	Sakhalin-1 Arkutun-Dagi[2]	90	–	30	■
U.S.	Lucius[2]	100	150	23	●
2015 (Projected)					
Angola	Kizomba Satellites Phase 2	85	–	40	■
Canada	Kearl Expansion	110	–	100	■
Indonesia	Banyu Urip	165	15	45	■
Nigeria	Erha North Phase 2	60	–	56	■
Norway	Aasgard Subsea Compression	40	415	14	●
Qatar	Barzan	90	1,400	7	▲
U.S.	Hadrian South	5	300	47	■
2016–2017 (Projected)					
Angola	AB32 Kaombo Split Hub	250	–	15	●
Australia	Gorgon Jansz[3]	20	2,765	25	●
Canada	Hebron	150	–	36	■
Kazakhstan	Kashagan Phase 1[4]	370	450	17	●
Russia	Sakhalin-1 Odoptu Stage 2	55	–	30	■
UAE	Upper Zakum 750	750	–	28	▲
2016–2017 (Projected) (continued)					
U.S.	Heidelberg	80	80	9	●
	Julia Phase 1	30	–	50	■
	Point Thomson Initial Production System	10	200	62	■
2018+ (Projected)					
Australia	Gorgon Area Expansion	10	915	25	●
	Scarborough	–	1,030	50	■
Canada	Aspen	90	–	100	■
	Cold Lake Grand Rapids	40	–	100	■
	Firebag	380	–	70	■
	Steam-Assisted Gravity Drainage (SAGD)	445	–	63-100	■
	Syncrude Aurora South Phases 1 and 2	210	–	25	▲
	Syncrude Mildred Lake Extension	210	–	25	▲
	West Coast Canada (WCC) LNG	–	1,600	100	■
Indonesia	Cepu Gas	5	180	41	●
	Natuna[5]	–	1,100		■
Iraq	West Qurna I	1,600	–	33	▲
Kazakhstan	Kashagan Future Phases	1,260	–	17	●
	Tengiz Expansion	655	–	25	●
Nigeria	Bonga North	200	–	20	●
	Bonga Southwest	200	–	16	●
	Bosi	140	315	56	■
	Satellite Field Development Phase 2	80	–	40	■
	Uge	110	20	20	■
	Usan Future Phases	50	–	30	■
Romania	Domino	–	630	50	■
Russia	Sakhalin-1 Future Phases	–	800	30	■
Tanzania	Tanzania Block 2	–	1,000	35	●
U.S.	Alaska LNG	60	3,500	36	▲
	Golden Pass Products LNG Export	–	2,500	30	▲
	Julia Phase 2	30	–	50	■
Vietnam	Ca Voi Xanh	3	375	64	■

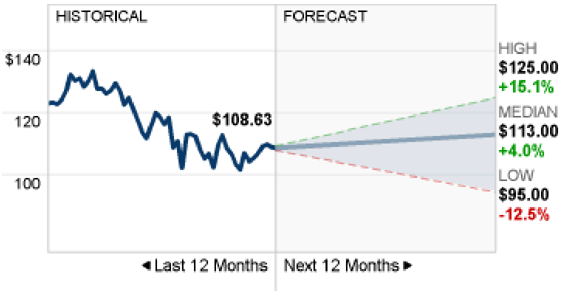
(1) The term "project" as used in this publication can refer to a variety of different activities and does not necessarily have the same meaning as in any government payment transparency reports.
(2) Projects completed in 2014 with first production in early 2015.
(3) Start-up target year-end 2015 with first ExxonMobil volumes in early 2016.
(4) Operations were suspended in 2013.
(5) Working interest pending final agreements.

KBD = Thousand barrels per day
MCFD = Million cubic feet per day

■ ExxonMobil Operated
● Co-Venturer Operated
△ Joint Operations

Source: 2014 ExxonMobil Financial and Operating Review

Chevron

Profile:	**Stock Forecast:**
Founded: 1879 *Headquarters: California, United States* *Type: Integrated Oil Company* *CEO: John S. Watson* *No of employees (2014): Approximately 64700.* *Revenue (2014): $191.8 billion (-9.45% change from last year)* *Profit (2014): $19.2 billion* *Net Profit Margin: 10.03%* *Market Capitalization (June 29, 2015): $185.4 billion*	

Source: CNN Money

History:

Originally established in 1879 in California as the Pacific Coast Oil Company, Chevron, like many others was acquired by the Standard Oil Trust in the early twentieth century. However by 1911, upon the breakup of Standard Oil, it emerged as the independent "Standard Oil Company of California". In the 1930s it expanded internationally, with oil exploration efforts in Bahrain and Saudi Arabia, followed by Asia, Africa, Europe (under the name Caltex) and soon thereafter Central America. The following decade, the company made discoveries in Indonesia, Australia, UK North Sea, and the Gulf of Mexico. In the 1960s, the company acquired Standard Oil Company (Kentucky), and dissolved its Caltex (Western Europe) operations into two companies, Socal and Texaco. By 1977, it merged six of its domestic subsidiaries into one, creating Chevron USA. In the wave of mergers of the 1980s, Chevron joined Gulf Oil Corp. doubling the company's size and officially renaming the company to Chevron.

Chevron is one of the major integrated energy companies, with operations across various segments of the petroleum industry. Its activities include: exploration and production of crude oil and natural gas; refine, market and transport fuels and lubricants; manufacture and sell petrochemicals; generate power and produce geothermal energy; and provide renewable energy and energy efficiency solutions. The company has operations and projects in North America, South America, Europe, Africa, Asia, and Australia (Chevron Corporation, 2015)

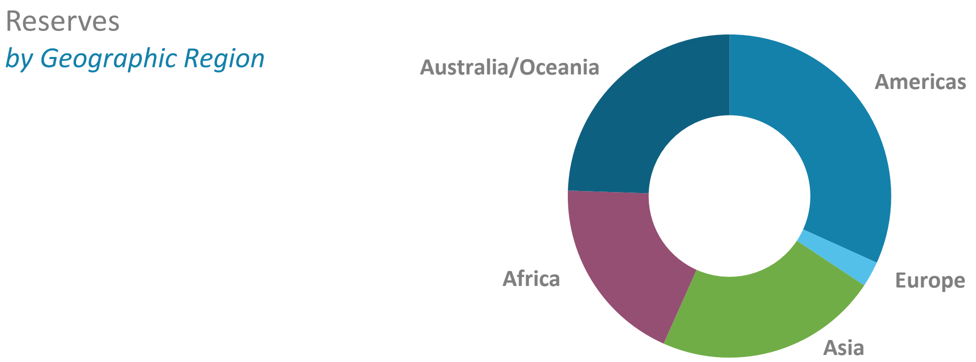
Financial Performance:

CORPORATE RESULTS FINANCIAL HIGHLIGHTS 2014	Earnings after Income Taxes	Average Capital Employed	Return on Average Capital Employed (%)	Capital & Exploration Expenditures
(millions of dollars)				
Upstream	16,893	148,972	N.A.	37,115
Downstream	4,336	25,050	N.A.	2,590
All Other	(1,988)	9,987	N.A.	611
Total	**19,241**	**184,009**	**10.9%**	**40,316**

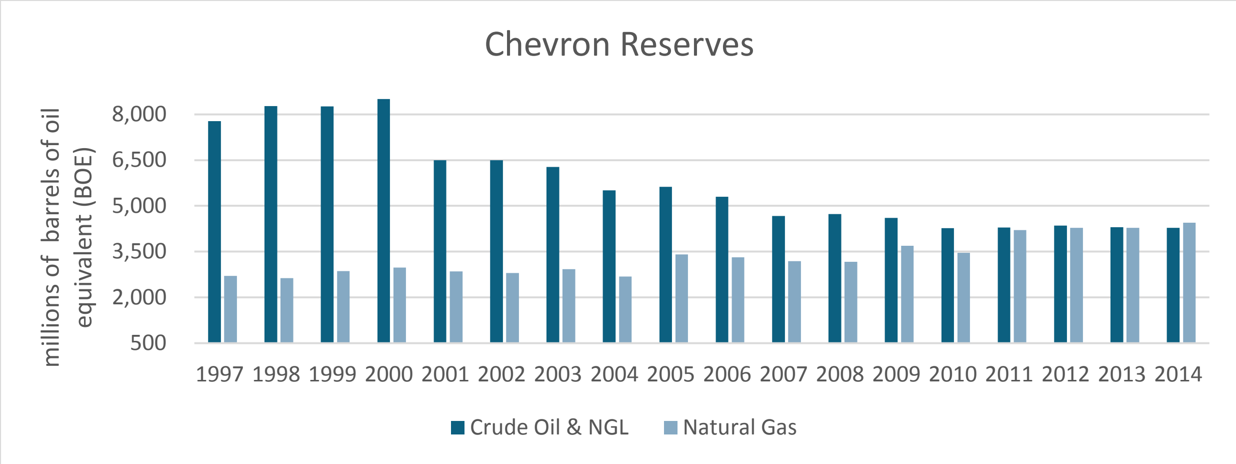
CORPORATE RESULTS HISTORICAL FINANCIAL HIGHLIGHTS	2014	2013	2012	2011	2010
(millions of dollars)					
Net income attributable to Chevron	**19,241**	21,423	26,179	26,895	19,024
Cash flow from operations and asset sales	**31,475**	35,002	38,812	41,095	31,359
Capital and exploration expenditures	**40,316**	41,877	34,229	29,066	21,755
Research and development costs	**707**	750	648	627	526
Total debt at year end	**27,818**	20,431	12,192	10,152	11,476
Market valuation at year end	**388,398**	438,684	389,680	401,249	364,035

Source: Company Annual Reports and SEC Filings 1997-2014

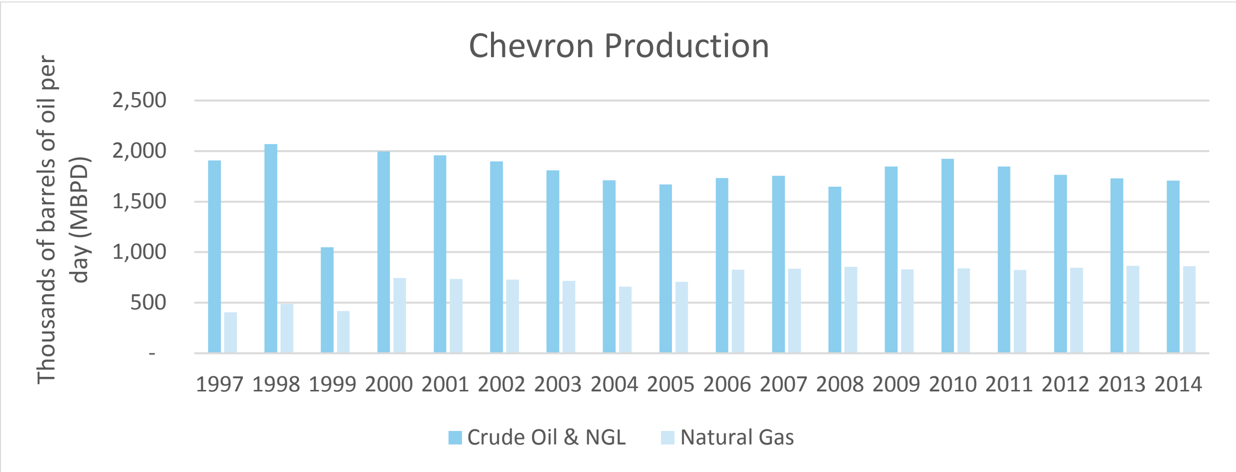
Operations:



Source: Chevron Corporation 2014 Supplement to the Annual Report



Source: OPEC Annual Statistical Bulletin 2014; Company Annual Reports and SEC Filings 1997-2014



Source: OPEC Annual Statistical Bulletin 2014; Company Annual Reports and SEC Filings 1997-2014

Global Upstream Portfolio:

Source: Chevron Corporation 2014 Supplement to the Annual Report

Major Capital Projects

Year of Start-Up/Location	Project	Ownership Percentage	Operator	Facility Design Capacity[1] Liquids (MBPD)	Natural Gas (MMCFPD)
2014					
Azerbaijan	Chirag Oil Project	11.3	Other	183	285
Bangladesh	Bibiyana Expansion	100.0	Chevron	4	300
Kazakhstan/Russia	CPC Expansion	15.0	Affiliate	670[2]	–
Nigeria	EGTL	75.0	Chevron	33[3]	–
United States	Jack/St. Malo	40.6-51.0	Chevron	170	42
	Tubular Bells	42.9	Other	58-67[4,5]	–
2015-2017					
Angola	Angola LNG Plant[6]	36.4	Affiliate	63[7]	670[7]
	Mafumeira Sul	39.2	Chevron	150	350
	Nemba ESR Stage 1 & 2	39.2	Chevron	9[4]	–
Angola-Republic of the Congo	Lianzi	31.3	Chevron	46	–
Australia	Gorgon LNG Trains 1-3	47.3	Chevron	20	2,580
	Wheatstone LNG Trains 1-2	80.2/64.1[8]	Chevron	30	1,608
Canada	Hebron	26.6	Other	150	–
	Hibernia SW Ben Nevis Avalon	26.9	Other	Maintain capacity	
China	Chuandongbei	49.0	Chevron	–	558[7]
Nigeria	Agbami 3	67.3	Chevron	Maintain capacity	
	Escravos Gas Plant Phase 3B	40.0	Chevron	–	120[9]
	Sonam Field Development	40.0	Chevron	30[4]	215[4]
Republic of the Congo	Moho Nord	31.5	Other	140[4]	–
United Kingdom	Alder	73.7	Chevron	14	110
	Clair Ridge	19.4	Other	120	100
United States	Big Foot	60.0	Chevron	75	25
2018+					
Canada	Kitimat LNG	50.0	Chevron	–	1,600
Indonesia	Gendalo-Gehem	~63.0	Chevron	47	1,100
Kazakhstan	TCO Future Growth Project	50.0	Affiliate	250-300[4]	–
	TCO Wellhead Pressure Management Project	50.0	Affiliate	Maintain capacity	
Nigeria	Bonga SW/Aparo	19.6	Other	225	–
Partitioned Zone	Central Gas Utilization Project	50.0	Chevron	–	Eliminate flaring
	Wafra Steamflood Stage 1	50.0	Chevron	80	–
Thailand	Ubon	35.0	Chevron	35	115
United Kingdom	Captain Enhanced Oil Recovery	85.0	Chevron	Maintain capacity	
	Rosebank	40.0	Chevron	100	80
United States	Buckskin/Moccasin	55.0/87.5	Chevron	30[10]	15[10]
	Jack/St. Malo Stage 2	40.6-51.0	Chevron	Maintain capacity	
	Stampede	25.0	Other	80	40

[1] MBPD – thousands of barrels per day; MMCFPD – millions of cubic feet per day.
[2] Represents incremental throughput capacity. Staged ramp-up with full capacity available in 2016.
[3] Represents total plant offtake of liquids.
[4] Represents expected total daily production.
[5] Expressed in thousands of oil-equivalent barrels per day.
[6] Plant restart in 2015.
[7] Represents facility design outlet capacity.
[8] Represents the company's ownership in the offshore licenses and LNG facilities, respectively.
[9] Excludes incremental crude oil production enabled by this project.
[10] Represents firm capacity rights to a third-party production facility.

Source: Chevron Corporation 2014 Supplement to the Annual Report

ConocoPhillips

Profile:	**Stock Forecast:**
Founded: 2002 *Headquarters: Texas, United States* *Type: Oil and Gas Production* *CEO: Ryan M. Lance* *No of employees (2014): 92,100 Approximately* *Revenue (2014): $52 billion (-9.27% change from last year)* *Profit (2014): $6.9 billion* *Net Profit Margin: 11.03 %* *Market Capitalization(June 29, 2015): $76.7 billion*	

Source: CNN Money

History:

ConocoPhillips was officially formed in 2001 with a merger between Conoco and Phillips Petroleum Company. Conoco, as a separate entity, was established in 1875 as the Continental Oil and Transportation Company and acquired by Standard Oil, the following decade. When Standard Oil was dissolved, the company that emerged was known as Continental Oil Company. The company manufactured aviation gasoline during World War II for the US Government, and later expanded into coal, chemicals, fertilizers and minerals. It was officially a subsidiary of Dupont from 1981 to 1998. Similarly Phillips Petroleum Company (Phillips) was founded in 1917 and was the first to develop aviation refueling trucks, propane for residential use, and a multi-product pipeline among other products. In 2000 it became part of the Duke Energy midstream segment and later with ChevronTexaco to establish the Chevron Philips Chemical Company. The same year it acquired Arco Alaska and Tosco Corporation the following year. Conoco and Phillips officially merged in 2002, creating ConocoPhillips, the sixth-largest publicly traded oil company in the world and the third-largest in the U.S. at the time.

Currently, ConocoPhillips is one of the world's largest independent exploration and production (E&P) companies. It operates in the US, Norway, the UK, Canada, Australia, offshore Timor-Leste in the Timor Sea, Indonesia, Malaysia, China, Libya, Qatar, and Russia. Its activities are divided into six categories defined by the geographic region. These include: the Lower 48 and Latin America, Europe, Alaska, Asia Pacific and Middle East, Canada and other international. In 2012, the company was split into two separate corporations, Phillips 66 for refining and marketing and ConocoPhillips for exploration and production. Prior to the spinoff of the downstream segment, ConocoPhillips was considered one of the supermajors. Today, it is still sometimes characterized as one due to its sheer size. The split made the ConocoPhillips the largest E&P company in the world based on proved reserves and production of liquids and natural gas (ConocoPhillips, 2015a).

Financial Performance:

CORPORATE RESULTS FINANCIAL HIGHLIGHTS 2014	Earnings	Average Capital Employed	Return on Capital Employed (%)	Capital & Exploration Expenditures
(millions of dollars)				
Alaska	2,041	N.A.	N.A.	1,564
Lower 48	(22)	N.A.	N.A.	6,054
Canada	940	N.A.	N.A.	2,340
Europe	804	N.A.	N.A.	2,521
Asia Pacific and Middle East	2,939	N.A.	N.A.	3,877
Other International	(90)	N.A.	N.A.	539
Corporate and Other	(874)	N.A.	N.A.	249
Total	**6,869***	**75,773**	**9%**	**17,144**

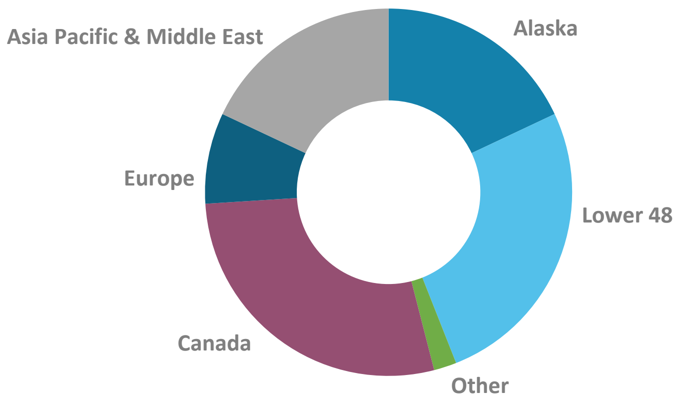
**includes discontinued operations*

CORPORATE RESULTS HISTORICAL FINANCIAL HIGHLIGHTS	**2014**	2013	2012	2011	2010
(millions of dollars)					
Net income attributable to ConocoPhillips	**6,869**	9,156	8,428	12,436	11,358
Cash flow from operations and asset sales	**16,735**	16,087	13,922	19,646	17,045
Capital and exploration expenditures	**17,144**	16,918	15,722	12,947	9,265
Research and development costs	**263**	258	221	193	172
Total debt at year end	**22,565**	21,662	21,725	22,623	23,592
Market valuation at year end *(billion)*	**86.02**	85.99	70.35	73.83	75.21

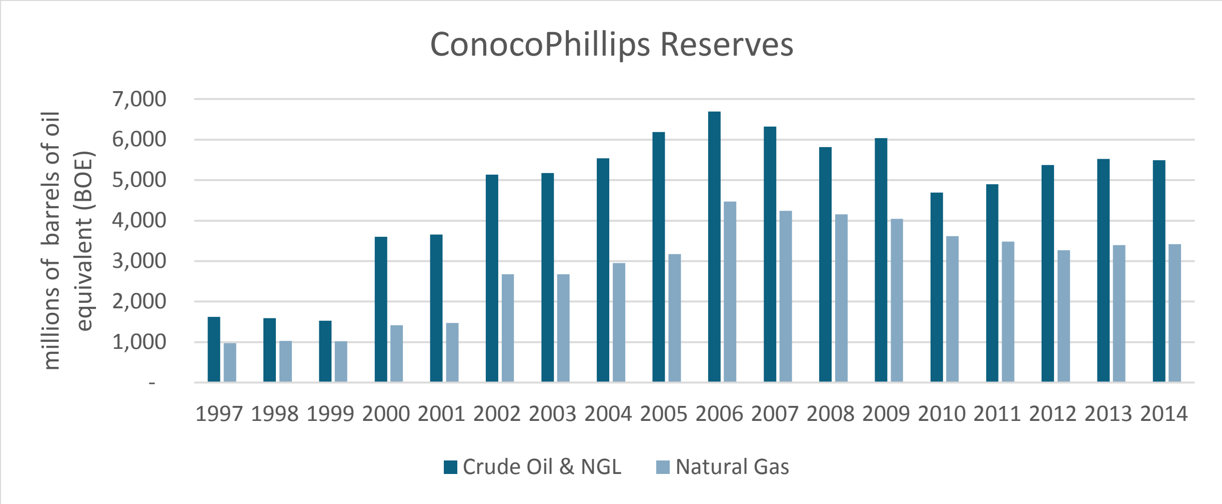
Source: Company Annual Reports and SEC Filings 1997-2014

Operations:

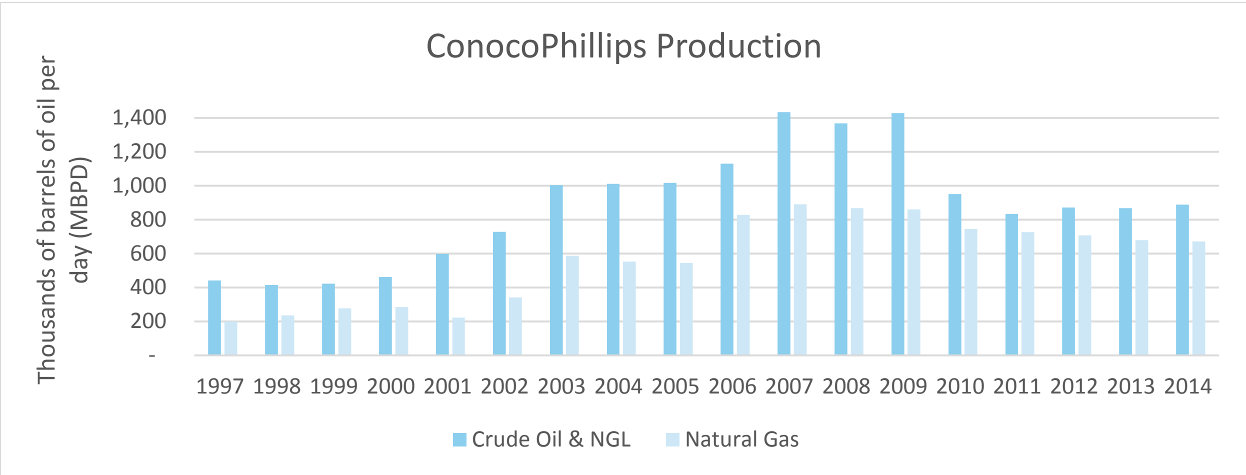
2014 Reserves
by Geographic Region



Source: ConocoPhillips Factsheet Overview 2014

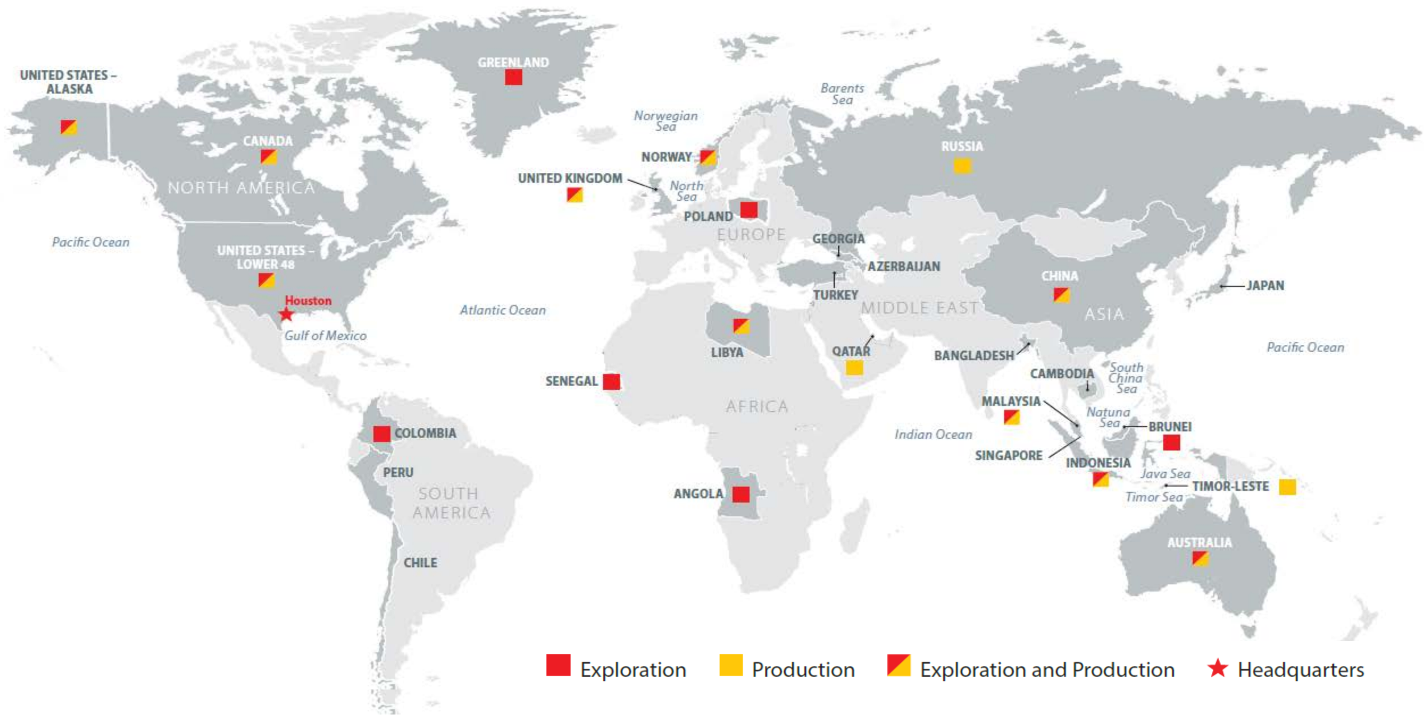


Source: OPEC Annual Statistical Bulletin 2014; Company Annual Reports and SEC Filings 1997-2014



Source: OPEC Annual Statistical Bulletin 2014; Company Annual Reports and SEC Filings 1997-2014

Global Upstream Portfolio:



Source: ConocoPhillips Factsheet Overview 2014

BP

Profile: **Stock Forecast:**

Founded: 1909
Headquarters: London, UK.
Type: Private Integrated Oil and gas Company
CEO: Bob Dudley
No of employees (2014): 84500.
Revenue (2014): $353.57 billion (-21% change from last quarter)
Net Income (2014): $3.78 billion
Net Profit Margin: 1.07 %
Market Capitalization (June 29, 2015): $126 billion

Source: CNN Money

History:

BP PLC (British Petrochemical Corporation) started in 1909 as the Anglo-Persian Oil Company, Ltd. At the time BP was the first company to make an oil discovery in the Middle East. By 1935, the company changed its name to the Anglo-Iranian Oil Company Ltd. In the 1950s, BP expanded its operations in petrochemicals, however following the nationalization of the Iranian oil industry, the company emerged as part of a new consortium called British Petroleum Company Limited. During the world wars, the British government was the principal owner of the company, up to 1987. Like the other majors, in the 1970s, BP diversified its portfolio by expanding operations in the North Sea and Alaska, and through energy sources like coal, gas and solar. It also decreased its refining and chemical operations and acquired a nutrition business to form BP Nutrition, to consolidate its operations in household cleaning products. In 1982, it changed its name to British Petroleum Company PLC. In the 1980s, the recession forced the company to reorganize once again. In 1988, it sold its IT subsidiary, Scicon, in 1989 all mineral interests, in 1990 the coal business and lastly in 1992, the nutrition business. In 1998, following a merger with Amoco it was renamed to BP Amoco, and soon after to BP PLC.

Today, BP is one of the largest vertically integrated oil and gas companies in the world. Its core activities include oil exploration and production, marketing and trading of natural gas, power and natural gas liquids. It operates in Europe, Asia Pacific, Africa and the Americas (BP Plc, 2015).

Financial Performance:

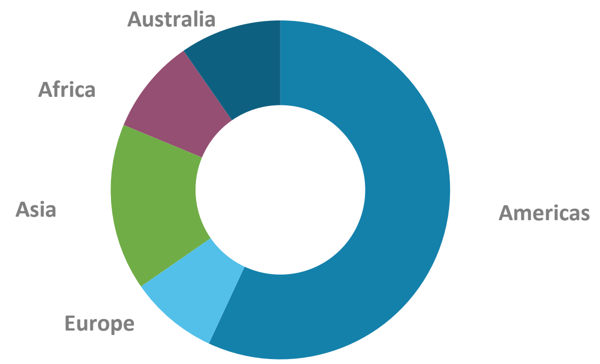
CORPORATE RESULTS FINANCIAL HIGHLIGHTS 2014	Earnings before Interest and Tax	Average Capital Employed	Return on Average Capital Employed (%)	Capital & Exploration Expenditures
(millions of dollars)				
Upstream	8,934	107,524	N.A.	19,772
Downstream	3,738	38,878	N.A.	3,106
Other business and corporate	(2,010)	20,689	N.A.	903
Total	**10,662**	**167,091**	**8.1%**	**23,781**

CORPORATE RESULTS HISTORICAL FINANCIAL HIGHLIGHTS	**2014**	2013	2012	2011	2010
(millions of dollars)					
Net income attributable to BP	**4,003**	23,758	11,251	26,097	(3,324)
Cash flow from operations and asset sales	**32,754**	21,100	20,479	22,154	13,616
Capital and exploration expenditures	**23,781**	36,612	25,204	31,959	23,016
Research and development costs	**663**	707	674	636	780
Total debt at year end	**52,854**	48,192	48,800	44,208	45,336
Market valuation at year end	**118,960**	150,640	132,360	136,310	137,690

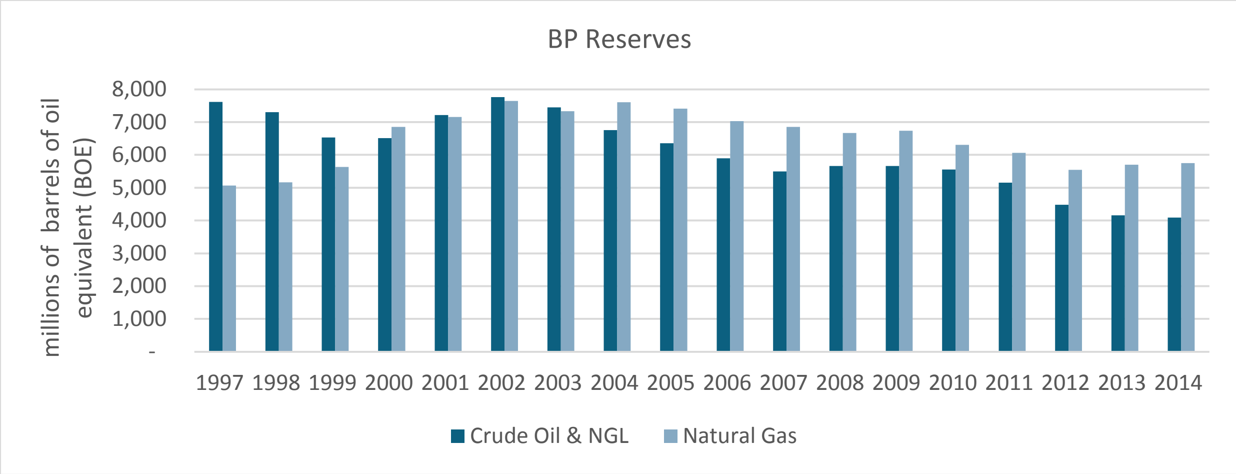
Source: Company Annual Reports and SEC Filings 1997-2014

Operations:

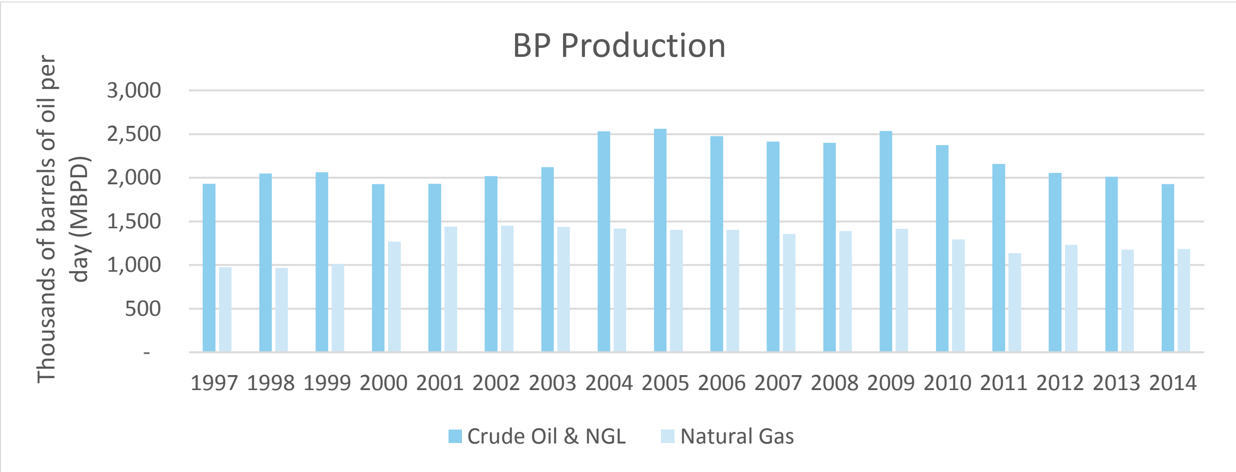
Reserves
by Geographic Region



Source: 2014 BP Annual Report

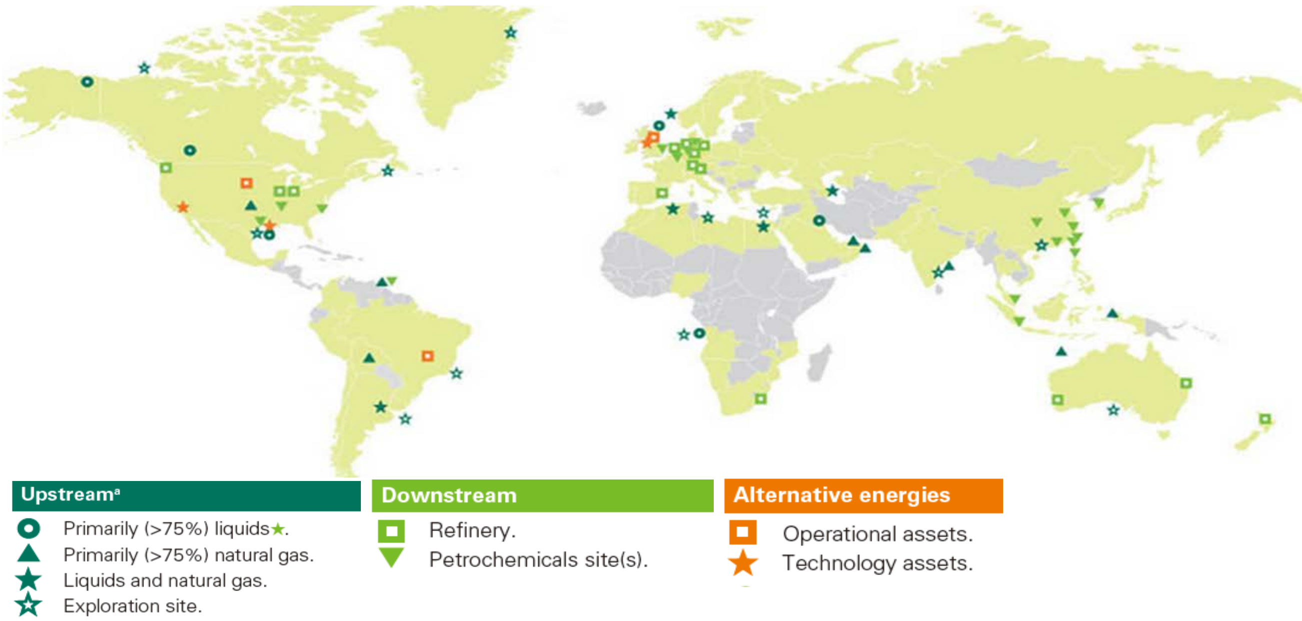


Source: OPEC Annual Statistical Bulletin 2014; Company Annual Reports and SEC Filings 1997-2014



Source: OPEC Annual Statistical Bulletin 2014; Company Annual Reports and SEC Filings 1997-2014

Global Upstream Portfolio:



Source: 2014 Investor Presentations

Major Upstream Projects						
Project Name	**Location**	**Operator**	**Partners**	**Project Type**	**Start-up**	**Gross-Production (peak)**
Clair Ridge	UK - North Sea	BP	BP (29%), Shell (28%), Conoco Phillips (24%), Chevron (19%)	Conventional oil	2017	104 mboed
Greater Plutonio Phase 3	Angola	BP	BP (50.0%), SSI (50.0%)	Deepwater oil	2015	22 mboed
In Amenas Compression	Algeria	In Amenas joint venture	Sonatrach (8.2%), BP (45.9%), Statoil (45.9%)	Conventional gas	2016	69 mboed
In Salah Southern Fields	Algeria	In Salah joint venture	Sonatrach (35%), BP (33.15%), Statoil (31.85%)	Conventional gas	2015	73 mboed
Juniper	Trinidad	BP	100% owned by BP Trinidad and Tobago which is owned by BP (70%) and Repsol (30%)	Conventional gas	2017	94 mboed
Kizomba Satellites Phase 2	Angola	ExxonMobil	BP (26.7%), ExxonMobil (40%), ENI (20%), Statoil (13.3%)	Deepwater oil	2015	59 mboed
Oman Khazzan	Oman	BP	BP (60%), Oman Government (40%) via nominated entity	Tight gas	2017	200 mboed
Persephone	Australia	Woodside	BP (16.67%), BHP, Chevron, Shell, Woodside and Mitsubishi-Mitsui (each with 16.67%)	Conventional gas	2017	47 mboed
Point Thomson	US - Alaska	ExxonMobil	ExxonMobil (62%), BP (32%), ConocoPhillips (5%), minors 1%	Conventional gas	2016	10 mboed
Quad 204	UK - North Sea	BP	BP (36.3%), Shell (54.0%), OMV UK Ltd (9.7%)	Deepwater oil	2016	122 mboed
Shah Deniz 2	Azerbaijan	BP	BP (28.8%), SOCAR (16.7%), Statoil (15.5%), Lukoil (10%), NICO (10%), TPAO (19%)	Conventional gas	2018	370 mboed
Thunder Horse South Expansion	US - Gulf of Mexico	BP	BP (75.0%), ExxonMobil (25.0%)	Deepwater oil	2017	42 mboed
Thunder Horse Water Injection	US - Gulf of Mexico	BP	BP (75.0%), ExxonMobil (25.0%)	Deepwater oil	2016	42 mboed
Western Flank A	Australia	Woodside	BP (16.67%), BHP, Chevron, Shell, Woodside and Mitsubishi-Mitsui (16.67% each)	Conventional gas	2015	78 mboed

Source: 2014 BP Investor Presentation

Royal Dutch Shell

Profile:	**Stock Forecast:**
Founded: 1907 *Headquarters: The Hague, Netherlands* *Type: Private* *CEO: Ben Van Beurden* *No of employees (2015): 92000* *Revenue (2014): $419.4 billion (-6.79% change from last year)* *Profit (2014): $14.8 billion* *Net Profit Margin: 3.53%* *Market Capitalization(June 29, 2015): $116.0 billion*	

Source: CNN Money

History:

Royal Dutch Shell was officially formed in 1907 with a merger of two former competitors, Royal Dutch Petroleum and the Shell Transport and Trading Company. The merger was orchestrated to compete against Standard Oil. The company grew by expanding to Europe, Africa and the Americas. It added chemicals to its portfolio by the 1930s. In the 1960s it became a key player in the Middle East, but during the 1970s crisis the Shell diversified by becoming involved in coal, nuclear power, and metals. However, the nuclear prospects diminished after the 1979 Three Mile Island accident forcing Shell to divest. The high prices pushed for further exploration efforts elsewhere. During the 1970s and well into the 1980s, Shell began to focus on offshore exploration with major project developments in the North Sea and later the Gulf of Mexico. In the 1990s it also added LNG to its business operations.

Shell operates across nearly all segments of the industry including oil and gas exploration and production, transportation, and marketing of natural gas, electricity, oil products and chemicals. Additionally, the company holds interests in renewables like wind, solar and hydrogen. It falls under the category of a "supermajor", a multinational corporation with operations in over 70 countries (Royal Dutch Shell Plc, 2015).

Financial Performance:

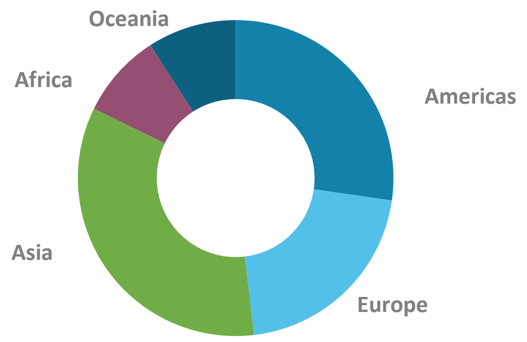
CORPORATE RESULTS FINANCIAL HIGHLIGHTS 2014	Earnings	Average Capital Employed	Return on Average Capital Employed (%)	Capital & Exploration Expenditures
(millions of dollars)				
Upstream	15,841	150,819	N.A.	26,218
Downstream	3,411	48,925	N.A.	5,520
Corporate	(156)	18,582	N.A.	116
Total	**19,096**	**218,326**	**7.1%**	**31,854**

CORPORATE RESULTS HISTORICAL FINANCIAL HIGHLIGHTS	**2014**	2013	2012	2011	2010
(millions of dollars)					
Net income attributable to ExxonMobil	**19,041**	16,745	27,164	28,533	18,643
Cash flow from operations and asset sales	**45,044**	40,440	46,140	36,771	27,350
Capital and exploration expenditures	**31,854**	40,145	32,572	26,301	26,940
Research and development costs	**1,222**	1,318	1,307	1,125	1,019
Total debt at year end	**38,332**	36,218	29,921	30,463	34,381
Market valuation at year end	**227,440**	235,820	225,840	241,020	206,160

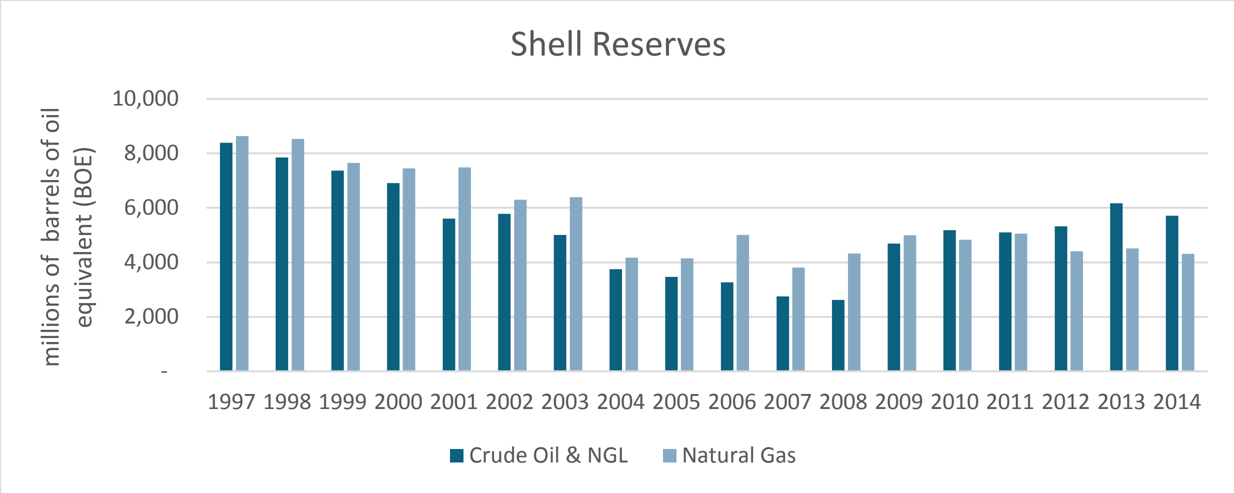
Source: Company Annual Reports and SEC Filings 1997-2014

Operations:

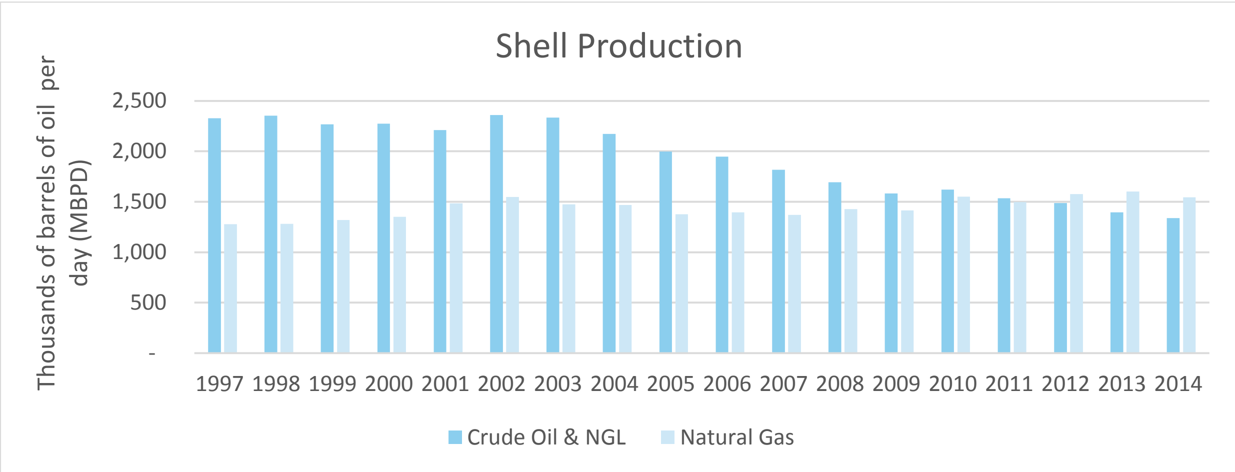
Reserves
by Geographic Region



Source: Shell 2014 Annual Report

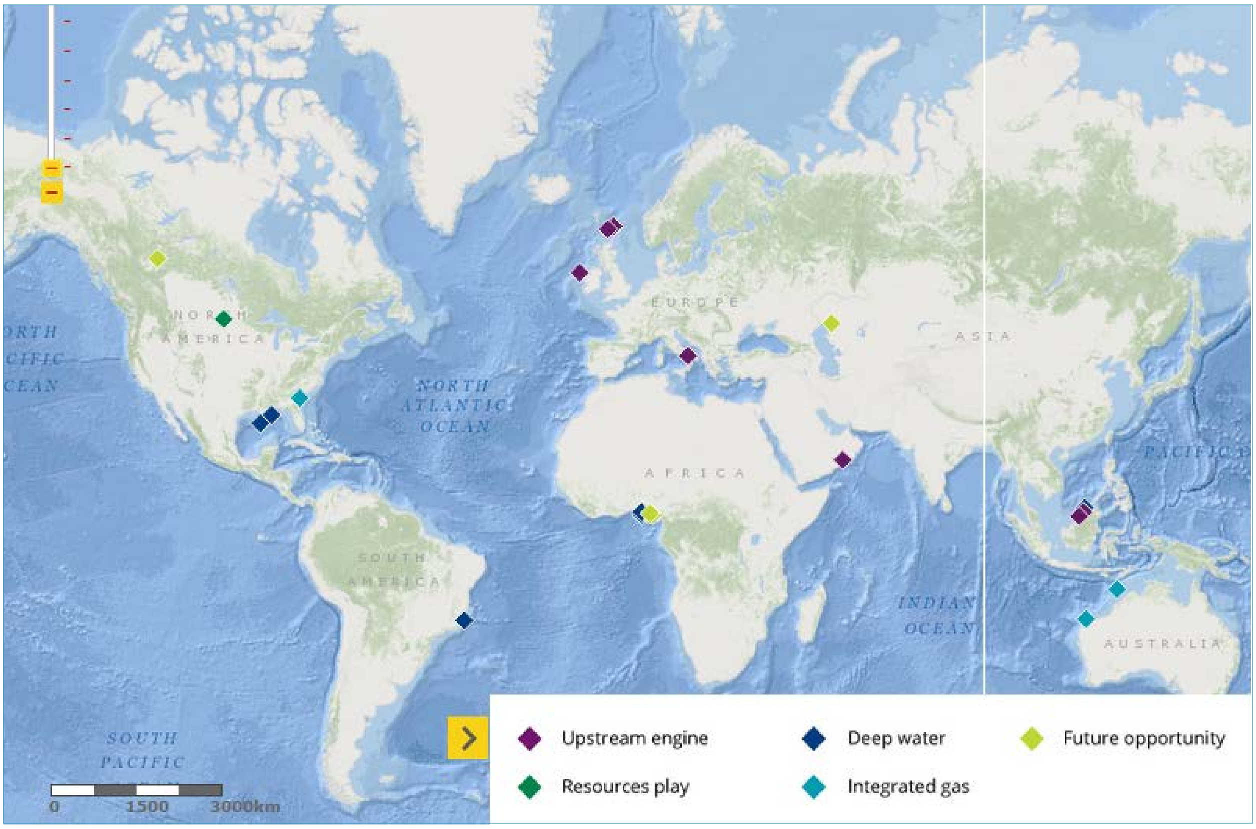


Source: OPEC Annual Statistical Bulletin 2014; Company Annual Reports and SEC Filings 1997-2014



Source: OPEC Annual Statistical Bulletin 2014; Company Annual Reports and SEC Filings 1997-2014

Global Portfolio:



KEY UPSTREAM PROJECTS UNDER CONSTRUCTION

Start-up	Project	Country	Shell share (direct & indirect) (%)	Peak production 100% (kboe/d)	LNG 100% capacity (mtpa)	Products	Legend	Strategic theme	Shell operated
2015–2016	BC-10 Phase 3	Brazil	50	28				Deep water	●
	Bonga Main Phase 3	Nigeria	55	40				Deep water	●
	Corrib	Ireland	45	45				Upstream engine	●
	Erha North Phase 2	Nigeria	44	45				Deep water	
	Forcados Yokri Integrated Project (FYIP)	Nigeria	30	50				Future opportunities	●
	Gbaran-Ubie Phase 2	Nigeria	30	150				Future opportunities	●
	Gorgon LNG	Australia	25	450	~15			Integrated gas	
	ML South	Brunei	35	35				Upstream engine	
	NA LRS/tight gas	USA/Canada	various	105[A]				Resources plays	●
	Stones	USA	100	50				Deep water	●
2017–2019	Baronia/Tukau Timur	Malaysia	40	65				Upstream engine	
	Carmon Creek Exp Phase 1&2	Canada	100	80				Future opportunities	●
	Clair Phase 2	UK	28	100				Upstream engine	
	Coulomb	USA	100	20				Deep water	●
	Kashagan Phase 1	Kazakhstan	17	300				Future opportunities	
	Malikai	Malaysia	35	60				Deep water	●
	MMLS LNG	USA	49		2.5			Integrated gas	
	Prelude FLNG	Australia	68	110	3.6	1.7 mtpa NGLs		Integrated gas	●
	Rabab Harweel Integrated Project	Oman	34	40				Upstream engine	
	Schiehallion Redevelopment	UK	55	125				Upstream engine	
	Southern Swamp AG	Nigeria	30	30				Future opportunities	●
	Tempa Rossa	Italy	25	45				Upstream engine	
	Trans Niger Pipeline Loopline (TNPL)	Nigeria	30	45				Future opportunities	●

[A] Shell share subject to investment.

Source: 2014 Royal Dutch Shell Investors' Handbook 2010-2014

Total SA

Profile:	**Stock Forecast:**
Founded: 1924 *Headquarters: Paris, France* *Type: Integrated Oil Company* *CEO: Patrick Pouyanné* *No of employees (2014): Approximately 100,3.* *Revenue (2014): $208.8 billion (-8.60% change from last year)* *Profit (2014): $4.2 billion* *Net Profit Margin: 2.00%* *Market Capitalization (June 29, 2015): $118.6 billion*	

Source: CNN Money

History:

Total's history dates back to the 1920s, with the creation of Compagnie Française des Pétroles (CFP) ("French Petroleum Company"). In its beginnings, the company was mainly active in exploration and production in the Middle East. By 1929 it expanded its exploration efforts internationally, and diversified its portfolio to include refining, petroleum product marketing, and chemicals. In made its first offshore discovery in Gabon, and by 1975 like other majors invested into solar energy. In 2011, Total further developed its renewable investments by acquiring 60% of the US company SunPower. In 1985 it was renamed Total Compagnie Française des Pétroles, or Total CFP and in 1991 to Total when it was listed on the New York Stock Exchange. From 1999 to 2000, it acquired Petrofina of Belgium and the French oil firm Elf Aquitaine.

TOTAL S.A. is one of the major global integrated oil and gas companies. The company's operations extend to upstream and downstream segments. Furthermore, Total participates in the chemicals, coal mining, and power generation businesses. The company has operations in more than 130 countries. (Total SA, 2014).

Financial Performance:

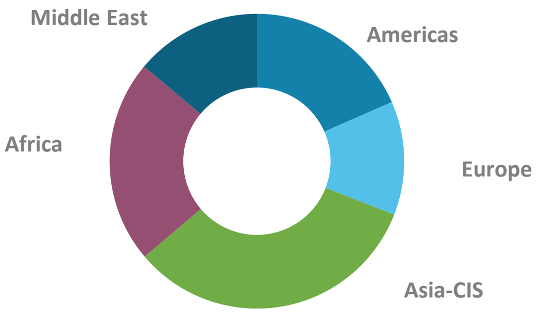
CORPORATE RESULTS FINANCIAL HIGHLIGHTS 2014	Earnings after Income Taxes	Average Capital Employed	Return on Average Capital Employed (%)	Capital & Exploration Expenditures
(millions of dollars)				
Upstream	10,504	98,013	10.7	26,520
Refining & Chemicals	2,489	16,602	15.0	2,022
Marketing & Services	1,254	9,438	13.3	1,818
Corporate		(2,564)	N.A	149
Total	**14,247**	**121,489**	**11.1**	**30,509**

CORPORATE RESULTS HISTORICAL FINANCIAL HIGHLIGHTS	**2014**	2013	2012	2011	2010
(millions of dollars)					
Net income attributable to Total	**4,244**	11,228	13,648	17,400	14,740
Cash flow from operations and asset sales	**25,608**	28,513	28,858	27,193	24,516
Capital and exploration expenditures	**30,509**	34,431	29,475	34,161	21574
Research and development costs	**1,353**	1,260	1,034	1,080	948
Net financial debt at year end	**28,754**	23,612	20,541	20,311	N.A
Market valuation at year end	**122.1**	145.7	123.1	120.8	125.7

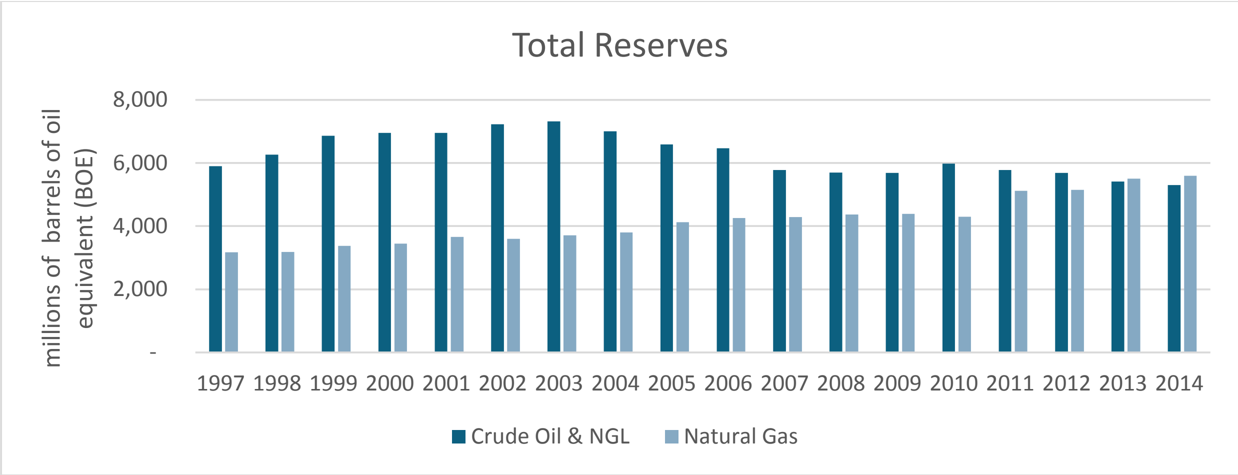
Source: Total Factbook 2014

Operations:

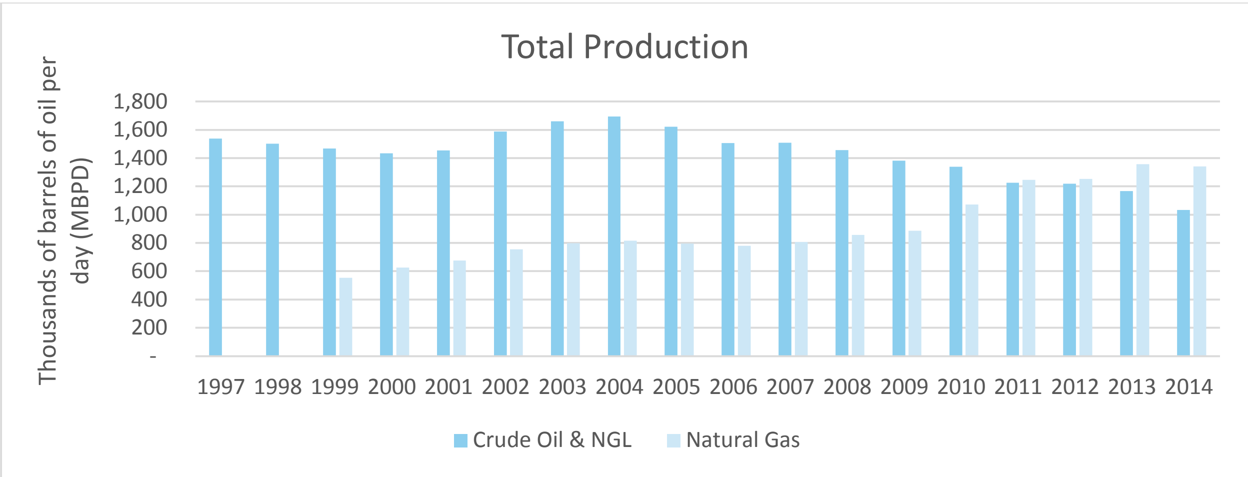
Reserves
by Geographic Region



Source: Total Factbook 2014

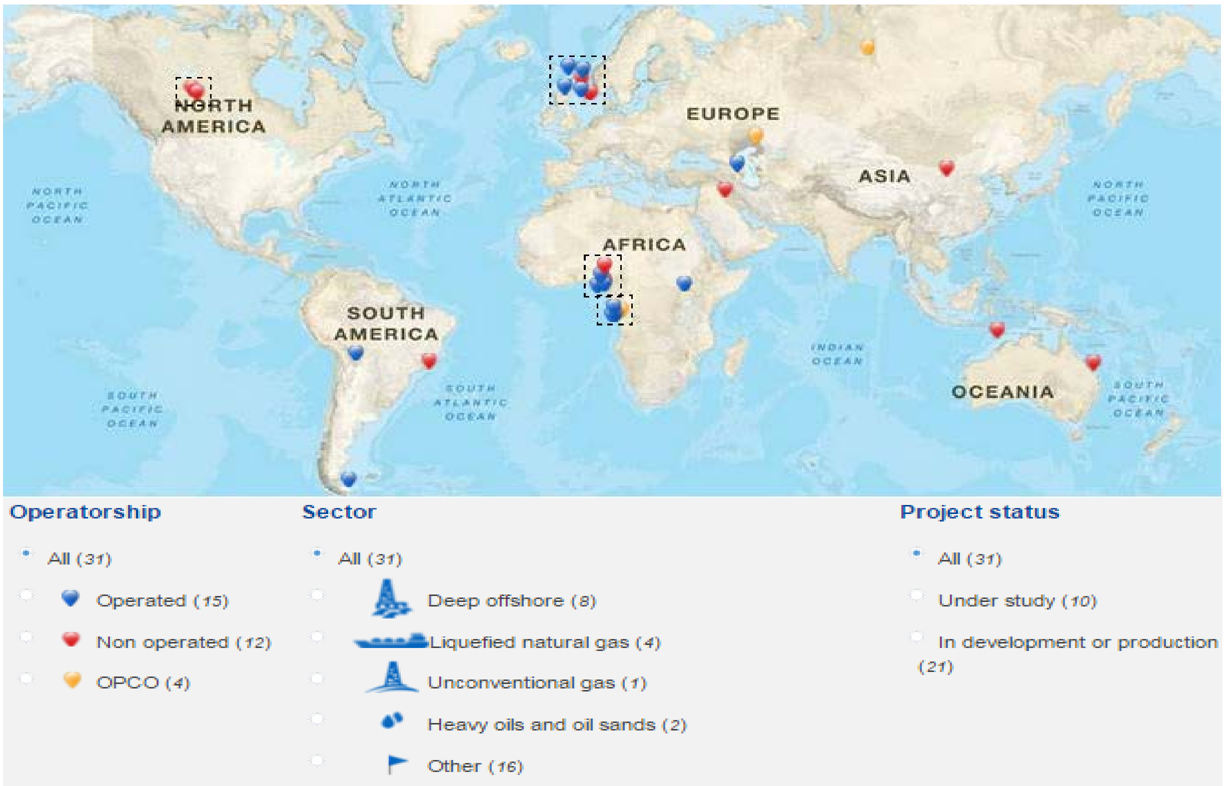


Source: OPEC Annual Statistical Bulletin 2014 and company annual reports



Source: OPEC Annual Statistical Bulletin 2014; Company Annual Reports and SEC Filings 1997-2014

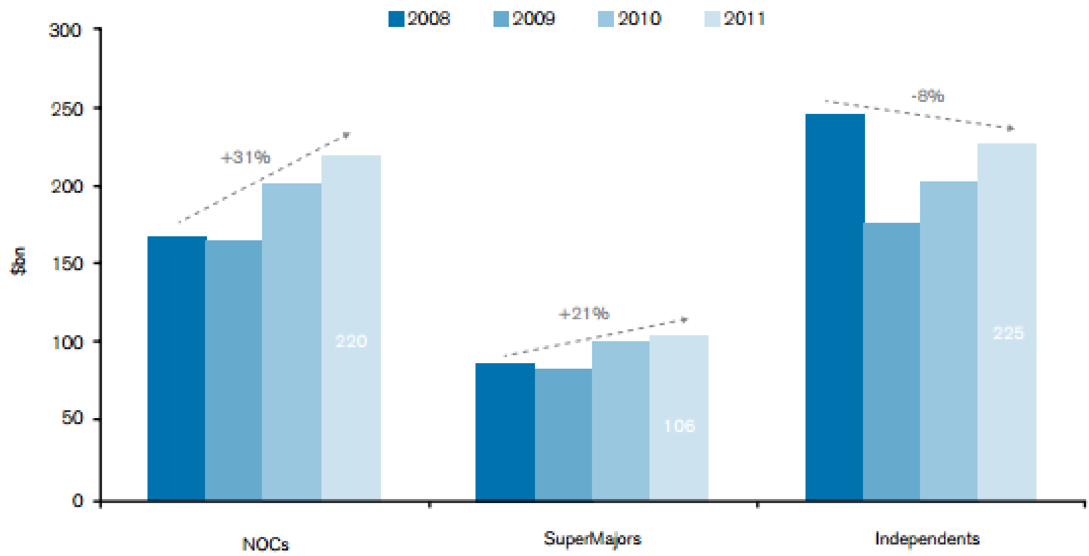
Global Upstream Portfolio:



Major Projects:

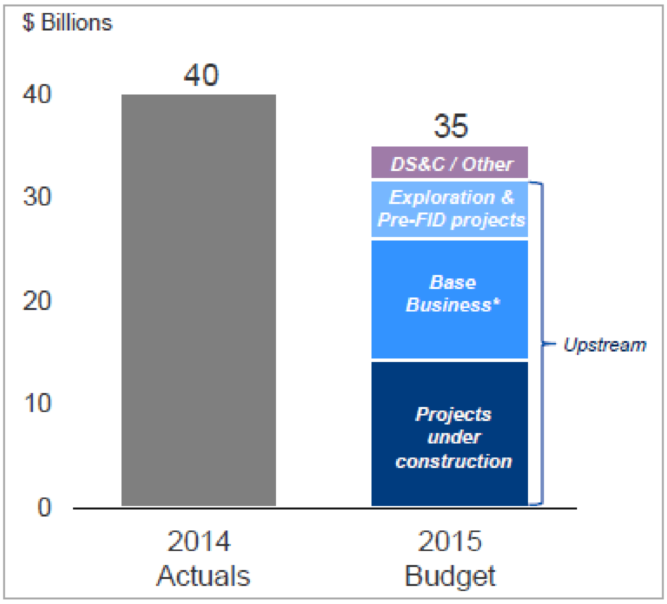
	Project	Country	Project	Capacity (kboe/d)	Share	Op	Status
2014	CLOV	Angola	Deep offshore	160	40%	✓	Prod.
	Eldfisk 2	Norway	Liquids/gas	70	39.9%		Prod.
	Ofon 2	Nigeria	Liquids/gas	70	40%	✓	Prod.
	West Franklin Ph.2	UK	Gas/cond.	40	46.2%	✓	Prod.
	Laggan-Tormore	UK	Deep offshore	90	80%	✓	Dev.
	Surmont Ph.2	Canada	Heavy oil	110	50%		Dev.
	Termokarstovoye	Russia	Gas/cond.	65	49%*		Dev.
	GLNG	Australia	LNG	150	27.5%		Dev.
End-2015	Vega Pleyade	Argentina	Gas	70	37.5%	✓	Dev.
	Angola LNG	Angola	LNG	175	13.6%		Dev.
	Martin Linge	Norway	Liquids/gas	80	51%	✓	Dev.
	Incahuasi	Bolivia	Gas	50	60%	✓	Dev.
	Moho Nord	Congo	Deep offshore	140	53.5%	✓	Dev.
	Kashagan	Kazakhstan	Liquids	370	16.8%		Dev.
	Ichthys	Australia	LNG	335	30%		Dev.
	Egina	Nigeria	Deep offshore	200	24%	✓	Dev.
	Kaombo	Angola	Deep offshore	230	30%	✓	Dev.
	Elgin/Franklin redev.	UK	Gas/cond.	35	46.2%	✓	Dev.
	Gina Krog	Norway	Liquids/gas	95	30%		Dev.
	Halfaya Ph.3	Iraq	Liquids	200	22.5%		FEED
	Libra EWT	Brazil	Deep offshore	50	20%		Dev.
	Yamal LNG	Russia	LNG	450	20%*		Dev.
End-2017	Fort Hills	Canada	Heavy oil	180	39.2%		Dev.
	Tempa Rossa	Italy	Heavy oil	55	50%	✓	Dev.
	Ikike (OML 99)	Nigeria	Liquids/gas	55	40%	✓	FEED
	Blocks 1, 2 and 3A**	Uganda	Liquids	230	33.3%	✓	Study
	Surmont Ph.3	Canada	Heavy oil	135	50%		FEED
	Bonga South West	Nigeria	Deep offshore	225	12.5%		FEED
	Elk-Antelope	PNG	LNG	150	31.1%	✓	Study

Appendix B - Upstream Capex by Company Type



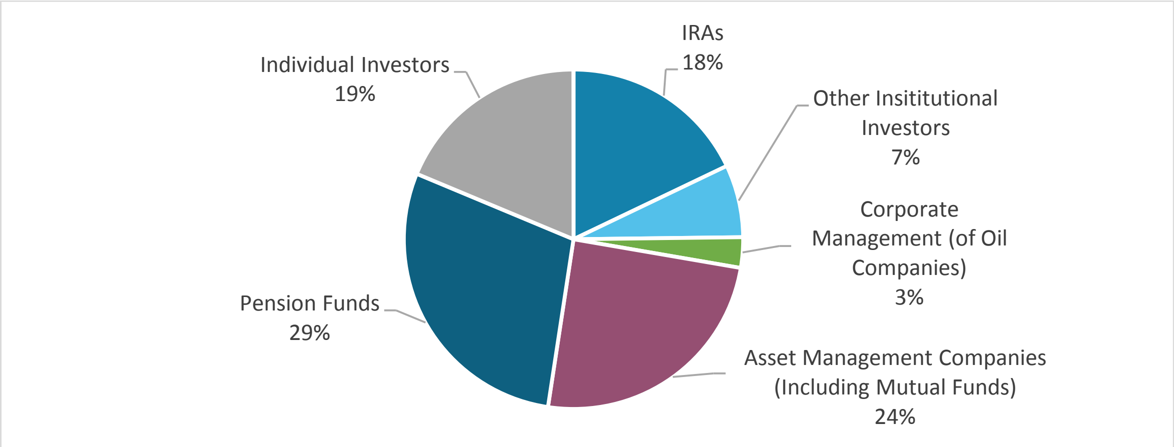
Source: (Mitchell et al. 2012) - Schlumberger Business Consulting (speech by Andrew Gould, Barclays Capital Commodities Conference, March 2012).

Appendix C- Chevron Total Capital Expenditures



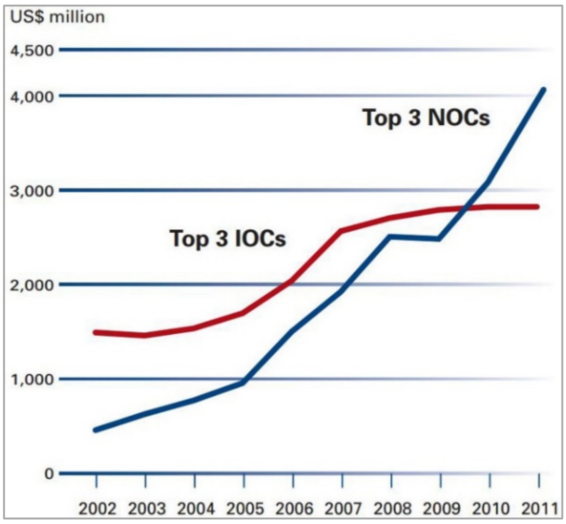
Source: Chevron Q4-2014 Earnings Presentation

Appendix D - Ownership of US Oil and Natural Gas Companies - 2014



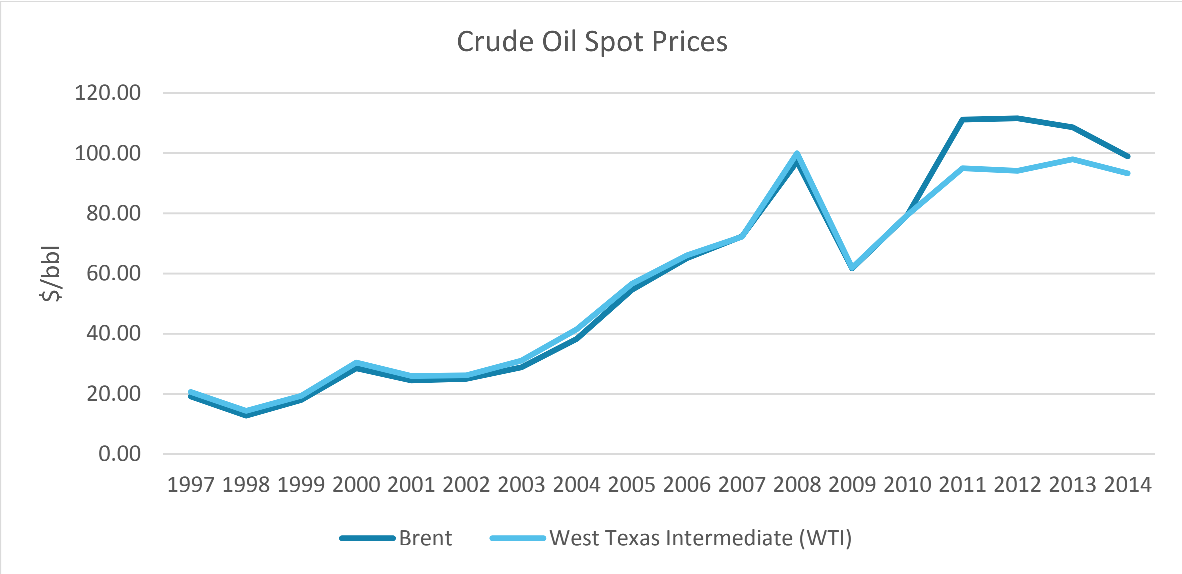
Source: American Petroleum Institute

Appendix E - R&D Spending -Top NOCs and IOCs

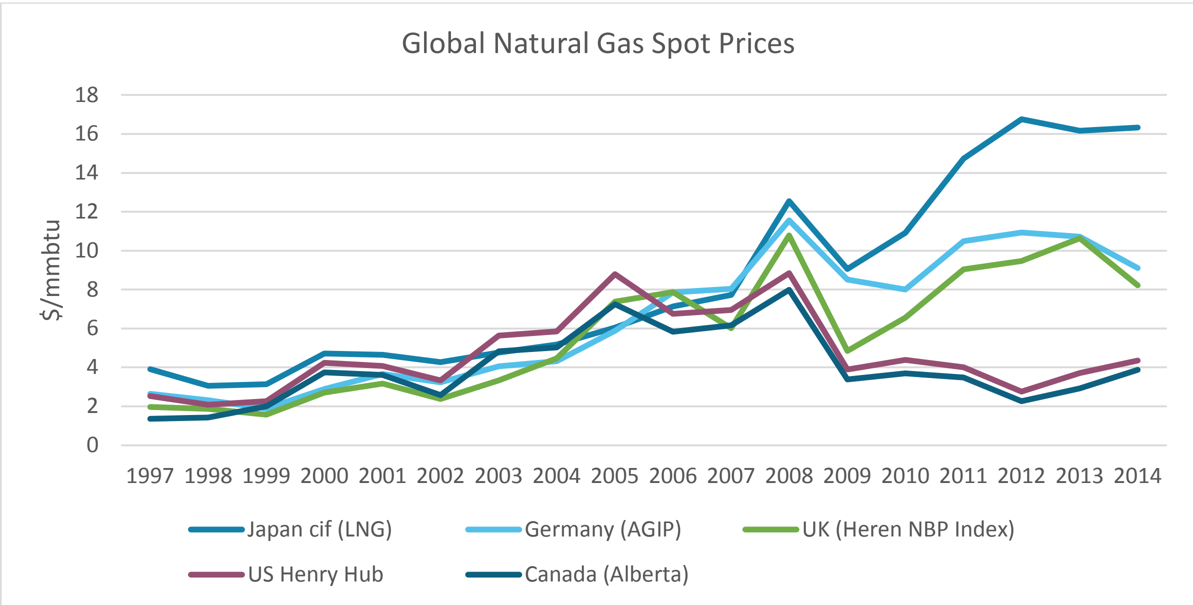


Source: SBC Analysis

Appendix F - Oil and Natural Gas Prices 1997 – 2014



Source: BP Statistical Review of World Energy 2014



Source: BP Statistical Review of World Energy 2014