The Oil Industry’s Growth Challenge: Expanding Capacity from the Wellhead to the Consumer

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THE OIL INDUSTRY’S GROWTH CHALLENGE:

Expanding Capacity from the Wellhead to the Consumer

Each era brings with it new challenges for the oil industry. This first decade of the new millennium is no different, except for one key distinction. Today’s growth challenge is of a scale that the oil industry has not experienced since the 1960s and early 1970s when upstream and downstream capacity raced ahead to keep pace with soaring demand. Today’s circumstances are fueling a widespread supply anxiety.

But it is not just the scale of the challenge that is remarkable. Several other elements add to the unique features of today’s market.

• **The geography of oil demand is changing.** New, high growth demand centers have emerged in China, India, and elsewhere in Asia. Demand growth is no longer just an Organization for Economic Cooperation and Development (OECD) story. The Middle East, Latin America, and Africa will also have an impact on global demand to varying degrees.

• **Product demand patterns.** Nearly all growth in world oil demand today consists of light and medium products: principally gasoline, jet fuel, and diesel. Demand for heavy fuel is in structural decline. However, the global refining system is not fully aligned with the profile of product demand, particularly in Asia. Expansion of crude distillation and upgrading capacity will put the refining industry in a growth mode for years to come.

• **The drive for cleaner fuels and efficiency.** Governments in major markets around the world have increased fuel quality standards because of environmental concerns. In many cases, this means removing sulfur from gasoline and diesel, which adds to the complexity and cost of aligning the global refining system with product demand and quality trends. There will also be new pressures to improve efficiency in the transportation system.

• **The evolution of where and how we produce oil.** The oil industry is producing increasing volumes of liquid hydrocarbons from the oil sands of Canada and the tar sands of Venezuela. In the late 1960s, oil sands production was minimal, but also very expensive—several times the price of crude oil at that time. Now in Canada alone there is 1 million barrels per day of oil sands production—with much more on the way. Also, it was not that long ago when exploring in 5,000 feet of water pushed the limits of technology. Today, deepwater production is a large and critical source of supply growth in West Africa, Brazil, and the US Gulf of Mexico. Frontier depths are now 10,000–11,000 feet. In addition to oil sands and the deep water, gas-to-liquids (GTL) and ethanol will play more important roles over the next decade.
THE CORE CHALLENGE: INCREASING UPSTREAM PRODUCTION CAPACITY

The most fundamental challenge facing the global oil industry is to increase oil production capacity. After all, if there is insufficient oil supply to process in refineries, then the downstream challenges fade in importance. The supply challenge is not new. Indeed, rising prices and the current thin cushion of spare liquid production capacity have resurrected an old worry: fear that the world is running out of oil. This has been a recurrent theme ever since the first oil well began production in Pennsylvania in 1859. It gathers steam and garners media attention about once every generation or so—particularly when oil prices are on the rise.

Are we running out of oil? CERA’s belief is no, we are not running of oil resources. In a CERA Private Report earlier this year, we concluded that production capacity has the potential to expand by 2015 to levels in excess of potential demand.* We also look to an “undulating plateau,” not a peak. Our outlook contradicts those who believe that peak oil is imminent. This research has also intensified the international debate over the peak oil issue and liquids supply in general.

In this new report, CERA projects that world liquids production capacity has the potential to rise from 87 million barrels per day (mbd) in 2005 to 108 mbd by 2015 (see Figure 1). Although there have been recent downside factors such as the slowing rate of expansion of capacity in Russia and continuing problems in Iraq, this is balanced by a more positive outlook for major producers such as Angola and Brazil, where a stream of major projects continues to come onstream. Our conclusions about the growing importance of unconventional liquids (condensates, natural gas liquids, deepwater production, and extra heavy oils) show that by 2015 they will represent 34 percent of total capacity.

Figure 1
World Liquid Productive Capacity

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*See the CERA Private Report Worldwide Liquids Capacity Outlook to 2010: Tight Supply or Excess of Riches?
To be sure, many significant risks to production capacity loom on the horizon, but these are largely above-ground risks. Perhaps the greatest problem at present is the severe lack of qualified manpower resources and limits imposed by rig and yard availability and materials. At current high oil prices most oil companies want to increase activity levels, especially with existing producing fields, that will have a rapid return on investment, but increased competition has driven the cost of manpower and services higher.

**ACCESS FOR NEW INVESTMENT LOOMS LARGE.**

Political risks also have an impact on capacity expansion in the Middle East, where the situation in Iraq continues to be highly problematic, and there is growing uncertainty over events in Iran. In addition, changes in ownership, the constraints of geology, and the fiscal and regulatory systems, as well as logistical bottlenecks and geological challenges have led to the end of the high supply growth era in Russia. In Venezuela fiscal and political changes have hindered the recovery of oil production and investment in the aftermath of the late 2002/early 2003 disruption.

Our views about the peak oil debate have been reinforced by a detailed new audit of our own analysis and also further evidence that has come to light concerning the enormous scale of field reserve upgrades of existing fields. We also draw upon the proprietary databases of IHS, of which CERA is now part. These are the most extensive and complete databases on field production around the world. We see no evidence to suggest a peak before 2020, nor do we see a transparent and technically sound analysis from another source that justifies belief in an imminent peak. It will be a number of decades into this century before we get to an inflexion point that will herald the arrival of the “undulating plateau.”

**CERA’S METHODOLOGY**

CERA methodology generates an activity-based model that involves a rigorous bottom-up analysis of each country, for which we sum component capacity profiles for fields in production (FIP), fields under development (FUD), fields under appraisal (FUA), and a yet-to-find (YTF) component. Decline rates are built into this analysis. It is important to understand that we do not predict production as such, but rather capacity to produce, and that our assessment is lower than the industry aggregated total. We do not simply focus on crude oil alone, but encompass unconventional liquids including condensates, natural gas liquids (NGLs), heavy oils, and ultradeepwater oils. Many of the other projections available do not include all of these components, and this may explain why CERA’s outlook is different. We also recognize that above-ground developments could lead to capacity growth’s falling short of its potential. We have three scenarios for oil production capacity (and demand and price). The numbers quoted in this report are from the November 2005 Supply Expansion scenario update and reflect the upper range of expectations. We also discuss our Supply Anxiety scenario, which illustrates the potential impact of delays and disruptions on capacity.
Major Trends and Signposts

Assuming no serious political crises in key producing countries, global liquids capacity will continue to grow strongly toward 102.4 mbd by 2010 from the current level of 87.2 mbd (see Figure 1). This expansion will be fairly evenly split between OPEC and non-OPEC countries: 8.5 mbd and 6.7 mbd, respectively. The expansion continues to 2015, but OPEC shows a greater increase: a net gain of 12.2 mbd (relative to 2005) versus 8.2 mbd for non-OPEC. At the regional level, the United States and North Sea show decreases to 2015 while Canada, West and North Africa, Latin America, and the Caspian, and the Middle East continue their current trend of strong expansion past 2010 and through 2015. Southeast Asia shows some modest growth, but declines after 2010. At the same time, Russian capacity growth slows.

By 2015 we also see a change in the geographic focus of the sources of liquids supply. The proportion of liquids capacity from the top 15 countries will rise from 58 percent in 2005 to 65 percent in 2015. While nearly every OPEC country, except Indonesia, shows potential for a significant increase to 2015, the sources of expansion in non-OPEC countries are more limited, with Russia, the Caspian, Brazil, Angola, and Canada leading the way. We also note the emergence of some new sources of liquids capacity both in the deep water, such as offshore Mauritania, and onshore in Sudan. In addition, mature areas such as Malaysia are reemerging and a new play is being successfully explored and developed in a previously unexplored deepwater area offshore Sabah, in northwest Borneo. However, this shift in emphasis may prove to be to more politically and operationally challenging countries, which increases the levels of risk and supply anxiety in some consumer countries.

There are a large number of major projects in both OPEC and non-OPEC countries that underpin the increases. The top 10 projects being brought onstream each year will add a cumulative gross capacity of 2.0–2.5 mbd per year until 2010 alone. These projects were approved under a much lower oil price regime, and even if the oil price falls significantly these projects will proceed. While there has been some slippage (e.g., Thunder Horse and Adar Yale), other projects are coming on ahead of schedule (e.g., Kizomba B).

Trends in Crude Quality and Unconventional Liquids

Analysis of the composition of new capacity shows that in the medium term there will be increasing proportions of light and heavy oils and a reduction in the proportion of medium grade crude. Among the unconventional oils we see a continuing rapid expansion of deepwater production capacity up to 2010, with a major surge from 3.4 mbd in 2005 to over 9 mbd by 2010. This surge will be dominated by growth from the “big four” deepwater areas: the US Gulf of Mexico, Brazil, Angola, and Nigeria, with more modest contributions from other areas.

Production capacity of extra heavy oil from Canada and Venezuela will expand from 1.8 mbd in 2005 to 4.9 mbd in 2015. Despite accidents earlier in 2005 the Canadian projects are moving forward as fast as manpower and resources can be found. Expansion from 1.2 mbd currently to 3.4 mbd by 2015 is anticipated, with approximately half being mined and the remainder in situ. In Venezuela the four main Orinoco projects are onstream (totaling 650,000 bd) and with debottlenecking could reach 700,000 bd by 2010.
Between 2005 and 2015 there is considerable potential to expand total condensate plus NGLs capacity from 14 mbd to 22 mbd. Notable condensate expansions will occur in Qatar as the liquid natural gas (LNG) business expands and more gas is produced for reinjection to enhance field recovery. Among the largest expansions of condensate capacity will occur in Norway as the Ormen Lange and Kristin fields are developed. The story for NGLs is similar, with much of the expansion to 2010 occurring in many OPEC countries, including Saudi Arabia, Qatar, and Nigeria. NGLs capacity in the United States will decline by 2010 in response to declining gas production.

Until recently the GTL business had contributed only a small proportion of production (160,000 bd in 2005), but there are a number of projects under way and planned that are expected to boost production capacity to 480,000 bd by 2010 and 1 mbd by 2015. This is a lower buildup than might be anticipated by summing the reports of current activity, but we expect that operators will not commit to new GTL projects until there is some certainty that the oil price will remain high on a sustained basis.

**OPEC Capacity Trends**

Although most OPEC members are currently producing at or very close to capacity, they are in a strong position to expand total liquids production capacity to 49.9 mbd by 2015, with the proportion of condensates and NGLs rising by that time. Much of this expansion will tend to come from existing fields and discoveries rather than extensive new exploration. The key challenges are to understand the impact of decision making and political uncertainties on project execution and to take into account price trends that will influence the buildup of capacity over the next half decade.

- **Saudi Arabia** possesses the largest resource base in the world, with 268 billion barrels of proven reserves. Recent reports suggest that some 200 billion barrels of reserves is likely to be added. CERA believes that, in common with other countries around the Gulf, the exploration potential is still very high, despite the high level of existing proven reserves. While there has been much debate about Saudi Arabia’s ability to expand production capacity, we see no comprehensive justification of claims that production is about to “fall off a cliff.” We anticipate an expansion of crude and condensate capacity from 11.1 mbd in 2005 to as much as 13.2 mbd by 2015. Much of this expansion boost will come from Haradh 3 (+300,000 bd in 2006), Shaybah (+200,000 bd in 2007), Khursaniyah (+500,000 bd in 2008), and if necessary Khurais (1.2 mbd in 2010). Saudi Arabia is working to sustain its 1.5–2.0 mbd level of surge capacity while concentrating on increasing production of lighter and sweeter crude oil.

- **Iran** is making slow progress in expanding capacity, which currently stands at just under 4.2 mbd. With relatively high annual decline rates, delays in bringing new projects onstream, problems with existing projects (Soroush-Nowruz), and the changing internal and external political environment, the rate of expansion will slow compared to previous projections, but is still expected to reach 5.2 mbd by 2015.

- **Iraq** did not reach its goal of achieving production of 2.8 mbd by April 2004. It is currently producing 1.9 mbd and it is difficult to predict exactly when the situation will stabilize and allow new investment in the oil and gas sector. We believe that progress will be slow, with capacity reaching 2.8 mbd by 2010 and 4 mbd by 2015. Iraq has the potential for sustained liquids capacity in excess of 5 mbd and has major exploration potential. It will likely be a major player in OPEC expansion after 2010.
• **Libya** has reopened its doors to US oil companies following the lifting of sanctions. Presanction license holders have renegotiated their contracts. In addition, a number of successful licensing rounds have occurred and we anticipate that new discoveries will start feeding into the development queue by 2007/08. Meanwhile, there is a backlog of discoveries to develop and the possibility of enhancing production from some of the major fields that have seen very little investment for 20 years. Libyan production capacity will average 1.8 mbd in 2005 and climb fairly slowly to 2.6 mbd by 2015. It remains to be seen, in these times of limited global resource, how rapidly activity will pick up, how the Libyan authorities will react to a sudden influx of investment, and what the role of the national oil company will be.

• **Nigeria**’s deepwater projects finally appear to be moving forward, with Bonga expected onstream later this year, after considerable delays and cost overruns, and Erha coming onstream early in 2006. Exploration appears to be bearing fruit with the recent Obra and Egina South discoveries. Expansion of production capacity to 4 mbd by 2010 from the current level of 2.9 mbd is strongly supported by current activity, but problems with ethnic tensions and strikes will persist.

• **Indonesian** production capacity is dominated by small, mature fields that show high rates of decline. Despite progress with the negotiation of the Cepu project (170,000 bd by 2008) and other new projects on the sidelines (Gendalo, Oyong, and Jeruk), as well as major efforts to attract investment, we believe that Indonesia will struggle to expand capacity much above 1 mbd in the foreseeable future.

• **Venezuelan** capacity is expected to continue to grow slowly from 2.9 mbd in 2005 to 3.4 mbd by 2015, despite the huge resource potential. Capacity is slowly being expanded at Ceuta and Tomoporo, and the 60,000 bd Corocoro field is due onstream in 2006. The Orinoco projects are currently contributing 650,000 bd. The sluggish recovery from the strike in 2002/03 is reflected by a slow increase in the number of active rigs and a slow buildup in investment. Also, changes in the investment climate will affect future levels of investment.

• **United Arab Emirates** crude plus condensate capacity is expected to expand from 2.9 mbd in 2005 to 3.5 mbd in 2015. Growth will be underpinned by expansion at the Bab, Bu Hasa, and Dhabiya fields and further supported by expansion at Upper Zakum, where negotiations with the foreign partner continue and approval is not expected until 2006.

• **In Kuwait** expansion from 2.5 mbd to 3.5 mbd is expected between 2005 and 2015. The schedule for implementing Project Kuwait, aimed at increasing the production of Northern Fields from 600,000 to 900,000 bd, is not clear at this point. Meanwhile maintenance and reconstruction of the western and northern gathering centers continue, and there are plans to expand capacity in the south in and around Burgan, all requiring major investment.
Non-OPEC Capacity Trends

Non-OPEC countries have a considerable inventory of projects under way and planned by 2010. There are 80 projects with reserves greater than 100 million barrels and a further 120 with reserves above 20 million barrels due to come onstream before the end of 2008. Non-OPEC production capacity is set to rise to 56.3 mbd by 2010, with the rate of growth slowing after that point. Capacity has the potential to reach 57.8 by 2015. This apparent reduction in the rate of increase after 2010 could be real, but could also reflect the less clarity in that time period as to our lack of knowledge which projects are likely to be developed, given that our Supply Expansion outlook is an activity-based model.

- **Brazil.** Current production capacity of 1.8 mbd is set to expand to 2.9 mbd by 2010. Following the inauguration of the Barracuda project in late 2004, three more major projects are due onstream in 2005—Albacora Leste, Caratinga, and Jubatre Phase 1—which will collectively add as much as 400,000 bd. In the next three years we will see an additional three major deepwater projects coming onstream per year, and with the recent successful Seventh Licensing Round and continued exploration success, we envisage continued expansion in total production capacity well past 2010.

- **Angola.** Capacity is expected to expand rapidly from current levels of 1.3 mbd to 2.5 mbd by 2010. The 250,000 bd Kizomba B field was recently brought onstream early, and further details of Kizomba C, which should be onstream in 2008, were recently released. The string of deepwater discoveries in Angola continues, especially in Blocks 31, 32, and 33. These discoveries will undoubtedly yield at least three major developments that will come onstream later this decade. Developments in Angola, Nigeria, and elsewhere in the region will push West African liquids capacity up to 9.2 mbd in 2015, from 6 mbd in 2005 (see Figure 2).
• **United Kingdom.** The United Kingdom is typical of a mature basin that is past its geometric peak of oil production. Indeed, there were two peaks, in 1985 and 1999, which marked a plateau lasting more than 15 years. Capacity is now on a broadly declining trend despite the relatively high levels of activity. However, at the current high oil prices, and capitalizing on the extensive mature infrastructure, many small (less than 20 million barrels of oil equivalent) projects are being developed and helping to arrest the decline. Occasional major discoveries are still made in the United Kingdom, and Buzzard, currently the largest development in the UK North Sea, will be onstream in 2006. Successful appraisal of the major Lochnagar/Rosebank discovery on the Atlantic Margin could drive it toward development soon after 2010. Even so, the overall trend is lower, and by 2015 we anticipate production capacity of 1.24 mbd (down from 2.09 mbd in 2005).

• **Norway** shows some slight positive momentum for capacity in the short term, but with current rates of success and an inventory of relatively small discoveries to develop, CERA predicts that production capacity will decline from 3.3 mbd in 2005 to 2.3 mbd in 2015. Interest in the Norwegian continental shelf is undiminished, as reflected by the recent APA (awards in predefined areas) licensing round and the increasing number of companies seeking to qualify to invest. If these and other recent awards yield exploration wells, we could see liquids capacity expanding past 2010. The current major projects are focused on gas with associated liquids: Kristin came onstream in October 2005 and Ormen Lange is due for start-up in 2007. There is a continuous stream of submissions and approvals for relatively small development projects, the most recent applications being Tordis (a field upgrade) and Ringhorn Ost, and recent approvals including Fram Ost and Volve. The project aimed at prolonging the life of the Statfjord field to 2020 is now under way, and other mature fields (e.g., Draugen) are being short-listed for similar late life interventions.

• **United States.** Supply disruption from the 2005 hurricane season could run well into 2006. Currently roughly 750,000 bd of oil production remains shut in, but it is estimated that only some 25,000 bd of capacity will be permanently lost from the destruction of old facilities. Disruption of gas supply has resulted in a fall in NGLs production. These factors will slow new project start-ups in the short term, exacerbating the existing problem with the Thunder Horse facility, which will now not produce until later in 2006. US liquids capacity is expected to fall from 7.5 mbd in 2005 to 7 mbd in 2010.

• **Canada.** Major expansion is expected. The main story is the oil sands projects, where capacity is expected to increase from 1.2 mbd in 2005 to 2.4 mbd by 2010 and 3.4 mbd by 2015. Conventional crude capacity will decline slowly to 2010 with the development of the White Rose and the Ben Nevis-Hebron fields, and then continue to decline gently thereafter to 1.9 mbd by 2015.

• **Russia.** Although we have adjusted the rate of growth of Russian capacity downward in the light of recent events, production is holding up and has actually increased to 9.6 mbd recently, and will be buoyed through 2006 by the start-up of Sakhalin-1 this year. After a number of years of rapid expansion Russia is moving back to slower long-term liquids capacity growth rates. There is much debate as to the reasons for the slowdown, and certainly multiple factors are at work.*

*See the CERA report Why Is Russian Oil Production Slowing Down?*
• **Caspian region.** Progress continues with the completion of the Baku-Tbilisi-Ceyhan pipeline and solid progress with the ACG field development in Azerbaijan. In Kazakhstan, the giant Kashagan field may be delayed by a year to 2010, but we expect total Caspian production capacity to rise strongly from current levels of 2.2 mbd to 4.2 mbd in 2010 and 5.3 mbd in 2015.

**What Could Go Wrong?**

The Supply Expansion scenario incorporates elements of risk involving existing project problems, annual maintenance, new project delays and attrition, and the timing and scale of appraisal and exploration projects. But there is another group of major risks that will materialize. While there is uncertainty about decline rates and the scale of contributions from new projects and exploration, CERA believes the risks to capacity expansion are mostly above ground: People, rigs, yard space, and raw materials are in very short supply; costs have been driven up; and the situation shows no sign of easing. This will limit the expansion of the exploration effort and slow the rate at which new projects will be sanctioned. Other above ground risks are

- **Operational risks** exist, especially in extreme environments such as ultradeep water where the cost base and the subsurface risks are also higher.

- **Weather and environmental effects** can be broad and unpredictable. The impact of Hurricanes Katrina and Rita are still being felt in the US Gulf Coast, where some 0.75 mbd of production is still shut in.

- **Creeping nationalization and reconsolidation** is occurring in key producing countries.

- **Resurgent nationalism** in some countries is creating considerable turmoil and increased risks for both international oil companies (IOCs) and the now-favored national oil companies (NOCs).

- **Tightening fiscal terms** in response to higher oil prices and policy changes where governments and NOCs do not see inward investment as absolutely essential are an ongoing risk.

- **Violence and insecurity** is having a sizable impact on production capacity in some areas.

**THE SPECTER OF PEAK OIL: WHAT PEAK?**

The timing of the worldwide peak in oil production continues to stimulate debate. Our outlook shows no evidence of a peak in worldwide oil production before 2020. It is true that total annual global production has not been replaced by exploration success in recent years, but production has been more than replaced by exploration plus field reserve upgrades. In 1995–2003 global production of 236 billion barrels was more than compensated by exploration success and field upgrades that collectively added 144 billion barrels and up to 175 billion barrels, respectively. Although oil is a finite resource, we still do not have an exact estimate of total reserves; meanwhile global resources should continue to expand. Many basins, even those producing significant volumes of oil, remain underexplored.
ALTERNATIVE FUTURES

As noted above, the Supply Expansion scenario is the core of our outlook. This model is a relatively unconstrained, business-as-usual case and is at the high end of CERA expectations but at the low end of a simple aggregated total of industry activity. Supply Anxiety is our low case outlook and incorporates the accumulated downside risks in many countries where we have particular concerns about business continuing as usual and where individual country outlooks have been discounted (see Figure 2). This scenario illustrates what could happen if most of the accumulated risks in many countries come to pass over prolonged periods.

The Post–2010 Supply Challenge

After 2010 it is possible that non-OPEC countries will struggle to expand production capacity at current rates partly because it is not clear where major new hydrocarbon provinces will be found, and what and where the major new projects will be. The geographic concentration of liquids capacity will boost supply risk and anxiety. OPEC has a huge inventory of resources and should become more influential as the surplus capacity expands, but significant investment and political confidence will be necessary.

REFINERY CAPACITY: A NEW CHALLENGE FOR THE OIL INDUSTRY MAKE SURE UPPERCASE

The past two years have witnessed unprecedented capacity tightness and considerable challenges for the refining industry in the face of the seemingly endless march of demand—even in light of a growing catalog of new projects under development.

For many years, the principal focus of the oil market has been on crude production and production capacity. But in the past two years—due in part to several years of lagging investment in capacity and exacerbated by surging product demand in 2004—the adequacy of refining capacity has quickly moved to the top of the list of oil industry concerns. Moreover demand-side pressure appears unlikely to subside anytime soon: in CERA’s estimate an additional 17 mbd of light product refinery production capability will be needed globally by 2015. Clearly, even in a future environment where demand growth moderates somewhat from the levels seen in 2004, the tight refinery capacity situation is expected to persist until at least 2007 or 2008, but is expected to ease gradually thereafter as additional refinery capacity is added in most world regions.

While there is clearly a need for additional refinery capacity investment worldwide, the refinery sector is also plagued by other challenges that make the task facing the downstream even more formidable. In addition to meeting the increases in demand growth expected in the coming years, refiners must also confront

• A changing product demand mix. Demand is shifting toward the middle of the barrel, with middle distillate products like diesel and jet fuel growing the fastest of any major products.

• Shifts in the concentration of demand. Demand growth in the years ahead will be concentrated in the emerging nations, particularly in Asia Pacific region, versus more sluggish growth in the mature markets of North America, Western Europe, and OECD Asia Pacific.

• Price controls. Many of the highest demand growth markets remain under some level of regulation, where prices below international market parity tend to stimulate demand and reduce margin incentives for new capacity investment.
• **Meeting increasingly tight refined product quality specifications.** The pressure to comply with tighter product quality specifications will continue to drive required refinery investment in all major markets. The American Petroleum Institute estimates that the refining sector spent $53 billion on meeting environmental regulations in 1992–2001.

In addition, from the supply perspective, the refining sector is also facing shifts in the quality and availability of crude oil and other feedstocks. Ongoing changes in crude supply patterns and the increasing supply of liquids associated with the aggressive development of natural gas worldwide will drive refinery changes in the sourcing of refinery feedstocks, while requiring investment to accommodate these challenges.

**Changing Product Demand Mix**

In every region of the world, demand for middle distillates (diesel fuel, heating oil, and jet fuel) is growing faster than for any other major refined product.* This is primarily the result of the fundamental role of commercial trucking in underpinning expanding economies in mature markets as well as in emerging markets. In addition, in some regions, such as Western Europe, there is a strong push for diesel-fueled passenger vehicles—a phenomenon called “dieselization” where fuel prices and taxes enhance the appeal of diesel-fueled vehicles for economic reasons. As economies expand, the role of commercial and business travel between nations becomes more significant, helping to spur the growth in air cargo and passenger air travel—along with a corresponding boost to jet fuel demand. Finally, when economies are growing rapidly and run into bottlenecks on electricity supply, diesel fuel is often used for on-site or portable generators.

A few statistics may help to dramatize the magnitude of this shift in the product demand mix. While middle distillates currently account for about 35 percent of global refined product demand, no less than 50 percent of every barrel of incremental demand over the next ten years will be diesel fuel, heating oil, or jet fuel—a shift that refineries around the world will have to make the necessary adjustments to accommodate.

**Shifts in Regional Concentration of Demand**

The recent patterns of refined product demand growth indicate that it is increasingly concentrated in the emerging markets, particularly in the Asia Pacific region. The rapid pace of economic expansion in emerging markets in Asia Pacific and elsewhere will continue to be the main driver underlying global refined product demand growth.

Although a repeat of the extraordinary gains in oil demand in 2004 is not expected, this trend of strong Asia Pacific demand growth is expected to continue—along with significant increases in requirements for additional refinery capacity to meet demand. Demand increases in Asia Pacific alone are expected to account for one half of the increase in global oil demand over the next ten years, versus less than 29 percent of global demand today. Led by continued robust increases in China, non-OECD Asian oil demand is projected to increase at rates of 4–5 percent per year over the next ten years, compared with global oil demand growth of about 1.9 percent annually. Beyond the pipeline of existing projects and firm plans for new capacity, plus capacity creep, increases in Asia Pacific demand are expected to require 3 mbd of additional new capacity to meet this increase in demand.

*See the CERA Private Report Distillates in the Driver's Seat*
The changing demand picture is not exclusively an Asian story—oil demand in other regions, including the Middle East, Africa, and Latin America, is also on track to grow rapidly, with each region claiming a larger share of global oil demand than at present. Rapid demand growth in the Middle East will lead to demand increases over the next ten years that are nearly as large as those in the slower-growing North American market.

North America, Western Europe, and OECD Asia Pacific account for a combined total of about 57 percent of global oil demand today, but only 20 percent of the increase in demand over the next ten years. Clearly, the developed regions of the world will make a diminishing contribution to the landscape of oil demand in the coming years; the focus of new refinery capacity growth will centered on the emerging markets where increased demand will be concentrated.

Meeting Ever-tightening Product Quality Standards

In addition to the costs of building new plants, some refiners will need to invest to meet stricter product standards, principally affecting gasoline and highway diesel fuel quality. Refiners planning on supplying markets where gasoline and diesel fuel specifications are becoming tighter will have to do whatever is necessary to meet mandatory sulfur limits in these products over the next few years. This means that refineries where the most aggressive sulfur reduction mandates have been enacted will continue to make significant capital expenditures to improve product quality. Varying domestic product quality specifications constrain intermarket fungibility and further limit refiners’ responsiveness to participate in constrained foreign markets. Moreover, as these standards apply universally across a given market, it is likely that capital costs incurred for nondiscretionary product quality improvements will not be fully recovered.

Price Controls Create Conflicting Signals

Often, observers tend to assume a homogeneous international market, as if all national markets are fully integrated into one single free market where common price signals are providing incentives (or disincentives) to supply and demand equally across the national markets. This view can be relevant, as long as governmental control of domestic prices is a negligible factor in international oil fundamentals. However, as the petroleum market continues to shift toward developing countries, a critical concern will be the influence of price controls on demand and new refinery investment. In many of the most prominent growth markets for refined products, there is still an ongoing and gradual transition to domestic oil market liberalization such that prices and refinery margins do not necessarily reflect international market parity. This tends to stimulate demand and confronts refiners with conflicting incentives to invest in new capacity.

As international light products prices have sharply risen since mid-2004, regulated prices in these growth markets tend to be substantially lower than import parity, preventing intentional price signals from fully reaching consumers and suppliers and creating a severe disconnect. As many of the world’s emerging demand centers are also net importers of crude oil, domestic refiners face costs for crude oil that have risen sharply in line with international prices, while domestic products remain artificially low, often rising only modestly. Consequently, local refining margins have actually fallen in some regulated markets, despite a pressing need for new supply capability. This stands in stark contrast with the strong margin environment currently enjoyed by refiners in many liberalized markets such as Europe, Japan, and the United States. While a variety of factors, such as rising construction costs and complicated local approval processes, is affecting the pace of capacity additions, the lack of downstream profitability could limit incentives for refiners in regulated markets to gear up facility investments further. If the artificially depressed downstream profitability continues in regulated markets, it may adversely affect investment in additional refining capacity.
**Changing Feedstock Quality and Supply Patterns**

A key factor in the ongoing refinery capacity situation is the poor match between the quality of the incremental Middle East crudes being supplied and the unfulfilled demand for light crude sought for the spare hydroskimming capacity available. The increases in crude capacity expected to occur after about 2007 or 2008 will help to ease the refining capacity squeeze by boosting refinery capability that can accommodate the available medium and heavy crudes.

In addition, CERA expects that between 2007 and 2010 significant additional non-OPEC production of light liquids will help to provide more suitable feedstocks for simple, hydroskimming refineries that will raise the yield of light products, while reducing heavy fuel oil output. CERA believes that the increased availability of these light liquids, combined with moderating demand growth and increases to refinery conversion capacity, will slowly begin to ease the pressure on wide light-heavy spreads.

**Refining Capacity Tightness: How Did We Get Here?**

The refining industry has had a long history of overcapacity and poor margins and returns. In the 1990s the US Gulf Coast benchmark refining margin, as expressed by the benchmark “3-2-1” crack, averaged less than $3 per barrel. In 2004 this picture changed dramatically. The 3-2-1 crack rose to an unprecedented $6.30 per barrel and in 2005 has averaged over $11 per barrel (although it has subsided in recent weeks due to indications of weakening global demand). Refiners that are able to take heavy crudes and process them into light products have gained comparative advantage. The light-heavy crude price differential also has widened dramatically over the past two years. The differential between WTI and Maya in the US Gulf Coast, for example, averaged $5 to $7 per barrel in the 1990s. This year that differential is averaging $15 per barrel. And these high margins and widening light-heavy differentials in the Gulf Coast are mirrored in every major refining center around the world, from Rotterdam to Singapore.

How did the refining industry—always the neglected and underperforming segment of the world oil market—reverse its fortunes? The catalyst was the unexpected surge in global oil demand in 2004—a function of the simultaneous and rapid expansion in the world’s economies that occurred that year. What was notable about this demand surge was the overwhelming increase in light product demand, especially middle distillates (which includes diesel fuel, jet fuel, and heating oil).

The demand surge prompted a call for increased utilization of available refinery capacity. Since refineries having the greatest capability to manufacture light products were already highly utilized, the available incremental capacity—largely simple, hydroskimming capacity—was called upon to operate at higher utilization rates. Since the demand increase was mainly for light products, hydroskimming capacity sought to run additional volumes of light, sweet crude. However, when the downstream market was at its tightest point, the majority of available crude supplies were primarily medium and heavy, sour crudes from the Arab Gulf.

Though the 2004 demand surge brought increases in crude oil production, mainly from Middle East, these grades were not what the market needed most; adequate crude oil volumes were available, just not the right type. The result was upward pressure on the prices of light crudes sought by hydroskimming refineries and depressed values for medium and heavy crudes. The extremely wide light-heavy crude price spreads were also accompanied by wide light-heavy product spreads, as supplies of gasoline and diesel remained tight and prices were driven higher, and additional, unneeded volumes of heavy fuel oil were produced, driving residual fuel oil values lower.
In sum, over the past two years an irresistible force—the unrelenting global strength of diesel fuel and jet fuel demand—has been meeting an immovable object: constrained production capacity and limits on current availability of incremental light, sweet crude oil supply. Demand for these fuels is inexorably being driven by a combination of global economic growth, the popularity of diesel cars in Europe, and price controls in parts of the developing world, which keep diesel artificially cheap. On the supply side, the world is facing shortages of two key resources: the type of highly complex refinery that can upgrade the majority of a barrel of crude oil into high-demand products like diesel; and light, sweet crude oil, which can most easily be processed into light transportation fuels. Over the next decade, therefore, conversion capacity will be the name of the game in the refining industry.

Refinery Sector Challenges Vary by Region

The surge in oil demand growth in 2004 revealed in stark reality the tightness of global refining capacity, not just in the Asia Pacific region, where much of the growth spurt was centered, but in virtually all other regions as well. Total world crude distillation capacity currently stands at 85.8 mbd (see Table 1). Continued rapid demand growth in Asia Pacific will likely lead to new, grassroots capacity being built—with many announcements indicating that a program of refinery expansion is well under way in the region. But the changing landscape of refined product demand will drive needed investments in refining capacity across the globe. In CERA’s view, each major region faces different refining sector challenges.

Table 1

Global Refinery Distillation Capacity
(million barrels per calendar day)

<table>
<thead>
<tr>
<th>Region</th>
<th>Capacity (mbd)</th>
</tr>
</thead>
<tbody>
<tr>
<td>North America</td>
<td>19.2</td>
</tr>
<tr>
<td>Latin America</td>
<td>8.3</td>
</tr>
<tr>
<td>Europe</td>
<td>16.0</td>
</tr>
<tr>
<td>Eurasia</td>
<td>8.3</td>
</tr>
<tr>
<td>Middle East</td>
<td>7.2</td>
</tr>
<tr>
<td>Africa</td>
<td>3.2</td>
</tr>
<tr>
<td>Asia-Pacific</td>
<td>23.7</td>
</tr>
<tr>
<td><strong>World</strong></td>
<td><strong>85.8</strong></td>
</tr>
</tbody>
</table>

Sources: Cambridge Energy Research Associates.
Asia Pacific

Since 2003, Asia Pacific has surpassed North America and now accounts for the largest share of regional oil demand in the world. The rapid global oil demand expansion witnessed in 2004 was largely concentrated in China and non-OECD Asia, firmly cementing this region as the main focus of global oil demand growth going forward. Oil demand growth in the Asia Pacific region has been facilitated by the vigorous economic expansion under way and the competitiveness of manufacturing for exports, in particular. Even when economic growth accelerates in other parts of the world, the Asia Pacific economies continues to speed ahead of growth in these trading partners, which rely increasingly on exports from Asia.

The increases in refining capacity required to slake the growing thirst for refined products in the region will likely be predominantly complex refineries, centered on hydrocracking and catalytic cracking conversion capacity, with middle distillates, again, as the main focus of production. Demand growth in the region averaging 4–5 percent per year for the next decade will require significant grassroots capacity construction in the region. Announcements of new capacity indicate a concentration of new refineries in China and India, with smaller projects expected in Thailand, Vietnam, and Taiwan.

However, there is growing recognition of the opportunity to site new, export-oriented refining capacity in nearby regions, with a focus on the rapidly growing markets in Asia. The Middle East is one such region where significant new refining capacity is expected.

Middle East

The proximity of the Middle East to the consuming areas in Asia has created a natural market for crude and liquid feedstock exports to Asia Pacific refineries. However, strong Asia Pacific refined products demand—accompanied by strong refining margins—is making a powerful case for expansion of Middle East refining capacity. The long-standing emphasis among Middle East producing countries on development of upstream assets has resulted in the region’s becoming a growing net importer of gasoline (currently India is a main supplier), which can be mitigated by additions to capacity.

Still, there may be an even more compelling reason for building new Middle East refining capacity: as a strategy to offset the low values earned by medium and heavy sour crudes by refining them domestically and exporting the much higher-valued light products. The record wide light-heavy crude price differentials and wide light-heavy product differentials constitute a very powerful economic incentive for processing these crudes in conversion refineries and gaining the elevated premium afforded by the market for light products. Thus, CERA expects to see a significant increase in Middle East refining capacity, with a focus on exports to Asia Pacific markets.

North America

The North American refining sector is facing a different set of challenges than the Asian and Middle East refiners. Although demand growth in the mature North American market will be much slower than in emerging markets like Asia Pacific, Latin America, and even Africa, there will nonetheless be a need for refining capacity expansion. Unlike the growth in new capacity seen for Asia Pacific and the Middle East, North American refining capacity will continue to grow more or less within the existing refinery footprint, with announced and unannounced expansions adding capacity at existing refinery locations.
As has been the case for nearly two decades, North American refiners have used both routine and extended maintenance turnarounds to add capacity through capacity creep. By debottlenecking operations, adopting new catalysts, and finding new efficiencies, the refining industry in aggregate has been able to expand existing capacity significantly. Generally, the cost of expanding an existing refinery capacity is much lower than the cost of permitting, siting, and building a grassroots facility. As a result, no new refineries have been built in North America in 30 years.

Western Europe

The Western European refined products market has continued to sustain a structural imbalance of inadequate diesel supply along with a surplus of gasoline and blending components. Overall, Western European refinery capacity is considered adequate to meet most of the region’s requirements, particularly at the slow rates of demand growth observed in recent years. However, the Western European refinery capacity challenge involves the need for restructuring the capacity in place to better match the patterns of demand.

European refining capacity has not yet adjusted to meet a growing shortfall of diesel fuel, even as countries in the region have overwhelmingly adopted diesel-powered automobiles—the dieselization of the vehicle fleet. In response to high fuel prices and taxes, and the differential taxation of diesel more favorably than gasoline, an increasing share of new autos sold in Western Europe are diesel fueled. Meanwhile, the dieselization of the car park has led to seven years of successive declines in gasoline demand in Western Europe, leading to ever-growing surpluses of gasoline and (following the United States’ introduction of Federal Reformulated Gasoline in 1995) of blendstocks as well.

In addition to the surplus of gasoline/blendstocks, Western European refiners also produce a surplus of heavy fuel oil. As power plant emission regulations have tightened, the use of heavy fuel oil has declined sharply, particularly in Mediterranean Europe. As a result, some Western European refineries are producing heavy fuel oil for which there is a declining market at best. So Western European refineries have a dual surplus of both gasoline and heavy fuel oil for which adjustments must be made.

Thus, CERA sees the growing pressure for investment to reconfigure Western European refinery capacity to be more compatible with demand trends.

The Capacity Response: Is Relief in Sight?

The challenge is clear: there will be a significant shortfall in light product production capacity by the close of this decade unless new capacity materializes swiftly. Moreover, changes in the refined product demand mix will require much of the new refinery capacity after 2005 to be configured differently than in the past. Although the pace of refinery investment has recently accelerated, it may still be some time before this provides some relief to the current tight global market. Whether through grassroots capacity, plant reconfiguration, or expansion of existing capacity and capability, the pace of additions throughout the refinery system is expected to be significantly higher in the 2005–10 period than at any time in the recent past. By the broadest measure—expansion of crude distillation—global capacity is expected to expand annually by an average of 1.6 mbd between 2005 and 2010, compared to an average of 450,000 bd in 2002–05. This takes into account CERA’s tally of known expansion projects plus an assumption that global capacity creep will maintain historical rates of about 0.5 percent per year.
A review of announced capacity additions suggests that while some easing may occur relatively soon, a return to historical norms remains at least a couple of years away. Nonetheless, if demand growth remains on par with the current rate through the end of the decade, it would continue to keep global refinery capacity utilization high.

**Historically Tight Global Conversion Balance**

Given that global deep conversion refining capacity is currently fully-utilized and the concentration of demand toward light products is growing, additions to conversion capacity will be the most critical element of any capacity build going forward. Not only will the world’s incremental crude production in the next decade continue to include significant volumes of heavy, sour crude oil grades, but the world’s demand profile will increasingly be dominated by light products such as gasoline, diesel, and jet fuel. Heavy fuel oil demand will continue its structural decline in virtually every region.

The surge in demand that materialized last year and has continued into 2005 has absorbed most of the world’s available complex refining capacity (capacity that can convert a barrel of crude into mostly light products with only a small fraction of residual fuel oil) such that light product demand can now only be fully met by increasing the utilization rates of the world’s marginal refining capacity. Essentially this marginal capacity is hydroskimming capacity, which produces a relatively large yield of heavy fuel oil and only a limited yield of light products like middle distillate.

Although considerable crude processing capacity will be added over the coming decade, perhaps more critical will be additions to the secondary processing units necessary to convert heavy crude oil fractions to light products and raise the quality levels of those same products. The rapid light product demand growth of the recent past has resulted in tightly constrained conversion processing across the globe. This has occurred relatively swiftly—over the past three years—and several years and considerable investment will be required to ease the current situation. A comparison of the current situation with that of three years ago helps to illustrate how conversion capacity utilization could have risen so quickly.

In 2002 global refining margins were low by historical standards and certainly relative to the current market. Over the past three years, the volume of crude oil processed in the global refining circuit increased by approximately 6 mbd—quite strong by historical standards. By CERA’s estimate, that incremental crude run contributed over 2.1 mbd of resid (including vacuum gasoil and vacuum resid fractions). However, product demand growth was entirely in light products, as global heavy fuel oil showed virtually no net growth.

On average, the global refining sector adds approximately 400,000–500,000 bd of resid destruction capacity each year. In fact, from 2002 to 2005 approximately 1.3 mbd of resid destruction came online, comprising virtually equal fractions of hydrocracking, fluid catalytic cracking, and delayed coking. In net, this left approximately 800,000 bd of surplus resid added to the market without corresponding capacity to convert it to light products. Much of this volume was either consumed through higher conversion utilization rates, as a substitute for direct-burned crude oil, or added to inventories—finite sources of flexibility that are now largely exhausted.

Currently, over 70 percent of refinery heavy oil conversion processing is located in the East of Suez markets. However, this appears likely to change over the course of the next decade owing to two clear drivers:
• shifting concentration of incremental light product demand toward the East of Suez markets

• a global downturn in resid fuel oil demand

As light product demand in Asia and the Middle East surges, those markets will undoubtedly require greater processing capacity. However, in a departure with the past, this new capacity will largely be complex, supported by greater conversion capabilities than the existing infrastructure. The economic incentive for new projects heavily favors complex processing: as complex refining margins have risen, margins for simple refineries have remained low.

Growing Contributions by Petroleum Alternatives

As petroleum prices have risen to record nominal levels and concerns about energy security are once again at the fore, alternative forms of energy and unconventional oil plays once thought too expensive or inefficient have begun to make noticeable strides and take their place alongside petroleum in the world’s energy mix. Biofuels, such as ethanol and biodiesel, coal-to-liquids (CTL) technology, and GTL technology are three areas are all receiving renewed scrutiny. As investment ramps up and technologies improve, many of these alternative energy resources will take their place in the supply mix. None, however, has the potential to displace oil on its own. Even in sum, their contribution, although growing, is likely to remain modest. And while each alternative resource has its advantages, each also presents unique risks and disadvantages.

Biofuels

Ethanol and biodiesel have received a lot of attention worldwide in the past year. Although still expensive, biofuels have become more competitive as world oil prices have risen. The prospects for the biofuels sector look fairly bright worldwide. The recently passed US Energy Bill mandates a large increase in ethanol usage in the United States by early next decade. The European Union has a voluntary target of nearly 6 percent for biofuel penetration in the transportation sector by the end of the decade. In Brazil, where the sugar cane–based álcool (ethanol) program has had a long and sometimes turbulent history, a renaissance of sorts is unfolding as consumers have embraced “flexible fuel” cars that can run on either gasoline or 85 percent ethanol.

The advantages of biofuels are well known. Ethanol, for example, has a high octane rating and can generally be blended into gasoline without any major modifications and used in relatively low-level blends in any gasoline-operated vehicle. The technology for converting corn, sugar cane, and other crops into alcohol is mature and well-understood.

Biofuels, however, face significant obstacles. On an energy equivalent basis with petroleum-based fuels, they are still not quite cost competitive and generally require substantial government subsidies. Furthermore, a significant ramping up of biofuels production would present a key challenge from a resource point of view. Corn, soy, wheat, and other crops that can currently be converted into ethanol and biodiesel are also major food crops, and in the future scaling up the biofuels industry will likely create unsustainable tensions as food and fuel compete.
Technology never sits still, however. Attention is growing to the possibilities for what is known as cellulosic ethanol, based on cheap feedstock such as grasses and forest waste, which do not compete with food resources. While cellulosic ethanol technology is feasible today, the economics do not support it. Should a breakthrough occur in the field of cellulosic ethanol, however, it would significantly alter the biofuels landscape by greatly expanding the resource base and would allow a significant ramping up of nonpetroleum fuel use.

Coal-to-Liquids

CTL production technology has a long and well supported history despite limited commercial applications. Like biofuels, CTL fuels can seamlessly be integrated into the existing petroleum supply chain and distribution infrastructure. Existing CTL technology holds the potential to produce liquid fuels within a range of $40 to $50 per barrel. These projects, however, are not cheap to build. CERA estimates that the capital costs of a facility capable of producing 80,000 bd would be in excess of $4 billion. Moreover, CTL project economics depend heavily upon immediate access to a large, low-cost, and long-term supply of coal.

The mega projects that are currently under development are mostly concentrated in China, especially in remote regions where coal reserves have few economic outlets. China’s overall objective is to produce 60 million metric tons (mt) of coal-derived oil products by 2015, which will require the development of 12 plants, each capable of processing 5 mt of coal per year.

Coal remains an extremely abundant and competitively priced energy source worldwide; however, prices for coal and the costs associated with its production have risen in step with the increase in oil prices.

Gas-to-Liquids

GTL technology is another area that has seen accelerated activity over the past two years. The core GTL technology (generation of synthesis gas from natural gas feedstock and catalyst-based conversion into liquid fuels such as zero-sulfur diesel and naphtha) is not new. However, ongoing technological and economic improvements have brought GTL within the range of commercial viability. CERA expects GTL capacity to reach 1 mbd by 2015.

Strong drivers ensure that the global GTL industry will be a growing part of the energy supply mix in the future. The economic imperative for IOCs and NOCs to monetize huge stranded gas resources has led to a number of commercial GTL projects, most of which will come onstream in the next decade. Technological advances in recent years have improved the commercial applicability of GTL projects by reducing costs and lowering the minimum efficient scale of the plants. Finally, surging world demand for middle distillates and a shift toward the use of ultralow-sulfur transportation fuels will also make GTL fuel a high-value blend stock.

Despite its promise, the global GTL industry is still in its infancy. There are only a handful of companies investing in these projects, which are extremely capital intensive and involve proprietary technology. Stranded gas supplies and large-scale economics are required, thereby limiting number of potential near-term applications. Under current conditions, projects do not go forward unless the natural gas feedstock is extremely low priced.
CONCLUSION

An argument can be made that refining has entered a Golden Age and a tight capacity situation and windfall margins across the global markets provides evidence that firmly supports this supposition. However, a descriptor that includes the term “age” in the context of an industry governed by the law of long lead times can be dangerous. There is mounting evidence that the global refining sector is, in fact, constituting a response to meet the demands of a growing market. However, much still depends on how refiners—historically a resourceful group—rise to meet what is perhaps their most challenging business environment ever.