“Recession Shock”: The Impact of the Economic and Financial Crisis on the Oil Market

Prepared by Cambridge Energy Research Associates

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EXECUTIVE SUMMARY

The past 12 months have seen volatility in oil prices on an unprecedented scale. The roller-coaster ride—scaling heights approaching $150 per barrel followed by a plunge to less than $40 per barrel—poses important questions about what is happening and what is next. What is driving this extraordinary volatility? What will be the effects on future demand and supply and on investment—and on energy security? How are the financial crisis and economic downturn exacerbating the volatility of oil prices? What are the possible risks and unanticipated consequences?

The UK Department of Energy and Climate Change and the Ministry of Petroleum and Mineral Resources of Saudi Arabia have asked Cambridge Energy Research Associates (CERA) to address these and other questions as part of the briefing for the London Energy Meeting on December 19, 2008. This Special Report provides context and a framework for understanding the unprecedented rise in oil prices since 2001, explains why economic growth was not derailed sooner and why prices have collapsed in the past few months. It also presents an illustrative outlook for the world economy and oil market.

The analysis concludes that spare capacity will increase in the short-term due to falling oil demand and as supply materializes from investments already under way. In the medium term, however low prices, and financial constraints may hinder investment. Consequently, as the economy picks up, spare capacity will start to erode and the oil market could begin to tighten again in the first half of the next decade. If prices fall “too far,” the lack of investment could accelerate this tightness significantly. Another era of strong global economic growth could also accelerate tightness. Conversely, if prices are supported at too high a level, long-term spare capacity will grow to levels that could result in a period of prolonged low oil prices.

Occasional shocks to the global economy and volatility in the oil market may be inevitable in the future. However, the best way to reduce potential peaks and troughs, like those recently experienced, is to increase the quality and frequency of global oil information, particularly as it relates to demand and supply.

HOW DID WE GET HERE?

The future can never be predicted reliably by extrapolating the past, but an understanding of how the current economic and oil market environment arose can provide essential context for preparing for the challenges of the next decade. Oil prices are a barometer of the world economy. Rising prices between 2003 and 2007 reflected the best global economic growth in a generation—growth that led to overleveraging on a global scale and that was brought to an end by the financial crisis that began to unfold in the summer of 2007. The tight balance between supply and demand in 2002-08 was not the only factor driving the increase in oil prices—oil
prices were also caught up in an increasingly unsustainable commodity boom. The final explosion in oil and other commodity prices began in late summer 2007, as a weakening dollar set off a “flight to commodities” and an increasing emphasis on oil and other commodities as an asset class and storehouse of value (see Figure 1). High oil prices in turn played a “contributing role” as a trigger in the economic downturn by undermining consumer spending and confidence, by burdening businesses, and by hitting hard at certain industries, notably automobiles and airlines.

The psychology of the oil market that reached its apogee in the summer of 2008 was triggered by events that began half a decade earlier. Supply disruptions in Venezuela and Nigeria in the run-up to the Iraq war and then the war’s impact on supply were the base ingredients. The 2004 “demand shock” that resulted from higher economic growth- added further pressure. Disruptions of various kinds continued to reduce output, sometimes in aggregate by as much as two million barrels per day, or even more. And there were delays in stepping up investments in new capacity, arising from

- skepticism about the durability of high and rising prices
- some resource-holding governments securing a larger share of the economic rents through tax hikes and changes to the terms on which resources could be accessed

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**Figure 1**

*Spare Liquids Production Capacity versus Average Oil Price*

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source: Cambridge Energy Research Associates. 81206-14
• a dramatic increase in the costs for upstream, downstream, and energy-related services to more than twice their level at the start of the decade

This cost issue, while very prominent within the energy industry, was largely unrecognized outside the industry. But a series of IHS/CERA cost indices clearly establish the impact: The cost of developing a portfolio of upstream assets more than doubled from 2004 to 2008 (see Figure 2). Downstream costs were subject to similar upward pressure (see Figure 3). This explosion in costs was the result of bottlenecks and shortages of people, equipment, inputs such as steel, and engineering skills.

Two more factors were key elements in belief systems that supported the drive to $147 oil. The first was a belief in what became known as “decoupling”—the conviction that the world economy had evolved to the point where Europe and emerging markets would be insulated or even immune from a US economic downturn. The second was an underlying, if unstated, assumption that price did not matter; that both demand and supply would not budge as prices soared—a view exacerbated by fears of “peak oil” among some. Yes, it was just possible that price had become irrelevant, but it would have been the first time in economic history. When such a strong consensus emerges, discordant views are less easily heard. So it turned out, and cycles are still with us.

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Figure 2
IHS/CERA Upstream Capital Costs Index

Source: Cambridge Energy Research Associates.
81206-15
Now as the world has moved into recession, oil prices have fallen by two thirds since July 2008. Of course, a price “collapse” to the $40 to $50 range is a collapse only if one forgets that the average oil price was $72 per barrel in 2007 (and $65 in 2006). This fall also reflects the power of price itself. For rising prices turned CERA’s “Break Point” scenario into reality—driving decisions by consumers, governments, and businesses that have changed the course of demand. Gasoline consumption in the United States peaked in 2007 and was beginning to decline before the economic crisis broke. Demand has responded to higher prices, although the impact was often muted in those parts of the world where retail fuel prices are controlled or subsidized. Total US oil demand in 2008 is expected to be at least 1 million barrels per day (mbd) less than in 2007. Other OECD countries tell similar stories. The last time demand dropped this much was in 1981, during the recession that was, until now, known as the “worst recession since the Great Depression.”

Government policies are also changing and consolidating the weaker demand trajectory, notably reflected in the first new fuel efficiency standards in the United States in 32 years. A shift in strategy in the beleaguered automobile industry toward electric cars, and increasing research and investment in batteries, could reinforce this trend—although this direction will be tested both by the price decline and by the deeply troubled condition of the auto industry.

On a global basis, estimates for demand in 2008 have come down from as high as 2.1 mbd of growth at the beginning of the year, according to some analysts, to a decline that CERA
now estimates at almost 300,000 barrels a day (bd). CERA expects demand to fall further in 2009.

THE IMPACT ON SUPPLY

The crucial question arises: What will happen to the supply picture? Estimates of the outlook for the global economy and energy markets are reacting to fast-moving events. Specific metrics, such as economic growth, oil demand, and levels of production (particularly in light of a meeting of OPEC members during the week between finalizing this report and presenting the analysis), are subject to changes in the specifics. The general anatomy of future supply capacity, production, and demand are, however, less volatile than the specifics. To support the analysis in this Special Report, CERA has used a baseline reference case prepared by our sister company, IHS Global Insight, in November 2008 that includes an integrated GDP framework. The forecast data do not, therefore, represent CERA’s forecast of the future but an illustration of a possible future to provide a foundation for discussion.

The baseline reference case illustrates how, notwithstanding the falls in oil demand and prices, oil supply capacity will continue to grow from projects already under way. Spare capacity—the difference between total liquids production capacity and actual output—is on the rise and could reach as much as 7 mbd, or 8 percent of demand, by 2010, compared with less than 3 percent in 2007 (see Figure 4).*

However, we estimate that 3.8 mbd of supply growth would be cut by 2013 if oil remained at $60 for 2009 and 2010. If prices are lower, the reduction in expected growth would be even sharper. This growth in capacity, even if diminished by lower prices, is expected to materialize despite the steep climb in the industry’s costs described previously. The specter of growing spare capacity is contributing directly to reduced oil prices. The fall in oil prices is likely to help hard-pressed consumers, especially for countries where the tax component of retail product prices is relatively small. If comparing the average US gasoline price in July ($4.14 per gallon) with the October price ($2.26) on an annualized basis, the savings to American consumers are $282 billion (€220 billion, or £180 billion). The fall in oil prices is a sort of de facto tax cut—an automatic stimulus package that does not need to be financed by consumer nation public funds.

What happens next to oil prices depends greatly—just as for the 2003–07 increases—on the pace of global economic growth. But this time the question is how deep and long the recession will be, and how big the hit on consumer spending. But even as demand recovers with the economy, there may be continued downward pressure on demand as energy policies of countries around the world are likely to emphasize greater energy efficiency and renewables. The justification will be not only for energy policy—looking across the valley to the next cycle—but also because of climate change policies and concerns. A green stimulus program is already under development by the new US Administration, and policymakers elsewhere in the world will be looking closely at its elements.

*Spare capacity is not simply the difference between productive capacity and demand. Productive capacity data are sometimes unavailable (because of maintenance or weather shutdowns, for example), so an “efficiency factor” needs to be applied to estimate actual production. Refinery and processing gains are then added.
Weak demand has led to lower oil prices, but this retreat has challenged the economics of new projects in various producing countries, although not necessarily in a consistent way. As a result, new investment will slow until prices recover or, as CERA expects, costs and taxes also retreat; upstream costs may decline by as much as 40 percent by 2011.

A key question is the extent to which national oil companies (NOCs) and smaller international oil companies (IOCs) will face funding difficulties in present circumstances, the former because of competing demands on their cash flows from their government owners and the latter because of questions about their continued access to capital markets. About 40 percent of the new capacity to come onstream by 2015 would be expected to require an investment contribution from the relevant host country’s NOC. The significance of the NOCs is underlined by their control over 80 percent of the world’s reserves.

**SOWING THE SEEDS OF THE NEXT OIL PRICE SPIKE?**

The oil industry would need to spend more than $150 billion per year on new oil supply over the next few years (from a total oil and gas spend of some $300 billion per year) if industry costs do not decline. CERA’s expectation of a 40 percent decline reduces the anticipated investment in new oil capacity, following such a decline, to some $90 billion per year. Table 1 outlines the calculation of future cumulative investment needs through to 2015 for developing new oil capacity.
However companies have already begun to scale back their spending in real terms in response to lower oil prices and reduced production revenues. The long lead times for exploration and new oilfield development will ensure that the impact on oil supplies of the current investment slowdown will be cumulative over the next several years. Eventually, as demand growth resumes, the oil market will tighten again. But how soon will this happen? It will depend on the speed and strength of recovery on the demand side and on the extent of investment cutbacks. In our illustrative reference case, the spare capacity margin would start to erode after 2013 and the market could again be very tight by 2018. However, too deep an overcorrection could lead to a rebound in prices above the mid-2008 levels and measures to support the price in the short term could build up excess supply capacity to unsustainable levels and cause the next price collapse (see Figure 5).

It is not inevitable that oil prices will spike dramatically, but conditions for a spike could emerge at some point in the next decade. A key question is, how can policy make this outcome less likely?

**DAMPENING DOWN FUTURE VOLATILITY**

Faced with the potential for more violent swings in the oil price—resulting from timing effects and market reactions, all adding to the bias toward underinvestment that is created by volatility—it is only natural to ask if there are ways to remove this volatility. If only producers could enjoy greater security of demand. If only consumers could rely on uninterrupted supply. If only inventories alone were sufficient to dampen price volatility and there were no need for the market to guess about future changes in spare production capacity. If only institutional investors were consistent in their demands on the energy companies in which they invest.

<table>
<thead>
<tr>
<th>Capacity (million barrels per day)</th>
<th>$1,000 per Daily Barrel</th>
<th>Investment Cost (billion dollars)</th>
</tr>
</thead>
<tbody>
<tr>
<td>North America</td>
<td>4.3</td>
<td>32.3</td>
</tr>
<tr>
<td>Europe</td>
<td>7.0</td>
<td>30.3</td>
</tr>
<tr>
<td>Middle East</td>
<td>13.8</td>
<td>15.4</td>
</tr>
<tr>
<td>Far East</td>
<td>3.8</td>
<td>29.3</td>
</tr>
<tr>
<td>Latin America</td>
<td>4.4</td>
<td>30.2</td>
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<td>Africa</td>
<td>6.2</td>
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<tr>
<td><strong>Total</strong></td>
<td><strong>39.4</strong></td>
<td><strong>23.0</strong></td>
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Source: Cambridge Energy Research Associates.


CERA projects that by the end of 2010 aggregate upstream costs will fall, on average, by 40 percent from these levels in the projected economic and oil price environment. Using this assumption, the estimated investment needed to maintain and add to production capacity worldwide is around $550 billion by 2015, as opposed to the $900 billion estimate above.
The oil market is too big, complex, diversified, and international. There are too many participants with major national, economic, or commercial interests at stake. The lead times are too long and the supply side too “lumpy.” There are also too many variables that can shock the market. CERA sees no escape from some degree of volatility in the oil market—indeed, volatility may be an unintended side effect of periods of consensus about expected future oil prices. Such periods are characteristic of the industry worldwide. The oil industry’s responses to such consensus frustrate expectations. However, episodes of extreme volatility such as in 2008 (or the early and mid-1980s and 1998–99) exacerbate imbalances between supply and demand because the more volatile the oil price, the more cautious the investment planning of oil companies.

Occasional shocks to the global economy and volatility in the oil market may be inevitable in the future, but the height from peak to trough of price movements need not be so extreme. In engineering terms, there are benefits to be gained if the ratio of market signals to market noise can be increased. Market noise is difficult to predict, much less to control. However, market signals can be provided if governments, the oil industry, and commodities markets—or those who regulate the last two—choose to provide them. Greater transparency of market information and data represents the best hope for limiting future volatility in prices and ensuring a more appropriate match over time between supply and demand.
I. THE DOWNTURN—AND, WHERE IS THE GLOBAL ECONOMY HEADED?

I.1 STATE OF THE GLOBAL ECONOMY

The world economy has been going through an increasingly difficult period since mid-2007. The lagged effect of cumulative monetary tightening finally dented the global housing boom, triggering a crisis in the subprime sector of the US mortgage market and expanding into a widespread credit crunch affecting all of the world’s economies. The impact can be measured in terms of an increasingly heavy penalty on gross domestic product (GDP) and in rising unemployment. The crisis is also a central factor in the extreme volatility of oil prices since the late summer of 2007—in both its dramatic rise and its equally dramatic fall.

This paper is being prepared at a critical juncture in the crisis. On the one side, the indicators of national economies and the global economy continue to worsen month by month. On the other side, government stimulus programs in 2009 will be pouring trillions of dollars, measured on a global basis, into troubled economies.

As it is, global GDP growth has slowed during the past 12 months, from a robust annualized rate (calculated using market exchange rates) of 4.4 percent in third quarter 2007 to only 0.7 percent in third quarter 2008—far below the global economy’s long-term annual trend growth rate of 3.4 percent. Moreover, growth will most likely weaken further—or even turn into a contraction over the coming quarters as a result of the unprecedented credit freeze in the global banking system, the wider turbulence in financial markets, and the resulting impact on the “real economy.” The common impact is evident across the different segments of the global economy.

The United States is likely to experience its deepest—and longest—recession since 1982, if not worse. The economy will contract in 2009, to be followed, at least according to current expectations, by a modest recovery in late 2009 or 2010. Housing remains a major drag on growth, and until the housing market stabilizes it will be impossible to draw a line under the financial crisis. Further, as the broader economy is now turning down, there will be higher unemployment, reduced household wealth, and much more insecurity among potential purchasers.

American consumers are retrenching. Real consumption dropped 3.1 percent in third quarter 2008—the worst decline in 28 years—and a similar drop is expected in the fourth quarter. Consumers are getting relief from tumbling oil prices and fiscal stimulus packages, but these are outweighed by the squeeze from the crumbling labor market, falling home prices, tighter credit availability, and lower stock-market wealth—including, of special note, the loss of value in retirement savings accounts. Inflation is yesterday’s problem. The global recession is bringing down commodity prices and shifting attention to deflation.

The Eurozone is now officially in recession, with GDP contracting in second quarter and third quarter 2008. The latest evidence suggests that the Eurozone downturn is deepening. Consumer and business confidence has fallen substantially across the zone and stood near a combined 15-year low in October 2008, thereby undermining prospects for investment, employment, and consumer spending. Retail sales are generally soft, and the manufacturing sector is struggling.
Financial sector turmoil, very tight credit conditions, and sharply lower equity prices are hurting economic activity across the Eurozone, and the full effect is still feeding through. Meanwhile, significant corrections in overvalued housing markets in Spain and Ireland are hitting the rest of the economy hard, and the same may happen to a lesser extent in other countries—e.g., France and the Netherlands. These factors more than outweigh the benefits from sharply lower oil and commodity prices, a significant retreat in the value of the euro, and lower interest rates.

Modest Eurozone recovery is forecasted from 2010, at 0.8 percent growth over the year. Real GDP in the United Kingdom contracted by 0.5 percent, quarter on quarter, in third quarter 2008. Japanese growth was healthy in late 2007 and early 2008, thanks to booming exports. But the economy has experienced weak to flat growth during the balance of 2008. In 2009 the Japanese economy is expected to report a modest 0.5 percent contraction. A short-lived return to deflation remains possible, with consumer prices decreasing in late 2008/early 2009 before returning to a slow upward trend.

Growth is slowing rapidly across most emerging markets, including in the economies of China and India, key locomotives of the global expansion in the past several years. As a result of globalization and China’s own export-led development strategy, China has become increasingly open to trade and therefore more exposed to external shocks. In 1997 (the start of the Asian financial crisis) exports accounted for 18.5 percent of China’s GDP, but this rose to 35.2 percent by 2007. The risk for China is demonstrated in the distribution of its exports. In 2007, the United States, European Union, and Japan represented half of China’s total export market. To avoid a hard landing for the economy, China’s domestic demand has to cushion the possible recession in exports. But expectations for Chinese growth continue to come down.

I.2 EVOLUTION OF THE OIL MARKET: 2001 TO DATE

Global GDP and the distribution of GDP are key determinants for the oil market. The period 2003 through 2007 yielded the best global economic growth for a generation, and this was the fundamental driver of oil prices over this period. The distribution of growth—the “emergence” of emerging markets—added further force to the growth, owing to the levels of development these countries were attaining. The result was a “demand shock” that contrasted with the supply shocks of the 1970s.

But the potential for such growth was not in prospect at the beginning of the decade. In 2001 the US economy was in recession. Growth was weak at best in Germany and Japan. The price of Brent crude oil fell 26 percent year on year to less than $20 in the fourth quarter. But despite a modest recovery during 2002–03, the supply side of the oil market consistently fell short of expectations, with the main shortfalls coming from Iraq, Venezuela, and Nigeria. The cumulative effect of these three disruptions was to tighten the oil market significantly, by depriving it of around 4 mbd of actual or expected production for much of 2003. Spare capacity in the oil market halved from 23 percent of the call on OPEC oil (5.3 mbd) in 2002 to 11 percent (2.9 mbd) in 2003. The price of Brent crude averaged $25 per barrel in 2002 and $29 in 2003—a 20-year high.
In 2004 the Brent price closed at nearly $44 and averaged over $38. The impact of these supply disruptions continued to be felt: spare capacity fell below 2 mbd. At this level, the capacity margin was 2.9 mbd, or only 2 percent of global demand)—the lowest level in at least three decades.

It was at this point that the impact of global economic growth came to be felt, particularly as economic growth in the emerging economies had become an increasing part of global oil demand. This was the beginning of the “demand shock.” In 2004 global oil consumption registered its largest annual increase (more than 3 mbd) since the 1970s. China was a main contributor: its oil demand increased by almost a million barrels per day that year (partly because of economic growth, but also in response to delays in the availability of coal-fired power generation). But China was only part of the picture, as demand was increasing elsewhere as well. Without this very strong demand growth, the level of spare capacity would have been higher, which would have eased supply concerns and the consequent price rise.

In each subsequent year, oil demand grew, albeit more slowly than in 2004, and physical crude oil supply rose by a little more than demand, increasing inventory levels. But this did not stop prices from rising each year (see Figure 6). There is no single explanation for this accelerating climb. By 2005 a significant tightness had developed in the availability of deep conversion refineries, resulting in intense competition for light, sweet crudes like Brent (and West Texas Intermediate). Also in 2005 the price rise was reinforced by Hurricanes Katrina and Rita, which rendered almost 1 mbd of refining capacity in Louisiana and Texas unusable for several

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**Figure 6**
Average Daily Oil Prices, Brent

Source: Cambridge Energy Research Associates.
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months and shut in up to 1.5 mbd of crude production from the Gulf of Mexico. During 2006 a series of geopolitical incidents and disruptions added to both supply and market psychology. Disruptions in Nigerian output were a continuing feature in the oil market. Contention over Iran’s nuclear program—and the possible impact on oil flows—became integral to market psychology. However, production exceeded demand, and oil stocks in OECD countries built up to levels at or above their historical ranges. Oil prices began to slide in August, and OPEC began a process of reducing production, which led to inventory drawdowns. The average price was $54.45 in 2006 and $65.12 in 2007.

One other factor was critical to the rise of oil prices—although this was more obvious to the oil industry itself than to consumers and governments. Cost inflation for developing oil (and natural gas) supplies increased at extraordinary and unprecedented levels. The IHS/CERA Upstream Capital Costs Index demonstrated that these costs increased by 130 percent between 2000 and third quarter 2008. This was the result of shortages and bottlenecks in terms of people, equipment, skills, and inputs such as steel. These costs fed into the price environment. The shortfalls they reflected also led to delays and postponements in the entry of new supplies into the market.

All these factors were already at work in the summer of 2007. By this point oil prices were averaging about $75, or triple the 2001 level.

It was at this point that oil prices took off to levels that generally had been unanticipated and that were regarded as alarming (and provided the backdrop to the Jeddah Summit of June 2008). In particular, as the US subprime mortgage crisis started to unfold, prices took off, exceeding $100 by early January 2008. It was in this period that financial markets emerged as one of the main drivers of oil prices.

“Speculation” captures only a fraction of the role of financial markets in setting oil prices. As the financial crisis began, the dollar started to weaken on the basis of interest rate cuts and expectations of more cuts. Instead of the normal “flight to the dollar” during times of instability, there was a “flight to commodities” during a time of currency instability. The price of oil and other commodities increased dramatically. In the eyes of many investors, commodities had emerged as a new asset class, an alternative to equities and fixed income. The largest pension plan in the United States announced its intention to increase its commitment to commodities 16-fold. Investors turned to oil as a hedge—against expectations of inflation, which were very strong; against geopolitical risk; and against expectations of very strong demand growth in emerging countries. And commercial buyers were also in the financial markets, hedging against higher prices in a critical commodity that they were being told would only go higher.

This commitment to oil was reinforced by two sentiments. One was described by Professor Robert Shiller of Yale University as “contagious excitement about investment prospects.” The other was an increasingly pervasive view that oil was moving toward a permanent shortage, that “peak oil” was near, and that the high prices were only signaling much higher prices to come as the twilight of oil neared. “Here Comes $500 Oil” was the headline in one of America’s leading business magazines as late as September 15, 2008! This conviction about “peak oil” seemed to become a new investment doctrine among many financial investors.
Hedge funds appeared to take the lead in seeking out new asset classes in which to invest for “superior returns” to those available from conventional equities and bonds. More and more hedge funds—as well as banks, insurance companies, pension funds, and endowments—poured money into financial derivatives, commodities, and commodity derivatives. Oil was not the only commodity to experience price rises and a growth in derivative volumes—nor was it the commodity whose price rose most steeply (see Figure 7).

In early 2008, as the US economy showed growing signs of weakness and prospects deteriorated for its housing, credit, and financial markets, “noncommercial investors” moved even more vigorously into oil and other commodities as a new asset class.* The CFTC reported that noncommercial investors held 14 percent of open interest in May 2008 and 81 percent by July (see Figure 8).

A critical part of the investment thesis was that the so-called emerging economies of Asia, Latin America, the Middle East, and Russia had “decoupled” themselves from the economic prospects of the developed world. Up to mid-2008, regions with expanding oil demand more

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*The US Commodity Futures Trading Commission (CFTC) defines noncommercial investors as those not physically exposed to the commodity but that trade “with the objective of achieving profits through the successful anticipation of price movements.”
than offset those where demand was flat or falling. The credit crunch changed all that. It now appears that of the world’s eight largest economies, only one—China—might register any GDP growth at all next year. Even there, after annual average growth rates (on official figures) above 10 percent for the past five years, the economy has slowed.

In the few months since oil prices peaked (on July 11, at $147.27 for WTI), they have fallen back below $50 before edging up again. This seemed like a high price as recently as three years ago; now it seems low, and it could fall further. In part, the change in perspective results from the rising costs since 2005 to find, develop, and produce oil (see Section III.4). For the rest, it is the speed of the price collapse that has been so startling—just as startling as the rapid last phase of the increase in 2008. To put the volatility of the 2008 oil market into perspective, it took well over three years to increase from the upper $40s to $147—a $100 rise—but less than four months to plunge $100.

I.3 THE FINANCIAL AND ECONOMIC CRISIS BREAKS

The global financial crisis and resulting recession follow what was, by some measures, the biggest housing and credit bubble in history. Credit growth was strong globally, not just in the United States. The source of this bubble was a combination of changing regulation, financial innovation, and the globalization of capital that flowed beyond the boundaries of national regulatory authorities. In the end, financial institutions and investors began to realize that they did not
understand the size of the risks to which they were exposed—and the spreading of risk meant that, when the crisis broke, nobody knew who was exposed and who was not. “Securitization” had created insecurities on a scale that was not understood. Trust among financial institutions and counterparties broke down.

The private sector’s credit boom was strongly influenced by government policies of various kinds. Monetary policies were too easy for too long, keeping short-term interest rates low. Regulation and legislation in the United States, especially in the 1990s and early years of this decade, promoted subprime lending. At the same time, efforts to strengthen regulatory oversight of the huge government-sponsored lending enterprises, failed. Elsewhere a large flow of surplus savings from Asian economies was funneled toward the United States. This flow of funds kept long-term interest rates low as well.

The subprime lending boom in the United States was just one manifestation of a much more pervasive worldwide credit bubble and global over-leveraging. But it was the trigger. High-risk mortgage loans (subprime and Alt-A combined) accounted for just 10 percent of US home mortgage lending in 2001. By 2006, at the peak of the housing market, they accounted for one third. The fatal flaw in the entire mortgage edifice was the assumption that house prices would keep rising. Once house prices began to fall, the pyramid of debt began to crumble.

However, the US subprime debacle was only one part of the global story. There were housing bubbles elsewhere in the world—for example in Spain, Ireland, and the United Kingdom, which saw even bigger bubbles than the United States. Throughout global financial markets, there was a systematic underpricing of risk and overleveraging of debt. The process of expanding leverage took many years—the current deleveraging is moving much faster. Financial firms have been forced to write down more than $500 billion in bad debt since second quarter 2007 and are finding it increasingly difficult to raise capital—in part because of the sharp drop in their share prices during the past 12 months. The International Monetary Fund estimates that losses on US originated loans will ultimately reach $1.4 trillion.

The speed at which financial markets deteriorated was greatly accelerated by the bankruptcy on September 15, 2008, of the 150-year-old investment bank Lehman Brothers. That was the day that the focus in global financial markets and regulatory organizations shifted from “moral hazard” to “systemic risk” as the entire global financial system froze up. In the aftermath, the scale of financial bailouts has grown enormous in the effort to prevent the unraveling of the entire financial system. Monetary and financial authorities around the world are seeking to mitigate the downturn with lower interest rates, increasingly large bailout and stimulus programs – with more to come. However, it appears that the best policymakers can hope for is to cushion the depth of the global recession.

What about the role of high oil prices themselves in the downturn? Every recession except one since the early 1970s has followed a period of high oil prices. This time excessive leverage and underpricing of risk are the central factors in the downturn. However, oil prices played what has been described as a “contributing role” by reducing consumer spending and confidence and placing burdens on many businesses, large and small. They hit particularly hard at certain industries, notably airlines and other transport industries and, crucially, the automobile industry.
Outside the United States, the spectre of commodity-driven inflation stimulated tighter monetary policies until late in the day.

I.4 WHY OIL PRICES COLLAPSED IN THE SECOND HALF OF 2008

There are four main reasons for the price drop.

The first is price itself. Both supply and demand do respond to prices, albeit with lags. The delays can take time, especially on the supply side, with its lead times and, in recent years, bottlenecks. Demand responds with lags as well, but they those lags can be shorter. CERA’s Break Point scenario projected that prices above $100–$120 per barrel would set off major responses from governments, companies, and consumers. And this is clearly what happened. The United States hit peak gasoline demand in 2007, and US demand was going down in 2008, well before the peak in oil prices. But these demand responses were discounted or ignored. This exclusion of contrary data is common during a boom market.

The second reason is the impact of the financial crisis on the global economy. As some countries move into recession and in all the rest GDP growth stalls, there is a corresponding weakness in oil demand. The “demand shock” of 2003–07 has now given way to the “recession shock” of 2008–09. CERA projects global demand to fall by 290,000 bd in 2008. OECD demand will fall by 1.5 mbd, of which the United States will account for more than 1 mbd (the largest such decline since the recession and oil price collapse of 1981, following the oil shocks of 1973 and 1979). On the other hand, oil demand in non-OECD economies will rise by 1.2 mbd, of which Asia will account for 370,000 bd (however, for 2007 these numbers were 1.5 mbd and 620,000 bd, respectively).

The third reason for the price drop has been financial “deleveraging”—the sale of assets by noncommercial investors in oil derivatives, to fund other obligations. After the freezing up in the credit markets, many institutions could no longer obtain short-term funding or roll over debt. They were also facing substantial redemptions. Thus, they were forced to raise cash by selling assets. Sellers disposed of the sellable—including their oil derivatives.

Fourth, there has been a sea change in oil market psychology—from anxiety about supply to fear for demand, in the face of a global recession whose severity is as yet unknown. Prior to this shift, and against the background of strong growth in both GDP and oil demand (even though aggregate supply growth over the period 2000–07 exceeded aggregate demand by 1.3 mbd), the potential for supply difficulties was often on people’s minds. As already observed, expectations of intractable supply problems, reinforced by fears of “peak oil,” had become deeply rooted in the minds of many market participants.

When the oil market is tight, risks of disruption to supplies and geopolitical concerns tend naturally to have more impact on the price than they do when there is a greater safety margin. As of late November 2008, OPEC’s crude oil production had been reduced by more than 2 mbd from July levels, to less than 28 mbd. If production is reduced again in December, spare capacity—the shock absorber for the world’s oil market—would rise further for 2009, from its
current level of 4.3 mbd. Falling demand has resulted in a still looser balance with supply; hence the passing of market anxiety about the reliability and adequacy of supply (see Figure 9).

I.5 BASELINE REFERENCE ECONOMIC OUTLOOK BY IHS GLOBAL INSIGHT

How will future supply and demand evolve, and what will be the impact on prices? Any answers cannot be separated from the overall world economy. As described above, CERA has used the November 2008 baseline reference case from our sister company, IHS Global Insight, to provide an integrated GDP framework that would provide the foundation for illustrating how future demand and supply dynamics might interact. The quantitative data referenced are indicative of a likely future but should not be used as most likely forecasts of the future.

In this outlook, a world recession results from a rapid contraction in consumer spending in the United States and other industrialized markets, a sharp drop in international trade volumes, and falling consumer and business confidence. This recession may well be the worst downturn since the Great Depression, exceeding that of the early 1980s. Although the steep decline in the price of oil and of other commodities since July 2008 is providing timely relief, these prices are still high compared with their long-term historical averages. Most countries are bracing for tough economic times that are likely to last at the very least until the second half of 2009 but that might, under certain circumstances, extend into 2010 and beyond.

The cumulative effect of financial market turmoil and delayed policy responses by some major central banks has led IHS Global Insight, in the baseline reference case for this report,
to reduce its projections for world economic growth for 2008 and 2009. The forecast envisages quarterly growth further decelerating in fourth quarter 2008, before hitting its trough in second quarter 2009, at close to zero. Thereafter, it will only gradually rebound to 2.4 percent in the first half of 2010 and break above trend into 2011.

The baseline forecast assumes that the aggressive reflationaly actions of the United States and other G8 countries will continue into 2009 and help stabilize the global economy, but the subsequent recovery will be protracted due to the long adjustment period required by housing markets around the globe. After the next several quarters of deceleration, readjustment, and consolidation, world growth is shown as rebounding to above its trend rate of 3.4 percent per year by 2011. The forecast projects that annual world growth will maintain a resilient pace of 3.6 percent during 2010–16 before edging down gradually to the long-term trend rate during the next decade. The main stimulus to renewed growth during the current recession is seen as coming from coordinated fiscal action by governments in all major industrialized and emerging economies. However, with nearly two thirds of the global economy (predominantly the OECD economies) now in poor shape, foreign trade cannot be a major pillar of world growth in the short term.

Weak growth will keep financial markets volatile. The deteriorating global economic outlook and uncertainties about the extent of damage to financial institutions’ balance sheets will keep lending activity subdued, risky assets out of favor, and investors skittish for at least the next several months. The resulting deleveraging and disintermediation have already depressed US economic activity. They are also severely hurting growth in Europe and starting to affect other economies. With many European housing markets now under pressure and inflationary pressures building up in many emerging markets, any stabilization in financial markets could prove fleeting. As a result of all these developments, global growth is not likely to rebound until late 2009 or potentially even 2010.

But even if the deterioration in the global economy stops, IHS Global Insight’s medium-term forecast for the global economy foresees continuing turmoil in global financial markets, a rapid deterioration in advanced economies, and increasing evidence of weakening in emerging markets. It now appears that deleveraging will be a protracted, multiyear process that will constrain world growth for some time. The collapse of energy and other primary commodity prices and the sudden deceleration of import demand in advanced economies will stunt the expansion of developing economies and emerging markets.

The US economy’s structural flexibility, compared to that of other developed countries, along with its higher population growth and greater attractiveness to skilled immigrants, should allow it to regain its global leadership and move above its medium-term trend growth rate—which, at close to 2.9 percent per year, will outpace by a wide margin those of Western Europe (1.9 percent) and Japan (1.6 percent) in the future.

In this baseline economic outlook global oil demand falls for two years and does not pass its 2007 level until 2011. Thereafter, it resumes its pre-recession rate of growth. By contrast, productive capacity is projected to grow faster in 2009–12 than it did in 2003–08—a result of the high oil prices in the earlier period. Then, in a lagged response to current market conditions,
capacity growth slows down from 2013. Consequently the margin of spare capacity rises up to 2012 and then falls. The annual values for GDP growth, oil demand, total and spare capacities are shown in Tables 2 and 3:

The price of Brent averages less than $52 per barrel in 2009, recovers almost to $80 in 2011 and above $90 in 2013–14, and settles to a plateau just below $85 from 2016. There is some tension between this profile and the projected levels of spare capacity—the latter would more normally be associated with a weaker price than an 80 percent increase, over the next few years. The outlook includes implicit assumptions about the success of exporting countries in adjusting production levels to support prices by targeting of inventory levels (see Table 4).

Therefore, the balance of this Special Report examines in more detail the effects of changing oil prices on demand (in the next chapter), on new investment in production capacity and the associated economics (in Chapter III) and on oil company decision making (in Chapter IV).

Table 2

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Table 3

Estimated Spare Crude Oil Production Capacity Worldwide

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<th>Year</th>
<th>World Demand (mbd)</th>
<th>Capacity (mbd)</th>
<th>Spare Capacity ¹</th>
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<td>84.0</td>
<td>86.5</td>
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<td>92.2</td>
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<td>2019</td>
<td>97.5</td>
<td>101.9</td>
<td>3.0</td>
</tr>
<tr>
<td>2020</td>
<td>98.9</td>
<td>103.3</td>
<td>3.0</td>
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¹. Spare capacity is not simply the difference between productive capacity and demand. Productive capacity is sometimes unavailable (because of maintenance or weather shutdowns, for example), so an “efficiency factor” needs to be applied to estimate actual production. Refinery and processing gains have then to be added.

Table 4

Baseline Reference Case Oil Prices

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<th>Year</th>
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<th>2007 US$ / barrel</th>
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<td>2020</td>
<td>85.00</td>
<td>84.75</td>
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Source: IHS Global Insight.
II. WHAT IS THE IMPACT OF THE GLOBAL ECONOMIC DOWNTURN ON OIL DEMAND?

II.1 CERA’S CURRENT OUTLOOK FOR OIL DEMAND

The immediate prospects for global and regional oil demand for 2008 and 2009 are for a global decrease of 0.3 percent (290,000 bd) in 2008, followed by a 0.4 percent (330,000 bd) decrease in 2009. This is considerably lower than expectations during the summer, when oil demand was expected to grow 600,000 bd in 2008 and 900,000 bd in 2009. And it is much lower than at the beginning of the year, when estimates for 2008 consumption ranged as high as 2.1 mbd according to some analysts. The revision reflects factors cited earlier—the impact of price itself and the impact of the financial crisis, which has put considerable pressure on GDP for emerging markets and OECD countries alike. Although the fall in oil prices has somewhat eased price pressures on oil demand, the spreading consequences of the global financial crisis are expected to more than offset any positive demand impact of lower prices (see Figure 10).

Figure 10

Changes in Oil Demand by Region
(volume change from previous year in million barrels per day)
North American demand in 2008 is contracting by more than 1 mbd, as unemployment rises and economic output declines. Continued if less severe declines are projected for 2009, resulting in an annual average drop of 360,000 bd. North American gasoline demand is expected to fall by almost 3 percent, or 270,000 bd, in 2008, and by a further 35,000 bd in 2009. Demand for diesel and jet fuel is also contracting sharply in North America. Distillate fuel demand (both heating oil and diesel) is expected to fall nearly 4 percent (180,000 bd) in 2008—the steepest annual decline in distillate demand since 1980. Distillate fuel demand is expected to drop another 0.6 percent, or 30,000 bd, in 2009. Jet fuel demand, already in continuous decline since 2005 owing to an intensified drive by the airlines for operational efficiency gains and capacity management, will fall by another 4.5 percent (80,000 bd) in 2008, with further declines expected in 2009. The large premium of oil over US natural gas prices in 2008 resulted in another deep cut in demand for residual fuel, primarily in the power and industrial sectors. Heavy fuel demand will decline by almost 100,000 bd in 2008. Lower oil prices are expected to slow this steep decline in 2009.

**European** oil demand will show negative 1.1 percent and negative 1.7 percent growth in 2008 and 2009 (down by 180,000 bd and 260,000 bd, respectively). Again, the financial crisis is the primary driver. In OECD Asia demand is projected to decline in both 2008 and 2009 (by 110,000 bd and 140,000 bd, respectively). Excluding residual fuel and crude burning (a result of the outage at a nuclear power station damaged in a major earthquake in 2007), Japanese demand will decline by 2.2 percent in second half 2008 year on year and by 2.9 percent in 2009. Corresponding estimates for total oil demand declines are 1.5 percent and 3.2 percent, respectively, as power demand remains weak and nuclear power generation begins to recover in the second half of 2009.

**China**’s third quarter oil market was very weak. Although total apparent demand grew by 3.2 percent year on year (and August demand increased by 7.1 percent), the strength was solely from inventory builds to ensure supply during the Beijing Olympics. If the NOCs’ stocks are deducted, total oil demand in July and August actually declined by approximately 10 percent year on year. Lower demand growth is expected for 2009 than in 2007 and the first half of 2008, especially for gasoline, diesel, and jet/kerosene. However, lower prices may revive some demand for liquefied petroleum gases and residual fuel oil to offset some of the weakness in demand for light transportation fuels.

For the rest of non-OECD Asia, consumers in countries where prices are government controlled have not seen price reductions. Earlier in 2008 the governments of Malaysia, Indonesia, Thailand, and India (a total of 60 percent of oil demand in non-OECD Asia, excluding China) all raised prices to reduce the burden of their oil subsidies, although prices for some products are still far below world markets.* Hence, demand in non-OECD Asia outside China is forecast to increase by 2 percent (180,000 bd) in 2008 and by 1.1 percent (110,000 bd) in 2009.

**Latin American** oil demand has also been shielded by government intervention from the full force of rising oil prices during the past five years, but it is not immune to the effects of economic slowdown. The impact will vary widely from country to country (Mexico being most

*Indian consumers pay higher than global market prices for some products such as gasoline because of taxes at the pump.
exposed to the US recession), but overall, oil demand growth is projected to be 1.7 percent in 2009, following more than 4 percent growth in 2007 and 2008.

Middle Eastern demand growth is expected to moderate to 4.4 percent in 2008 and 4.2 percent in 2009, compared with a 4.7 percent average over the past five years. Saudi Arabia and Iran (which together account for 61 percent of the region’s demand) and Iraq are still driving demand growth.

Eurasian oil demand in 2008 and 2009 is projected to grow by 0.8 percent, or 33,000 bd. Rising consumption of motor fuels is being offset by further declines in heavy products, thereby changing the composition of product demand. We expect a 1.7 percent increase in demand for gasoline in 2008 and a 1 percent increase in 2009. Fuel oil consumption is on track to decline by 12.1 percent in 2008, resuming a downward trend that was interrupted in 2007 by severe winter weather.

Eighty-five percent of Africa’s oil demand is in North Africa, South Africa, and Nigeria, and the global crisis will affect each area differently. Both global trends and domestic drivers will continue to influence the growth in African products demand—by 2.3 percent in both 2008 and in 2009. Egypt is the largest demand center on the continent, and diesel demand is expected to rise by 5 percent, to 233,000 bd. South Africa’s economy is most integrated with international markets, particularly in Europe, but the preparation for the 2010 World Cup is mitigating that impact.

Looking at oil demand in this way, region by region, serves to illustrate two key points. First, the economic slowdown is depressing demand everywhere (although the effect can be masked by accidents or events giving rise to a local and temporary boost), and second, the price effect on demand is much more variable. Each of these points begs a question:

- Why did high oil prices, in themselves, not have a depressing effect on economic growth?

- What explains the geographic variations in the demand response to high prices?

II.2 THE “SLOW BURNING FUSE” FROM PRICE TO OIL DEMAND

High oil prices have become less damaging to GDP growth than they used to be, because the modern economy uses less oil than previously to make $1,000 of GDP. The impact of high prices on consumers is also diluted by the varying levels of national tax and subsidy on oil products. Exchange rate movements against the US dollar can also affect the picture. Even so, experience has shown in the past few years that oil prices still matter to demand: high prices reduce demand growth, although the effects may take some time to be seen. By the same token, lower oil prices work equally slowly in restimulating demand growth.
Oil Prices and GDP

Until around 2005, people set great store by the deflationary impact of higher oil prices. The relationship was well tested. In the early 1970s global GDP was growing at annual rates of 6–9 percent. The so-called first oil shock took place in 1973, and in 1974–75, GDP growth was less than 2 percent.

Likewise, GDP grew at 6–7 percent for 1976–79 (the year of the Iranian revolution and accompanying “second oil shock”); for 1980–82 the average was again below 2 percent. From 1983 to 1988 it recovered to around 6 percent, but following the 1990 price spike it fell again below 3 percent by 1991. Oil prices spiked again in 2000, and in 2001, GDP growth registered a similar drop.

The highest average annual oil price before 2004 was $36 in 1980. For 2004–07 the price of Brent crude averaged $38, $54, $65, and $72, respectively. In 2007 dollars, the earlier years’ prices were $42, $57, and $67. Yet GDP continued to grow at 6–7 percent in 2004–07. The main reason that the previously well-established relationship between high oil prices and slower growth did not materialize is the steady decline in the amount of oil required, on average, to make a unit of global GDP—from almost 1,860 barrels per real $1,000 in 1980 to just over 480 barrels in 2007 (see Figure 11).

---

**Figure 11**

*Oil Demand Intensity by Region*

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Source: Cambridge Energy Research Associates.
Note: Real GDP measured on a PPP basis.
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Oil Prices and Demand

Exchange rate movements have offset some of the changes in dollar oil prices. For example, relative both to sterling and the euro, the dollar weakened from 2002 to mid-2008, as has since strengthened again. Dollar oil prices rose more than fivefold from January 2000 to their peak, but four fifths as much in sterling terms and, in euros, only two thirds of the dollar-denominated rise (see Figures 12 and 13). Conversely, since the collapse of Lehman Brothers, the dollar has again strengthened sharply. Therefore, oil prices denominated in sterling or in euros have not fallen by as much as they have in dollars.

A second reason for geographic differences in the demand response to changing oil prices is the very wide variations in their impact on the prices actually paid by consumers. Only oil companies (together with some manufacturers of base petrochemicals and—in occasional small quantities—a few power generators) buy crude oil; they then refine it for sale as oil products to consumers. In some oil-producing countries, such products are sold domestically at cost. In others, and not just oil producers, they are more or less heavily subsidized. In most OECD countries they are more or less heavily taxed. Taking road fuels as an example (for May 2008), the consumer price of gasoline ranged from almost $10 per US gallon in the Netherlands to almost one hundredth of this level in Venezuela. The range for diesel was a little over 100-fold, with Venezuela again being the cheapest and the United Kingdom the most expensive (see Figure 14).

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Figure 12

US Dollar Exchange Rates versus Euro and Sterling

Source: Cambridge Energy Research Associates,
81206-5
Broadly speaking, across the European Union as a whole, 15 percent of the cost of road fuel represents the cost of crude, another 10 percent the cost of refining and distribution (including the oil companies’ margin), and the remaining 75 percent is taxation. In these circumstances, and all else being equal, a doubling of the crude price would result in much less than a doubling of the cost of road fuel—though, in EU countries, the increase will exceed 26 percent (which would be the mathematical result, if nothing were to change except the crude price), because some of the tax burden is ad valorem value-added tax and, therefore, also rises with the crude price.

II.3 DEMAND DESTRUCTION IN ACTION

This section looks at two examples of how, over time, oil demand responds to high prices. First, there has been a marked reduction in road fuel demand (petrol, or gasoline in the United States, and diesel in Europe), and second, the use of ethanol as a substitute for petroleum-based road fuels has surged.

US Gasoline Demand

The decline in US demand for gasoline noted in Section II.1 is the first in over 17 years. This has a global impact because US gasoline demand is about 9 mbd and makes up nearly half of total US oil demand. The scale is such that the US gasoline market by itself is larger
than the entire oil market of China, the world’s second largest oil consumer. Recession partly explains this decline in demand. However, it is also due to shifts in consumer behavior that began as much as two years ago in response to rising prices:

- **Americans are driving less.** For the first time since the 1970s and early 1980s the number of miles driven by Americans has clearly begun trending downward.

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• **Inefficient vehicles are losing popularity.** Consumer preference has begun to shift away from large, inefficient vehicles and toward cars and light duty trucks that emphasize fuel efficiency instead of size and performance. For the first time since 2001, light trucks’ share of overall light vehicle sales has declined below 50 percent. Perhaps no data point captures this preference shift more clearly than the fact that Americans bought more Toyota Prius hybrids in 2007 (350,000 vehicles) than they did Ford Explorer sport utility vehicles (SUVs). This is a significant indicator because the Explorer was the best-selling SUV in the United States for more than a decade.

In California, where gasoline prices have historically led the rest of the United States, gasoline demand has already declined for two years—by 0.7 percent in 2006 and 1 percent in 2007. The most recent data indicate a continuation of this trend.

The trend toward more fuel-efficient vehicles will continue regardless of consumer preference. New fuel efficiency standards for light vehicles—passed on top of the rising tide of oil prices in December 2007 and scheduled to phase in starting in 2011—by themselves have the potential to begin reducing US gasoline demand within the next decade.

Prior to 2005, gasoline demand in the United States grew steadily on average at a rate of nearly 2 percent per year. However, from 2005 to 2007 demand growth slowed significantly to less than 1 percent. From fourth quarter 2007 gasoline demand has actually declined—the first quarterly declines since 2000. Rising gasoline prices were taking a bigger bite out of Americans’ income. At the end of May 2008, the average retail price of regular unleaded gasoline in the United States stood at $3.94 a gallon—a record in nominal terms and also higher than the inflation-adjusted peak reached in 1981 (although gasoline makes up a smaller portion of consumer expenditures today than it did then—3.9 percent in first quarter 2008 versus about 5 percent in 1981).

For 20 years from 1984, total vehicle miles travelled (VMT) in the United States grew on average by nearly 3 percent per year. These VMT data are the sum of all the miles driven by vehicles in the United States, including commercial trucks. However, 92 percent of these miles are driven by the more than 230 million light duty vehicles on US roads. This light duty vehicle fleet has grown an average of 1.7 percent per year over the past ten years, roughly in line with the increase in the overall population and the number of licensed drivers. With each licensed driver logging an average of more than 13,000 miles per year, national VMT has historically increased year after year. However, VMT growth slowed dramatically in 2005 and 2006, and VMT have actually decreased since then. A sustained decrease in VMT of this nature has not occurred since the two oil shocks in the 1970s, when high prices and a recessionary economic climate discouraged driving. During the early 1990s recession, growth in VMT slowed somewhat, but the total did not decrease.

Evidence is increasing that consumers are cutting back on their driving. A poll conducted in March 2008 found that 64 percent of those surveyed had made some changes to their driving behavior as a result of high prices, and 19 percent had cut back on driving enough to have a
major effect on their daily lives. The number of trips taken on public transit reached a 50-year high in 2007.

In addition, overall US vehicle sales have been trending downward since mid-2005, and sales of vehicles in the light truck category have been especially weak. The 12-month rolling average of light duty vehicle sales has declined 10 percent from its peak in mid-2005, while the rolling average of light truck sales has declined about 17 percent (see Figure 15). Lower prices at the pump are likely only to partly mitigate these trends.

**European Road Fuel Demand**

In Europe, 2008 saw the first decline in road fuel demand since 1993, with gasoline declining faster than in previous years and diesel growth starting to turn negative. Use of public transport was up by 6 percent versus 2007. Sales of passenger cars have been down year on year in each month since May (the fall was 8 percent in June and July, 16 percent in August, and 15 percent in October).

**Ethanol**

Growth in ethanol blending is another source of reduced demand for the petroleum portion of the gasoline pool. US ethanol use was about 4 percent of the gasoline pool by volume in

![Figure 15](image-url)

**Source:** US Department of Commerce, Cambridge Energy Research Associates. 80515-6_1512
2006 and displaced 240,000 bd of gasoline (ethanol has only two thirds the energy content of petroleum gasoline, so does not displace gasoline gallon for gallon). By third quarter 2008 it had risen above 7 percent, displacing 460,000 bd of gasoline. Worldwide, in 2007 fuel ethanol production totaled 13 billion gallons, or enough to displace 570,000 bd of gasoline consumption (biodiesel production is about 1 billion gallons a year).

II.4 THE LONG LIFE OF DEMAND DESTRUCTION

All that ethanol capacity will be available for many years. Much of it is also likely to be put to use, so long as gasoline prices and policy help ethanol producers to cover their costs. If oil prices were to stay low, some production facilities for converting corn to ethanol would prove very unprofitable for the original investors (unless government increased its financial support for ethanol production)—but not necessarily for subsequent owners of those facilities who might be able to buy them for less than they cost to build.

Nor will a low oil price quickly reverse the motorist’s decision to replace an SUV with a hybrid or a high-efficiency car. Just as the original switch was unlikely until the SUV was ready for replacement, trading back up to a vehicle with higher fuel consumption—if it happens at all—will have to wait until the motorist has had some use out of the hybrid, which will then be available in the used car market. Changes in fuel efficiency have a slow-acting but long-lasting impact on demand. Increasing overall fleet efficiency takes time, as newly purchased efficient vehicles work their way into the fleet and older, less efficient vehicles are retired. However, once a vehicle is added to the fleet, it will be in service for 15 years or more, on average, continuing to contribute to demand reduction.

Householders installing better insulation in their homes to cut their heating bills will not take it out again if fuel costs decline. Airlines that invest in new, more fuel efficient aircraft will use them for their serviceable lives. In short, sluggish as consumers’ demand-saving responses may be to high oil prices, a full reversal of those savings takes even longer to materialize—if it ever does. The falling oil intensity of GDP that was noted in Section II.2 suggests that any reversal will be less than complete.

For the time being, even a partial reversal has yet to begin. True, with oil prices back to their levels of 2004–05, the price pressure on demand has been greatly reduced in comparison to the first three quarters of 2008. However, real oil prices in 2005 were close to the previous all-time high. In addition, until the world’s large economies start growing again, rising unemployment and falling output in the wake of the financial crisis will more than offset the reduced price pressure on demand. In the period between the first two oil shocks—1973 and 1979—oil demand grew on average by only 0.4 percent, even though the average annual rate of GDP growth in this period was over 3 percent.

II.5 SIGNPOSTS FOR THE FUTURE OF OIL DEMAND

More than half of the world’s oil is used in transport, so policies to reduce oil demand tend to focus on this sector. Vehicle fuel efficiency targets are a common tool; only five members of the OECD—Iceland, Mexico, Norway, Switzerland, and Turkey—do not have them. So
does China, which is now one of the four largest automobile markets (along with the United States, European Union, and Japan). The European Union is in the process of changing its vehicle carbon dioxide emissions standards from voluntary to mandatory. In the United States, there were new proposals for 2011–15, as a result of the Energy Security and Independence Act of 2007; they are more stringent in the early years than many expected, and their impact on gasoline demand will build, as increasing numbers of compliant vehicles work their way into the fleet. In addition, the feasibility of regulating the fuel efficiency of medium and heavy trucks is now being examined.

Another approach is the promotion of alternative fuels. There are mandates or subsidies for biofuels use in Argentina, Australia, Brazil, Canada, China, Columbia, the Dominican Republic, the European Union, India, Jamaica, Japan, South Korea, and the United States. In Brazil more than half of the cars on the road and 80 percent of new cars sold are flex-fuel, meaning that they can run on any mixture of ethanol and gasoline, including 100 percent ethanol. In the United States, the recently increased renewable fuel standards will steadily raise the amount of petroleum gasoline displaced by ethanol. Substitution of ethanol in the US gasoline pool could theoretically reach 2.3 mbd by 2022 on the basis of these standards, although some of that volume would be so-called second-generation biofuels, produced from nonfood raw materials that are not yet in commercial production (see Figure 16).

Figure 16
Composition of US Gasoline Demand: Break Point Scenario

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Note: This calculation assumes that the biofuel goals set in the Energy Security and Independence Act of 2007 are met.
80515-10_2805
Making that breakthrough could represent a major advance in the prospects for increased use of biofuels. It would reduce concerns about competition with food production over the raw materials and ameliorate some environmental issues. Changes in trade policy to reduce national protection for biofuels could also allow increased production and so displace more oil from the transport sector.

Some countries encourage the purchase of vehicles powered by natural gas. Natural gas vehicles are most often used in fleets and public transport, to reduce the required investment in refuelling infrastructure. Argentina and Brazil provide corridors of natural gas refueling stations along major routes. The United States offers tax credits. Natural gas vehicles represent, 24 percent of the vehicle fleet in Pakistan, 22 percent in Argentina, and Iran has a target to reach 25 percent.

The climate change negotiations taking place in Copenhagen in 2009 will be another key signpost for long-term oil demand. The Kyoto Protocol expires in 2012, and the Copenhagen negotiations aim to create an agreement to replace it. The number of countries that agree to greenhouse gas emissions targets, the stringency of those targets, and the treatment of transportation fuels in various countries’ compliance policies will have far-reaching implications for long-term oil demand.
III. WHAT IS THE IMPACT OF THE CREDIT CRUNCH AND FINANCIAL CRISIS ON FUTURE OIL SUPPLY?

III.1 OIL PRICES AND FUTURE PRODUCTION

The time required to bring new oil supplies into production varies widely. At the short end of the spectrum, infill or extension drilling can be accomplished in months. At the other extreme, a discovery that calls for new engineering solutions and the construction of its own facilities may take several years to bring into production. It can take even longer if the legal, fiscal, and commercial frameworks for such a project are not already in place.

The oil price that matters is the price that investors expect during the life of the asset, although we shall see that “today’s price” represents a powerful anchor for those expectations. One way to illustrate the impact of current oil prices on future supplies is to take a date—say, 2010—and compare the estimates over previous years for the size of productive capacity once it arrives with the oil price at the time those estimates were made. The US Energy Information Agency makes such estimates available and there is a clear relationship—with a one-year lag—up to 2002 (see Figure 17). Thereafter it appears to break down (save for 2005). Chapter IV explains that the industry was slow to respond to rising prices after 2001 because it had lacked confidence that higher prices would last. The fall in 2007 for supplies projected by 2010
may also reflect the extreme tightness in 2007 of human and physical resources available to
the industry.

As of late 2008, it is difficult to generalize about companies’ expectations for future prices.
Some expect—or hope for—a quick recovery above $100 others see $70–$90 as a sustainable
range, and still others anticipate several years at or below $50. These differences are themselves
likely to make agreement between joint venture parties on starting new projects more difficult to
reach. The unprecedented economic, financial, and oil market volatility of September–November
2008 are likely to make oil companies more cautious than they were previously about committing
to large new long-term projects until they can see some sort of pattern emerging.

Even if companies think they know the right price to use for planning and investment
purposes, they will see an argument for delay if they believe thereby they can secure better
terms and lower costs. Their experience gives them support for such a belief, as discussed in
Sections III.3 et seq.

III.2 VULNERABLE SUPPLY AND SPARE CAPACITY

These uncertainties and delays have a differential impact on the various components of supply.
Investment in producing fields will continue so long as the price covers their cash costs. Some
high-cost, low-producing “stripper” wells and expensive projects for enhanced oil recovery are
vulnerable—but the volumes immediately at risk are less than 500,000 bd. Most fields under
development will also proceed because of the impact of “sunk cost” economics.

The momentum of fields already under development will continue to add to supply in the
short to medium term: CERA expects that productive capacity in 2010 will be more than 4
mbd higher than in 2008.* Oil demand is projected to be broadly flat over this period, with
some growth in 2010 offsetting declines in 2008–09. Therefore, shut-in and spare capacity could
increase to 7 mbd on average for 2010.

The categories most at risk are development projects that have not yet started, discoveries not
yet approved for development, and spending on exploration. Other, nontraditional components
of future supply such as new biofuel, coal-to-liquids, and gas-to-liquids projects will also be
affected. Because these are the project categories that bear the brunt of any delays, their impact
on total supply builds up over time—and would be clearly seen by, say, 2013.

The IHS Global Insight baseline economic forecast used in this report contains an oil price
averaging $57 for 2009–10. At this level, there are projects at risk in the deep water offshore
Brazil, the US Gulf of Mexico, Angola, and Nigeria; in Norway and the United Kingdom; and
in the Canadian oil sands and Venezuelan heavy oil. The impact on supply starts to show after
2010, and in 2013 the capacity at risk could total 3.8 mbd. Fields currently in development
account for only 0.6 mbd of this figure, with 2.5 mbd coming from discoveries still being
appraised. Reduced exploration accounts for most of the balance—relatively little by 2013, and

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*This figure of 4 mbd is a net increase over and above replacement of production declines at an average aggregate rate of
4.5 percent per year from existing fields.
because deepwater projects have a long lead time to first production. The impact on future supply of reduced exploration will be felt increasingly in subsequent years.

If the prices foreseen in the baseline forecast are realized, we would expect to see supply capacity still growing after 2010, but more slowly as a result of this “lost” investment—on average, at 1.8 mbd per year for 2011–12 and then at 0.7 mbd per year to 2020. Meanwhile, demand is projected to be growing again although, for 2011–12, not yet faster than capacity. Therefore, the shut-in and spare capacity remains at 7–8 mbd until 2013, after which the market starts to tighten once again. It is the expectation of this tightening that causes prices to begin rising even with spare capacity at historically high levels. But from 2018 onward, spare capacity is down to 3 mbd—almost as narrow a margin in percentage terms as prevailed in 2007 and early 2008.

If the oil price turns out to be significantly lower than $60, on average, for 2009–10—or if there is a long period of uncertainty about the economic outlook—there would be larger cutbacks and more delays in the industry’s spending on future supply. However, the reason for prices’ remaining low would be a continuing weak economy and therefore a lack of demand growth—preventing spare capacity from being reduced. Suppose, for the sake of illustration, that the recession is so severe that oil prices languish at $40 or so for 2009–11. Capacity would still rise by 5 mbd by 2012 and the margin of shut-in and surplus would be 7–8 mbd from 2010. After 2012 in this scenario, demand would grow briskly and capacity only very slowly. The surplus would erode and the market would be looking tight again by 2016 (with 3 mbd of spare capacity, equivalent to 3.3 percent of demand). In other words, the trough would be deeper and the recovery steeper than in the baseline forecast case.

Were upstream investment not to slow at all—admittedly, an unlikely outcome in present circumstances—perhaps, because oil prices were supported at $80 through concerted reductions in production, most of the projects at risk identified above would go ahead. Shut-in and spare capacity could reach 10 mbd by 2013. This would be an unprecedented margin and would tend to undermine the oil price well ahead of its fully materializing. However, the projects to deliver it would all be under way by that stage. Prices could be expected to start falling in 2012–13 and to stay low until enough investment had been choked off to let the market move back into balance—a process that would probably take several years.

**III.3 THE PENDULUM SWINGS FOR FISCAL TERMS**

Just as oil companies have adapted to these changing market conditions, so too have resource-holding nations. In the years after 1998, higher oil prices and intense competition for upstream opportunities tipped the balance of power in their favor in their negotiations with the companies. Energy policies initially designed to attract investment and stimulate the development of new basins gave way to government initiatives aimed at capturing a larger share of the growing economic rent.

In many major oil-producing nations (i.e., those countries holding more than 200 billion barrels of reserves), the state take now averages 85 percent, having risen over recent years by
more than 15 percent. Some host governments have set tougher terms only for new activities, while others have also increased their take from existing contracts (see Figure 18).

What Is State Take?

State take is a general term used to describe the share of revenue that accrues to the state over the life of a project. We use the calculation below:

**Calculation of State Take**

\[
State \text{ Take} = \left(1 - \frac{\text{Company after tax cash flow}}{\text{Gross project revenue} - \text{OPEX} - \text{CAPEX}}\right) \times 100
\]

---

**Figure 18**

State Take, 2002–08

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Source: Cambridge Energy Research Associates; IHS Data.

*United Kingdom terms applicable to post-1992 developments.

**Nigeria deepwater offshore leases.

***Sakhalin II PSA contract.

70916-2_1512
When oil prices seem strong and are rising, momentum can quickly build for governments to legislate for increases in state take. In a flatter or declining oil market, it has sometimes taken longer to reverse policies already in place. However, there is little precedent for an oil price collapse on the scale of late 2008. Critical imbalances between price, costs, and taxes may call for emergency responses. There has already been one such response: in November, Russia announced a cut of 32 percent in oil export duties.

III.4 RUNAWAY UPSTREAM COSTS

From 2005 to the summer of 2008, there was a dramatic increase in the cost to find, develop, and produce oil and gas. The IHS/CERA Upstream Capital Costs Index looks at a range of projects around the world, onshore and offshore, for oil and gas. It takes account of changes in cost for industry-specific resources (skilled engineers, dedicated technologies, and so on) as well as more generic commodities (steel, nickel, cargo ships, etc.). This index has increased by 130 percent since 2000. For comparison, the producer price index for finished goods (excluding food and energy) has risen by just 2.6 percent over the same period (see Figure 19).

Rising oil prices from 2003 onward gave the oil companies the wherewithal to raise their capital budgets, and the market’s focus on possible tightness in supply gave them encouragement to take on more projects. On the other hand, during the previous 20 years of contraction, there

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**Figure 19**

IHS/CERA Upstream Capital Costs Index

![Graph of IHS/CERA Upstream Capital Costs Index](image_url)


*Producer Price Index for the United States,*

Finished Goods excluding food and energy.

70113-3_1512
has been strong pressure to “do more for less,” to reduce costs and to improve productivity. Thus, in both the oil and oilfield service companies, neither the people nor the facilities were all in place to respond easily to the increased appetite for projects that developed from 2005.

In addition to tight markets for upstream services and equipment and a shortage of skilled personnel and labor, the industry’s cost base was inflated by some of the same factors that drove the broader economic boom. There were big increases in the price of raw materials such as steel: the industry’s costs of steel rose by an unprecedented 32 percent from first to third quarter 2008. Bulk shipping costs also increased, driven partly by higher fuel prices but also by capacity constraints. Currency fluctuations played a part, especially since most host governments have local content requirements for oil companies developing resources in their jurisdictions.

There is now strong downward pressure on many of these components of cost. New tenders are beginning to reflect reductions, and oil companies are revisiting existing contracts that do not reflect the current market environment. In cases where the expected oil price is too low to justify the prevailing cost level, projects will be canceled or postponed. In a slackening equipment market, part of the price fall may be absorbed, as in the past, by suppliers in the form of lower rates. If the suppliers’ alternative is to see people and equipment idled, they may prefer to cover just their cash costs and absorb the loss on their own recent investments while waiting for the cycle to turn.

These are not just theoretical possibilities. In 1981 the oil price fell from its highs following the second oil shock in 1979. Just as in 2008, the industry’s cost base was left uncomfortably high in relation to the newly prevailing oil price. By 1996 these costs had been reduced to about a third of their 1981 level (see Figure 20).

At the cost levels prevailing in third quarter 2008, the average aggregate investment cost of new supply is $23,000 per daily barrel (ranging, as shown in Table 5 below, from $15,400 per daily barrel in the Middle East to $32,300 in North America). To replace the decline in existing production and allow the net growth in capacity shown in Table 3, above, the total cost to 2015 would be $909 billion—an average of approximately $150 billion a year. However, as argued in this section, costs are now likely to fall from their peak in third quarter 2008; CERA’s estimate is that they could be down by 40 percent over two years.

III.5 RISING COSTS ERODE INDUSTRY MARGIN

The rise and fall of oil prices normally translates rather directly into similar movements in the oil industry’s profitability—whether expressed in absolute terms or as a percentage of its upstream revenues. This was not the case in 2007, because accelerating activity levels were accompanied by a rapid increase in the industry’s costs and because the ever higher oil price led to changes in fiscal terms required by host governments. Thus, although the oil price was almost 11 percent higher in 2007 than in 2006, net income per barrel hardly changed. As a percentage of revenue, it flattened out in 2006 (although the oil price was up nearly 17 percent on 2005) and declined in 2007 for the first time since 2002 (see Figure 21).
Table 5

Regional Breakdown and Investment Cost (2009–15)
Using Third Quarter 2008 Costs Estimates ($ per daily barrel)*

<table>
<thead>
<tr>
<th>Region</th>
<th>Capacity (million barrels per day)</th>
<th>$1,000 per Daily Barrel</th>
<th>Investment Cost (billion dollars)</th>
</tr>
</thead>
<tbody>
<tr>
<td>North America</td>
<td>4.3</td>
<td>32.3</td>
<td>139</td>
</tr>
<tr>
<td>Europe</td>
<td>7.0</td>
<td>30.3</td>
<td>212</td>
</tr>
<tr>
<td>Middle East</td>
<td>13.8</td>
<td>15.4</td>
<td>212</td>
</tr>
<tr>
<td>Far East</td>
<td>3.8</td>
<td>29.3</td>
<td>111</td>
</tr>
<tr>
<td>Latin America</td>
<td>4.4</td>
<td>30.2</td>
<td>133</td>
</tr>
<tr>
<td>Africa</td>
<td>6.2</td>
<td>16.3</td>
<td>101</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>39.4</strong></td>
<td><strong>23.0</strong></td>
<td><strong>909</strong></td>
</tr>
</tbody>
</table>

Source: Cambridge Energy Research Associates.

Notes: Net capacity growth for 2009–15 = 8.5 mbd. Replacement of decline in existing production for 2009–15 = 30.9 mbd. Therefore, gross new production for 2009–15 = 39.4 mbd. CERA projects that by the end of 2010 aggregate upstream costs will fall, on average, by 40 percent from these levels in the projected economic and oil price environment. Using this assumption, the estimated investment needed to maintain and add to production capacity worldwide is around $550 billion by 2015, as opposed to the $900 billion estimate above.
III.6 HOW AND WHY COSTS FALL

As noted in Section III.4, project delays reduce the demand for oilfield services and equipment, but some of these projects will be reactivated if their costs can be cut. One way to achieve this result is for savings to be made by the oilfield service sector. Thus, the question of delay becomes critical both for oil companies and oil service companies, though from different perspectives. The key point, however, is that the prevailing cost base at the time prices start to fall gives little support as a floor to prices (see Figure 22).

Oil companies can also take their own steps to reduce costs. Considering both the operator and contractor sides of the industry together, there are three main sources of reductions: changes in technology, consolidation of assets and companies, and the streamlining of both procurement practice and work processes.

Technology has a critical role in allowing oil companies to manage field development costs. Some asset types—e.g., ultradeepwater and arctic resources, extra heavy oil reserves—would still be unusable without the recent introduction of certain key technologies. In addition, new technology can reduce field development costs and improve the economics of all asset types. For example, technology can improve exploration success rates, and improvements in wellbore architecture can result in higher flow rates per well.
Ownership of oilfield interests is often divided between several oil companies. Even though one company will almost always be appointed as “operator” on behalf of the whole group, each interest holder has a fiduciary duty to its shareholders to exercise a degree of technical and financial supervision over its asset. One way to reduce costs is to economize on this supervisory overhead by consolidating ownership into fewer assets through disposals of small interests and swaps between asset owners.

Similarly, corporate consolidation takes place whether prices are high or low, but the activity level increases with a fall in price and vice versa. If, as expected, the price collapse of 2008 now leads to increased corporate activity, buyers will be seeking overlap rather than extension (so they can cut costs by stripping out duplication of work and positions), and more sellers may be constrained rather than profit taking. The same drivers for consolidation exist in the service sector, which is already more concentrated than its clients, the oil companies. Those clients may have fewer competitors to choose from once they are ready to increase their activity levels. If so, the next run-up in the industry’s cost base may be even quicker and steeper than it was during this cycle. More serious still will be the loss of capacity and, especially, of skilled and experienced people from the service sector. People who leave the industry tend to move on to other careers and not to return when conditions improve. (Given the demographic profile

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Source: Cambridge Energy Research Associates.
*UK North Sea shallow water.
**US Gulf of Mexico.
***Steam-assisted gravity drainage (SAGD) with upgrader.
****Mining with upgrader.
Note: Venezuela heavy oil includes upgrader.
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of the industry today, many of these people will just retire.) New recruits lack the training and experience to replace them. In addition, recruitment may be inhibited if the industry is seen as very cyclical.

Opportunities remain to improve the efficiency and thus reduce the costs of major project design and execution. A business unit of one large oil company adopted the approach of consolidating the activities of the operator, main contractor, and its subcontractors for its modification projects (for which its annual budget was $250 million) and achieved a 7 percent cost reduction.

III.7 MEETING THE COST OF UPSTREAM INVESTMENT

Self-Financing by the Majors

“Project finance”, whereby a developer borrows from (usually) a syndicate of banks, and all or most of the project’s future revenues, once these commence, are dedicated to repaying the loan limits or, on the face of it, eliminates recourse to the developer’s balance sheet should the revenues fall short of requirements. Large companies tend to avoid this method of financing because they have cheaper alternatives. Most large oil companies can raise corporate credit at lower interest than project finance allows—and more flexibly as to the use and servicing of the debt. Since this segment of the industry is almost always cash positive in its operations—both upstream and downstream—they have generally low levels of corporate debt. In essence, upstream investment is normally funded from upstream cash flow, and upstream cash flow is normally sufficient to meet those investment needs (see Figure 23). Because corporate balance sheets are particularly strong, following several years of rising oil prices, the large investor-owned oil companies are well placed to meet the cost of many if not all of the projects that they wish to pursue, even in current conditions when the oil price has fallen steeply but costs have not yet followed suit. Nevertheless, they will initiate a process of reprioritization in a period when spending will be much more tightly controlled in terms of volumes and of timing.

Borrowing by the Independents

Smaller oil companies—the so-called independents, some of which are themselves quite large—face more of a challenge. A large part of their business model depends on their offering a faster rate of growth than the majors. So they invest more in relation to their existing production (small independents with no production at all are not uncommon) and as a result their cash flow usually needs to be supplemented by external finance. Independents normally operate with higher levels of corporate debt than the majors and make greater use of project finance.

Whichever the form of borrowing, the amount obtainable by independents is affected by changes in the oil price. Their “borrowing base” is normally calculated by reference to their future cash flow; this depends on the banks’ assumptions about future oil prices, on which the current level and most recent history have a powerful influence. Even in the absence of the credit crunch, the independents would not now be able to raise all the funding for investment on which they had been planning up to mid-2008.
Retained Cash Flow Funds the NOCs

*Majors* and *independents* are convenient labels, covering considerable diversity among their many member companies. The third conventional category within the industry, *National Oil Companies*—NOCs— is even less homogeneous. Some are wholly owned by government, some are partly privatized—but the degree to which each acts commercially, independent of government policy, does not always follow neatly from the extent of state ownership. Some operate upstream only at home; others have international interests. On the latter, each must pay its own way; some do likewise for domestic investment, and others are “carried” by their partners under production-sharing arrangements.

In this context, the key question is the extent to which the NOC decides its own dividend policy: Now that the oil price has collapsed and revenues are greatly reduced, how much of what remains will be available for reinvestment? Even if the NOC has partners in the project, all of whom are willing and able to proceed, the project will not go ahead unless the national company has the necessary capital budget for its share. (Similarly, of course, in the absence of a national company, a major with partners among the independents will find its project delayed if those partners cannot finance their shares.)

CERA has examined, country by country, the upstream projects that are currently scheduled to come into production in the period 2010–15—and are therefore vulnerable to delay or cancellation.
in the current price environment. In our assessment, about 40 percent of this new capacity requires an investment contribution from the relevant host country’s NOC. This is not to say that all, or even most, of the 40 percent will be postponed. However, it does provide a measure of the potential exposure of future supply to any revenue squeeze faced by host governments as a result of low oil prices, if transmitted to their NOCs. It is rare for the aggregate net cashflows of the entire industry to fall short of providing sufficient funds to support a self sustaining level of investment. But the mismatches between the individual ownership of investment opportunities and access to funds (whether the result of government spending priorities or, particularly for the independent oil companies, access to new capital) can provide a barrier to sufficient investment happening in a timely fashion.
IV. THE RISKS TO FUTURE SUPPLY ARISING FROM VOLATILITY IN OIL PRICES

Is there a “right price” for oil that would remove the volatility and uncertainty from investment planning by governments and oil companies? Superficially this might seem like an attractive proposition. If only producers could enjoy greater security of demand. If only consumers could rely on there being no disruptions to supply. If only inventories alone were sufficient to dampen price volatility and there was no need for the market to guess about future changes in spare production capacity. If only institutional investors were consistent in their demands on the energy companies in which they invest.

This chapter outlines the reasons that volatility in oil prices reduces investment in new supply capacity below its theoretical level and, in fact, is subject to an unavoidable asymmetric bias to the downside. The consequences are that markets take longer to react to increasing tightness than to react to loosening through a weakening of demand growth. However, excessive consensus in outlooks can create imbalances that accentuate cycles to the same extent that lack of transparent information can exacerbate volatility.

In this chapter, volatility refers to significant changes in the oil price over periods of weeks and months rather than intraday or day-to-day variations. Over the past three decades, there have been several incidents of extreme such volatility. The purpose of this chapter is to explain how the uncertainty so created reduced capital investment below the levels that would have been expected in a more stable world, with a resulting increase in the imbalances that lead to volatility. This was particularly the case in 2003–04, when the industry’s caution—a lack of confidence that the price rise was not just another spike that would soon abate—delayed its response to the signal of a rising price and contributed to the scale of the rise. This caution was reinforced by the “demands” of institutional investors that companies exert “discipline”—i.e. restraint—in their investments.

To describe how volatility reduces investment, it is first necessary to discuss the way field development decisions are taken by oil companies—whether NOCs, IOCs, or some hybrid of the two.

IV.1 FIELD DEVELOPMENT DECISIONS

When deciding how to allocate their capital to develop new oil reserves, different oil companies perform broadly consistent analyses of the economic attractiveness of the investments based on the expected costs of development, the volumes of production, the fiscal terms under which eventual production will take place, and a projection of the prices they will receive for their production.

Approaches to Allocating Capital

For the most part, companies face a constraint on the capital resources that they can deploy. The constraint arises either because the expected economic returns of a project do not meet a threshold to secure funds (internally or externally) or as a result of actual realized net cash
flows being insufficient to fund the investment. Either way, there is a ratcheting downward on capital expenditures because investments cannot be retrospectively increased if realized prices are higher than forecasted.

In deciding between projects, CERA’s analysis suggests that two main approaches are adopted. Companies set a “hurdle rate” of return that forecasted project economics must exceed. This hurdle is set at a level that exceeds the cost of capital by a margin to account for both the abortive costs that oil companies incur (such as for unsuccessful exploration wells) and the general costs of running the business (salaries, office facilities, etc.). However, companies with more options than either capital or manpower resources to execute them prepare “ranking lists” to identify which of their projects deliver the highest returns (or shortest paybacks, highest value per unit of investment, etc.) and choose the top performing options.

IV.2 TOOLS FOR DECISION MAKING ON INVESTMENTS IN NEW FIELDS

Oil companies tend to behave cautiously when making field development decisions. They consider the preceding exploration and appraisal (E&A) phase as high risk, calling for the investment of tens of millions of dollars in acquiring petroleum rights, conducting surveys and studies to evaluate prospectivity, and then drilling wells. Most such efforts “fail” (that is, do not discover commercial quantities of oil or gas), and their costs must be recovered from the returns earned in the successful cases. However, the capital commitments for developing the successes are typically an order of magnitude larger than for E&A. Therefore, the consequences of volatility in the outcomes are far greater, so companies protect themselves in each of several dimensions.

• **Oil price assumptions.** The oil price outlook chosen to evaluate a development project is typically lower than IOCs expect for the actual outturn. During the 1990s most companies looked for projects that were resilient to $16 per barrel—notwithstanding some sought resilience to $12 or $13. NOCs normally develop their budgets based on revenues calculated at a price provided by their government shareholder. This will be the price on which the national budget is based and is generally set quite conservatively.

• **Reserve volumes.** More often than not, companies evaluate investment decisions on the basis of a field’s proved reserves—broadly equivalent to a 90 percent likelihood that the actual volumes will turn out to be higher and only a 10 percent likelihood that they will turn out lower.

• **Hurdle rates of return.** Major IOCs and independents typically use a hurdle rate that is greater than the company’s cost of capital. NOCs typically use a less conservative approach to determining the appropriate hurdle rate: during the 1990s some such companies used a hurdle rate equal to their cost of debt funding. The result is that NOCs sometimes proceed with investments that might earn less than 10 percent rates of return in nominal terms, while the largest IOCs might require real rates of return of 15 percent to support a project. Such rates of return are appreciably higher than the long-term average returns
achieved by the industry, but this margin over industry-normal returns shows shareholders the value creation they can expected to achieve.

- **Net present value (NPV) calculations and cover ratios.** Another point of reference is provided by the independents. Their developments are often funded by project finance, by bank debt, or through the issuance of loan notes into a partially traded market in the United States. Bank debt is usually limited to some percentage of the NPV (calculated after the application of a cover ratio).

- **Net appraised values.** When companies seek to raise equity, the valuation of their assets by market analysts focuses, in the case of US independents, on multiples of their net cash flow as a proxy for the value of their assets. International independents (and indeed NOCs undergoing partial privatization and raising capital in the markets) present appraisals of their net asset value (NAV), prepared by independent consultants. In either case, equity issues tend to be conducted at a discount to the NAV.

Regardless of the approach that companies use in making their decisions, layer upon layer of caution is included—on prices, volumes, rates of return required, and values or cover ratios calculated using those parameters. The purpose of all these “haircuts” is to protect against volatility—particularly in oil prices and to the downside—that would lead to negative returns on capital-intensive projects.

Although all companies use variants on the themes just described to decide where to allocate their capital, the actual processes naturally vary from company to company. Budgets do not authorize expenditure; there are additional processes for determining the release of budget funds to specific projects, and for NOCs often several stakeholders must approve such spending. Even for major IOCs, it takes time to decide to increase expenditures in any fiscal year—in contrast to the speed with which cutbacks can be demanded by both NOCs and IOCs in the event that prices fall below expected budget levels. Independents tend to be smaller and have more flexible budget processes.

**IV.3 IMPACT OF FALLING VOLATILITY ON INVESTMENT DECISION MAKING**

The 1990s provide an example of how these tools are used by oil companies. During the early part of the decade, the cover ratios demanded by banks and other lenders were reduced, proved-plus-probable reserves were accepted in appraising NAVs, equity issues narrowed the discount to the appraised NAVs, and the rates of return demanded by investors fell. It is not possible to demonstrate that this dwindling caution was caused by falling volatility in oil prices, but it is striking that the more distant the memory of the 1980s price collapses became, the smaller the risk margin that all sources of finance demanded—until prices collapsed once again in 1998–99.
Oil Price Assumptions

The process began with the oil companies themselves. As the 1990s passed it became increasingly accepted that prices would likely remain in a range of $15–$20 a barrel. Each layer of caution in investment appraisal began to erode. The further in the past that the price collapses of the late 1980s receded, the more companies were prepared to reduce their “insurance” against potential downside.

Oil prices had been falling for much of the previous decade. As they did so, projections of future prices were revised downward and each was considered prudent at the time it was made—although they were constantly being overtaken by the facts. By the early 1990s a gap was finally established between expectations of future prices (illustrated here through the annual survey conducted by the California Energy Commission—see Figure 24) and the prices then being used to appraise development decisions. Prices for Brent blend averaged some $18 per barrel, but most companies were using outlooks for investment decisions of $15–$16, escalated with inflation—i.e., constant in real terms. Some majors made a point of using prices that were even lower. In 1994 the average price of Brent was, in fact, within this range but was out again by 1995. Thereafter, investments were being made as if on the assumption that this represented a price floor.

By 1998 the growing supply capacity resulting from these stable conditions ran headlong into the Asian financial crisis. This coincided with an increase in the OPEC members’ production.
quotas, and prices fell rapidly to average below $13 per barrel. Despite a rebound in the following year, companies began testing their developments against increasingly low price sensitivities—our thesis is that such caution is the typical response to volatility—and capital discipline again became a source of competitive differentiation between oil companies.

When prices broke out of their established range in 2003, few companies—whether IOCs or NOCs—or their owners were anxious to increase their spending, much less their oil price outlooks for evaluating investments. The memory of 1998–99 was still too vivid. Prices rose further in 2004, but the outlooks that companies used to evaluate their investment decisions lay nearer $20 per barrel than $30: the layer of caution associated with them had been re-established by the renewed volatility. Companies were also under pressure from their investors to demonstrate capital discipline. Levels of investment did not start to increase until 2005. The time taken before the industry stepped up its investment contributed to the delays in bringing new capacity onstream. This added to market tightness in 2006–08 and helped prices to scale their unprecedented heights.

Rates of Return

Rates of return showed a similar pattern. Following the late 1980s decline in prices, companies required high rates of return on new developments—real rates as high as 17 percent, in some cases. As the 1990s progressed, these hurdles began to fall. The most visible examples are the rates of return built into the Iranian “buyback” contracts that were offered in the 1990s (the early contracts allowed higher rates of return than those concluded toward the end of the decade) and in the Mexican Multiple Services Contracts to cover the costs of financing. Significant development commitments were made on the basis of these agreements that presumed rates of return only a few percentage points higher than companies’ cost of capital.

Reserves Estimates

Reserves estimates also became more generous as companies scrambled to increase their investments after 2004. When hurdle rates could not be jumped based on proved reserves alone, some companies began to evaluate projects on the proved-plus-probable reserves (the level at which the likelihood of the actual recovery’s being higher than the estimate is equal to the likelihood of its being lower). In the past few years, several projects have received development sanction from their owners—and several acquisitions have been made—despite that the proved reserves alone were not sufficient to support the costs.

IV.4 REDUCTIONS IN CAPITAL INVESTMENT RESULTING FROM VOLATILITY

As volatility increases the levels of caution in investment decisions, companies invest in fewer projects, thereby reducing the productive capacity that will be available. Price expectations that are lowered and hurdles that are raised disqualify projects that would otherwise have passed. This is an asymmetric bias—when price expectations are too optimistic, there is no offsetting surplus of new capacity because future cash flow that falls short of expectations is itself a source
of budget restrictions. Whether prices rise or fall, the effect is to reduce capital investment over time below the level that would have pertained had they been more stable.

When the majors invest less than actual oil prices would allow, some of the capital investment they forgo becomes dividend payments or share buybacks instead. For NOCs, excess funds are normally transferred to the national treasury and thence, in part, to additional government spending. In either case, extra funds for shareholders or government generate additional oil demand to the extent that they contribute to GDP growth. Thus, the imbalance between lower supply than otherwise in future and higher demand is further increased.

The delay in increasing expenditures between 2003 and 2005 is a measure of the lag that can emerge if companies are unsure that an increase in prices will be lasting. Even when the decision is made to increase levels of investment, there can be further delays resulting from the logistical constraints of adding personnel, rigs, etc. Looking forward to the period beyond 2009, the extent to which companies reduce workforces and cut costs in the downturn will affect the lag in reaction to the start of the next up-cycle. There is a danger that the expected depth and length of the current down-cycle may undershoot the fundamentals to the same extent as prices in the first half of 2008 overshot.

IV.5 BRINGING STABILITY TO FUTURE OIL PRICES

The extent of the current undershoot may lead to the eventual rebound in prices testing highs above even the levels recorded in July 2008 unless companies begin investing in anticipation of a recovery. Otherwise, it is hard to see how demand growth can recover both so clearly that it calls forth new investment, yet so gradually that the long lead times for new oil investment do not create another timing mismatch between the growth of supply and demand.

Faced with the potential for increasingly violent swings in the oil price—resulting from timing effects and market reactions, all adding to the bias toward underinvestment that is created by volatility—it is only natural to ask if there are ways to remove this volatility. Simply put, stable prices are not an option; the oil market is too big, complex, diversified, and international. There are too many participants with major national, economic, or commercial interests at stake. The lead times are too long and the supply side too “lumpy.” There are also too many variables that can “shock” the market—although such shocks may sometimes take years to develop. In addition to difficulties in forecasting supply and demand, the relentless march of technology widens the economically recoverable resource base and alters the costs of development and production. Technology affects the demand side, as well—by altering the impact of changes in price or income, over both the short and long term. The reduction in oil demand for power generation as combined-cycle gas turbines consolidated the incursion of gas as an alternative fuel provides just one example. Political and civil unrest in producing countries can remove significant quantities of supply from the market just as easily and as suddenly as economic or financial crises—for example, from the housing market—can remove significant quantities of expected demand growth.

The history of oil prices from 1945 to 1972, however it appeared at the time, now looks like a long period of great stability. The story since then illustrates the market’s exposure to
the unexpected—and the history of oil price forecasts over the same period shows dramatically the difficulty facing anyone, consumer or producer, trying to foresee the path that oil prices will follow. Even though major geopolitical surprises such as those that led to the increases of 1973 and 1979 have had less impact on the market for the past 20 years, macroeconomic, technological, and operational changes have kept it just as unpredictable.

Thus the conundrum facing the oil industry over forecasts of the oil price. Stability leads to consensus about expectations for the future and—as shown by the California Energy Commission surveys—expectations for the future are mostly rooted in current prices, whatever they may be at the time. The longer that stability is perceived in the market, the more the consensus solidifies around the current price. In light of this apparent stability, companies invest in new supply, with less of a safety margin between those expectations and the economics necessary to support their investment. Similarly, consumers make decisions about fuel choices and volumes less conservatively than otherwise might be the case. When all players in a long-term and lumpy market foresee the same future outcomes, imbalances develop that eventually cause this consensus to fall apart.

The price run-up to 2008 managed to ignore the evidence of slowing demand growth because of uncertainty about the prospects for supply, both short and long term. Part of this uncertainty was caused by what emerged as shortages of skills, experience, and equipment across the industry and its supply chain. However, worries about supply were magnified by variable availability and quality of data on the demand side, a perceived lack of transparency about production, and a real lack of stock levels in some parts of the world. Geopolitical tensions focused attention on the potential for supply disruptions that could exceed then available spare capacity. Uncertainties about the global economy—a financial “flight” to commodities and theories decoupling emerging markets from the OECD economies—added noise to the market.

Occasional shocks to the global economy and volatility in the oil market may be inevitable in the future, but the height from peak to trough of price movements need not be so extreme. In engineering terms, there are benefits to be gained if the ratio of market signals to market noise can be increased. Market noise is difficult to predict, much less to control. However, market signals can be provided if governments, the oil industry, and commodities markets—or those who regulate the last two—choose to provide them. Greater transparency of market information and data represents the best hope for limiting future volatility in prices and ensuring a more appropriate match over time between supply and demand.
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