CHAPTER 4

GAS MARKET OUTLOOK

HIGHLIGHTS

- Primary gas consumption increases in all regions over the period 2004-2030 in the Reference Scenario, from 2.8 trillion cubic metres in 2004 to 3.6 tcm in 2015 and 4.7 tcm in 2030. Globally, demand grows by an average of 2% per year – well down on the 2.6% rate of 1980-2004 and slightly below the rate projected in *WEO-2005*. The biggest increase in volume terms occurs in the Middle East, though demand rises at a faster rate in China, India and Africa. OECD North America and Europe remain the largest markets in 2030. The power sector accounts for more than half of the increase in global primary gas demand.
- In aggregate, annual world gas production expands by almost 1.9 tcm, or two-thirds, between 2004 and 2030. The Middle East and Africa contribute most to this increase. Output also increases quickly in Latin America and developing Asia. Europe is the only region to experience a drop in output between now and 2030.
- Inter-regional gas trade expands even faster than output, because of the geographical mismatch between resource endowment and demand. The main gas-consuming regions become increasingly dependent on imports. In absolute terms, the biggest increases in imports occur in Europe and North America. LNG accounts for most of the increase in global inter-regional trade.
- The Middle East and Africa provide more than two-thirds of the increase in global inter-regional exports over the *Outlook* period. The bulk of the exports from these two regions goes to Europe and the United States. Africa overtakes the transition economies, including Russia, as the largest regional supplier to Europe. There are doubts about whether Russia will be able to raise production capacity fast enough to even maintain current export levels to Europe and to start exporting to Asia.
- Cumulative investment in gas-supply infrastructure amounts to $3.9 trillion over the period 2005-2030. Capital needs are highest in North America, where most spending goes simply to maintaining current capacity. The upstream absorbs 56% of global spending. Most of the investment to 2010 is already committed. Thereafter, it is far from certain that all the investment needed will, in fact, occur. A particular concern is whether the projected increase in exports in some regions, especially the Middle East, is achievable in light of institutional, financial and geopolitical factors and constraints.

Demand

Primary gas consumption is projected to increase in all regions over the next two-and-a-half decades. Globally, demand grows by an average of 2% per year from 2004 to 2030 – well down on the rate of 2.6% per year of 1980-2004 and slightly below the rate projected in *WEO-2005*. Demand grows at the fastest rates in Africa, the Middle East and developing Asia, notably China. The biggest increase in volume terms occurs in the Middle East, driven by demand from the power and petrochemical sectors. Nonetheless, OECD North America and Europe remain the largest markets in 2030 (Table 4.1). The share of gas in the global primary energy mix increases marginally, from 21% in 2004 to 23% in 2030. Our gas-demand projections in most regions have been scaled down since the last edition of the *Outlook*, mainly because the underlying gas-price assumptions have been raised and because of growing concerns about the security of imported gas supplies.

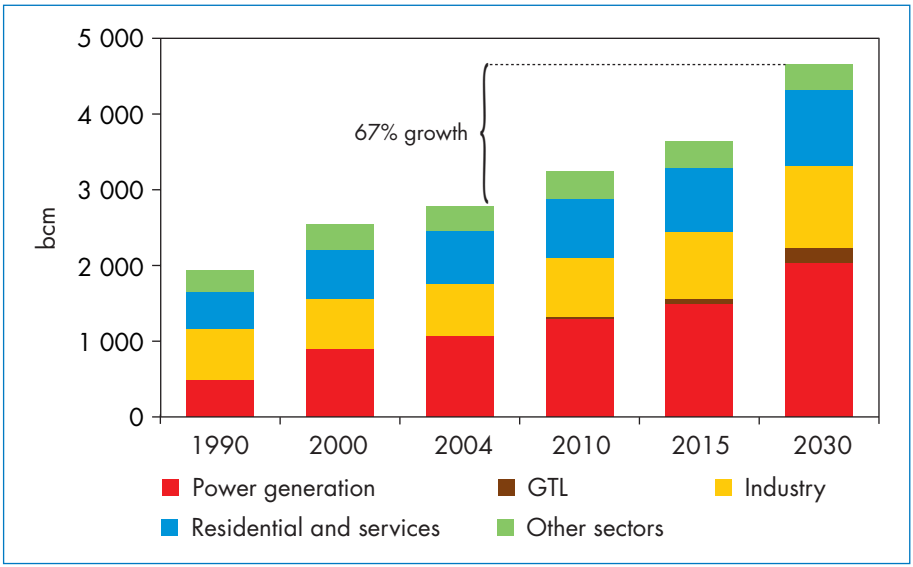
Table 4.1: **World Primary Natural Gas Demand in the Reference Scenario** (bcm)

	1980	2004	2010	2015	2030	2004-2030*
OECD	**959**	**1 453**	**1 593**	**1 731**	**1 994**	**1.2%**
North America	659	772	830	897	998	1.0%
United States	*581*	*626*	*660*	*704*	*728*	*0.6%*
Canada	*56*	*94*	*109*	*120*	*151*	*1.8%*
Mexico	*23*	*51*	*62*	*74*	*118*	*3.3%*
Europe	265	534	592	645	774	1.4%
Pacific	35	148	171	188	223	1.6%
Transition economies	**432**	**651**	**720**	**770**	**906**	**1.3%**
Russia	n.a.	420	469	503	582	1.3%
Developing countries	**121**	**680**	**932**	**1 143**	**1 763**	**3.7%**
Developing Asia	36	245	337	411	622	3.7%
China	*13*	*47*	*69*	*96*	*169*	*5.1%*
India	*1*	*31*	*43*	*53*	*90*	*4.2%*
Indonesia	*6*	*39*	*56*	*65*	*87*	*3.2%*
Middle East	36	244	321	411	636	3.7%
Africa	14	76	117	140	215	4.1%
North Africa	*13*	*63*	*88*	*104*	*146*	*3.3%*
Latin America	36	115	157	180	289	3.6%
Brazil	*1*	*19*	*28*	*31*	*50*	*3.8%*
World	**1 512**	**2 784**	**3 245**	**3 643**	**4 663**	**2.0%**
European Union	*n.a.*	*508*	*560*	*609*	*726*	*1.4%*

* Average annual growth rate.

The power sector accounts for more than half of the increase in primary gas demand worldwide (Figure 4.1). Its use of gas increases by 2.5% per year from 2004 to 2030. In many regions, gas is still preferred to other generation-fuel options – particularly for mid-load – because of its cost competitiveness and its environmental advantages over other fossil fuels. Distributed generation, which is expected to play an increasingly important role in power supply, and the shorter lead times and lower costs of building efficient gas-fired combined-cycle gas-turbines also favour the use of gas. In absolute terms, gas demand in the power sector increases most in the Middle East.

Figure 4.1: **World Primary Natural Gas Demand by Sector in the Reference Scenario**



In line with previous projections, gas-to-liquids (GTL) plants are expected to emerge as a significant new market for gas. Global GTL demand for gas is projected to increase from a mere 8 bcm in 2004 to 29 bcm in 2010, 75 bcm in 2015 and 199 bcm in 2030. In 2006, a new 34-kb/d plant called Oryx, built by Qatar Petroleum and Sasol in Qatar, was commissioned. This doubled existing capacity at two small plants in South Africa and Malaysia. Several other plants are under construction or planned, including a 95-kb/d facility in Nigeria due on stream in 2008-2009 and an expansion of the Oryx plant.[1] Much of the gas used by GTL plants is for the conversion process, which is extremely energy-intensive.

1. See Chapter 12 for more details on near-term GTL investment plans.

The long-term rate of increase in GTL production will hinge on reduced production costs, lower energy intensity, the ratio of gas to oil prices, the premium available for high-quality GTL fuels over conventional products and the economics of liquefied natural gas projects, which compete with GTL for use of available gas.

Final gas consumption grows markedly less rapidly than primary gas use – by 1.8% a year in industry and 1.4% in the residential, services and agricultural sectors. Final consumption slows in the OECD because of saturation effects, sluggish output in the heavy manufacturing sector and modest increases in population. Demand grows more strongly in developing countries and transition economies along with rising industrial output and commercial activity. But residential gas use nonetheless remains modest compared with OECD countries, because incomes are often too low to justify the investment in distribution infrastructure. End-use efficiency gains in the transition economies also temper the growth in residential gas demand. Some oil-producing developing countries continue to encourage switching to gas in order to free up more oil for export.

Supply

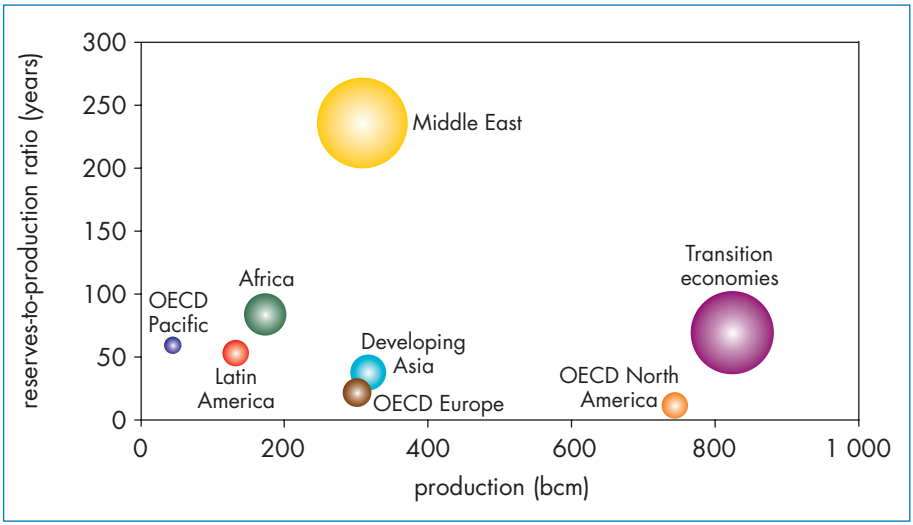
Resources and Reserves

Gas resources are more than sufficient to meet projected increases in demand to 2030. Proven reserves amounted to 180 trillion cubic metres at the end of 2005, equal to 64 years of supply at current rates (Cedigaz, 2006). Were production to grow at the 2% annual rate projected in the Reference Scenario, reserves would last about 40 years. Close to 56% of these reserves are found in just three countries: Russia, Iran and Qatar. Gas reserves in OECD countries represent less than a tenth of the world total (Figure 4.2).

Worldwide proven gas reserves have grown by more than 80% over the past two decades, with large additions being recorded in Russia, Central Asia and the Middle East. Much of this gas has been discovered while exploring for oil. In recent years, the larger share of reserve additions have come from upward revisions to reserves in fields that have already been discovered and are undergoing appraisal or development. As with oil, the gas fields that have been discovered since the start of the current decade are smaller on average than those found previously.

Ultimately recoverable remaining gas resources, including proven reserves, reserve growth and undiscovered resources, are considerably higher than reserves alone. According to the US Geological Survey, they could total 314 tcm in a mean probability case (USGS, 2000). Cumulative production to date amounts to only around 15% of total resources.

Figure 4.2: **Proven Gas Reserves and Production by Region, 2005**



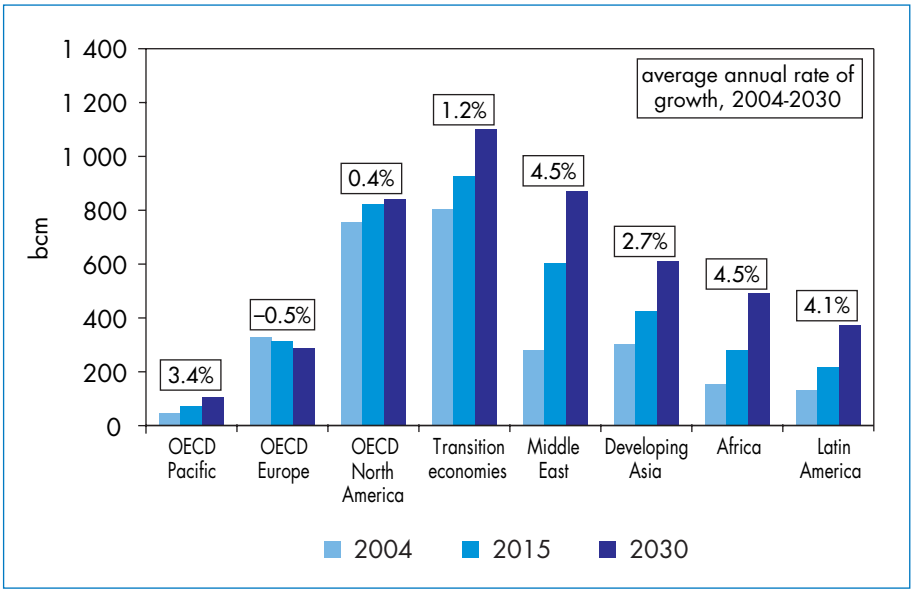
Note: The size of each bubble indicates the size of reserves at the end of 2005.
Source: Cedigaz (2006).

Production

Projected trends in regional gas production in the Reference Scenario generally reflect the relative size of reserves and their proximity to the main markets.[2] Production grows most in volume terms in the Middle East and Africa (Figure 4.3). Most of the incremental output in these two regions will be exported, mainly to Europe and North America. Output also grows quickly in Latin America, where Venezuela emerges as an important supplier to North America and possibly Europe too. Output is expected to grow less rapidly in Russia, despite the region's large reserves: much of that gas will be technically difficult to extract and transport to market. There are also doubts about how much investment will be directed to developing reserves in the transition economies (see below). Other developing Asia sees slower growth, as Indonesia struggles to develop its reserves for export to other countries in the region. Europe is the only region which experiences a drop in output between now and the end of the projection period, as North Sea production peaks early in the next decade and gradually declines thereafter. In aggregate, annual world production expands by almost 1.9 tcm, or two-thirds, between 2004 and 2030.

2. They also take into account special factors, including depletion policies, development costs, geopolitical considerations and the use of gas for reinjection to boost oil recovery.

Figure 4.3: **Natural Gas Production by Region in the Reference Scenario**



Most natural gas supplies will continue to come from conventional sources. The share of associated gas is expected to fall progressively, as more non-associated fields are developed to meet rising demand – despite a further reduction in the amount of associated gas flared. Several countries, especially in the Middle East and Africa, are implementing programmes to reduce gas flaring. Around 150 bcm of gas is flared each year, mostly in the Middle East, Nigeria and Russia (IEA, 2006b; World Bank, 2006). Non-conventional gas production, including coal-bed methane (CBM) and gas extracted from low permeability sandstone (tight sands) and shale formations (gas shales), increases significantly in North America. The United States is already the biggest producer of non-conventional gas, mainly tight sands gas and CBM from the Rocky Mountains. Together, they account for about one-quarter of total US gas output. In most other regions, information on the size of non-conventional gas resources is sketchy. In some cases, there is no incentive to appraise these resources, as conventional gas resources are large.

In general, the share of transportation in total supply costs is likely to rise as reserves located closest to markets are depleted and supply chains lengthen. Technology-driven reductions in unit production and transport costs could, however, offset the effect of distance on total supply costs to some extent. Pipelines will remain the principal means of transporting gas in North America, Europe and Latin America. Yet LNG is set to play an increasingly important role in gas transportation worldwide over the projection period, mainly to supply Asia-Pacific and Atlantic Basin markets.

Inter-Regional Trade

The geographical mismatch between resource endowment and demand means that the main gas-consuming regions become increasingly dependent on imports (Table 4.2). In volume terms, the biggest increase in imports is projected to occur in OECD Europe. Imports in OECD Europe jump by 280 bcm between 2004 and 2030, reaching almost 490 bcm – equal to about two-thirds of inland consumption. North America, which is largely self-sufficient in gas at present, emerges as a major importer. By 2030, imports – all of which are in the form of LNG – meet 16% of its total gas needs. Chinese gas imports also grow from around 1 bcm in 2004 to 56 bcm by 2030. The country's first LNG terminal, with a capacity of 3.7 million tonnes (6 bcm) per year was commissioned in 2006. Nonetheless, gas still meets only 5% of Chinese energy needs by 2030, up from 3% today.

The Middle East and Africa account for 72% of the increase in global exports over the *Outlook* period. The bulk of the exports from these two regions goes to Europe and the United States (Figure 4.4). Africa overtakes the transition economies, including Russia, as the largest regional supplier to Europe. In light of current investment plans, there are doubts about whether Russia will be able to raise production fast enough to maintain current export levels to European markets given rising domestic needs (IEA, 2006b). Russia, Central Asia, Australia and the Middle East emerge as new exporters of gas to China during the projection period. Russia is also expected to begin exporting gas to OECD Asia before 2030.

Gas continues to be traded on a largely regional basis, as there are few physical connections now between the main regional markets of North America, Europe, Asia-Pacific and Latin America. But these markets are set to become more integrated as trade in LNG expands. This will open up opportunities for arbitrage, leading to a degree of convergence of regional prices. LNG accounts for almost 70% of the increase in inter-regional trade (Figure 4.5). Exports of LNG grow from 90 bcm in 2004 to 150 bcm in 2010 and 470 bcm in 2030. Much of the new liquefaction, shipping and regasification capacity that is due to come on stream by 2010 is either already being built or is at an advanced planning stage. Total liquefaction capacity worldwide would double between end-2005 and 2010, from 178 Mt (242 bcm) per year to 345 Mt (470 bcm) if all the projects under development are completed on time, though some will undoubtedly be delayed or cancelled.[3] North America is expected to see the biggest increase in LNG imports over the whole projection period (Box 4.1).

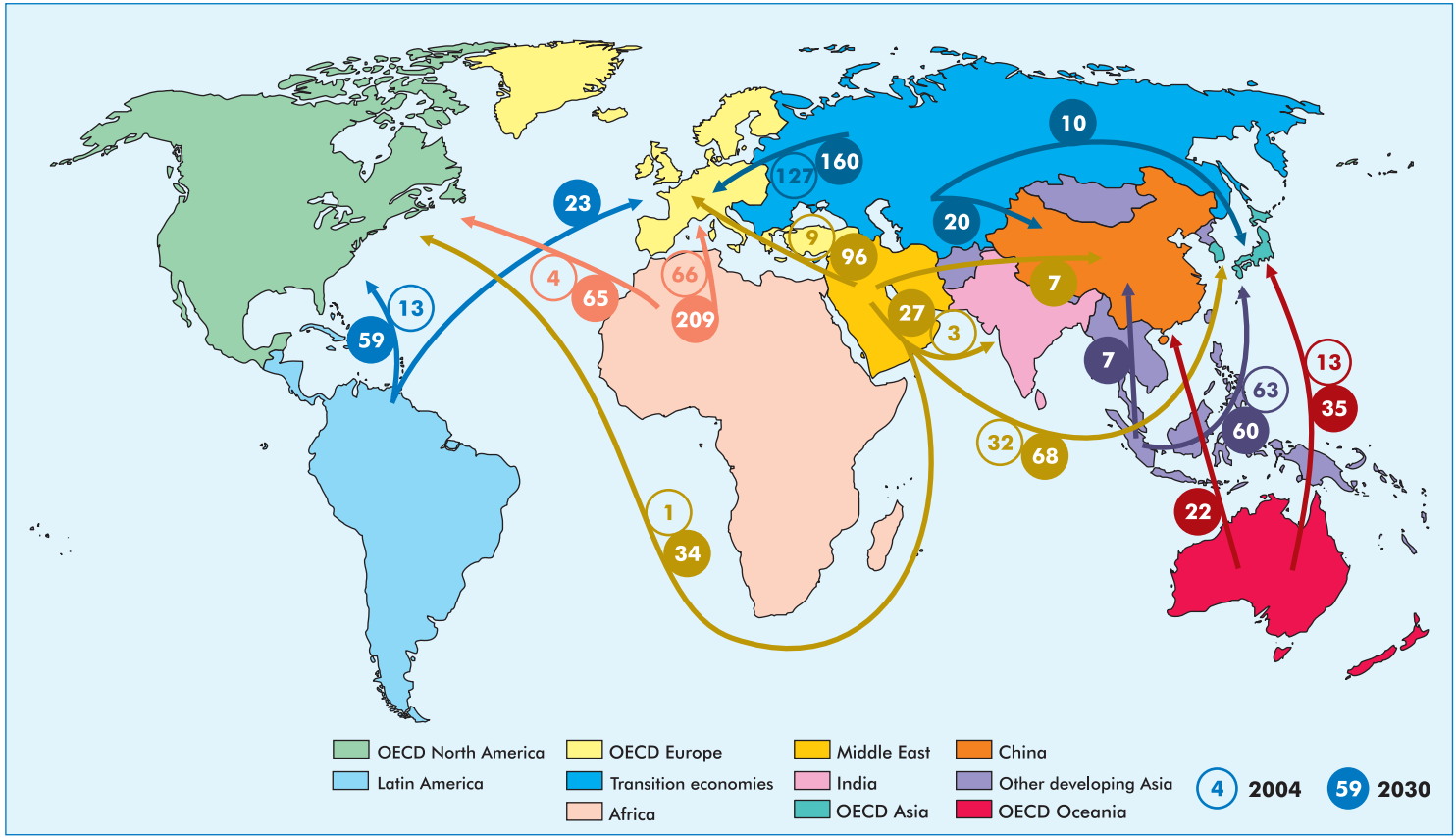
3. See Chapter 12 for a detailed near-term analysis of LNG and pipeline investment.

Table 4.2: **Inter-Regional* Natural Gas Trade in the Reference Scenario**

	2004		2015		2030	
	bcm	% of inland gas consumption**	bcm	% of inland gas consumption**	bcm	% of inland gas consumption**
OECD	**–328**	**22.6**	**–526**	**30.4**	**–764**	**38.3**
North America	–18	2.3	–77	8.6	–159	15.9
Europe	–214	40.1	–333	51.7	–488	63.0
Pacific	–96	65.0	–116	61.3	–117	52.7
OECD Asia	*–109*	*93.5*	*–145*	*96.7*	*–174*	*97.2*
OECD Oceania	*13*	*29.7*	*29*	*40.3*	*57*	*53.7*
Transition economies	**145**	**18.2**	**152**	**16.5**	**190**	**17.3**
Russia	202	32.7	194	27.8	222	27.7
Developing countries	**183**	**21.2**	**374**	**24.7**	**574**	**24.6**
Developing Asia	60	20.0	11	2.7	–15	2.4
China	*0*	*0.0*	*–27*	*27.6*	*–56*	*33.3*
India	*–3*	*9.7*	*–10*	*19.3*	*–27*	*30.1*
Middle East	40	14.4	189	31.5	232	26.7
Africa	70	45.3	137	49.4	274	56.0
Latin America	13	10.0	37	17.0	82	22.2
World	**413**	**14.8**	**634**	**17.4**	**936**	**20.1**

* Trade between *WEO* regions only. See Annex C for regional definitions.
** Production for exporters.
Note: Positive figures denote exports; negative figures imports.

Figure 4.4: **Main Net Inter-Regional Natural Gas Trade Flows in the Reference Scenario, 2004 and 2030** (bcm)



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Box 4.1: LNG Set to Fill the Growing US Gas-Supply Gap

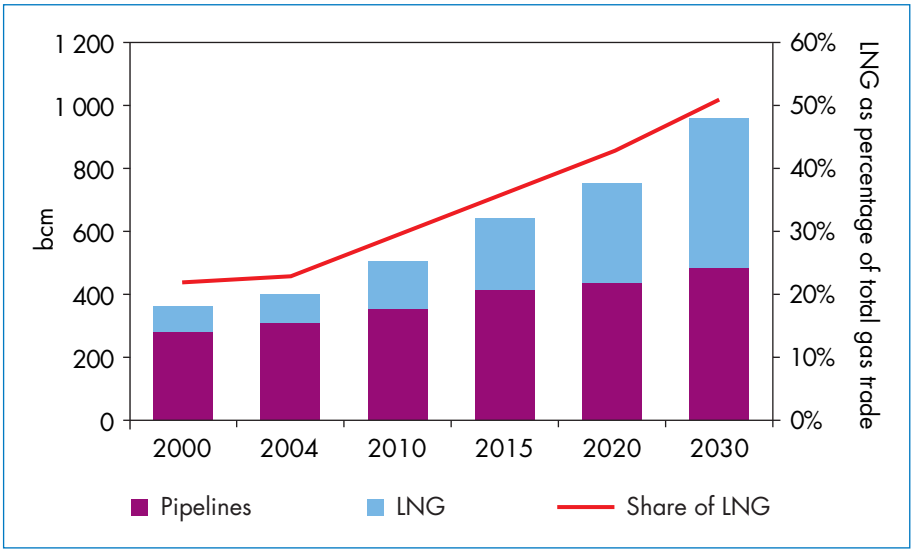
The roller-coaster rise of US natural gas prices in recent years bears testimony to the shifting balance of gas supply and demand. Average monthly well-head prices peaked at almost $11/MBtu in October 2005 in the wake of Hurricane Katrina, sliding to only $6.50 by March 2006 and remaining below $7 for most of the time through to July. The ratio of gas to oil prices is now at its lowest level since early 2000. The main reason is that rising prices since the end of the 1990s have choked off demand – particularly in the chemicals and power sectors. Warmer weather in the winter of 2005-2006 also curtailed demand. Higher prices have, by contrast, been much less effective in stimulating indigenous output, despite increased drilling: marketed production in 2005 would barely have increased had Katrina not occurred, even though the number of gas wells drilled reached almost 26 000 – an increase of 28% on 2004 and almost two-thirds on 2000. In fact, output in 2005 fell to its lowest level since 1992. Increased imports of LNG have made good most of the shortfall, with piped gas imports from Canada rising only modestly.

The diminishing additions to net capacity from increased drilling reflect the maturity of conventional gas basins, as drilling focuses on smaller and smaller pockets of gas and as decline rates at producing fields and wells gather pace. Raising US production in the long term will undoubtedly call for a shift in drilling to new basins, including non-conventional deposits. One of the most prospective areas is the Alaskan North Slope, but development of the region's vast gas reserves will require the construction of a pipeline system to connect with the existing systems in British Columbia and Alberta in Western Canada that export gas to the United States. A 40-50 bcm/year pipeline to ship gas from the North Slope, proposed by producers BP, ConocoPhillips and ExxonMobil, is assumed to be commissioned after 2015.

Supply from indigenous sources is nonetheless not expected to keep pace with demand over the projection period. We expect total US gas production to level off after 2015, leading to higher imports – mostly in the form of LNG. Five regasification terminals are under construction, another 12 projects have been approved by the national authorities and dozens more have been proposed. Local opposition may prevent some of these projects from going ahead. The terminals now being built will, alone, add about 65 bcm/year of capacity by 2010 to the 60 bcm/year of capacity at the country's five existing terminals. If all the approved projects go ahead, capacity would exceed 200 bcm/year.

Sources: IEA databases; EIA/DOE online databases (www.eia.doe.gov); IEA (2006a).

Figure 4.5: **World Inter-Regional Natural Gas Trade by Type in the Reference Scenario**



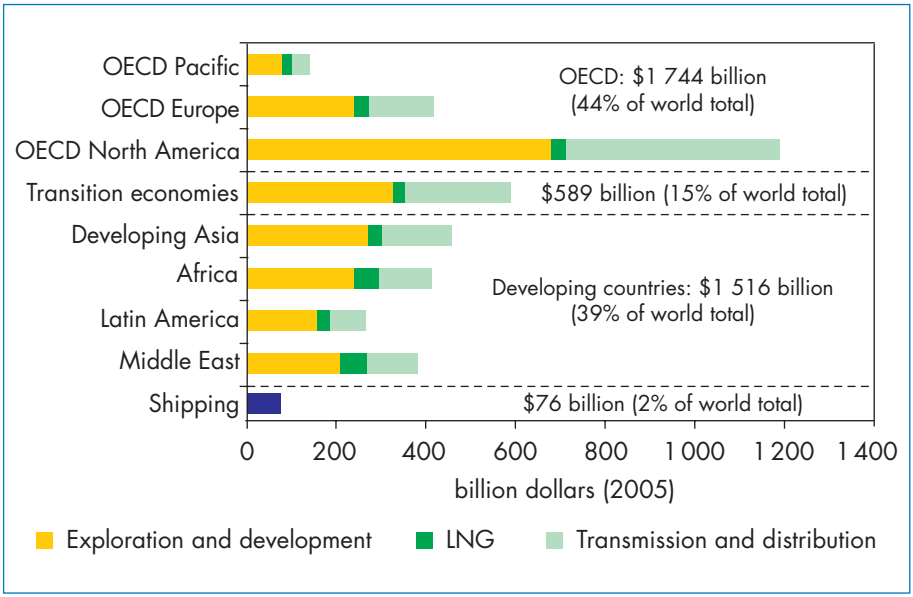
Investment

Cumulative investment in gas-supply infrastructure, including upstream facilities, liquefaction plants, LNG tankers and regasification terminals, transmission pipelines and storage facilities, and distribution networks, is projected to amount to $3.9 trillion ($151 billion per year) in the Reference Scenario over the period 2005-2030. Capital needs are highest in OECD North America, where demand increases strongly and where construction costs are high (Figure 4.6). The upstream absorbs 56% of total spending. Investment in new transmission pipelines and in extending existing distribution networks amounts to around $1.4 trillion over the period 2005-2030.

Decisions on the investment in gas-supply capacity additions that will come on stream by the end of the current decade have already been taken. So the amount of capacity that will be available by 2010 to meet the rise in demand that we project is known with a reasonable degree of certainty. The analysis of Chapter 12 suggests that there will be enough supply capacity to meet projected demand by then. However, it is far from certain that all the investment needed *beyond 2010* will in fact occur. As with oil, the opportunities and incentives to invest are a major source of uncertainty. Environmental policies and not-in-my-backyard resistance may impede the

construction of upstream and downstream facilities and push up their cost, especially in OECD countries. On the other hand, technological developments could open up new opportunities for investment and help lower costs in the longer term. Chapter 3 outlines potential barriers to upstream investment, affecting both oil and gas development.

Figure 4.6: **Cumulative Investment in Gas-Supply Infrastructure by Region and Activity in the Reference Scenario, 2005-2030**



A particular concern is whether the high rates of increase in exports projected for some regions, especially the Middle East, are achievable in light of institutional, financial and geopolitical factors and constraints. A small number of countries are expected to provide the bulk of the gas to be exported, mainly as LNG. If problems were to arise within these countries or between these countries and importers, it would be less likely that all the required investments in export-related infrastructure would be forthcoming. The availability of LNG carriers and trained crews may also constrain investment in LNG chains. Any deferral of upstream oil investment, analysed in Chapter 3, would also reduce associated gas production.

The future rate of investment in Russia's gas industry is a particularly critical uncertainty. The bulk of Russia's gas production comes from three super-giant fields – Urengoy, Yamburg and Medvezhye – which are declining at a combined rate of 20 bcm per year (IEA, 2006b). Production at a fourth super-

giant, Zapolyarnoye, which came on stream in 2001, has already peaked at 100 bcm per year. Enormous investments are needed to develop new fields in deeper strata and/or in the Arctic region and other regions where reserves are expensive to develop, simply to compensate for the depletion at the old super-giants. Gazprom, which produces 90% of Russia's gas, recently announced an increase in its capital spending to almost $13 billion per year, but this is still below the $17 billion per year that we estimate the Russian gas industry will need to spend on average over the projection period. Moreover, much of Gazprom's spending is being directed at foreign acquisitions and export infrastructure, rather than the domestic network and the upstream sector. One relatively low-cost option for augmenting supplies would be to allow oil companies and independent gas companies, which could sharply increase their marketed gas output, to gain access to Gazprom's network. Reducing waste in domestic consumption would free up more gas for export. The development of the Shtokman field in the Barents Sea and the Bovanenskoye field in Yamal, announced in October 2006, would also increase export availability.

Another source of uncertainty concerns the possibility of major gas-exporting countries coordinating their investment and production plans in order to avoid surplus capacity and to keep gas prices up. The Algerian national oil and gas company, Sonatrach, and Russia's Gazprom recently signed a memorandum of understanding on cooperation in upstream activities – a move that has raised concerns among European gas importers about its implications for competition and prices.

Investment in downstream gas infrastructure in consuming countries – including transmission pipelines, storage facilities and distribution networks – will hinge on appropriate regulatory frameworks, as much of the capital will have to come from the private sector. This is the case in many developing countries, where publicly-owned gas companies face difficulties in raising sufficient funds. Investment prospects are more secure for domestic downstream projects in OECD countries, particularly those that involve the extension or enhancement of existing pipeline networks. This type of investment is usually considered to be relatively low-risk, particularly where demand trends are reasonably stable and predictable and where returns are protected by the regulator through explicit price controls. The returns that can be made on such investments usually depend to a large extent on price controls. Most downstream gas transmission and distribution companies operating in regulated markets are also well-placed to obtain finance for new infrastructure investments.

Pricing policies are critical to incentives to invest in gas networks. The allowed rate of return is generally low relative to the average return on investment in other industries, reflecting the lower level of risk – especially where the

investment is incremental and where the regulatory framework provides a high level of assurance to the investor that he will be able to recover his costs through regulated tariffs. There is nonetheless a danger that the regulator may fix the allowed rate of return too low, which can discourage investment and create bottlenecks. In OECD countries, regulated tariffs are generally set so as to cover the full cost of supply. In some cases, the regulatory regime may incorporate incentives for utilities to reduce costs – an approach pioneered in Great Britain. In the vast majority of non-OECD countries, price ceilings that keep retail prices below the full long-run marginal cost of supply can impede the capacity of gas utilities – whether private or public – to invest in expanding and maintaining the network (see the discussion of subsidies in Chapter 11). This is a major problem in Russia and several other transition economies.

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