CHIEF EXECUTIVE OFFICER'S REVIEW

We made good progress in 2012 toward improving our performance, even as we dealt with continued volatile economic conditions. We are on target to meet strategic objectives. And we are delivering the projects that form the foundation of our aim to become the world's most competitive and innovative energy company.

Still, there is work to do. We are focused on further improving our operating performance in key areas, such as oil and gas production and internal processes that influence customer satisfaction.

Let me highlight some of 2012's milestones and achievements. Our overall safety performance in 2012 matched that of 2011. And we continued our strong focus on ensuring our facilities are safely run and maintained. The Shell Sustainability Report has details on our safety and environmental performance.

For 2012 our earnings on a current cost of supplies basis attributable to shareholders were $27 billion. Cash flow from operating activities was $46 billion and, excluding working capital movements, was $43 billion. Net capital investment was $30 billion, as we build a solid foundation for future growth.

We produced 3.3 million barrels of oil equivalent per day in 2012, up 3% from 2011 excluding the effect of divestments and exits, with important contributions from our Pearl GTL plant in Qatar, which is now ramped up, and the Pluto LNG Project in Australia, through our participation in Woodside Petroleum Ltd. Equity LNG sales volumes of 20.2 million tonnes were up 7% compared with 2011.

In exploration, we continue to expand our portfolio, adding 120,000 square kilometres of new exploration acreage in 2012, including positions in liquids-rich shales. We participated in seven notable conventional exploration discoveries and appraisals, and 10 successful unconventional appraisals.

Harnessing innovation

We are building on our heritage as innovators and gaining public recognition for our accomplishments. Shell was one of 50 innovation leaders worldwide identified by the MIT Technology Review. We also received industry awards for our Perdido deep-water project in the Gulf of Mexico and our Prelude floating LNG project.

We continue to fine-tune our global network of technology centres to support future business opportunities. That includes increasing our capabilities in India and China. In November, we laid the foundation stone for a new technology centre in Bangalore, India, which we aim to build into a world-class technology hub.

Our Downstream business had a good operating performance for the year, with reduced levels of unplanned downtime. We continued to build on the strength of Shell's brand in markets with growth potential. In Brazil our Raízen biofuels joint venture is making good progress. In its first full year of operation, the venture made a notable contribution to Downstream earnings. Last year we broke ground on Shell's seventh lubricants blending plant in mainland China, to meet rising demand there. And we also announced plans to build a blending plant in Indonesia, another expanding market in Asia.

Our accomplishments in 2012 helped underpin Shell's strong track record since 2010. Over the last three years, our earnings on a current cost of supplies basis attributable to shareholders increased by 45% and our cash flow from operating activities increased by 69%. Compared with our major competitors, over the past three years we have delivered the highest rates of growth in earnings per share and cash flow from operating activities.

Building our future

Looking to the future, the projects that will help drive growth are advancing well. We have about 30 projects under construction. We produced the first oil from the Gumusut-Kakap project off the coast of Malaysia and that will ramp up once a floating production facility is in place. We added a new development phase to our Changbei tight-gas operation in China, adding nearly 1,700 square kilometres, as well as agreeing with our partner, China National Petroleum Corporation, to potentially develop the main reservoir.

In October, we cut the first steel for the hull of our ground-breaking Prelude floating LNG project. In November, the hull for the Mars B project was completed in South Korea and shipped to Texas for installation in the Gulf of Mexico. And we took the final investment decision on the Quest carbon capture and storage project associated with our oil sands operations in Canada, which will reduce our environmental footprint. In all, we took final investment decisions on seven projects during the year.

With our progress in 2012, the growth agenda set out at the beginning of the year is on track. It includes $175-200 billion of cash flow from operating activities, excluding working capital movements, for 2012-2015, assuming the Brent oil price remains in the range of $80-100 per barrel and conditions for North American natural gas and downstream margins improve relative to 2012. It also includes net capital investment of $120-130 billion, and a competitive dividend for shareholders.

Looking further ahead, we are considering about 30 additional projects, giving us an attractive set of options for the longer term. We are now more constrained by capital than by opportunities, which allows us to focus resources where the potential for growth is greatest.

Gas leadership

Let me highlight one area where we are already industry leaders and that has great potential for the future: integrated gas projects, which include LNG and gas-to-liquids (GTL), such as our Pearl plant. Integrated gas projects contributed approximately 40% of our total earnings in 2012.

Integrated gas builds on our strengths in exploration and production, our downstream expertise in creating and marketing high-value products, and our know-how in managing huge projects. Growth will come from Australia, where we have an additional 7 million tonnes per year under construction. Longer term, we are studying projects with capacity of another 20 million tonnes per year, so there is significant growth potential.

North America is one region of opportunity. The shale gas revolution there has unlocked vast resources that provide an attractively priced feedstock. We will soon supply LNG for long-haul trucks in Canada. And we have other LNG, GTL and chemicals options on the drawing board.

In February 2013, we agreed to acquire part of Repsol S.A.'s LNG portfolio, subject to regulatory approval and other conditions precedent. This acquisition will extend our international LNG portfolio.

I expect our strength in integrated gas projects will be one of the drivers of our earnings and cash flow in the coming decades.

Strategic priorities

As we push ahead with our strategy, we have taken a fresh look at how we manage our portfolio. Going forward we are using a clear set of strategic themes to drive our choices about investment, people and innovation.

First we have our upstream and downstream "engines", which are mature businesses. They generate much of our cash flow. We will continue to invest to keep them running smoothly and to extract additional value.

Next we have our growth priorities, which are three areas of great opportunity for us in the years ahead, thanks to our superior technology and innovation. They are integrated gas, deep water and resources plays, such as shale oil and gas.

Finally we have future opportunities for the longer term, including the Arctic, Iraq, Kazakhstan, Nigeria, and heavy oil. We also continue to ramp up our conventional exploration activities, which we think is a cost-effective way of identifying new resources.

To conclude, we are making good progress toward our objectives. We continue to work hard to improve our operating performance. And we have clear strategic priorities to drive growth and value for our shareholders.

Peter Voser
Chief Executive Officer

BUSINESS REVIEW

PERFORMANCE INDICATORS

Key performance indicators

Total shareholder return
2012 **-0.2%** 2011 **17.1%**

Total shareholder return (TSR) is the difference between the share price at the start of the year and the share price at the end of the year, plus gross dividends delivered during the calendar year (reinvested quarterly), expressed as a percentage of the year-start share price. The TSRs of major publicly traded oil and gas companies can be directly compared, providing a way to determine how Shell is performing against its industry peers.

Net cash from operating activities ($ billion)
2012 **46** 2011 **37**

Net cash from operating activities is the total of all cash receipts and payments associated with our sales of oil, gas, chemicals and other products. The components that provide a reconciliation from income for the period are listed in the "Consolidated Statement of Cash Flows". This indicator reflects Shell's ability to generate cash for both investment and distribution to shareholders.

Project delivery
2012 **90%** 2011 **79%**

Project delivery reflects Shell's capability to complete major projects on time and within budget on the basis of targets set in the annual Business Plan. The set of projects consists of at least 20 Shell-operated capital projects that are in the execution phase (post final investment decision).

Production available for sale (thousand boe/d)
2012 **3,262** 2011 **3,215**

Production is the sum of all average daily volumes of unrefined oil and natural gas produced for sale by Shell subsidiaries and the Shell share of equity-accounted investments. The unrefined oil comprises crude oil, natural gas liquids, synthetic crude oil and bitumen. The gas volume is converted into equivalent barrels of oil to make the summation possible. Changes in production have a significant impact on Shell's cash flow.

Equity sales of liquefied natural gas (million tonnes)
2012 **20.2** 2011 **18.8**

Equity sales of liquefied natural gas (LNG) is a measure of the operational performance of Shell's Upstream business and the LNG market demand.

Refinery and chemical plant availability
2012 **92.9%** 2011 **91.2%**

Refinery and chemical plant availability is the weighted average of the actual uptime of plants as a percentage of their maximum possible uptime. The weighting is based on the capital employed adjusted for cash and non-current liabilities. It excludes downtime due to uncontrollable factors, such as hurricanes. This indicator is a measure of operational excellence of Shell's Downstream manufacturing facilities.

Total recordable case frequency (injuries per million working hours)
2012 **1.3** 2011 **1.2**

Total recordable case frequency (TRCF) is the number of staff or contractor injuries requiring medical treatment or time off for every million hours worked. It is a standard measure of occupational safety.

Additional performance indicators

Earnings on a current cost of supplies basis attributable to Royal Dutch Shell plc shareholders ($ million)
2012 **27,044** 2011 **28,625**

Earnings per share on a current cost of supplies basis ($)
2012 **4.32** 2011 **4.61**

Earnings on a current cost of supplies (CCS) basis attributable to Royal Dutch Shell plc shareholders is the income for the period, adjusted for the after-tax effect of oil-price changes on inventory and non-controlling interest. CCS earnings per share is calculated by dividing CCS earnings attributable to shareholders by the average number of shares outstanding. See page 16 and Note 2 to the "Consolidated Financial Statements".

Net capital investment ($ million)
2012 **29,803** 2011 **23,503**

Net capital investment is defined as capital expenditure, adjusted for: proceeds from disposals; exploration expense excluding exploration wells written off; investments in equity-accounted investments; and leases and other items. See Notes 2 and 4 to the "Consolidated Financial Statements" for further information.

Return on average capital employed
2012 **12.7%** 2011 **15.9%**

Return on average capital employed (ROACE) is defined as annual income, adjusted for after-tax interest expense, as a percentage of average capital employed during the year. Capital employed is the sum of total equity and total debt. ROACE measures the efficiency of Shell's utilisation of the capital that it employs and is a common measure of business performance. See page 45.

Gearing
2012 **9.2%** 2011 **13.1%**

Gearing is defined as net debt (total debt less cash and cash equivalents) as a percentage of total capital (net debt plus total equity), at December 31. It is a measure of the degree to which Shell's operations are financed by debt. For further information see Note 15 to the "Consolidated Financial Statements".

Proved oil and gas reserves attributable to Royal Dutch Shell plc shareholders (million boe)
2012 **13,556** 2011 **14,250**

Proved oil and gas reserves attributable to Royal Dutch Shell plc shareholders are the total estimated quantities of oil and gas from Shell subsidiaries (excluding reserves attributable to non-controlling interest) and the Shell share of equity-accounted investments that geoscience and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs, as at December 31, under existing economic conditions, operating methods and government regulations. Gas volumes are converted into barrels of oil equivalent (boe). Reserves are crucial to an oil and gas company, since they constitute the source of future production. Reserves estimates are subject to change based on a wide variety of factors, some of which are unpredictable. See "Risk factors".

Operational spills of more than 100 kilograms
2012 **204** 2011 **211**

The operational spills indicator reflects the total number of incidents in which 100 kilograms or more of oil or oil products were spilled by a Shell-operated entity as a result of its operations. The number for 2011 was updated from 207 to reflect completion of investigations into spills.

Employees (thousand)
2012 **87** 2011 **90**

The employees indicator consists of the annual average full-time employee equivalent of the total number of people on full-time or part-time employment contracts with Shell subsidiaries.

SELECTED FINANCIAL DATA

The selected financial data set out below is derived, in part, from the Consolidated Financial Statements. This data should be read in conjunction with the Consolidated Financial Statements and related Notes, as well as the Business Review in this Report.

CONSOLIDATED STATEMENT OF INCOME AND OF COMPREHENSIVE INCOME DATA					$ MILLION
	2012	2011	2010	2009	2008
Revenue	467,153	470,171	368,056	278,188	458,361
Income for the period	26,840	31,185	20,474	12,718	26,476
Income attributable to non-controlling interest	248	267	347	200	199
Income attributable to Royal Dutch Shell plc shareholders	26,592	30,918	20,127	12,518	26,277
Comprehensive income attributable to Royal Dutch Shell plc shareholders	27,178	29,727	20,131	19,141	15,228

All results are from continuing operations.

CONSOLIDATED BALANCE SHEET DATA					$ MILLION
	2012	2011	2010	2009	2008
Total assets	360,325	345,257	322,560	292,181	282,401
Total debt	37,754	37,175	44,332	35,033	23,269
Share capital	542	536	529	527	527
Equity attributable to Royal Dutch Shell plc shareholders	188,494	169,517	148,013	136,431	127,285
Non-controlling interest	1,433	1,486	1,767	1,704	1,581

EARNINGS PER SHARE					$
	2012	2011	2010	2009	2008
Basic earnings per €0.07 ordinary share	4.25	4.98	3.28	2.04	4.27
Diluted earnings per €0.07 ordinary share	4.24	4.97	3.28	2.04	4.26

SHARES					NUMBER
	2012	2011	2010	2009	2008
Basic weighted average number of A and B shares	6,261,184,755	6,212,532,421	6,132,640,190	6,124,906,119	6,159,102,114
Diluted weighted average number of A and B shares	6,267,839,545	6,221,655,088	6,139,300,098	6,128,921,813	6,171,489,652

OTHER FINANCIAL DATA					$ MILLION
	2012	2011	2010	2009	2008
Net cash from operating activities	46,140	36,771	27,350	21,488	43,918
Net cash used in investing activities	28,453	20,443	21,972	26,234	28,915
Dividends paid	7,682	7,315	9,979	10,717	9,841
Net cash used in financing activities	10,630	18,131	1,467	829	9,394
Increase/(decrease) in cash and cash equivalents	7,258	(2,152)	3,725	(5,469)	5,532
Earnings/(losses) by segment [A]					
Upstream	22,162	24,455	15,935	8,354	26,506
Downstream	5,350	4,289	2,950	258	5,309
Corporate	(209)	86	91	1,310	(69)
Total segment earnings	27,303	28,830	18,976	9,922	31,746
Attributable to non-controlling interest	(259)	(205)	(333)	(118)	(380)
Earnings on a current cost of supplies basis attributable to Royal Dutch Shell plc shareholders [B]	27,044	28,625	18,643	9,804	31,366
Net capital investment [A]					
Upstream	25,320	19,083	21,222	22,326	28,257
Downstream	4,275	4,342	2,358	6,232	3,104
Corporate	208	78	100	324	60
Total	29,803	23,503	23,680	28,882	31,421

[A] See Notes 2 and 4 to the "Consolidated Financial Statements".
[B] See table on page 16.

BUSINESS OVERVIEW

History

From 1907 until 2005, Royal Dutch Petroleum Company and The "Shell" Transport and Trading Company, p.l.c. were the two public parent companies of a group of companies known collectively as the "Royal Dutch/Shell Group". Operating activities were conducted through the subsidiaries of these parent companies. In 2005, Royal Dutch Shell plc became the single parent company of Royal Dutch Petroleum Company and of The "Shell" Transport and Trading Company, p.l.c., now The Shell Transport and Trading Company Limited.

Royal Dutch Shell plc (the Company) is a public limited company registered in England and Wales and headquartered in The Hague, the Netherlands.

Activities

Shell is one of the world's largest independent oil and gas companies in terms of market capitalisation, operating cash flow and oil and gas production. We aim to sustain our strong operational performance and continue our investments primarily in countries that have the necessary infrastructure, expertise and remaining growth potential. Such countries include Australia, Brazil, Brunei, Canada, China, Denmark, Germany, Malaysia, the Netherlands, Nigeria, Norway, Oman, Qatar, Russia, the UK and the USA.

We are bringing new oil and gas supplies on-stream from major field developments. We are also investing in growing our integrated gas activities. For example, our Pearl GTL plant completed its ramp-up at the end of 2012. In Downstream we seek innovative ways to market LNG, for example through the use of LNG in the transport sector.

At the same time, we are exploring for oil and gas in prolific conventional geological formations, such as those found in Australia, Brazil and the Gulf of Mexico. But we are also exploring for hydrocarbons in formations, such as low-permeability reservoirs in the USA, Australia, Canada and China, which can be developed by fracturing techniques.

We also have a focused portfolio of refineries and chemical plants. Furthermore, we are a leading biofuel producer and fuel retailer in Brazil, through our Raízen joint venture. We have a strong retail position not only in the major industrialised countries, but also in the developing ones. The distinctive Shell pecten, (a trademark in use since the early part of the twentieth century), and trademarks in which the word Shell appears, support this marketing effort throughout the world. A strong patent portfolio underlies the technology that we employ in our various businesses. In total, Shell currently has more than 14,000 granted patents and pending patent applications.

Businesses

Upstream International manages the Upstream businesses outside the Americas. It explores for and recovers crude oil, natural gas and natural gas liquids, liquefies and transports gas, and operates the upstream and midstream infrastructure necessary to deliver oil and gas to market. Upstream International also manages Shell's LNG and GTL businesses. Since January 2013, it manages its operations primarily by line of business, with this structure overlaying individual country organisations. This organisation is supported by activities such as Exploration and New Business Development. Previously activities were organised primarily by geographical location.

Upstream Americas manages the Upstream businesses in North and South America. It explores for and recovers crude oil, natural gas and natural gas liquids, transports gas and operates the upstream and midstream infrastructure necessary to deliver oil and gas to market. Upstream Americas also extracts bitumen from oil sands that is converted into synthetic crude oil. Additionally, it manages the US-based wind business. It manages its operations by line of business, supported by activities such as Exploration and New Business Development.

Downstream manages Shell's refining and marketing activities for oil products and chemicals. These activities are organised into globally managed classes of business, although some are managed regionally or provided through support units. Refining includes manufacturing, supply and shipping of crude oil. Marketing sells a range of products including fuels, lubricants, bitumen and liquefied petroleum gas (LPG) for home, transport and industrial use. Chemicals produces and markets petrochemicals for industrial customers, including the raw materials for plastics, coatings and detergents. Downstream also trades Shell's flow of hydrocarbons and other energy-related products, supplies the Downstream businesses, governs the marketing and trading of gas and power, and provides shipping services. Additionally, Downstream oversees Shell's interests in alternative energy (including biofuels but excluding wind) and CO_2 management.

Projects & Technology manages the delivery of Shell's major projects and drives the research and innovation to create technology solutions. It provides technical services and technology capability covering both Upstream and Downstream activities. It is also responsible for providing functional leadership across Shell in the areas of safety and environment, and contracting and procurement.

Segmental reporting

Upstream combines the operating segments Upstream International and Upstream Americas, which have similar economic characteristics, products and services, production processes, types and classes of customers, and methods of distribution. Upstream and Downstream earnings include their respective elements of Projects & Technology and of trading activities. Corporate represents the key support functions comprising holdings and treasury, headquarters, central functions and Shell's self-insurance activities.

REVENUE BY BUSINESS SEGMENT (INCLUDING INTER-SEGMENT SALES) — $ MILLION

	2012	2011	2010
Upstream			
Third parties	43,431	42,260	32,395
Inter-segment	51,119	49,431	35,803
Total	94,550	91,691	68,198
Downstream			
Third parties	423,638	427,864	335,604
Inter-segment	772	782	612
Total	424,410	428,646	336,216
Corporate			
Third parties	84	47	57
Total	84	47	57

REVENUE BY GEOGRAPHICAL AREA (EXCLUDING INTER-SEGMENT SALES) — $ MILLION

	2012	%	2011	%	2010	%
Europe	184,223	39.4	187,498	39.9	137,359	37.3
Asia, Oceania, Africa	156,310	33.5	148,260	31.5	110,955	30.2
USA	91,571	19.6	91,946	19.6	77,660	21.1
Other Americas	35,049	7.5	42,467	9.0	42,082	11.4
Total	467,153	100.0	470,171	100.0	368,056	100.0

RISK FACTORS

The risks discussed below could have a material adverse effect separately, or in combination, on our operational performance, earnings, cash flows and financial condition. Accordingly, investors should carefully consider these risks.

We are exposed to fluctuating prices of crude oil, natural gas, oil products and chemicals.
Prices of oil, natural gas, oil products and chemicals are affected by supply and demand, both globally and regionally. Moreover, prices for oil and gas can move independently from each other. Factors that influence supply and demand include operational issues, natural disasters, weather, political instability, conflicts, economic conditions and actions by major oil-exporting countries. Price fluctuations could have a material effect. For example, in a low oil and gas price environment, Shell would generate less revenue from its Upstream production, and as a result certain long-term projects might become less profitable, or even incur losses. Additionally, low oil and gas prices could result in the debooking of proved oil or gas reserves, if they become uneconomic in this type of environment. Prolonged periods of low oil and gas prices, or rising costs, could also result in projects being delayed or cancelled, as well as in the impairment of certain assets. In a high oil and gas price environment, we could experience sharp increases in cost and under some production-sharing contracts our entitlement to proved reserves would be reduced. Higher prices could also reduce demand for our products. Lower demand for our products might result in lower profitability, particularly in our Downstream business.

Our ability to achieve strategic objectives depends on how we react to competitive forces.
We face competition in each of our businesses. While we seek to differentiate our products, many of them are competing in commodity-type markets. If we do not manage our expenses adequately, our cost efficiency could deteriorate and our unit costs may increase. This in turn could erode our competitive position. Increasingly, we compete with government-run oil and gas companies, particularly in seeking access to oil and gas resources. Today, these government-run companies control vastly greater quantities of oil and gas resources than the major, publicly held oil and gas companies. Government-run entities have access to significant resources and may be motivated by political or other factors in their business decisions, which may harm our competitive position or hinder our access to desirable projects.

As our business model involves trading and treasury risks, we are affected by the global macroeconomic environment as well as financial and commodity market conditions.
Shell subsidiaries and equity-accounted investments are subject to differing economic and financial market conditions throughout the world. Political or economic instability affects such markets. Shell uses debt instruments such as bonds and commercial paper to raise significant amounts of capital. Should our access to debt markets become more difficult, the potential impact on our liquidity could have an adverse effect on our operations. Commodity trading is an important component of our supply and distribution function. Trading and treasury risks include, among others, exposure to movements in commodity prices, interest rates and foreign exchange rates, counterparty default and various operational risks (see also page 83). As a global company doing business in more than 70 countries, we are exposed to changes in currency values and exchange controls. While we undertake some currency hedging, we do not do so for all of our activities. See Notes 6 and 21 to the "Consolidated Financial Statements". Shell has significant financial exposure to the euro and could be materially affected by a significant change in its value or any structural changes to the European Union (EU) or the European Economic and Monetary Union affecting the euro. While we do not have significant direct exposure to sovereign debt, it is possible that our partners and customers may have exposure which could impair their ability to meet their obligations to us. Therefore, a sovereign debt downgrade or default could have a material adverse effect on Shell.

Our future hydrocarbon production depends on the delivery of large and complex projects, as well as on our ability to replace proved oil and gas reserves.
We face numerous challenges in developing capital projects, especially large ones. Challenges include uncertain geology, frontier conditions, the existence and availability of necessary technology and engineering resources, availability of skilled labour, project delays, expiration of licences and potential cost overruns, as well as technical, fiscal, regulatory, political and other conditions. These challenges are particularly relevant in certain developing and emerging market countries, such as Iraq and Kazakhstan, and in frontier areas, such as the Arctic. Such potential obstacles may impair our delivery of these projects, as well as our ability to fulfil related contractual commitments. Future oil and gas production will depend on our access to new proved reserves through exploration, negotiations with governments and other owners of proved reserves and acquisitions, as well as developing and applying new technologies and recovery processes to existing fields and mines. Failure to replace proved reserves could result in lower future production.

OIL AND GAS PRODUCTION AVAILABLE FOR SALE	MILLION BOE [A]		
	2012	2011	2010
Shell subsidiaries	825	811	855
Shell share of equity-accounted investments	369	362	355
Total	1,194	1,173	1,210

[A] Natural gas volumes are converted to oil equivalent using a factor of 5,800 scf per barrel.

PROVED DEVELOPED AND UNDEVELOPED OIL AND GAS RESERVES [A][B] (AT DECEMBER 31)	MILLION BOE [C]		
	2012	2011	2010
Shell subsidiaries	9,873	10,320	10,176
Shell share of equity-accounted investments	3,701	3,946	4,097
Total	13,574	14,266	14,273
Attributable to non-controlling interest [D]	18	16	24
Attributable to Royal Dutch Shell plc shareholders	13,556	14,250	14,249

[A] We manage our total proved reserves base without distinguishing between proved reserves from subsidiaries and those from equity-accounted investments.
[B] Includes proved reserves associated with future production that will be consumed in operations.
[C] Natural gas volumes are converted to oil equivalent using a factor of 5,800 scf per barrel.
[D] Represents proved reserves attributable to non-controlling interest in Shell subsidiaries.

An erosion of our business reputation would have a negative impact on our brand, our ability to secure new resources and our licence to operate.
Shell is one of the world's leading energy brands, and its brand and reputation are important assets. The Shell General Business Principles and Code of Conduct govern how Shell and its individual companies conduct their affairs. It is a challenge for us to ensure that all employees and contractors, well above 100,000 in total, comply with

the principles. Failure – real or perceived – to follow these principles, or other real or perceived failures of governance or regulatory compliance, could harm our reputation. This could impact our licence to operate, damage our brand, harm our ability to secure new resources and limit our ability to access the capital market.

Our future performance depends on the successful development and deployment of new technologies.
Technology and innovation are essential to Shell. If we do not develop the right technology, do not have access to it or do not deploy it effectively, the delivery of our strategy and our licence to operate may be adversely affected. We operate in environments where the most advanced technologies are needed. While these technologies are regarded as safe for the environment with today's knowledge, there is always the possibility of unknown or unforeseeable environmental impacts that could harm our reputation, licence to operate or expose us to litigation or sanctions.

Rising climate change concerns could lead to additional regulatory measures that may result in project delays and higher costs.
In the future, in order to help meet the world's energy demand, we expect our production to rise and more of our production to come from unconventional sources than at present. Energy intensity of production of oil and gas from unconventional sources can be higher than that of production from conventional sources. Therefore, it is expected that both the CO_2 intensity of our production, as well as our absolute Upstream CO_2 emissions, will increase as our business grows. Examples of such developments are our expansion of oil sands activities in Canada and our gas-to-liquids project in Qatar. Additionally, as production from Iraq increases, we expect that CO_2 emissions from flaring will rise. We are working with our partners on finding ways to capture the gas that is flared. Over time, we expect that a growing share of our CO_2 emissions will be subject to regulation and carry a cost. If we are unable to find economically viable, as well as publicly acceptable, solutions that reduce our CO_2 emissions for new and existing projects or products, we may incur additional costs, delayed projects or reduced production in certain projects.

Moreover, continued public and political attention to climate change concerns, including existing and future regulatory frameworks to reduce greenhouse gas emissions, could result in increasing production costs, lengthening project implementation times and reducing demand for hydrocarbons.

The nature of our operations exposes us to a wide range of health, safety, security and environment risks.
The health, safety, security and environment (HSSE) risks to which we are potentially exposed cover a wide spectrum, given the geographic range, operational diversity and technical complexity of Shell's daily operations. We have operations, including oil and gas production, transport and shipping of hydrocarbons, and refining, in difficult geographies or climate zones, as well as environmentally sensitive regions, such as the Arctic or maritime environments, especially in deep water. These and other operations expose us to the risk, among others, of major process safety incidents, effects of natural disasters, social unrest, personal health and safety lapses, and crime. If a major HSSE risk materialises, such as an explosion or hydrocarbon spill, this could result in injuries, loss of life, environmental harm, disruption to business activities and, depending on their cause and severity, material damage to our reputation and eventually loss of licence to operate. In certain circumstances, liability could be imposed without regard to Shell's fault in the matter. Requirements governing HSSE matters often change and are likely to become more stringent over time. We could incur significant additional costs in the future complying with such requirements or as a result of violations of, or liabilities under, HSSE laws and regulations, such as fines, penalties, clean-up costs and third-party claims.

Shell mainly self-insures its risk exposures.
Shell insurance subsidiaries provide insurance coverage to Shell entities, generally up to $1.15 billion per event and usually limited to Shell's percentage interest in the relevant entity. The type and extent of the coverage provided is equal to that which is otherwise commercially available in the third-party insurance market. While from time to time the insurance subsidiaries may seek reinsurance for some of their risk exposures, such reinsurance would not provide any material coverage in the event of an incident like BP Deepwater Horizon. Similarly, in the event of a material environmental incident, there would be no material proceeds available from third-party insurance companies to meet Shell's obligations.

An erosion of the business and operating environment in Nigeria would adversely impact Shell.
We face various risks in our Nigerian operations. These risks include: security issues surrounding the safety of our people, host communities, and operations; our ability to enforce existing contractual rights; limited infrastructure; and potential legislation that could increase our taxes or costs of operation. The Nigerian government is contemplating new legislation to govern the petroleum industry which, if passed into law, would likely have a significant adverse impact on Shell's existing and future activities in that country.

We operate in more than 70 countries, with differing degrees of political, legal and fiscal stability. This exposes us to a wide range of political developments that could result in changes to laws and regulations. In addition, Shell subsidiaries and equity-accounted investments face the risk of litigation and disputes worldwide.
Developments in politics, laws and regulations can – and do – affect our operations. Potential developments include: forced divestment of assets; expropriation of property; cancellation or forced renegotiation of contract rights; additional taxes including windfall taxes, restrictions on deductions and retroactive tax claims; import and export restrictions; foreign exchange controls; and changing environmental regulations and disclosure requirements. Certain governments, states and regulatory bodies have, in the opinion of Shell, exceeded their constitutional authority by attempting unilaterally to amend or cancel existing agreements or arrangements; by failing to honour existing contractual commitments; and by seeking to adjudicate disputes between private litigants. As a result of the financial crisis, US regulators have adopted regulations that require disclosure of information on payments to governments that we believe is immaterial to investors, but that could compromise confidential commercial arrangements and create conflicting legal requirements. EU regulators have also proposed similar regulations. Additional regulations targeted at the financial sector could have unintended consequences for our trading, treasury and pension operations. In our Upstream activities these developments can and do affect land tenure, re-writing of leases, entitlement to produced hydrocarbons, production rates, royalties and pricing. Parts of our Downstream activities are subject to price controls in some countries. From time to time, cultural and political factors play a role in unprecedented and unanticipated judicial outcomes that could adversely affect Shell. If we do not comply with policies and regulations, it may result in regulatory investigations, litigation and ultimately sanctions.

Our operations expose us to social instability, terrorism, acts of war, piracy and government sanctions that could have an adverse impact on our business.
As seen recently in north Africa and the Middle East, social and civil unrest, both within the countries in which we operate and internationally, can – and does – affect Shell. Potential developments that could impact our business include international sanctions, conflicts including war, acts of political or economic terrorism and acts of piracy on the high seas, as well as civil unrest and local security concerns that threaten the safe operation of our facilities and transport of our products. For example, EU sanctions have prohibited us from producing oil and gas in Syria, and the USA and the EU have imposed sanctions relating to transactions involving Iran and Sudan, among other countries. If such risks materialise, they could result in injuries and disruption to business activities.

We rely heavily on information technology systems for our operations.
The operation of many of our business processes depends on the availability of information technology (IT) systems. Our IT systems are increasingly concentrated in terms of geography, number of systems, and key contractors supporting the delivery of IT services. Shell, like many other multinational companies, has been the target of attempts to gain unauthorised access through the internet to our IT systems, including more sophisticated attempts often referred to as advanced persistent threat. Shell seeks to detect and investigate all such security incidents, aiming to prevent their recurrence. Disruption of critical IT services, or breaches of information security, could have adverse consequences for Shell.

We have substantial pension commitments, whose funding is subject to capital market risks.
Liabilities associated with defined benefit plans can be significant, as can the cash funding of such plans; both depend on various assumptions. Volatility in capital markets, and the resulting consequences for investment performance and interest rates, may result in significant changes to the funding level of future liabilities. In case of a shortfall, Shell might be required to make substantial cash contributions, depending on the applicable local regulations.

The estimation of proved oil and gas reserves involves subjective judgements based on available information and the application of complex rules, so subsequent downward adjustments are possible.
The estimation of proved oil and gas reserves involves subjective judgements and determinations based on available geological, technical, contractual and economic information. The estimate may change because of new information from production or drilling activities, or changes in economic factors, including changes in the price of oil or gas and changes in the taxation or regulatory policies of host governments. It may also alter because of acquisitions and divestments, new discoveries, and extensions of existing fields and mines, as well as the application of improved recovery techniques. Published proved oil and gas reserves estimates may also be subject to correction due to errors in the application of published rules and changes in guidance. Any downward adjustment would indicate lower future production volumes.

Many of our major projects and operations are conducted in joint ventures or associates. This may reduce our degree of control, as well as our ability to identify and manage risks.
A significant share of our capital is invested in joint ventures or associates. In cases where we are not the operator we have limited influence over, and control of, the behaviour, performance and costs of operation of joint ventures or associates. Despite not having control, we could still be exposed to the risks associated with these operations. For example, our partners or members of a joint venture or an associate (particularly local partners in developing countries) may not be able to meet their financial or other obligations to the projects, threatening the viability of a given project.

Violations of antitrust and competition law carry fines and expose us or our employees to criminal sanctions and civil suits.
Antitrust and competition laws apply to Shell subsidiaries and equity-accounted investments in the vast majority of countries in which we do business. Shell subsidiaries and equity-accounted investments have been fined for violations of antitrust and competition law. These include a number of fines by the European Commission Directorate-General for Competition (DG COMP). Due to the DG COMP's fining guidelines, any future conviction of Shell subsidiaries or equity-accounted investments for violation of EU competition law could result in larger fines. Violation of antitrust laws is a criminal offence in many countries, and individuals can be either imprisoned or fined. Furthermore, it is now common for persons or corporations allegedly injured by antitrust violations to sue for damages.

Shell is currently subject to a Deferred Prosecution Agreement with the U.S. Department of Justice for violations of the Foreign Corrupt Practices Act.
In 2010, a Shell subsidiary agreed to a Deferred Prosecution Agreement (DPA) with the U.S. Department of Justice (DOJ) for violations of the Foreign Corrupt Practices Act (FCPA), which arose in connection with its use of the freight-forwarding firm Panalpina. Also, the Company has consented to a Cease and Desist Order from the U.S. Securities and Exchange Commission (SEC) for violations of the record keeping and internal control provisions of the FCPA as a result of another Shell subsidiary's violation of the FCPA, which also arose in connection with the use of Panalpina in Nigeria. The DPA requires Shell to continue to implement a compliance and ethics programme designed to prevent and detect violations of the FCPA and other applicable anti-corruption laws throughout Shell's operations. The DPA also requires the Company to report to the DOJ, promptly, any credible evidence of questionable or corrupt payments. Any violations of the DPA, or of the SEC's Cease and Desist Order, could have a material adverse effect on the Company.

The Company's Articles of Association determine the jurisdiction for shareholder disputes. This might limit shareholder remedies.
Our Articles of Association generally require that all disputes between our shareholders in such capacity and the Company or our subsidiaries (or our Directors or former Directors) or between the Company and our Directors or former Directors be exclusively resolved by arbitration in The Hague, the Netherlands, under the Rules of Arbitration of the International Chamber of Commerce. Our Articles of Association also provide that, if this provision is for any reason determined to be invalid or unenforceable, the dispute may only be brought to the courts of England and Wales. Accordingly, the ability of shareholders to obtain monetary or other relief, including in respect of securities law claims, may be determined in accordance with these provisions. See "Corporate governance" for further information.

SUMMARY OF RESULTS AND STRATEGY

INCOME FOR THE PERIOD			$ MILLION
	2012	2011	2010
Earnings by segment [A]			
Upstream	22,162	24,455	15,935
Downstream	5,350	4,289	2,950
Corporate	(209)	86	91
Total segment earnings	27,303	28,830	18,976
Attributable to non-controlling interest	(259)	(205)	(333)
Earnings on a current cost of supplies basis attributable to Royal Dutch Shell plc shareholders	27,044	28,625	18,643
Current cost of supplies adjustment [A]	(463)	2,355	1,498
Non-controlling interest	11	(62)	(14)
Income attributable to Royal Dutch Shell plc shareholders	26,592	30,918	20,127
Non-controlling interest	248	267	347
Income for the period	26,840	31,185	20,474

[A] Segment earnings are presented on a current cost of supplies basis. See Note 2 to the "Consolidated Financial Statements" for further information.

Earnings 2012-2010

On average, 2012 realised liquids and gas prices remained stable compared with 2011. The increase in Asia-Pacific realised gas prices approximately offset the decrease in Americas realised gas prices. Average realised synthetic crude oil prices for 2012 decreased compared with 2011. Oil and gas production available for sale in 2012 was 3,262 thousand barrels of oil equivalent per day (boe/d), compared with 3,215 thousand boe/d in 2011. Excluding the impact of divestments and exits, production volumes were 3% higher than in 2011. Refining margins were generally higher in 2012 than in 2011 in key refining hubs, except Asia. This increase was driven by the closure of some refining capacity and then refinery outages later in the year, partly offset by an unfavourable economic environment and geopolitical tensions.

Earnings on a current cost of supplies basis attributable to shareholders in 2012 were $27,044 million, 6% lower than in 2011, which, in turn, were 54% higher than in 2010.

In 2012, Upstream earnings were $22,162 million, compared with $24,455 million in 2011 and $15,935 million in 2010. The 9% decrease from 2011 to 2012 reflected higher depreciation charges, increased operating and exploration expenses, lower gains associated with the fair-value accounting of certain gas and derivative contracts and additional tax charges, partly offset by higher contributions from our integrated gas activities (LNG and GTL). In 2011, earnings increased by 53% compared with 2010, reflecting higher realised oil and gas prices, together with higher equity LNG sales volumes, increased trading contributions and a reduced level of impairment, partly offset by higher operating expenses, lower production volumes and increased taxes.

Downstream earnings are presented on a current cost of supplies basis (CCS earnings). On this basis, the purchase price of the volumes sold during a period is based on the current cost of supplies during the same period, after making allowance for the tax effect. CCS earnings therefore exclude the effect of changes in the oil price on inventory valuation. Downstream earnings in 2012 were $5,350 million, compared with $4,289 million in 2011 and $2,950 million in 2010. The 25% increase from 2011 to 2012 reflected higher realised refining margins, lower operating expenses and a reduced level of impairment. These items were partly offset by lower trading contributions, lower Chemicals earnings, lower divestment gains and lower gains associated with the fair-value accounting of commodity derivatives. Earnings increased between 2010 and 2011 as a result of higher chemical margins, increased trading contributions and lower operating expenses, partly offset by a larger loss in refining and lower sales volumes.

Balance sheet and net capital investment

Shell's strategy to invest in the development of major growth projects primarily in Upstream, explains the most significant changes to the balance sheet in 2012. Property, plant and equipment increased by $20 billion. Net capital investment was $30 billion, 27% higher than in 2011; see Note 4 to the "Consolidated Financial Statements". The effect of net capital investment on property, plant and equipment was partly offset by depreciation, depletion and amortisation of $15 billion.

Of the 2012 net capital investment, approximately 85% related to Upstream projects, providing growth over the long term. They include multibillion dollar, integrated facilities that are expected to provide significant cash flows in the coming decades. In 2012, equity attributable to Royal Dutch Shell plc shareholders increased by $19 billion, to $188 billion, principally as a result of increased retained earnings.

Gearing was 9.2% at the end of 2012, compared with 13.1% at the end of 2011. The change reflects the increase in total equity and in cash and cash equivalents.

Market overview

We estimate that global economic growth weakened to 3.2% in 2012, down from 3.9% the previous year, largely as a result of the recession in the eurozone and a slowdown in most emerging markets. In our view, global economic growth in 2013 is estimated to be 3.4%, below the annual average of 3.8% of the last 10 years.

Within the eurozone, uncertainty and austerity measures weighed heavily on economic sentiment and consumer and business spending. In January 2013, the International Monetary Fund (IMF) projected the eurozone economy to have contracted by 0.4% in 2012. According to the same projections, growth of gross domestic product (GDP) in China slowed to 7.8% in 2012, down from 9.3% in 2011, mainly due to lower export growth and slower domestic demand growth. Other emerging economies including Brazil, Russia and India also had lower GDP growth rates. Brazil decelerated most to a rate of 1.0% in 2012, down from 2.7% in 2011. The USA was a notable exception in this environment; its GDP growth rate accelerated in 2012 to 2.3%, compared with 1.8% in 2011.

Reflecting the state of the global economy, global oil demand rose by 0.9% (0.8 million b/d) in 2012 according to the International Energy Agency December 2012 Oil Market Report. A 1.2 million b/d demand increase in emerging economies offset a decline of 0.4 million b/d in developed economies. We estimate that global gas demand grew by about 3% in 2012 with approximately two-thirds of that growth coming from countries outside the Organisation for Economic Co-operation and Development (OECD). Demand grew strongest in Asia-Pacific, the Middle East and North America, while demand in Europe contracted by an estimated 1% overall, and particularly in electricity generation.

OIL AND NATURAL GAS PRICES

The following table provides an overview of the main oil and gas price markers that Shell is exposed to:

OIL AND GAS AVERAGE INDUSTRY PRICES [A]

	2012	2011	2010
Brent ($/b)	111.67	111.26	79.50
West Texas Intermediate ($/b)	94.13	95.04	79.45
Henry Hub ($/MMBtu)	2.76	4.01	4.40
UK National Balancing Point (pence/therm)	59.74	56.35	42.12
Japan Customs-cleared Crude ($/b)	114.91	109.10	79.17

[A] Yearly average prices are based on daily spot prices.

The Brent crude oil price, the international crude-oil benchmark, traded in a range of $88-128 per barrel during 2012, ending the year at $110 per barrel. Both the Brent and the West Texas Intermediate (WTI) average crude oil prices for 2012 were little changed compared with 2011. WTI continued to trade at a significant discount to Brent due to production in the US mid-continent exceeding pipeline capacity to clear the growing volumes. This resulted in crude oil being transported to the Gulf coast by less efficient modes of transport, such as rail, depressing prices in landlocked areas, such as Cushing, Oklahoma, where WTI is delivered.

Unlike crude-oil pricing, which is global in nature, gas prices vary significantly from region to region.

In the USA, the average natural gas price at Henry Hub was 31% lower in 2012 compared with 2011, and traded in a range of $1.91-3.90 per million British thermal units (MMBtu). Domestic production increased strongly, particularly from onshore gas, which more than offset increased demand, and led to lower prices. The daily Henry Hub spot price briefly dropped below $2 per MMBtu in April following an unusually warm winter, meaning that inventories were high and production had to be discouraged. The daily price recovered to a monthly average of $2.50 per MMBtu in May, and continued to recover due to warmer than normal summer temperatures stimulating gas-fired power generation demand due to its price advantage over coal.

In Europe, prices rose. In the UK, the average price at the UK National Balancing Point was 6% higher compared with 2011. In continental Europe, price increases at the main gas trading hubs in Belgium, Germany and the Netherlands were similar to those at the UK National Balancing Point. These prices reflect a tightening of LNG markets and higher prices in Asia-Pacific. The use of oil-indexed gas pricing is decreasing in continental Europe, with many natural gas contracts now including spot market pricing as a major component.

We also produce and sell natural gas in regions whose supply, demand and regulatory circumstances differ markedly from those in the USA or Europe. Long-term contracted LNG prices in Asia-Pacific are predominantly indexed to the price of Japan Customs-cleared Crude (JCC). In Japan, LNG import contracts have historically been indexed to the JCC benchmark, as burning crude and fuel oil is the alternative option for Japanese power utilities.

OIL AND NATURAL GAS PRICES FOR INVESTMENT EVALUATION

The range of possible future crude oil and natural gas prices used in project and portfolio evaluations within Shell is determined after an assessment of short-, medium- and long-term price drivers under different sets of assumptions. Historical analysis, trends and statistical volatility are considered in this assessment, as are analyses of possible future economic conditions, geopolitics, actions by the Organization of the Petroleum Exporting Countries (OPEC), supply costs and the balance of supply and demand. Sensitivity analyses are used to test the impact of low-price drivers, such as economic weakness, and high-price drivers, such as strong economic growth and low investment levels in new production capacity. Short-term events, such as relatively warm winters or cool summers affecting demand, and supply disruptions due to weather or politics, contribute to price volatility.

We expect oil and gas prices to remain volatile. For the purposes of making investment decisions, generally we test the economic performance of long-term projects against price ranges of $70-110 per barrel for Brent oil and $3-5 per MMBtu for gas at Henry Hub. As part of our normal business practice, the range of prices used for this purpose is subject to review and change, and was last updated in the fourth quarter of 2012.

REFINING AND PETROCHEMICAL MARKET TRENDS

Industry refining margins were generally higher in 2012 than in 2011 in key refining hubs, except Asia. Support for margins in 2012 came from refinery closures in North America and Europe at the beginning of the year, and from unplanned refinery outages later in the year. Some demand growth, especially around the summer holiday driving season in the USA, also contributed, although the economic environment and geopolitical tensions dampened further gains. In the USA a surge of light sweet crude supply and infrastructure bottlenecks also acted to support margins.

A key driver of refining margins in 2013 is expected to be middle distillate demand growth with some support from gasoline during the middle of the year. The overall outlook remains uncertain, with the economic environment remaining fragile, a structural overcapacity in global refining, and geopolitical tensions in some regions that could lead to supply disruptions.

Industry chemical margins in Europe and Asia during 2012 were lower than in 2011 due to declining demand in Europe and lower demand growth in Asia. US ethane cracker margins rose significantly due to increased supply of natural gas liquids, and the wide price differential between crude oil and natural gas. The outlook for petrochemicals in 2013 remains uncertain as demand is strongly correlated to economic growth.

Strategy and outlook

STRATEGY

Our strategy seeks to reinforce our position as a leader in the oil and gas industry, while helping to meet global energy demand in a responsible way. We aim to create competitive returns for shareholders. Safety and environmental and social responsibility are at the heart of our activities.

Intense competition exists for access to upstream resources and to new downstream markets. But we believe that our technology, project delivery capability and operational excellence will remain key differentiators for our businesses. We expect about 80% of our capital investment in 2013 to be in our Upstream businesses.

In Upstream we focus on exploration for new liquids and natural gas reserves, and on developing major new projects where our technology and know-how add value to the resources holders.

We focus on a series of strategic themes, each requiring distinctive technologies and risk management:

- our upstream and downstream "engines" are strongly cash-generative, mature businesses, which will underpin our financial

performance to at least the end of this decade. Here we only make investments in selective growth positions, and we apply Shell's distinctive technology and operating performance to extend the productive lives of our assets and to enhance their profitability;
- our growth priorities are in three strategic themes, namely integrated gas, deep water and resources plays such as shale oil and gas. These will provide our medium-term growth, and we expect them to become core engines in the future. Here, we use the advantages of Shell's technological know-how and global scale to unlock highly competitive resources positions; and
- our future opportunities include the Arctic, Iraq, Kazakhstan, Nigeria, and heavy oil, where we believe large reserves positions could potentially become available, with the pace of development driven by market and local operating conditions.

Meeting the growing demand for energy worldwide in ways that minimise environmental and social impact is a major challenge for the global energy industry. We aim to improve energy efficiency in our own operations, support customers in managing their energy demands, and continue to research and develop technologies that increase efficiency and reduce emissions in liquids and natural gas production.

Our commitment to technology and innovation continues to be at the core of our strategy. As energy projects become more complex and more technically demanding, we believe our engineering expertise will be a deciding factor in the growth of our businesses. Our key strengths include the development and application of technology, the financial and project-management skills that allow us to deliver large field development projects, and the management of integrated value chains.

We aim to leverage our diverse and global business portfolio and customer-focused businesses built around the strength of the Shell brand.

OUTLOOK

We continuously seek to improve our operating performance, with an emphasis on health, safety and environment, asset performance and operating costs. Asset sales are a key element of our strategy – improving our capital efficiency by focusing our investment on the most attractive growth opportunities. Sale of non-core assets in 2010-2012 generated $21 billion in divestment proceeds. Exits from further positions in 2013 are expected to generate up to $3 billion in divestment proceeds. We have initiatives underway that are expected to improve Shell's integrated Downstream business, focusing on the profitability of our portfolio and growth potential.

In early 2012, Shell set out a new growth agenda, to deliver $175-200 billion of cash flow from operations excluding working capital movements for 2012-2015 in aggregate, some 30-50% higher than in 2008-2011. This assumes that the Brent oil price is in the range of $80-100 per barrel and conditions for North American natural gas and downstream margins improve relative to 2012. This cash flow is to finance a 2012-2015 expected net capital investment programme of $120-130 billion, an increase of some 10-20% compared with the 2008-2011 level, and fund a competitive dividend for shareholders. Shell is on track to deliver these targets.

In Upstream we have the potential to reach an average production of some 4.0 million boe/d in 2017-2018, compared with 3.3 million boe/d in 2012. Shell's strategy in Upstream is designed to drive financial growth, with production growth regarded as a proxy for this over the long term. Our 2017-2018 production potential will be driven by the timing of investment decisions and the near-term macroeconomic outlook, and assumes some 250 thousand boe/d of expected asset sales and licence expiries from 2011 to 2017-2018. In Downstream we evaluate selective growth opportunities in chemicals, biofuels and growth markets.

Shell has built up a substantial portfolio of options for a next wave of growth. This portfolio has been designed to capture energy price upside and manage Shell's exposure to industry challenges from cost inflation and political risk. Key elements of these opportunities are in global exploration and established resources positions in the Gulf of Mexico, North American tight gas, liquids-rich shales and Australian LNG. These projects are part of a portfolio that has the potential to underpin production growth to the end of this decade. Shell is working to mature these projects, with an emphasis on financial returns.

The statements in this Strategy and outlook section do not take into account the impact of the recently announced agreement to acquire part of Repsol S.A.'s LNG portfolio. See page 137.

The statements in this Strategy and outlook section, including those related to our growth strategies and our expected or potential future cash flow from operations, net capital investment and production, are based on management's current expectations and certain material assumptions and, accordingly, involve risks and uncertainties that could cause actual results, performance or events to differ materially from those expressed or implied herein. See page 3 and "Risk factors".

Proved reserves and production

Shell subsidiaries' and the Shell share of equity-accounted investments' estimated net proved oil and gas reserves are summarised in the table on page 28 and are set out in more detail in "Supplementary information – oil and gas (unaudited)".

In 2012, Shell added 542 million boe of proved reserves before taking into account production, of which 408 million boe came from Shell subsidiaries and 134 million boe from the Shell share of equity-accounted investments. These additions were negatively impacted by lower commodity prices (431 million boe) and divestments (74 million boe).

In 2012, total oil and gas production available for sale was 1,194 million boe. An additional 40 million boe were produced and consumed in operations. Production available for sale from subsidiaries was 825 million boe with an additional 30 million boe consumed in operations. The Shell share of the production available for sale of equity-accounted investments was 369 million boe with an additional 10 million boe consumed in operations.

Accordingly, after taking into account total production, there was a decrease of 692 million boe in proved reserves, comprising 447 million boe from subsidiaries and 245 million boe from the Shell share of equity-accounted investments.

Research and development

Technology and innovation provide ways for Shell to stand apart from its competitors. They help our current businesses perform, and they make our future businesses possible. We have been spending more than any other international oil and gas company to research and develop innovative technology – more than $1 billion annually since 2007. In 2012, research and development (R&D) expenses were $1,314 million, compared with $1,125 million in 2011 and $1,019 million in 2010.

Sustained investment in our key technologies continues to deliver results. In 2012, we launched new fuels and lubricant formulations meeting specific customer needs for improved efficiency and better performance. We also began construction of what is likely to be the world's first floating LNG facility, more than 480 metres long and six times heavier than a fully loaded aircraft carrier. The facility is designed to produce natural gas from the Prelude field offshore Australia, cool it into a liquid and pump it onto LNG tankers – all done at sea. The idea was born and developed entirely within Shell as part of an innovation-stimulating programme called GameChanger. Also in 2012, Shell committed itself to design, build and operate the world's first commercial-scale facility to capture and store safely underground CO_2 emissions of an oil-sands project. The facility, based near Edmonton, Canada, will help develop Shell's CO_2 capture technology.

The development of Shell technology is based on the needs of our customers and partners, and is intrinsically linked to our strategic objectives. In 2013, the key objectives of our R&D programme will remain unchanged. We will continue to focus strongly on technologies supporting our various businesses. For example: novel seismic acquisition systems that help reveal previously unnoticed geological details; methods based on the application of chemicals, heat or solvent gases to increase the amount of oil ultimately recovered from fields; and biofuels derived from non-edible plants or crop waste. We also continue to work on technologies to reduce the environmental footprint of our operations and products.

We remain committed to further shortening the time taken for technology to move from the laboratory to deployment in the field. Our technology portfolio will maintain a healthy balance of new and mature developments. That will mean an increase in the number of proposed concepts, more rapid termination of less promising projects and increasing focus on larger-scale field tests and demonstrations. Our single, integrated R&D organisation will continue to bring together in-house technology development with external scientific, engineering and commercial partnerships. Such partnering helps to ensure a healthy influx of new ideas and to speed up their realisation.

Key accounting estimates and judgements

Refer to Note 3 to the "Consolidated Financial Statements" for a discussion of key accounting estimates and judgements.

Legal proceedings

Refer to Note 25 to the "Consolidated Financial Statements" for a discussion of legal proceedings.

UPSTREAM

KEY STATISTICS			$ MILLION
	2012	2011	2010
Segment earnings	22,162	24,455	15,935
Including:			
Revenue (including inter-segment sales)	94,550	91,691	68,198
Share of profit of equity-accounted investments	8,001	7,127	4,900
Production and manufacturing expenses	16,474	15,606	13,697
Selling, distribution and administrative expenses	1,226	1,276	1,512
Exploration	3,104	2,266	2,036
Depreciation, depletion and amortisation	11,387	8,827	11,144
Net capital investment [A]	25,320	19,083	21,222
Oil and gas production available for sale (thousand boe/d)	3,262	3,215	3,314
Equity LNG sales volume (million tonnes)	20.2	18.8	16.8
Proved oil and gas reserves at December 31 (million boe) [B]	13,556	14,250	14,249

[A] See Notes 2 and 4 to the "Consolidated Financial Statements".
[B] Excludes reserves attributable to non-controlling interest in Shell subsidiaries.

Overview

Our Upstream businesses explore for and extract crude oil and natural gas, often in joint ventures with international and national oil and gas companies. This includes the extraction of bitumen from mined oil sands which we convert into synthetic crude oil. We liquefy natural gas by cooling and transport the liquefied natural gas (LNG) to customers across the world. We also convert natural gas to liquids (GTL) to provide high quality fuels and other products, and we market and trade natural gas (including LNG) in support of our Upstream businesses.

Business conditions

According to the International Energy Agency, oil demand in 2012 increased by 0.9% (0.8 million b/d). Demand was impacted by further weakened global economic growth in 2012, largely as a result of a recession in the eurozone and a slowdown in most emerging markets. Increased production, particularly in North America, Libya and Iraq, helped meet this demand, partly offset by a fall in supply from some Middle Eastern countries, especially Iran and Syria. The average Brent crude oil price in 2012 was $112 per barrel, slightly higher than in 2011.

Demand for gas, especially LNG, was robust in markets east of Suez. This was driven by economic growth across Asia-Pacific and nuclear power generation capacity still being offline following Japan's natural disaster in March 2011. In Europe, gas demand was lower as a result of the ongoing recession and competition from cheap coal imports from the USA. Continued high levels of supply and warmer than normal weather at the beginning of 2012 weakened gas prices in North America by approximately 30% compared with 2011.

Earnings 2012-2011

Segment earnings of $22,162 million included a net gain of $2,137 million, mainly related to gains on divestments, partly offset by impairments for natural gas assets in the USA, net tax charges and decommissioning provisions. Segment earnings in 2011 of $24,455 million included a net gain of $3,855 million, mainly related to gains on divestments, the fair-value accounting of certain gas and derivative contracts, and the cost impact of the US offshore drilling moratorium. All gains and losses identified above relate to items that individually exceed $50 million.

Compared with 2011, segment earnings, excluding the items identified above, benefited from the increased contribution of integrated gas activities (LNG and GTL), reflecting the ramp-up of the Pearl GTL plant in Qatar, higher realised LNG prices as well as increased LNG trading contributions and equity LNG sales volumes. Earnings also reflected higher realised gas prices outside the Americas. These items were more than offset by reduced contributions from the Americas, mainly as a result of higher depreciation, increased operating expenses, higher exploration expenses and lower realised gas prices.

During 2012, our earnings in the Americas were $512 million, excluding the related items identified at the beginning of the earnings section. However, our Americas onshore gas business reported a loss, mainly due to low North American gas prices, and higher depreciation and exploration costs. This was more than offset by earnings from our deep-water and heavy oil production.

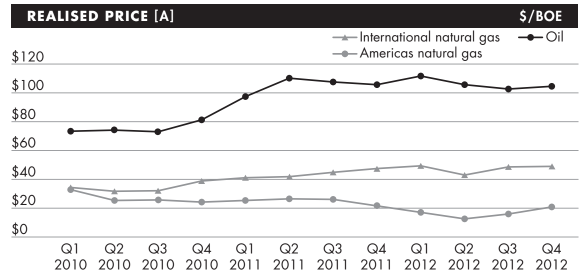
Realised global liquids prices were 1% higher than in 2011. In Canada, realised synthetic crude oil prices were 11% lower than in 2011. Realised global natural gas prices were 1% higher than in 2011, with a 31% decrease in the Americas and a 9% increase outside the Americas.

In 2012, production was 3,262 thousand boe/d compared with 3,215 thousand boe/d in 2011. Liquids production was down 2% and natural gas production increased by 5% compared with 2011. Natural gas represented 50% of total production in 2012. Approximately 18% of our natural gas production in 2012 was in the Americas. Excluding the impact of divestments and exits, production volumes in 2012 were 3% higher than in 2011.

New field start-ups and the continuing ramp-up of new projects, in particular the ramp-up of the Pearl GTL plant in Qatar and the Pluto LNG plant in Australia (Shell indirect interest 20.8%), contributed some 225 thousand boe/d to production in 2012, which more than offset the impact of field declines.

Equity LNG sales volumes in 2012 were a record of 20.2 million tonnes, 7% higher than in 2011. The increase mainly came from the first full year of operations for Qatargas 4, the start-up of the Pluto LNG plant in the second quarter of 2012, and the continued strong operational performance of the Sakhalin-2 LNG plant.

REALISED PRICE [A] $/BOE



[A] Includes subsidiaries and European equity-accounted investments. Excludes deemed transfer prices.

Earnings 2011-2010

Segment earnings in 2011 of $24,455 million included a net gain of $3,855 million as described above. Segment earnings in 2010 of $15,935 million included a net gain of $1,493 million, mainly related to gains on divestments, partly offset by asset impairments, the fair-value accounting of certain gas contracts and the cost impact of the US offshore drilling moratorium. All gains and losses identified above relate to items that individually exceed $50 million.

Excluding these gains and losses, segment earnings in 2011 were 43% higher than in 2010, driven by continuing portfolio optimisation, higher realised oil, natural gas and LNG prices, higher equity LNG sales volumes and higher trading contributions, partly offset by higher operating expenses, mainly reflecting the start-up of new projects, lower production volumes and increased taxes.

Net capital investment

Net capital investment was $25 billion in 2012, compared with $19 billion in 2011 and $21 billion in 2010. Capital investment in 2012 was $31 billion (of which $14 billion was exploration expenditure, including acquisitions of unproved properties). Divestment proceeds were $6 billion in 2012.

Portfolio actions and business development

In Australia we increased our interest in the West Browse joint venture to 35% and in the East Browse joint venture to 25% in an exchange with Chevron for our 33.3% interest in Clio-Acme plus cash of approximately $0.5 billion.

Also in Australia we formed a joint venture (Shell interest 82%) with Nexus Energy and Osaka Gas to operate the Crux gas and condensate field.

In Norway we acquired BP's 18.4% interest in the offshore Draugen field for a consideration of $0.2 billion. Shell is already the operator of the field and this transaction brought Shell's interest to 44.6%.

In the UK we acquired 75% of Hess Corporation's interests in the Beryl area fields and Scottish Area Gas Evacuation system. This transaction was completed in January 2013, increasing Shell's production in the Beryl area fields from 9 thousand boe/d to 20 thousand boe/d.

Also in the UK we acquired Hess Corporation's 15.7% interest in the Schiehallion field and its 12.9% interest in the Schiehallion floating production, storage and offloading (FPSO) facility for $0.5 billion. In February 2013, we also acquired an additional 5.9% interest in the offshore Schiehallion field from Murphy Schiehallion Ltd. bringing our interest in the field to 55%.

Low North American gas prices led to an accelerated shift in exploration and appraisal activities, along with production, from existing dry gas fields to those rich in liquids.

In the USA Shell acquired acreage in the Delaware Permian Basin, West Texas, from Chesapeake Energy Corporation for an announced consideration of $1.9 billion. The acreage of approximately 2,200 square kilometres, with an additional 300 square kilometres linked to contractual conditions, is expected to be rich in oil and natural gas liquids and currently produces approximately 26 thousand boe/d with growth potential.

We also took the following final investment decisions during 2012.

In Nigeria we took the final investment decision on the Forcados Yokri Integrated Project (Shell interest 30%) and the Southern Swamp Associated Gas Gathering Project (Shell interest 30%). These projects are expected to produce at peak production approximately 90 thousand boe/d and 85 thousand boe/d respectively, and reduce flaring intensity.

In Italy we took the final investment decision on the onshore Tempa Rossa field (Shell interest 25%) in the Basilicata region. This project is expected to produce approximately 45 thousand boe/d at peak production.

In Malaysia we took the final investment decision for the development of the Malikai deep-water oil field, part of the Block G PSC (Shell interest 35%), offshore Sabah. The Shell-operated project is expected to produce approximately 60 thousand boe/d at peak production.

In Canada we took the final investment decision on the Quest carbon capture and storage project (Shell interest 60%) near Edmonton, Alberta. The Quest project is expected to capture and store deep underground more than 1 mtpa of CO_2 produced in bitumen processing, and reduce direct emissions from the Scotford Upgrader by up to 35%.

We continued to divest selected Upstream assets during 2012, including our 40% participating interest in the BS-4 oil and gas exploration block in the Santos Basin offshore Brazil; our interest in the Gassled natural gas transport infrastructure joint venture in Norway; our 30% interest in oil mining leases 30, 34 and 40 in the Niger Delta, Nigeria; our 50% interest in the Holstein field in the Gulf of Mexico; and our interest in the Seal area within the Peace River oil sands of Alberta, Canada. Also in Canada, we sold a 20% interest in our Groundbirch tight-gas project. In Australia we completed the sale of a 17.5% interest in the Prelude FLNG project to INPEX, and a 10% interest to KOGAS. We also completed the sale of a further 5% interest to CPC Corporation in the first quarter of 2013.

Available-for-sale production

In 2012, hydrocarbon production from new start-ups and the continuing ramp-up of new projects more than offset the impact of field declines, and the impact of divestments and exits. There was also further upside from new wells and improved reliability compared with 2011, partly offset by changes in contractual entitlements and other non-operational factors.

Production growth was mainly driven by the continued ramp-up of new projects, notably our Pearl GTL plant in Qatar, the start-up of the Pluto LNG Project in Australia, and the first full year of production from Qatargas 4. Further additions also came from new start-ups such as Harweel in Oman, and the early first production from Gumusut-Kakap in Malaysia.

In Qatar we achieved full GTL production at our Pearl GTL plant at the end of the fourth quarter of 2012, with both trains reaching 90% of capacity. This completed the ramp-up period for this project. The plant is designed to run at sustained operating rates of 90% or higher.

In Malaysia the Gumusut-Kakap field, located about 120 kilometres offshore Sabah, began a phase of early production via the Murphy Sabah Oil operated Kikeh production facility. A dedicated floating production system is currently under construction for the Gumusut-Kakap field (Shell interest 33%), which is Shell's first deep-water opportunity in the country, and is expected to produce approximately 135 thousand boe/d at peak production.

In the USA first production was achieved at the Caesar/Tonga deep-water project (Shell interest 22.5%) in the Gulf of Mexico. At peak production, the project is expected to produce approximately 40 thousand boe/d.

In Oman production began at the Harweel Enhanced Oil Recovery project, which is expected to produce approximately 30 thousand boe/d at peak production.

Proved reserves

Shell subsidiaries' and the Shell share of equity-accounted investments' estimated net proved oil and gas reserves are summarised in the table on page 28 and are set out in more detail in "Supplementary information - oil and gas (unaudited)".

In 2012, Shell added 542 million boe of proved reserves before taking into account production, of which 408 million boe came from Shell subsidiaries and 134 million boe from the Shell share of equity-accounted investments.

The change in the yearly average commodity prices between 2011 and 2012 resulted in a net negative impact on the proved reserves of 431 million boe.

Shell subsidiaries

Before taking into account production, Shell subsidiaries added 408 million boe of proved reserves in 2012. This comprised 655 million barrels of oil and natural gas liquids and a reduction of 247 million boe (1,431 thousand million scf) of natural gas. Of the 408 million boe: 268 million boe were from the net effects of revisions and reclassifications; a net decrease of 69 million boe related to acquisitions and divestments; 196 million boe came from extensions and discoveries; and 13 million boe were from improved recovery.

After taking into account production of 855 million boe (of which 30 million boe were consumed in operations), Shell subsidiaries' proved reserves decreased by 447 million boe in 2012.

Shell subsidiaries' proved developed reserves increased by 19 million boe to 6,502 million boe, while proved undeveloped reserves decreased by 466 million boe to 3,371 million boe.

The total addition of 408 million boe before taking into account production included a net negative impact from commodity price changes of 438 million boe of proved reserves.

SYNTHETIC CRUDE OIL

As part of the total proved reserves' addition of 542 million boe, we added 131 million barrels to our synthetic crude oil proved reserves. In 2012, we had synthetic crude oil production of 48 million barrels of which 2 million barrels were consumed in operations. At December 31, 2012, we had total synthetic crude oil proved reserves of 1,763 million barrels, of which 1,271 million barrels were proved developed reserves and 492 million barrels were proved undeveloped reserves.

BITUMEN

As part of the total proved reserves' addition of 542 million boe, we added 1 million barrels of bitumen proved reserves. After taking into account production of 7 million barrels, bitumen proved reserves were 49 million barrels at December 31, 2012.

Shell share of equity-accounted investments

Before taking into account production, there was an increase of 134 million boe in the Shell share of equity-accounted investments' proved reserves in 2012. This comprised 91 million barrels of oil and natural gas liquids and 43 million boe (248 thousand million scf) of natural gas. Of the 134 million boe: 129 million boe were from the net effects of revisions and reclassifications; a net decrease of 5 million boe related to acquisitions and divestments; 7 million boe came from extensions and discoveries; and 3 million boe were from improved recovery.

After taking into account production of 379 million boe (of which 10 million boe were consumed in operations), the Shell share of equity-accounted investments' proved reserves decreased by 245 million boe in 2012.

The Shell share of equity-accounted investments' proved developed reserves decreased by 5 million boe to 3,002 million boe, and proved undeveloped reserves decreased by 240 million boe to 699 million boe.

The total addition of 134 million boe before taking into account production included a net positive impact from commodity price changes of 7 million boe of proved reserves.

Proved undeveloped reserves

In 2012, Shell subsidiaries' and the Shell share of equity-accounted investments' proved undeveloped reserves (PUD) decreased by 706 million boe to 4,070 million boe. This is the result of additions of 122 million boe of new PUD offset by the maturation of 828 million boe of PUD to proved developed reserves through project execution. During 2012, Shell spent $9.3 billion on development activities related to PUD maturation.

Proved undeveloped reserves held for five years or more (PUD5+) at December 31, 2012, were 1,012 million boe. These relate to installation of gas compression and drilling of additional gas wells, which will be executed when required to support existing gas delivery commitments (Australia, the Netherlands, Nigeria, Norway, the Philippines and Russia); gas cap blow-down awaiting end-of-oil production (Nigeria); ongoing onshore oil and gas development (USA); Gulf of Mexico water-injection project execution in progress (USA); and major complex projects taking longer than five years to develop (such as in Kazakhstan). Most of the PUD5+ are held in locations where Shell has a proven track record of developing similar major projects or where project execution is ongoing but is taking longer than expected.

Delivery commitments

Shell sells crude oil and natural gas from its producing operations under a variety of contractual obligations. Most contracts generally commit Shell to sell quantities based on production from specified properties, although some natural gas sales contracts specify delivery of fixed and determinable quantities, as discussed below.

In the past three years, Shell met all contractual delivery commitments.

In the period 2013 to 2015, Shell is contractually committed to deliver to third parties and equity-accounted investments a total of approximately 4,600 thousand million scf of natural gas from Shell subsidiaries and equity-accounted investments. The sales contracts contain a mixture of fixed and variable pricing formulae that are generally referenced to the prevailing market price for crude oil, natural gas or other petroleum products at the time of delivery.

The shortfall between Shell's delivery commitments and its proved developed reserves is estimated at 24% of Shell's total gas delivery commitments. This shortfall is expected to be met through the development of proved undeveloped reserves as well as new projects and purchases on the spot market.

Exploration

During 2012, Shell participated in seven notable conventional exploration discoveries and appraisals in Australia, Brazil, Malaysia, Nigeria and the USA, and 10 notable successful unconventional appraisals in Australia, Canada, China, and the USA.

In 2012, Shell participated in 230 productive exploratory wells with proved reserves allocated (Shell share: 168 wells). See page 155 for further information.

In 2012, Shell participated in a further 314 wells (Shell share: 214 wells) that remained pending determination at December 31, 2012.

In 2012, Shell added acreage to its exploration portfolio mainly from new licences in Albania, Australia, Benin, Canada, China, Malaysia, New Zealand, Russia, South Africa, Tanzania, the UK and the USA.

In total, Shell secured rights to 120,000 square kilometres of new exploration acreage, including positions in liquids-rich shales. This was offset by divestments and relinquishments of acreage, which took place in various countries (mainly Australia, China, Egypt, Germany, Italy, New Zealand, Norway and Tanzania).

Business and property

Shell subsidiaries and equity-accounted investments are involved in all aspects of Upstream activities, including matters such as land tenure, entitlement to produced hydrocarbons, production rates, royalties, pricing, environmental protection, social impact, exports, taxes and foreign exchange.

The conditions of the leases, licences and contracts under which oil and gas interests are held vary from country to country. In almost all cases outside North America the legal agreements are generally granted by or entered into with a government, government entity or government-run oil and gas company, and the exploration risk usually rests with the independent oil and gas company. In North America these agreements may also be with private parties who own mineral rights. Of these agreements, the following are most relevant to Shell's interests:

- licences (or concessions), which entitle the holder to explore for hydrocarbons and exploit any commercial discoveries. Under a licence, the holder bears the risk of exploration, development and production activities, and is responsible for financing these activities. In principle, the licence holder is entitled to the totality of production less any royalties in kind. The government, government entity or government-run oil and gas company may sometimes enter as a joint-venture participant sharing the rights and obligations of the licence but usually without sharing the exploration risk. In a few cases, the government entity, government-run oil and gas company or agency has an option to purchase a certain share of production;
- lease agreements, which are typically used in North America and are usually governed by similar terms as licences. Participants may include governments or private entities, and royalties are either paid in cash or in kind; and
- production-sharing contracts (PSCs) entered into with a government, government entity or government-run oil and gas company. PSCs generally oblige the independent oil and gas company, as contractor, to provide all the financing and bear the risk of exploration, development and production activities in exchange for a share of the production. Usually, this share consists of a fixed or variable part that is reserved for the recovery of the contractor's cost (cost oil). The remaining production is split with the government, government entity or government-run oil and gas company on a fixed or volume/revenue-dependent basis. In some cases, the government, government entity or government-run oil and gas company will participate in the rights and obligations of the contractor and will share in the costs of development and production. Such participation can be across the venture, or on a field-by-field basis. Additionally, as the price of oil or gas increases above certain predetermined levels, the independent oil and gas company's entitlement share of production normally decreases. Accordingly, its interest in a project may not be the same as its entitlement.

EUROPE

Denmark

We hold a non-operating interest in a producing concession covering the majority of our activities in Denmark. The concession was granted in 1962 and will expire in 2042. Our interest reduced to 36.8% from 46% in July 2012, when the government entered the partnership with a 20% interest and the government profit share of 20% was abolished.

Ireland

We are the operator of the Corrib Gas project (Shell interest 45%), which is currently at an advanced stage of construction. At peak production, Corrib is expected to supply a significant proportion of the country's natural gas needs.

The Netherlands

Shell and ExxonMobil are 50:50 shareholders in Nederlandse Aardolie Maatschappij B.V. (NAM), the largest hydrocarbon producer in the Netherlands. An important part of NAM's gas production comes from the onshore Groningen gas field, in which the Dutch government has a 40% interest, with NAM holding the remaining 60%. NAM also has a 60% interest in the Schoonebeek oil field, which has been redeveloped using enhanced oil recovery technology. NAM also operates a significant number of other onshore gas fields and offshore gas fields in the North Sea.

Norway

We are a partner in more than 20 production licences on the Norwegian continental shelf and are the operator in six of these, including the Ormen Lange gas field (Shell interest 17%) and the Draugen oil field, where we increased our interest to 44.6%. We have interests in the Troll, Gjøa, and Kvitebjørn fields, and have further interests in the Valemon field development and various other potential development assets.

United Kingdom

We operate a significant number of our interests on the UK Continental Shelf on behalf of a 50:50 joint venture with ExxonMobil. Most of our UK oil and gas production comes from the North Sea. We hold various non-operated interests in the Atlantic Margin area, principally in the West of Shetlands area. We have increased our interest in the non-operated Schiehallion field to 55%, and in the Beryl area fields, with interests ranging from 25% to 66%.

Rest of Europe

Shell also has interests in Albania, Austria, Germany, Greece, Hungary, Italy, Slovakia, Spain and Ukraine.

ASIA (INCLUDING THE MIDDLE EAST AND RUSSIA)

Brunei

Shell and the Brunei government are 50:50 shareholders in Brunei Shell Petroleum Company Sendirian Berhad (BSP). BSP holds long-term oil and gas concession rights onshore and offshore Brunei, and sells most of its natural gas production to Brunei LNG Sendirian Berhad (BLNG, Shell interest 25%). BLNG was the first LNG plant in Asia-Pacific, and sells most of its LNG on long-term contracts to customers in Asia.

We are the operator for the Block A concession (Shell interest 53.9%), which is under exploration and development. We have a 35% interest in the Block B concession, where gas and condensate are produced from the Maharaja Lela Field. In addition, we have a 12.5% interest in exploration Block CA-2 under a PSC.

China

We operate the onshore Changbei tight-gas field under a PSC with PetroChina. The PSC was amended in July 2012 for developing tight gas in different geological layers of the same block.

Shell and PetroChina have also agreed to appraise, develop and produce tight gas in the Jinqiu block under a PSC that expires in 2040 (Shell interest 49%) and signed a PSC in March 2012 for shale-gas exploration, development and production in the Fushun Yongchuan block (Shell interest 49%), both in Sichuan. Shell and PetroChina are also assessing opportunities in coalbed methane in the Ordos Basin.

In 2012, Shell became a party to the Zitong PSC for tight gas exploration, development and production in Sichuan (Shell interest 44.1%).

Shell has agreed with Chinese National Offshore Oil Corporation to appraise and potentially develop two offshore oil and gas blocks in the Yinggehai Basin under a PSC signed in July 2012 (Shell interest 49%).

Indonesia

We have a 30% participating interest in the offshore Masela block where INPEX Masela is the operator. The Masela block contains the Abadi gas field. The operator has currently selected a floating LNG (FLNG) concept for the field's first development phase.

Iran

Shell transactions in Iran are disclosed in accordance with Section 13(r) of the US Securities Exchange Act of 1934. See page 51.

Iraq

We have a 45% interest in the Majnoon oil field that we operate under a technical service contract that expires in 2030. The other Majnoon shareholders are PETRONAS (30%) and the Iraqi government (25%), which is represented by the Missan Oil Company. Majnoon is located in southern Iraq and is one of the world's largest oil fields. The first phase of the development is planned to bring production to approximately 175 thousand b/d from the level of 45 thousand b/d when the contract entered into effect in March 2010. We also have a 15% interest in the West Qurna 1 field. At the end of 2012, production was approximately 460 thousand b/d. According to the provisions of both contracts, Shell's equity entitlement volumes will be lower than the Shell interest implies.

In 2012, Shell continued to work in establishing Basrah Gas Company, a joint venture between Shell (44%), South Gas Company (51%) and Mitsubishi Corporation (5%). The Basrah Gas Company will gather, treat and process raw gas produced from the Rumaila, West Qurna 1 and Zubair fields. Currently, an estimated 700 million scf/d of gas is flared because of a lack of infrastructure to collect and process it. The processed natural gas and associated products, such as condensate and liquefied petroleum gas (LPG), will be sold primarily to the domestic market with the potential to export any surplus.

Kazakhstan

We have a 16.8% interest in the offshore Kashagan field, where the North Caspian Operating Company is the operator. This shallow-water field covers an area of approximately 3,400 square kilometres. Phase 1 development of the field is expected to lead to plateau production of approximately 300 thousand boe/d, increasing further with additional phases of development. NC Production Operations Company, a joint venture between Shell and KazMunayGas, will manage production operations. First production is expected in 2013.

We have an interest of 55% in the Pearls PSC, covering an area of approximately 900 square kilometres located in the Kazakh sector of the Caspian Sea that includes two oil discoveries (Auezov and Khazar) and several exploration prospects.

Malaysia

We produce oil and gas located offshore Sabah and Sarawak under 19 PSCs, in which our interests range from 30% to 85%.

In Sabah we operate four producing offshore oil fields with interests ranging from 50% to 80% as part of the 2011 North Sabah EOR PSC and SB1 PSC (the latter expired at the end of December 2012). We also have additional interests ranging from 30% to 50% in PSCs for the exploration and development of five deep-water blocks. These include the Gumusut-Kakap deep-water field (Shell interest 33%) and the Malikai field (Shell interest 35%). Both these fields are currently being developed with Shell as the operator. We started production from Gumusut-Kakap in November 2012, ahead of completion of a floating production system. We did this by connecting two wells to the Kikeh production facility, which is operated by Murphy Sabah Oil. We also have a 21% interest in the Siakap North-Petai field and a 30% interest in the Kebabangan field.

In Sarawak we are the operator of 20 gas fields with interests ranging from 37.5% to 70%. Nearly all of the gas produced is supplied to Malaysia LNG in Bintulu where we have a 15% interest in each of the Dua and Tiga LNG plants. We also have a 40% interest in the 2011 Baram Delta EOR PSC and a 50% interest in Block SK-307.

In 2012, we signed five new exploration PSCs: Deepwater Block 2B, SK318, SK319 and SK408, all offshore Sarawak, and SB311, offshore Sabah.

We also operate a GTL plant (Shell interest 72%), which is adjacent to the Malaysia LNG facilities in Bintulu. Using Shell technology, the plant converts natural gas into high-quality middle distillates, drilling fluids, waxes and other speciality products.

Oman

We have a 34% interest in Petroleum Development Oman (PDO), the operator of an oil concession expiring in 2044. In 2012, production began at its Harweel Enhanced Oil Recovery project, which is expected to produce approximately 30 thousand boe/d at peak production.

We are also participating in the development of the Mukhaizna oil field (Shell interest 17%) where steam flooding, an enhanced oil recovery method, is being applied on a large scale.

We have a 30% interest in Oman LNG, which mainly supplies Asian markets under long-term contracts. We also have an 11% indirect interest in Qalhat LNG, another Oman-based LNG facility.

Qatar

Pearl in Qatar is the world's largest GTL plant. Shell operates the plant under a development and production-sharing contract with the government of Qatar. The fully integrated facility includes production, transport and processing of approximately 1.6 billion scf/d of well-head gas from Qatar's North Field with installed capacity of about 140 thousand boe/d of high-quality liquid hydrocarbon products and 120 thousand boe/d of NGL and ethane. Ramp-up of the project was completed in the fourth quarter of 2012. The plant

delivered its 100th cargo in mid-December and produced GTL Jet fuel, with its first commercial market introduction in January 2013.
We have a 30% interest in Qatargas 4, which comprises integrated facilities to produce approximately 1.4 billion scf/d of natural gas from Qatar's North Field, an onshore gas-processing facility and an LNG train with a collective production capacity of 7.8 mtpa of LNG and 70 thousand boe/d of NGL. The train delivered its first LNG in 2011 and has been operating at full capacity in 2012. The LNG is shipped mainly to markets in North America, China, Europe and the United Arab Emirates.

We are the operator of Block D under the terms of an exploration and production-sharing contract with Qatar Petroleum, representing the national government. We have a 75% interest, with PetroChina holding the remaining 25% interest.

Russia
We have a 27.5% interest in Sakhalin-2, one of the world's largest integrated oil and gas projects. Located in a subarctic environment, the project produced approximately 335 thousand boe/d in 2012. Following optimisation of the LNG plant, production from its two trains exceeded 10 million tonnes in 2012.

We have a 50% interest in the Salym fields in western Siberia, where production was approximately 155 thousand boe/d during 2012.

We also have a 100% interest in four exploration and production licences. They are for the East Talotinskiy area in the Nenets Autonomous District, the Barun-Yustinsky block in Kalmykia and the Arkatoitsky and the Lenzitsky blocks in the Yamalo Nenets Autonomous District. We also have an exploration licence in the North-Vorkutinsky area in the Komi Republic.

United Arab Emirates
In Abu Dhabi we hold a concessionary interest of 9.5% in the oil and gas operations run by Abu Dhabi Company for Onshore Oil Operations (ADCO). The licence expires in 2014. We also have a 15% interest in the licence of Abu Dhabi Gas Industries Limited (GASCO), which expires in 2028. GASCO exports propane, butane and heavier-liquid hydrocarbons that it extracts from the wet natural gas associated with the oil produced by ADCO.

Rest of Asia (including the Middle East and Russia)
Shell also has interests in India, Japan, Jordan, Kuwait, the Philippines, Saudi Arabia, Singapore, South Korea and Turkey. We suspended all exploration and production activities in Syria in December 2011.

OCEANIA

Australia
We have interests in offshore production and exploration licences in the North West Shelf (NWS) and Greater Gorgon areas of the Carnarvon Basin, as well as in the Browse Basin and Timor Sea. Some of these interests are held directly and others indirectly through a shareholding of approximately 23% in Woodside Petroleum Ltd (Woodside). All interests in Australian assets quoted below are direct interests.

Woodside is the operator of the Pluto LNG Project which produced its first LNG in 2012. Woodside is also the operator on behalf of six joint-venture participants of the NWS gas, condensate and oil fields, which produced more than 470 thousand boe/d in 2012. Shell provides technical support for the NWS development.

We have a 50% interest in Arrow Energy Holdings Pty Limited (Arrow), a Queensland-based joint venture with PetroChina. Arrow owns coalbed methane assets, a domestic power business and the site for a proposed LNG plant on Curtis Island, near Gladstone. In January 2012, Arrow completed the acquisition of coalbed methane company Bow Energy Ltd (Shell-share consideration $0.3 billion).

We have a 25% interest in the Gorgon LNG project, which involves the development of some of the largest gas discoveries to date in Australia, beginning with the offshore Gorgon (Shell interest 25%) and Jansz-lo (Shell interest approximately 20%) fields. It includes the construction of a 15.3 mtpa LNG plant on Barrow Island.

We are the operator of a permit in the Browse Basin in which two separate gas fields were found: Prelude in 2007, and Concerto in 2009. We are developing these fields on the basis of our innovative FLNG technology. The Prelude FLNG project is expected to produce about 110 thousand boe/d of natural gas and NGL, delivering approximately 3.6 mtpa of LNG, 1.3 mtpa of condensate and 0.4 mtpa of LPG. During 2012, we commenced construction of the Prelude FLNG project and completed the sale of a 17.5% interest to INPEX and a 10% interest to KOGAS. We also completed the sale of a 5% interest to CPC Corporation in the first quarter of 2013, reducing our interest to 67.5%.

We formed a joint venture to operate the Crux gas and condensate field (Shell interest 82%). We also operate the AC/P41 block (Shell interest 75%).

We are also a partner in the Browse joint ventures covering the Brecknock, Calliance and Torosa gas fields. During 2012, we increased our interest in the West Browse joint venture to 35% and in the East Browse joint venture to 25%. The Browse resources are being assessed for development on the basis of an LNG export project.

In the Timor Sea we have a 26.6% interest in the Sunrise gas field. The joint-venture partners have selected FLNG as the preferred development concept for Sunrise. The development is subject to approval from both the Australian and Timor-Leste governments.

Shell is a partner in both Shell-operated and non-operated exploration joint ventures in multiple basins including the Bonaparte, Exmouth Plateau, Greater Gorgon, Outer Canning and South Exmouth.

We also have a 6.4% interest in the Wheatstone LNG project, which includes the construction of two LNG trains with a combined capacity of 8.9 mtpa.

Rest of Oceania
Shell also has interests in New Zealand.

AFRICA

Nigeria
Shell-share production in Nigeria was approximately 365 thousand boe/d in 2012 compared with approximately 385 thousand boe/d in 2011. Security, crude oil theft and flooding in the Niger Delta were significant challenges in 2012.

Onshore The Shell Petroleum Development Company of Nigeria Ltd (SPDC) is the operator of a joint venture (Shell interest 30%) that holds more than 25 Niger Delta onshore oil mining leases (OMLs), which expire in 2019. To provide funding, Modified Carry Agreements are in place for certain key projects and a bridge loan was drawn down by the Nigerian National Petroleum Company (NNPC) in 2010. The Modified Carry Agreements are being reimbursed, and in

December 2012 NNPC repaid the bridge loan with interest. New financing agreements with NNPC are under discussion and are expected to be put in place during 2013.

We have a 30% interest in the Gbaran-Ubie integrated oil and gas project in Bayelsa State, which delivered 0.9 billion scf/d of gas in 2012. Gas from Gbaran-Ubie is delivered to Nigeria LNG Ltd (NLNG) for export. In October 2012, SPDC declared force majeure on gas supplies, as a result of a security incident on the Bomu-Bonny trunkline and rain flooding. This force majeure was lifted the following month and the impact on SPDC gas production was very limited.

In 2012, we sold our 30% interests in OMLs 30, 34 and 40 for a consideration of $1.1 billion.

Offshore Our main offshore deep-water activities are carried out by Shell Nigeria Exploration and Production Company (Shell interest 100%) which holds interests in three deep-water blocks. We operate two of the blocks, including the Bonga field 120 kilometres offshore. Deep-water offshore activities are typically governed through PSCs.

SPDC also holds an interest in six shallow-water offshore leases, of which five expired on November 30, 2008. However, SPDC satisfied all the requirements of the Nigerian Petroleum Act to be entitled to an extension. Currently, the status quo is maintained following a court order issued on November 26, 2008. SPDC is pursuing a negotiated solution with the federal government of Nigeria. Production from the EA field, in one of the disputed leases, continued throughout 2012.

LNG Shell has a 25.6% interest in NLNG, which operates six LNG trains with a total capacity of 22.0 mtpa. NLNG continued production near full capacity during 2012.

Rest of Africa
Shell also has interests in Benin, Egypt, Gabon, Ghana, Libya, South Africa, Tanzania and Tunisia.

NORTH AMERICA

Canada
We hold more than 2,200 mineral leases in Canada, mainly in Alberta and British Columbia. We produce and market natural gas, NGL, synthetic crude oil and bitumen. In addition, we hold significant exploration acreage offshore. Bitumen is a very heavy crude oil produced through conventional methods as well as through enhanced oil-recovery methods. Synthetic crude oil is produced by mining bitumen-saturated sands, extracting the bitumen from the sands, and transporting it to a processing facility where hydrogen is added to produce a wide range of feedstocks for refineries.

Gas and liquids-rich shale We hold rights to more than 10,000 square kilometres of conventional gas, tight gas and liquids-rich shale acreage. We own and operate four natural gas processing and sulphur-extraction plants in southern and south-central Alberta. We continued to develop conventional gas, tight gas and liquids-rich shale fields in west-central Alberta and east-central British Columbia during 2012, through drilling programmes and investment in infrastructure facilitating new production.

Synthetic crude oil We operate the Athabasca Oil Sands Project (AOSP) in north-east Alberta as part of a joint venture (Shell interest 60%). The AOSP's bitumen production capacity is 255 thousand boe/d. The bitumen is transported by pipeline for processing at the Scotford Upgrader, which is operated by Shell and located in the Edmonton area, Alberta. The first phase of the AOSP debottlenecking project comes online in 2013, and is expected to add an additional 10 thousand boe/d at peak production. We also took the final investment decision on the Quest carbon capture and storage project (Shell interest 60%), which is expected to capture and permanently store more than 1 mtpa of CO_2 from the Scotford Upgrader.

Shell also holds a number of other minable oil sands leases in the Athabasca region with expiry dates ranging from 2018 to 2025. By completing a certain minimum level of development prior to their expiry, leases may be extended.

Bitumen We produce and market bitumen in the Peace River area of Alberta, and have a steam-assisted gravity drainage project in operation near Cold Lake, Alberta. Additional heavy oil resources and advanced recovery technologies are under evaluation on approximately 1,200 square kilometres in the Grosmont oil sands area, also in northern Alberta.

Offshore We have a 31.3% interest in the Sable Offshore Energy project, a natural-gas complex offshore eastern Canada. We also have a 100% operating interest in frontier deep-water acreage offshore Nova Scotia, a 20% non-operating interest in an exploration asset off the east coast of Newfoundland, and a number of exploration licences in the Mackenzie Delta in the Northwest Territories.

United States of America
We produce oil and gas in the Gulf of Mexico, heavy oil in California and primarily tight gas and associated liquid hydrocarbons in Louisiana, Pennsylvania, Texas and Wyoming. The majority of our oil and gas production interests are acquired under leases granted by the owner of the minerals underlying the relevant acreage (including many leases for federal onshore and offshore tracts). Such leases usually run on an initial fixed term that is automatically extended by the establishment of production for as long as production continues, subject to compliance with the terms of the lease (including, in the case of federal leases, extensive regulations imposed by federal law).

Gulf of Mexico The Gulf of Mexico is the major production area in the USA, accounting for almost 50% of Shell's oil and gas production in the country. We have approximately 420 federal offshore leases in the Gulf of Mexico, about one-fifth of which are producing. Our share of production in the Gulf of Mexico averaged almost 190 thousand boe/d in 2012. Key producing assets are Auger, Brutus, Enchilada, Mars, NaKika, Perdido, Ram-Powell and Ursa.

Deferments resulting from the 2010 drilling moratorium, delivery of new-build drilling rigs and new regulatory requirements continued to affect the operational flexibility and delivery timing of our Gulf of Mexico activities in 2012. While the new regulatory regime has resulted in a longer and more complex permitting process, Shell continues to meet all deep-water regulatory permitting and environmental assessment requirements. Despite these challenges, we continued to grow our presence in the Gulf of Mexico, with the addition of two drilling rigs to our contracted offshore fleet in 2012. We also secured 24 blocks in the 2012 central lease sale for a sum of $400 million.

Onshore We hold more than 15,000 square kilometres of tight-gas and liquids-rich shale acreage. This includes significant holdings in the Marcellus shale, centred on Pennsylvania in north-east USA, the Eagle Ford shale formation in south Texas, the Sand Wash and Niobrara Shale in north-west Colorado, as well as the Mississippi Line in south-central Kansas. In 2012, we also acquired approximately 2,200 square kilometres of mineral rights, with an additional

300 square kilometres linked to contractual conditions, in the Delaware Permian Basin in west Texas.

California We have a 51.8% interest in Aera Energy LLC (Aera), which holds assets in the San Joaquin Valley and Los Angeles Basin areas of southern California. Aera operates more than 15,000 wells, producing approximately 130 thousand boe/d of heavy oil and gas.

Alaska We hold more than 410 federal leases for exploration in the Beaufort and Chukchi seas in Alaska. During the 2012 drilling season, we drilled two exploratory wells, one each in the Beaufort and Chukchi seas. These wells are known as top holes as they do not go deep enough to reach hydrocarbon reservoirs. After drilling they were safely capped in accordance with regulatory requirements.

Rest of North America
Shell also has interests in Greenland and Mexico.

SOUTH AMERICA

Brazil
We are the operator of several producing fields offshore Brazil. They include the Bijupirá and Salema fields (Shell interest 80%) and the BC-10 field (Shell interest 50%). We also operate one offshore exploration block in the Santos Basin, BMS-54 (Shell interest 80%). We have interests in two offshore exploration blocks in the Espirito Santo basins, BMES-23 and BMES-27, with a 20% and 17.5% interest respectively. Shell also operates five blocks in the São Francisco onshore basin area. In 2012, we divested our 40% interest in the offshore Block BS-4 in the Santos Basin.

We also have an 18% interest in Brazil Companhia de Gas de São Paulo (Comgás), a natural gas distribution company in the state of São Paulo.

French Guiana
We are the operator of an exploration block in the 24,000 square kilometres deep-water Guyane Maritime Permit (Shell interest 45%).

Rest of South America
Shell also has interests in Argentina, Colombia, Guyana and Venezuela.

TRADING

We market a portion of our share of equity production of LNG and also trade LNG volumes around the world through our hubs in Dubai, the Netherlands and Singapore. We also market and trade natural gas, power and emission rights in the Americas and Europe.

SUMMARY OF PROVED OIL AND GAS RESERVES OF SHELL SUBSIDIARIES AND SHELL SHARE OF EQUITY-ACCOUNTED INVESTMENTS [A] (AT DECEMBER 31, 2012) — BASED ON AVERAGE PRICES FOR 2012

	Oil and natural gas liquids (million barrels)	Natural gas (thousand million scf)	Synthetic crude oil (million barrels)	Bitumen (million barrels)	Total all products (million boe)[B]
Proved developed					
Europe	448	11,599	–	–	2,448
Asia	1,277	14,454	–	–	3,769
Oceania	53	1,424	–	–	299
Africa	496	1,012	–	–	670
North America					
USA	500	1,674	–	–	789
Canada	28	872	1,271	18	1,467
South America	48	84	–	–	62
Total proved developed	2,850	31,119	1,271	18	9,504
Proved undeveloped					
Europe	345	2,569	–	–	788
Asia	429	1,857	–	–	749
Oceania	121	5,186	–	–	1,015
Africa	192	1,229	–	–	404
North America					
USA	403	678	–	–	520
Canada	5	139	492	31	552
South America	39	15	–	–	42
Total proved undeveloped	1,534	11,673	492	31	4,070
Total proved developed and undeveloped					
Europe	793	14,168	–	–	3,236
Asia	1,706	16,311	–	–	4,518
Oceania	174	6,610	–	–	1,314
Africa	688	2,241	–	–	1,074
North America					
USA	903	2,352	–	–	1,309
Canada	33	1,011	1,763	49	2,019
South America	87	99	–	–	104
Total	4,384	42,792	1,763	49	13,574

[A] Includes 18 million boe of reserves attributable to non-controlling interest in Shell subsidiaries.

[B] Natural gas volumes are converted to oil equivalent using a factor of 5,800 scf per barrel.

LOCATION OF OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES [A] (AT DECEMBER 31, 2012)

	Exploration	Development and/or production	Shell operator[B]
Europe			
Albania	■		
Denmark	■	■	
Germany	■	■	
Ireland	■	■	■
Italy	■	■	
The Netherlands	■	■	■
Norway	■	■	■
UK	■	■	■
Ukraine	■		■
Asia [C]			
Brunei	■	■	■
China	■	■	■
Indonesia	■	■	
Iraq	■	■	■
Jordan	■		■
Kazakhstan	■	■	
Malaysia	■	■	■
Oman	■	■	
Philippines	■	■	■
Qatar	■	■	■
Russia	■	■	■
Saudi Arabia	■		
Turkey	■		■
United Arab Emirates	■	■	
Oceania			
Australia	■	■	■
New Zealand	■	■	■
Africa			
Benin	■		
Egypt	■	■	
Gabon	■	■	■
Libya	■		■
Nigeria	■	■	■
South Africa	■		■
Tanzania	■		
Tunisia	■		■
North America			
USA	■	■	■
Canada	■	■	■
Greenland	■		■
South America			
Argentina	■	■	
Brazil	■	■	■
Colombia	■		■
French Guiana	■		■
Guyana	■		
Venezuela		■	

[A] Includes equity-accounted investments. Where an equity-accounted investment has properties outside its base country, those properties are not shown in this table.

[B] In several countries where "Shell operator" is indicated, Shell is the operator of some but not all exploration and/or production ventures.

[C] Shell suspended all exploration and production activities in Syria in December 2011.

CAPITAL EXPENDITURE ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES AND EXPLORATION EXPENSE OF SHELL SUBSIDIARIES BY GEOGRAPHICAL AREA [A] $ MILLION

	2012	2011	2010
Europe	3,175	1,907	2,033
Asia	3,412	4,319	3,137
Oceania	5,534	3,349	1,804
Africa	2,277	1,701	1,629
North America – USA	11,344	6,445	9,400
North America – Other [B]	3,475	2,913	3,455
South America	907	487	373
Total	30,124	21,121	21,831

[A] Capital expenditure is the cost of acquiring property, plant and equipment for exploration and production activities, and – under the successful efforts method of accounting for exploration costs – includes exploration drilling costs capitalised pending determination of commercial reserves. See also Note 2 to the "Consolidated Financial Statements" for further information. Exploration expense is the cost of geological and geophysical surveys and of other exploratory work charged to income as incurred. Exploration expense excludes depreciation and release of cumulative currency translation differences.

[B] Comprises Canada and Greenland.

Average realised price by geographical area

OIL AND NATURAL GAS LIQUIDS — $/BARREL

	2012		2011		2010	
	Shell subsidiaries	Shell share of equity-accounted investments	Shell subsidiaries	Shell share of equity-accounted investments	Shell subsidiaries	Shell share of equity-accounted investments
Europe	108.13	104.60	106.77	103.97	73.35	83.24
Asia	107.76	67.33	103.73	62.81	76.21	44.27
Oceania	91.62	90.14[A]	92.38	99.74[A]	67.90	78.05[A]
Africa	112.45	–	111.70	–	79.63	–
North America – USA	103.59	110.00	104.93	109.49	76.36	74.27
North America – Canada	68.31	–	70.72	–	53.23	–
South America	100.01	97.33	100.44	97.76	69.99	63.57
Total	107.15	76.01	105.74	73.01	75.74	52.42

[A] Includes Shell's ownership of 23% of Woodside Petroleum Ltd as from April 2012 (previously: 24% as from November 2010; 34% before that date), a publicly listed company on the Australian Securities Exchange. We have limited access to data; accordingly, the numbers are estimated.

NATURAL GAS — $/THOUSAND SCF

	2012		2011		2010	
	Shell subsidiaries	Shell share of equity-accounted investments	Shell subsidiaries	Shell share of equity-accounted investments	Shell subsidiaries	Shell share of equity-accounted investments
Europe	9.48	9.64	9.40	8.58	6.87	6.71
Asia	4.81	10.13	4.83	8.37	4.40	6.55
Oceania	11.14	9.48[A]	9.95	10.09[A]	8.59	8.79[A]
Africa	2.74	–	2.32	–	1.96	–
North America – USA	3.17	7.88	4.54	8.91	4.90	7.27
North America – Canada	2.36	–	3.64	–	4.09	–
South America	2.63	1.04	2.81	0.99	3.79	–
Total	5.53	9.81	5.92	8.58	5.28	6.81

[A] Includes Shell's ownership of 23% of Woodside Petroleum Ltd as from April 2012 (previously: 24% as from November 2010; 34% before that date), a publicly listed company on the Australian Securities Exchange. We have limited access to data; accordingly, the numbers are estimated.

SYNTHETIC CRUDE OIL — $/BARREL

	2012	2011	2010
	Shell subsidiaries	Shell subsidiaries	Shell subsidiaries
North America – Canada	81.46	91.32	71.56

BITUMEN — $/BARREL

	2012	2011	2010
	Shell subsidiaries	Shell subsidiaries	Shell subsidiaries
North America – Canada	68.97	76.28	66.00

Average production cost by geographical area

OIL, NATURAL GAS LIQUIDS AND NATURAL GAS [A]						$/BOE
	2012		2011		2010	
	Shell subsidiaries	Shell share of equity-accounted investments	Shell subsidiaries	Shell share of equity-accounted investments	Shell subsidiaries	Shell share of equity-accounted investments
Europe	14.50	3.56	12.17	3.12	10.09	2.78
Asia	7.53	4.71	6.92	4.60	6.07	4.68
Oceania	9.06	16.97[B]	8.50	14.46[B]	5.85	8.37[B]
Africa	9.52	–	8.45	–	7.09	–
North America – USA	20.09	18.24	17.91	17.63	12.90	16.47
North America – Canada	19.47	–	18.12	–	17.48	–
South America	16.36	11.01	12.50	12.25	8.88	25.05
Total	12.47	6.05	11.00	5.60	9.10	5.29

[A] Natural gas volumes are converted to oil equivalent using a factor of 5,800 scf per barrel.
[B] Includes Shell's ownership of 23% of Woodside Petroleum Ltd as from April 2012 (previously: 24% as from November 2010; 34% before that date), a publicly listed company on the Australian Securities Exchange. We have limited access to data; accordingly, the numbers are estimated.

SYNTHETIC CRUDE OIL			$/BARREL
	2012	2011	2010
	Shell subsidiaries	Shell subsidiaries	Shell subsidiaries
North America – Canada	40.40	46.19	49.83

BITUMEN			$/BARREL
	2012	2011	2010
	Shell subsidiaries	Shell subsidiaries	Shell subsidiaries
North America – Canada	24.11	31.81	23.82

Oil and gas production (available for sale)

CRUDE OIL AND NATURAL GAS LIQUIDS [A]						THOUSAND B/D
		2012		2011		2010
	Shell subsidiaries	Shell share of equity-accounted investments	Shell subsidiaries	Shell share of equity-accounted investments	Shell subsidiaries	Shell share of equity-accounted investments
Europe						
Denmark	73	–	88	–	98	–
Italy	39	–	35	–	33	–
Norway	40	–	37	–	48	–
UK	60	–	71	–	98	–
Other [B]	3	4	3	5	3	5
Total Europe	215	4	234	5	280	5
Asia						
Brunei	2	73	2	76	3	77
Malaysia	41	–	40	–	40	–
Oman	205	–	200	–	199	–
Russia	–	104	–	117	–	117
United Arab Emirates	–	145	–	144	–	135
Other [B]	59	23	40	20	29	1
Total Asia	307	345	282	357	271	330
Total Oceania	27	18	30	18	30	29
Africa						
Gabon	38	–	44	–	34	–
Nigeria	240	–	262	–	302	–
Other [B]	12	–	20	–	20	–
Total Africa	290	–	326	–	356	–
North America						
USA	155	67	141	70	163	74
Other [B]	15	–	18	–	20	–
Total North America	170	67	159	70	183	74
South America						
Brazil	34	–	45	–	53	–
Other [B]	1	10	1	9	1	7
Total South America	35	10	46	9	54	7
Total	1,044	444	1,077	459	1,174	445

[A] Includes natural gas liquids. Royalty purchases are excluded. Reflects 100% of production attributable to subsidiaries except in respect of PSCs, where the figures shown represent the entitlement of the subsidiaries concerned under those contracts.

[B] Comprises countries where 2012 production was lower than 20 thousand b/d or where specific disclosures are prohibited.

NATURAL GAS [A]						MILLION SCF/D
	2012		2011		2010	
	Shell subsidiaries	Shell share of equity-accounted investments	Shell subsidiaries	Shell share of equity-accounted investments	Shell subsidiaries	Shell share of equity-accounted investments
Europe						
Denmark	202	–	256	–	328	–
Germany	217	–	253	–	267	–
The Netherlands	–	1,808	–	1,767	–	1,997
Norway	713	–	618	–	643	–
UK	328	–	403	–	541	–
Other [B]	43	–	41	–	38	–
Total Europe	1,503	1,808	1,571	1,767	1,817	1,997
Asia						
Brunei	51	512	52	524	55	497
China	131	–	174	–	253	–
Malaysia	572	–	763	–	807	–
Russia	–	374	–	382	–	359
Other [B]	795	317	363	246	209	–
Total Asia	1,549	1,203	1,352	1,152	1,324	856
Oceania						
Australia	352	243	373	167	404	204
New Zealand	182	–	175	–	202	–
Total Oceania	534	243	548	167	606	204
Africa						
Egypt	141	–	133	–	137	–
Nigeria	740	–	707	–	587	–
Total Africa	881	–	840	–	724	–
North America						
USA	1,062	5	961	6	1,149	4
Canada	616	–	570	–	563	–
Total North America	1,678	5	1,531	6	1,712	4
Total South America	44	1	51	1	61	–
Total	6,189	3,260	5,893	3,093	6,244	3,061

[A] Reflects 100% of production attributable to subsidiaries except in respect of PSCs, where the figures shown represent the entitlement of the companies concerned under those contracts.

[B] Comprises countries where 2012 production was lower than 115 million scf/d or where specific disclosures are prohibited.

SYNTHETIC CRUDE OIL			THOUSAND B/D
	2012	2011	2010
	Shell subsidiaries	Shell subsidiaries	Shell subsidiaries
North America – Canada	125	115	72

BITUMEN			THOUSAND B/D
	2012	2011	2010
	Shell subsidiaries	Shell subsidiaries	Shell subsidiaries
North America – Canada	20	15	18

LNG and GTL plants at December 31, 2012

LNG LIQUEFACTION PLANTS IN OPERATION	Location	Shell interest (%)[A]	100% capacity (mtpa)[B]
Australia North West Shelf	Karratha	21	16.3
Australia Pluto 1	Karratha	21	4.3
Brunei LNG	Lumut	25	7.8
Malaysia LNG (Dua and Tiga)	Bintulu	15	17.3[C]
Nigeria LNG	Bonny	26	22.0
Oman LNG	Sur	30	7.1
Qalhat (Oman) LNG	Sur	11	3.7
Qatargas 4	Ras Laffan	30	7.8
Sakhalin LNG	Prigorodnoye	27.5	9.6

[A] Interest may be held via indirect shareholding.
[B] As reported by the operator.
[C] Our interests in the Dua and Tiga plants are due to expire in 2015 and 2023 respectively.

LNG LIQUEFACTION PLANTS UNDER CONSTRUCTION	Location	Shell interest (%)	100% capacity (mtpa)
Gorgon	Barrow Island	25	15.3
Prelude	Offshore Australia	72.5[A]	3.6
Wheatstone	Onslow	6.4	8.9

[A] We divested a further 5% interest in Prelude during the first quarter of 2013, reducing our interest to 67.5%.

GTL PLANTS IN OPERATION	Country	Shell interest (%)	100% capacity (b/d)
Bintulu	Malaysia	72	14,700
Pearl	Qatar	100	140,000

Equity LNG sales volumes

SHELL SHARE OF EQUITY LNG SALES VOLUMES			MILLION TONNES
	2012	2011	2010
Australia	3.6	3.1	3.4
Brunei	1.7	1.7	1.7
Malaysia	2.5	2.4	2.4
Nigeria	5.1	5.0	4.5
Oman	1.9	2.0	2.0
Qatar	2.4	1.7	–
Sakhalin	3.0	2.9	2.8
Total	20.2	18.8	16.8

DOWNSTREAM

KEY STATISTICS			$ MILLION
	2012	2011	2010
Segment earnings [A]	5,350	4,289	2,950
Including:			
Revenue (including inter-segment sales)	424,410	428,646	336,216
Share of earnings of equity-accounted investments [A]	1,354	1,577	948
Production and manufacturing expenses	9,484	10,547	10,592
Selling, distribution and administrative expenses	12,996	12,920	13,716
Depreciation, depletion and amortisation	3,083	4,251	4,254
Net capital investment [A]	4,275	4,342	2,358
Refinery availability (%)	93	92	92
Chemical plant availability (%)	91	89	94
Refinery processing intake (thousand b/d)	2,819	2,845	3,197
Oil products sales volumes (thousand b/d)	6,235	6,196	6,460
Chemicals sales volumes (thousand tonnes)	18,669	18,831	20,653

[A] Segment earnings are presented on a current cost of supplies basis. See Notes 2 and 4 to the "Consolidated Financial Statements" for further information.

Overview

Shell's Downstream organisation is made up of a number of different business activities, part of an integrated value chain, that collectively turn crude oil into a range of refined products, which are moved and marketed around the world for domestic, industrial and transport use. The products include gasoline, diesel, heating oil, aviation fuel, marine fuel, lubricants, bitumen, sulphur and liquefied petroleum gas (LPG). In addition, we produce and sell petrochemicals for industrial use worldwide.

Our Refining activities comprise Manufacturing, Supply and Distribution. Marketing includes Retail, Lubricants, Business to Business (B2B) and Alternative Energies. Chemicals has dedicated manufacturing and marketing units of its own. We also trade crude oil, oil products and petrochemicals, primarily to optimise feedstock for Manufacturing and Chemicals and to supply our Marketing businesses.

Downstream earnings are presented on a current cost of supplies basis (CCS earnings). On this basis, the purchase price of the volumes sold during a period is based on the current cost of supplies during the same period, after making allowance for the tax effect. CCS earnings therefore exclude the effect of changes in the oil price on inventory valuation. Accordingly, when oil prices increase during the period, CCS earnings are likely to be lower than earnings calculated on a first-in first-out basis (FIFO). Similarly, in a period with declining oil prices, CCS earnings are likely to be higher than earnings calculated on a FIFO basis. This explains why 2012 CCS earnings were $463 million higher than earnings calculated on a FIFO basis (2011: $2,355 million lower; 2010: $1,498 million lower).

Business conditions

The industrial landscape in 2012 reflected weaker economic growth in several regions, which reduced demand. Even so, refining margins were higher in 2012 compared with 2011 in key refining hubs, except Asia. Chemical margins in Europe and Asia were lower than in 2011 as a result of weak macroeconomic conditions, although US ethane cracker margins rose significantly due to the wide price differential between crude oil and natural gas, and improved marketing margins.

Earnings 2012-2011

Segment earnings in 2012 were $5,350 million, 25% higher than in 2011. This increase reflected a return to profitability in Refining, although marginal, as a result of higher realised refining margins and better refinery availability that were partly offset by lower Chemicals earnings. Trading contributions were lower in 2012 than in 2011, while Marketing contributions were broadly unchanged. Both activities continued to contribute significantly to Downstream earnings.

Realised refining margins recovered strongly from their low level at the end of 2011, and improved across all regions apart from Asia. Refinery intake volumes were 1% lower compared with 2011. However, when portfolio impacts are excluded, refinery intake volumes were 4% higher than in 2011. Refinery availability increased to 93% compared with 92% in 2011.

Chemicals earnings were lower, mainly as a result of the global economic slowdown, supply constraints of favourable feedstocks in the USA, and the impact of hurricane Isaac on operations. Chemicals sales volumes were 1% lower compared with 2011, as reductions in European manufacturing capacity and rationalisation of the contract portfolio were largely offset by improved operating performance. Chemical plant availability increased to 91% compared with 89% in 2011.

Oil products sales volumes were 1% higher compared with 2011. Lower marketing volumes, mainly as a result of portfolio divestments, were more than offset by higher trading volumes. Excluding the impact of divestments and the effect of the formation of the Raízen biofuel joint venture, oil products sales volumes were 3% higher compared with 2011.

Overall, operating expenses decreased in 2012 compared with 2011. Production and manufacturing expenses declined, driven by manufacturing divestments, cost reduction initiatives and favourable currency exchange rate effects. Selling, distribution and administrative expenses were broadly unchanged; cost reductions, portfolio divestments and favourable currency exchange rate effects were offset by spending related to higher volumes, and growth-stimulating programmes.

Earnings in 2012 included a net gain of $39 million. There were net gains on divestments and a tax credit, partly offset by legal and environmental provisions. The divestments relate to a number of retail sites in Canada, LPG businesses in Malaysia and the Philippines, as well as the continuation of the divestment of our Downstream activities in Africa.

Earnings in 2011 included a net gain of $15 million. There was a gain from the fair-value accounting of commodity derivatives, a gain arising from the formation of the Raízen joint venture, a net gain on divestments and a tax credit. These gains were significantly offset by charges related to impairments, redundancy, decommissioning and legal provisions. The 2011 divestments included the sale of our Stanlow refinery in the UK, the majority of our Downstream activities in seven African countries, our Downstream activities in Chile and additional non-core business exits.

Earnings 2011-2010

Segment earnings in 2011, which included a net gain of $15 million as described above, were $4,289 million, 45% higher than in 2010. Earnings in 2010 included a net charge of $923 million. Impairment charges were partly offset by a gain related to the fair-value accounting of commodity derivatives, gains from divestments and a

BUSINESS REVIEW

gain from the sale of land holdings associated with the former Shell Haven refinery in the UK.

All gains and charges identified above relate to items that individually exceed $50 million. The following comments relate to earnings after excluding the net gain of $15 million from the 2011 results and the net charge of $923 million from the 2010 results.

Downstream earnings increased in 2011 compared with 2010, supported by improved realised unit marketing margins in most businesses, although oil products sales volumes declined, mainly as a result of portfolio divestments and the effects of the formation of the Raízen joint venture. Chemicals reported record earnings in 2011 as the market environment was favourable during most of the year, resulting in higher realised margins, partly offset by the impact of unplanned operational events on Chemicals sales volumes. Realised refining margins were in line with 2010 until the fourth quarter, when margins declined significantly as global market conditions deteriorated. As a result, Refining reported a larger loss in 2011 than in 2010. This loss was largely offset by increased contributions from trading activities due to higher market volatility and greater arbitrage opportunities relative to 2010.

Net capital investment

Net capital investment was $4.3 billion in both 2012 and 2011.

Capital investment was $5.5 billion in 2012, of which $3.2 billion was in Refining and Chemicals, and $2.3 billion was in Marketing. Approximately 56% of our 2012 capital investment was used to maintain the integrity and performance of our asset base.

In 2011, capital investment was $7.5 billion, of which $3.3 billion was in Refining and Chemicals, and $4.2 billion was in Marketing. Of the $4.2 billion in Marketing, we invested $1.7 billion in Raízen and $0.4 billion in the acquisition of 253 retail stations in the UK.

Divestment proceeds were $1.2 billion in 2012 compared with $3.2 billion in 2011. The planned asset divestment programme to refocus our Downstream portfolio is now mostly complete.

Portfolio actions

In Refining, Shell acquired the remaining outstanding shares in Gasnor AS, a market leader in Norway, that supplies LNG as a transport fuel to industrial and marine customers.

In Australia refining operations at the 79 thousand b/d Clyde refinery ceased. The Clyde refinery and the Gore Bay terminal are in the process of being converted into a fuel import facility.

In Marketing, Shell agreed to acquire Neste Oil Corporation’s network of 105 retail sites in Poland.

Shell completed the sale of the majority of its shareholding in downstream activities in Botswana, Burkina Faso, Côte d’Ivoire, Guinea, Kenya and Namibia, whilst downstream activities in Tanzania were discontinued. The agreements form part of the divestment of Shell’s shareholding in most of its downstream activities in Africa as announced in 2011. Shell continues to divest non-strategic Downstream positions. Divestments included retail stations in North America and most of our LPG activities in Asia-Pacific.

Business and property

REFINING

Manufacturing

We have interests in more than 30 refineries worldwide with the capacity to process approximately 3.4 million barrels of crude oil per day. Approximately 40% of our refining capacity is in Europe and Africa, 35% in the Americas and 25% in Asia-Pacific. The Port Arthur refinery expansion project in Texas, USA, owned by Motiva Enterprises (Shell interest 50%), restarted operations in early 2013, following operational issues in 2012. The expansion brings an additional 320 thousand b/d of capacity online in the US Gulf Coast region (increasing the refinery’s total capacity to 620 thousand b/d).

Supply and Distribution

With more than 1,500 storage tanks and approximately 150 distribution facilities in approximately 25 countries, our Supply and Distribution infrastructure is well positioned for making deliveries throughout the world. Deliveries include feedstock for our refineries as well as finished products for our Marketing businesses and customers worldwide.

MARKETING

Retail

We have about 44,000 service stations in more than 70 countries and more than 100 years’ experience in fuel development. In recent years, we have concentrated on developing differentiated fuels with special formulations designed to clean engines and improve performance. We sell such fuels under the Shell V-Power brand in more than 60 countries.

Lubricants

Across approximately 100 countries we make, market and sell technically advanced lubricants not only for passenger cars, trucks and coaches but also for industrial machinery in manufacturing, mining, power generation, agriculture and construction.

Our strong competitive positioning was highlighted by a number of leading market research firms. The tenth annual Kline & Company report on the global lubricants sector (Global Lubricants Industry 2011: Market Analysis and Assessment) confirmed that Shell maintained its volume and branded leadership position during 2011 with a 13% market share.

Business to Business

Our Business to Business (B2B) activities sell fuels, speciality products and services to a broad range of commercial customers.

Shell Aviation provides fuel for approximately 7,000 aircraft every day at more than 800 airports in more than 35 countries. On average we refuel a plane every 12 seconds.

Shell Gas (LPG) provides liquefied petroleum gas and related services to retail, commercial and industrial customers for cooking, heating, lighting and transport.

Shell Commercial Fuels provides transport, industrial and heating fuels in 20 countries. Our wide range of products, from reliable main-grade fuels with standard quality to premium products, can offer tangible benefits. These include fuel economy, enhanced equipment performance, such as longer life and lower maintenance costs, and environmental benefits, such as reduced emissions.

Shell Bitumen supplies on average 11,000 tonnes of products every day to 1,600 customers worldwide and invests in technology research and development to create innovative, award-winning new products.

Shell Sulphur Solutions has developed a dedicated sulphur business to manage the complete value chain of sulphur, from refining to marketing. The business provides sulphur for industries such as mining and textiles and also develops new products which incorporate sulphur, for example in road surfaces, fertilisers and concrete.

Our **marine activities** provide lubricants, fuels and related technical services to the shipping and boating industries. We supply more than 100 grades of lubricants and 20 different types of fuel for marine vessels powered by diesel, steam-turbine and gas-turbine engines. We serve more than 15,000 vessels worldwide, ranging from large ocean-going tankers to small fishing boats.

Alternative Energies

We investigate alternative energy technologies with a long-term aspiration to develop them into business opportunities. We were one of the first companies to invest in advanced biofuels. Our Raízen joint venture in Brazil produces sustainable ethanol from sugar, and manages a retail network. With an annual production capacity of more than 2 billion litres, it is one of the largest biofuel producers in the world. We also continue to research and explore the potential of hydrogen as an alternative energy source for the longer term.

Shell CO_2 is responsible for coordinating and driving CO_2 management activities across all our businesses.

CHEMICALS

Manufacturing

Our plants produce a range of base chemicals, including ethylene, propylene and aromatics, as well as intermediate chemicals, such as styrene monomer, propylene oxide, solvents, detergent alcohols, ethylene oxide and ethylene glycol. We have the capacity to produce nearly 6 mtpa of ethylene.

Marketing

We sell petrochemicals to about 1,000 major industrial customers worldwide, with the top 20 customers accounting for more than 40% of our revenue. Our Chemicals business is in the top 10 of chemicals enterprises in the world by revenue. Its products are used to make numerous everyday items, from clothing and cars, to bubble bath and bicycle helmets.

TRADING

Our trading activities include the optimisation of our oil value chain, including where necessary the sale or purchase of the excess or shortfall of oil products, as well as trading around the physical flow of hydrocarbons.

We trade in physical and financial contracts, lease storage and transportation capacities around the globe and manage shipping activities.

Downstream business activities with Iran, Sudan and Syria

IRAN

Shell transactions in Iran are disclosed in accordance with Section 13(r) of the US Securities Exchange Act of 1934. See page 51.

SUDAN

Shell-controlled companies ceased all operational activities in Sudan in 2008. We have, however, continued soil remediation related to earlier operations in the country.

SYRIA

Shell-controlled companies are in compliance with all EU and US sanctions. Shell-controlled companies continue to supply limited quantities of polyols via a Netherlands-based distributor to private sector customers in Syria. Polyols are commonly used for the production of foam in mattresses and soft furnishings.

Downstream data tables

The tables below reflect Shell subsidiaries, the 50% Shell interest in Motiva in the USA and instances where Shell owns the crude or feedstock processed by a refinery. Other equity-accounted investments are only included where explicitly stated.

OIL PRODUCTS – COST OF CRUDE OIL PROCESSED OR CONSUMED [A]			$ PER BARREL
	2012	2011	2010
Total	106.82	104.71	77.22

[A] Includes Upstream margin on crude oil supplied by Shell subsidiaries and equity-accounted investment exploration and production companies.

CRUDE DISTILLATION CAPACITY [A]	THOUSAND B/CALENDAR DAY [B]		
	2012	2011	2010
Europe	1,243	1,243	1,501
Asia-Pacific	822	861	855
Americas	1,212	1,064	1,155
Other	83	83	83
Total	3,360	3,251	3,594

[A] Average operating capacity for the year, excluding mothballed capacity.
[B] Calendar day capacity is the maximum sustainable capacity adjusted for normal unit downtime.

ETHYLENE CAPACITY [A]		THOUSAND TONNES/YEAR	
	2012	2011	2010
Europe	1,659	1,659	1,878
Asia-Pacific	1,556	1,556	1,565
Americas	2,212	2,212	2,212
Other	366	366	366
Total	5,793	5,793	6,021

[A] Includes the Shell share of equity-accounted investments' capacity entitlement (offtake rights), which may be different from nominal equity interest. Nominal capacity is quoted as at December 31.

OIL PRODUCTS – CRUDE OIL PROCESSED [A]			THOUSAND B/D
	2012	2011	2010
Europe	1,069	1,058	1,306
Asia-Pacific	704	731	729
Americas	1,024	985	1,007
Other	220	200	222
Total	3,017	2,974	3,264

[A] Includes natural gas liquids, share of equity-accounted investments and processing for others.

REFINERY PROCESSING INTAKE [A]			THOUSAND B/D
	2012	2011	2010
Crude oil	2,620	2,652	2,932
Feedstocks	199	193	265
Total	2,819	2,845	3,197
Europe	970	1,041	1,314
Asia-Pacific	670	666	650
Americas	1,117	1,075	1,158
Other	62	63	75
Total	2,819	2,845	3,197

[A] Includes crude oil, natural gas liquids and feedstocks processed in crude distillation units and in secondary conversion units.

REFINERY PROCESSING OUTTURN [A]			THOUSAND B/D
	2012	2011	2010
Gasolines	995	993	1,224
Kerosines	321	339	354
Gas/Diesel oils	996	977	1,074
Fuel oil	256	252	315
Other	452	385	442
Total	3,020	2,946	3,409

[A] Excludes "own use" and products acquired for blending purposes.

CHEMICALS SALES VOLUMES [A]			THOUSAND TONNES
	2012	2011	2010
Europe			
Base chemicals	3,771	4,006	4,507
First-line derivatives and others	2,626	2,689	2,795
Total	6,397	6,695	7,302
Asia-Pacific			
Base chemicals	2,209	2,027	2,209
First-line derivatives and others	3,053	3,111	3,415
Total	5,262	5,138	5,624
Americas			
Base chemicals	3,336	3,405	3,949
First-line derivatives and others	3,145	3,193	3,134
Total	6,481	6,598	7,083
Other			
Base chemicals	379	229	461
First-line derivatives and others	150	171	183
Total	529	400	644
Total product sales			
Base chemicals	9,695	9,667	11,126
First-line derivatives and others	8,974	9,164	9,527
Total	18,669	18,831	20,653

[A] Excludes chemical feedstock trading and by-products.

OIL PRODUCT SALES VOLUMES [A]			THOUSAND B/D
	2012	2011	2010
Europe			
Gasolines	450	467	505
Kerosines	234	261	299
Gas/Diesel oils	909	876	953
Fuel oil	180	227	205
Other products	184	192	227
Total	1,957	2,023	2,189
Asia-Pacific			
Gasolines	319	315	308
Kerosines	176	164	172
Gas/Diesel oils	445	423	370
Fuel oil	304	273	301
Other products	227	220	224
Total	1,471	1,395	1,375
Americas			
Gasolines	1,123	1,136	1,128
Kerosines	264	265	270
Gas/Diesel oils	528	461	523
Fuel oil	89	91	90
Other products	233	236	249
Total	2,237	2,189	2,260
Other			
Gasolines	184	156	174
Kerosines	60	93	86
Gas/Diesel oils	230	236	253
Fuel oil	64	60	75
Other products	32	44	48
Total	570	589	636
Total product sales [B][C]			
Gasolines	2,076	2,074	2,115
Kerosines	734	783	827
Gas/Diesel oils	2,112	1,996	2,099
Fuel oil	637	651	671
Other products	676	692	748
Total	6,235	6,196	6,460

[A] Excludes deliveries to other companies under reciprocal sale and purchase arrangements, which are in the nature of exchanges. Sales of condensate and natural gas liquids are included.

[B] Certain contracts are held for trading purposes and reported net rather than gross. The effect in 2012 was a reduction in oil product sales of approximately 856,000 b/d (2011: 925,000 b/d; 2010: 934,000 b/d).

[C] Export sales as a percentage of total oil product sales volumes amounted to 27.9% in 2012 (2011: 26.0%; 2010: 24.1%).

REFINERIES IN OPERATION (AT DECEMBER 31, 2012)

	Location	Asset class	Shell interest (%)[A]	Thousand barrels/calendar day, 100% capacity[B] Crude distillation capacity	Thermal cracking/ visbreaking/ coking	Catalytic cracking	Hydro-cracking
Europe							
Czech Republic	Kralupy[C]		16	59	–	24	–
	Litvinov[C]		16	101	14	–	30
Denmark	Fredericia	●	100	63	40	–	–
Germany	Harburg	●	100	108	14	15	–
	Miro[C]		32	310	65	89	–
	Rheinland	■●	100	327	57	–	79
	Schwedt[C]		38	220	47	50	–
The Netherlands	Pernis	■●	90	404	45	48	81
Norway	Mongstad[C]	●	21	205	23	55	–
Asia-Pacific							
Australia	Geelong	♦	100	118	–	38	–
Japan	Mizue (Toa)[C]	●♦	18	60	23	38	–
	Yamaguchi[C]	♦	13	110	–	25	–
	Yokkaichi[C]	●♦	26	193	–	55	–
Malaysia	Port Dickson	♦	51	107	–	39	–
Pakistan	Karachi[C]		30	43	–	–	–
Philippines	Tabangao		67	96	31	–	–
Singapore	Pulau Bukom	■●	100	462	63	34	55
Turkey	Batman[C]		1	23	–	–	–
	Izmir[C]		1	217	17	14	18
	Izmit[C]		1	217	–	13	25
	Kirikale[C]		1	106	–	–	16
Americas							
Argentina	Buenos Aires	●♦	100	100	18	20	–
Canada							
Alberta	Scotford	♦	100	92	–	–	62
Ontario	Sarnia	♦	100	71	5	19	9
USA							
California	Martinez	●	100	145	42	65	37
Louisiana	Convent[C]	♦	50	227	–	82	45
	Norco[C]	■	50	229	25	107	34
Texas	Deer Park	■●	50	312	79	63	53
	Port Arthur[C][D]	●	50	569	138	81	67
Washington	Puget Sound	●♦	100	137	23	52	–
Other							
Saudi Arabia	Al Jubail[C]	●♦	50	292	62	–	45
South Africa	Durban[C]	♦	38	165	23	34	–

[A] Shell interest rounded to nearest whole percentage point; Shell share of production capacity may differ.
[B] Calendar day capacity is the maximum sustainable capacity adjusted for normal unit downtime.
[C] Not operated by Shell.
[D] Includes the refinery expansion, whose crude distillation unit was restarted in January 2013 and is in ramp up phase.

■ *Integrated refinery and chemical complex.*
● *Refinery complex with cogeneration capacity.*
♦ *Refinery complex with chemical unit(s).*

MAJOR CHEMICAL PLANTS IN OPERATION [A] (AT DECEMBER 31, 2012)

		Thousand tonnes/year, Shell share capacity				
	Location	Ethylene	Styrene monomer	Ethylene glycol	Higher olefins[B]	Additional products
Europe						
Germany	Rheinland	272	–	–	–	A
The Netherlands	Moerdijk	972	789	155	–	A, I
UK	Mossmorran [C]	415	–	–	–	–
	Stanlow [C]	–	–	–	330	I
Asia-Pacific						
China	Nanhai [C]	475	320	175	–	A, I, P
Japan	Yamaguchi [C]	–	–	–	11	A, I
Singapore	Jurong Island [D]	281	720	940	–	A, I, P, O
	Pulau Bukom	800	–	–	–	A, I
Americas						
Canada	Scotford	–	450	450	–	A, I
USA	Deer Park	836	–	–	–	A, I
	Geismar	–	–	375	920	I
	Norco	1,376	–	–	–	A
Other						
Saudi Arabia	Al Jubail [C]	366	400	–	–	A, O
Total		5,793	2,679	2,095	1,261	

[A] Includes joint-venture plants, with the exception of the Infineum additives joint ventures.
[B] Higher olefins are linear alpha and internal olefins (products range from C6-C2024).
[C] Not operated by Shell.
[D] Combination of 100% Shell-owned plants and joint ventures (Shell and non-Shell operated).

A Aromatics, lower olefins.
I Intermediates.
P Polyethylene, polypropylene.
O Other.

OTHER CHEMICAL LOCATIONS

	Location	Products
Europe		
Germany	Harburg	I
	Karlsruhe	A
	Schwedt	A
The Netherlands	Pernis	A, I, O
Asia-Pacific		
Australia	Geelong	A, I
Japan	Kawasaki	A, I
	Yokkaichi	A
Malaysia	Bintulu	I
	Port Dickson	A
Americas		
Argentina	Buenos Aires	I
Canada	Sarnia	A, I
USA	Martinez	O
	Mobile	A
	Puget Sound	O
Other		
South Africa	Durban	I

A Aromatics, lower olefins.
I Intermediates.
O Other.

CORPORATE

EARNINGS			$ MILLION
	2012	2011	2010
Net interest and investment expense	(1,001)	(624)	(309)
Foreign exchange gains/(losses)	169	(77)	42
Other – including taxation	623	787	358
Segment earnings	(209)	86	91

Overview

The Corporate segment covers the non-operating activities supporting Shell. It includes Shell's holdings and treasury organisation, its headquarters and central functions as well as its self-insurance activities. All finance expense and income as well as related taxes are included in the Corporate segment earnings rather than in the earnings of the business segments.

The holdings and treasury organisation manages many of the Corporate entities and is the point of contact between Shell and the external capital markets. It conducts a broad range of transactions – from raising debt instruments to transacting foreign exchange. Treasury centres in London, Singapore and Rio de Janeiro support these activities.

Headquarters and central functions provide business support in the areas of communications, finance, health, human resources, information technology, legal services, real estate and security. They also provide support for the shareholder-related activities of the Company. The central functions are supported by business service centres located around the world which process transactions, manage data and produce statutory returns, among other services. The majority of the headquarters and central-function costs are recovered from the business segments. Those costs that are not recovered are retained in Corporate.

Shell mainly self-insures its risk exposures. Shell insurance subsidiaries provide insurance coverage to Shell entities, generally up to $1.15 billion per event and usually limited to Shell's percentage interest in the relevant entity. The type and extent of the coverage provided is equal to that which is otherwise commercially available in the third-party insurance market.

Earnings 2012-2010

Segment earnings for 2012 were a loss of $209 million, compared with a gain of $86 million in 2011 and a gain of $91 million in 2010.

Net interest and investment expense increased by $377 million between 2011 and 2012. Interest expense was significantly higher, mostly driven by the liquidity premium associated with our currency swaps, and an increase in Shell's share of interest expense from equity-accounted investments. Further, the amount of interest capitalised on projects declined overall as major projects came on-stream, partly offset by the development of new projects. These effects were partly offset by higher interest income. In 2011, net interest and investment expense increased by $315 million compared with 2010. There was a substantial reduction in the amount of interest capitalised with projects coming on-stream, and Shell's share of interest expense from equity-accounted investments was higher due to the debt portfolios of new investments. These effects were partly offset by an increase in interest income as a result of higher average levels of cash balances.

Foreign exchange gains of $169 million in 2012 were principally due to the favourable impact of exchange rates on non-functional currency loans and cash balances in operating units. In 2011, foreign exchange losses of $77 million were principally due to the adverse impact of exchange rates on these items.

Other earnings decreased by $164 million in 2012 compared with 2011, mainly because of increased costs partly offset by higher tax credits. The increase from 2010 to 2011 of $429 million was mainly due to increased tax credits and reduced costs.

LIQUIDITY AND CAPITAL RESOURCES

We manage our assets and liabilities with the aim that, across the business cycle, "cash in" (including cash from operations and divestments) at least equals "cash out" (including capital investment, interest and dividends), while maintaining a strong balance sheet.

A key measure of our capital structure management is the proportion of debt to equity. Across the business cycle we aim to manage gearing (net debt to net debt plus total equity) within the range of 0-30%. During 2012, gearing ranged from 8.1% to 13.1% (2011: 10.8% to 17.1%). See Note 15 to the "Consolidated Financial Statements".

With respect to the objective of maintaining a strong balance sheet, our priorities for applying our cash are investing for organic and inorganic growth, servicing debt commitments, paying dividends and returning surplus cash to our shareholders.

Overview

The most significant factors affecting our operating cash flow are earnings and movements in working capital. The main drivers impacting our earnings include: realised prices for crude oil and natural gas; production levels of crude oil and natural gas; and refining and marketing margins.

Since the contribution of Upstream to earnings is larger than that of Downstream, changes affecting Upstream – particularly changes in realised crude oil and natural gas prices and production levels – have the largest impact on Shell's operating cash flow. While Upstream benefits from higher realised crude oil and natural gas prices, the extent of such benefit (and the extent of an impact from a decline in these prices) depends on: the extent to which contractual arrangements are tied to market prices; the dynamics of production-sharing contracts; the existence of agreements with governments or national oil companies that have limited sensitivity to crude oil prices; tax impacts; and the extent to which changes in commodity prices flow through into operating costs. Changes in benchmark prices of crude oil and natural gas in any particular period therefore provide only a broad indicator of changes in Upstream earnings experienced in that period.

In Downstream, changes in any one of a range of factors derived from either within the industry or the broader economic environment can influence margins. The precise impact of any such changes depends on how the oil markets respond to them. The market response is affected by factors such as: whether the change affects all crude oil types or only a specific grade; regional and global crude-oil and refined-products inventories; and the collective speed of response of the industry refiners and product marketers in adjusting their operations. As a result, refinery and marketing margins fluctuate from region to region and from period to period. Downstream earnings are reported on a current cost of supplies basis, which excludes the effect of changes in the oil price on inventory carrying amounts. However, cash flow from operations is not affected by the reporting basis.

In the longer term, replacement of proved oil and gas reserves will affect our ability to maintain or increase production levels in Upstream, which in turn will affect our cash flow and earnings. We will need to take measures to maintain or increase production levels in future periods. These may include: developing new fields and mines; developing and applying new technologies and recovery processes to existing fields and mines; and making selective acquisitions. Our goal is to increase proved reserves and more than offset their decline due to production. However, proved reserves and production increases are subject to a variety of risks and other factors, including: crude oil and natural gas prices; the uncertainties of exploration; operational interruptions; geology; frontier conditions; availability of new technology and engineering capacity; availability and cost of skilled or specialist resources; project delays; cost overruns; and fiscal, regulatory and political changes.

We have a diverse portfolio of field-development projects and exploration opportunities. This diversity can help to reduce the impact of the political and technical risks in Upstream, including the impact on the cash flow generated by our operating activities.

It is our intention to continue to make selective acquisitions and divestments as part of active portfolio management that is in line with our strategy and influenced by market opportunities.

Statement of cash flows

Net cash from operating activities in 2012 was $46.1 billion, an increase from $36.8 billion in 2011. This increase mainly reflected a working capital decrease in 2012, compared with a working capital increase in 2011. In 2010, net cash from operating activities was $27.4 billion. The increase in 2011 compared with 2010 mainly reflected the increase in earnings.

Net cash used in investing activities was $28.4 billion in 2012, an increase from $20.4 billion in 2011. The increase was mainly the result of higher capital expenditure and investments in equity-accounted investments. In 2010, net cash used in investing activities was $22.0 billion. The decrease in 2011 compared with 2010 was mainly the result of higher proceeds from the sale of assets and lower capital expenditure, partly offset by lower proceeds from the sale of equity-accounted investments.

Net cash used in financing activities in 2012 was $10.6 billion (2011: $18.1 billion; 2010: $1.5 billion). This included payment of dividends of $7.4 billion (2011: $6.9 billion; 2010: $9.6 billion), interest paid of $1.4 billion (2011: $1.7 billion; 2010: $1.3 billion) and repurchases of shares of $1.5 billion (2011: $1.1 billion; 2010: $nil). Debt issued in 2012 was largely offset by debt repaid (2011: net repayments of debt of $7.1 billion; 2010: net new borrowings of $9.3 billion).

Cash and cash equivalents were $18.6 billion at December 31, 2012 (2011: $11.3 billion; 2010: $13.4 billion).

CASH FLOW INFORMATION [A]			$ BILLION
	2012	2011	2010
Net cash from operating activities excluding working capital movements			
Upstream	32.9	33.3	24.6
Downstream	8.0	8.7	8.1
Corporate	1.8	1.2	0.6
Total	42.7	43.2	33.3
Increase in inventories	(1.7)	(1.9)	(2.9)
(Increase)/decrease in accounts receivable	14.1	(10.1)	(11.9)
Increase/(decrease) in accounts payable and accrued liabilities	(9.0)	5.6	8.9
(Increase)/decrease in working capital	3.4	(6.4)	(5.9)
Net cash from operating activities	46.1	36.8	27.4
Net cash used in investing activities	(28.4)	(20.4)	(22.0)
Net cash used in financing activities	(10.6)	(18.1)	(1.5)
Currency translation differences relating to cash and cash equivalents	0.2	(0.4)	(0.2)
Increase/(decrease) in cash and cash equivalents	7.3	(2.1)	3.7
Cash and cash equivalents at the beginning of the year	11.3	13.4	9.7
Cash and cash equivalents at the end of the year	18.6	11.3	13.4

[A] For the "Consolidated Statement of Cash Flows" see page 102.

Financial condition and liquidity

Our financial position is strong. In 2012, we generated a return on average capital employed (ROACE) of 12.7% (see page 45) and year-end gearing was 9.2% (2011: 13.1%). We returned $11.0 billion to our shareholders through dividends in 2012. Some of those dividends were paid out as 103.8 million shares issued to shareholders who had elected to receive new shares instead of cash. To partly offset the dilution created by the issuance of those shares, 43.7 million shares were repurchased and cancelled as part of our share buyback programme.

The size and scope of our businesses require a robust financial control framework and effective management of our various risk exposures. Financial turbulence in the eurozone and other international events continue to put significant stress on the business environment in which we operate. We are following closely the developments and the challenges that the eurozone and other markets face, and are taking all reasonable steps to ensure that we are well positioned to deal with unexpected events should they occur.

Our treasury and trading operations are highly centralised, and are effective in controlling credit exposures associated with managing our substantial cash, foreign exchange and commodity positions.

We diversify our cash investments across a range of financial instruments and counterparties to avoid concentrating risk in any one type of investment or country. We carefully monitor our investments and adjust them in light of new market information.

Exposure to failed financial and trading counterparties was minimal in 2012 (see Note 21 to the "Consolidated Financial Statements").

Total employer contributions to our defined benefit pension plans in 2012 were $2.3 billion (2011: $2.3 billion) and are estimated to be $2.5 billion in 2013, reflecting current funding levels. See Notes 3 and 18 to the "Consolidated Financial Statements" for further information.

Cash and cash equivalents amounted to $18.6 billion at the end of 2012 (2011: $11.3 billion). Cash and cash equivalents are held in various currencies but primarily in dollars, euros and sterling. Total debt increased by $0.6 billion in 2012 to $37.8 billion at December 31, 2012. The total debt outstanding (excluding leases) at December 31, 2012, will mature as follows: 23% in 2013; 8% in 2014; 12% in 2015; 6% in 2016; and 51% in 2017 and beyond. The debt maturing in 2013 is expected to be repaid from a combination of cash balances and cash generated from operations.

We also maintain a $5.1 billion credit facility that was undrawn as at December 31, 2012.

We believe our current working capital is sufficient for present requirements. We satisfy our funding and working capital requirements from the cash generated by our businesses and through the issuance of external debt. Our external debt is principally financed from the international debt capital markets through central debt programmes consisting of:

- a $10 billion global commercial paper (CP) programme, exempt from registration under section 3 (a)(3) of the US Securities Act of 1933, with maturities not exceeding 270 days;
- a $10 billion CP programme, exempt from registration under section 4(2) of the US Securities Act of 1933, with maturities not exceeding 397 days;
- a $25 billion euro medium-term note (EMTN) programme; and
- an unlimited US universal shelf (US shelf) registration.

All CP, EMTN and US shelf issuances have been undertaken by Shell International Finance B.V., the issuance company for Shell, and are guaranteed by Royal Dutch Shell plc. Further disclosure on debt is included in Note 15 to the "Consolidated Financial Statements". Certain joint-venture operations are financed separately.

In 2012, despite our strong cash position, we took advantage of favourable market conditions, including historically low interest rates, to pre-finance bond maturities in 2013 and issued $4.25 billion of long-term bonds under the US shelf registration. Periodically, for working capital purposes, we issued commercial paper (2011: we issued commercial paper, but no long-term bonds).

Our $5.1 billion committed credit facility, which is due to expire in 2015, and internally available liquidity provide back-up coverage for commercial paper. Aside from certain borrowings in local subsidiaries, we do not have any other committed credit facilities. We consider additional facilities to be neither necessary nor cost-effective for financing purposes, given our size, credit rating and cash-generative nature.

The maturity profile of our outstanding commercial paper is actively managed to ensure that the amount of commercial paper maturing within 30 days remains consistent with the level of supporting liquidity.

While our subsidiaries are subject to restrictions, such as foreign withholding taxes on the transfer of funds in the form of cash dividends, loans or advances, such restrictions are not expected to have a material impact on our ability to meet our cash obligations.

The consolidated unaudited ratio of earnings to fixed charges of Shell for each of five years ending December 31, 2008-2012, is as follows:

RATIO OF EARNINGS TO FIXED CHARGES					
	2012	2011	2010	2009	2008
Ratio of earnings to fixed charges	30.99	35.78	21.75	12.90	26.80

For the purposes of the above table, earnings consist of pre-tax income from continuing operations (before adjustment for non-controlling interest) plus fixed charges (excluding capitalised interest) less undistributed income of equity-accounted investments. Fixed charges consist of expensed and capitalised interest (excluding accretion expense) plus interest within rental expenses (for operating leases). Refer to "Exhibit 7.1" regarding the calculation of the ratio of earnings to fixed charges.

CAPITALISATION TABLE		$ MILLION
	Dec 31, 2012	Dec 31, 2011
Equity attributable to Royal Dutch Shell plc shareholders	188,494	169,517
Current debt	7,833	6,712
Non-current debt	29,921	30,463
Total debt [A]	37,754	37,175
Total capitalisation	226,248	206,692

[A] Of total debt, $33.4 billion (2011: $32.7 billion) was unsecured and $4.4 billion (2011: $4.5 billion) was secured. Further disclosure on debt, including the amount guaranteed by Royal Dutch Shell plc, is included in Note 15 to the "Consolidated Financial Statements".

Dividends

Our policy is to grow the US dollar dividend through time in line with our view of Shell's underlying earnings and cash flow. When setting the dividend, the Board of Directors looks at a range of factors, including the macro environment, the current balance sheet and future investment plans. We have announced an interim dividend in respect of the fourth quarter 2012 of $0.43 per share, a 2.4% increase compared with the US dollar dividend for the same quarter of 2011. Shareholders have a choice to receive dividends in cash or in shares via our Scrip Dividend Programme. The Board expects that the first quarter 2013 interim dividend will be $0.45 per share, an increase of 4.7% compared with the US dollar dividend for the same quarter of 2012.

Net capital investment

Our net capital investment was $29.8 billion in 2012 (2011: $23.5 billion; 2010: $23.7 billion). Of the total net capital investment, $25.3 billion (2011: $19.1 billion; 2010: $21.2 billion) related to Upstream; $4.3 billion (2011: $4.3 billion; 2010: $2.4 billion) to Downstream; and $0.2 billion (2011: $0.1 billion; 2010: $0.1 billion) to Corporate.

Our 2012 net capital investment comprised $36.8 billion of capital investment (2011: $31.1 billion; 2010: $30.6 billion) less $7.0 billion of divestment proceeds (2011: $7.5 billion; 2010: $6.9 billion)

See Note 4 to the "Consolidated Financial Statements" for further information.

Financial framework

We manage our businesses to deliver strong cash flows to fund investment and growth. Our management decisions are based on assumptions about future oil and gas prices.

Repurchases of shares

On May 22, 2012, the shareholders approved an authority, which will expire at the end of the 2013 AGM, for the Company to repurchase up to 632 million of its shares. In accordance with a similar authority granted at the 2011 AGM, a share buyback programme was commenced in that year to offset the dilution created by the issuance of shares under our Scrip Dividend Programme. All of the shares purchased under the buyback programme were cancelled. A resolution will be proposed at the 2013 AGM to renew authority for the Company to purchase its own share capital up to specified limits for another year. Shares are also purchased by the employee share ownership trusts (see page 58), in part through re-investment of dividends received, to meet delivery commitments under employee share plans. All share purchases are made in open-market transactions.

The following table provides information on repurchases of shares in 2012 and up to February 19, 2013. Purchases in euros and sterling are converted to dollars using the exchange rate at each transaction date.

ISSUER PURCHASES OF EQUITY SECURITIES							
	A shares		B shares			A ADSs	
Purchase period	Number repurchased for employee share plans	Weighted average price ($)[A]	Number repurchased for employee share plans	Number repurchased for cancellation[B]	Weighted average price ($)[A]	Number repurchased for employee share plans	Weighted average price ($)[A]
2012							
January	–	–	–	–	–	768,737	73.15
March	844,295	36.32	–	1,325,366	35.29	187,410	73.91
April	–	–	–	6,854,706	34.83	–	–
May	–	–	–	8,146,667	32.44	–	–
June	720,984	32.79	2,265,336	11,956,000	33.91	438,085	64.86
July	–	–	–	2,446,231	35.27	519,100	68.18
August	–	–	–	–	–	1,211,128	69.84
September	681,524	35.43	–	–	–	168,090	70.85
October	–	–	–	2,493,369	35.28	–	–
November	–	–	–	8,132,813	34.52	–	–
December	732,278	32.91	2,290,370	2,332,831	35.07	181,367	65.81
Total 2012	2,979,081	34.42	4,555,706	43,687,983	34.19	3,473,917	69.75
2013							
January	–	–	–	–	–	928,694	69.05
Total 2013 [C]	–	–	–	–	–	928,694	69.05

[A] Average price paid per share includes stamp duty and brokers' commission.
[B] Under the share buyback programme.
[C] As at February 19, 2013.

Contractual obligations

The table below summarises Shell's principal contractual obligations at December 31, 2012, by expected settlement period. The amounts presented have not been offset by any committed third-party revenue in relation to these obligations.

CONTRACTUAL OBLIGATIONS					$ BILLION
	Less than 1 year	Between 1 and 3 years	Between 3 and 5 years	5 years and later	Total
Debt [A]	7.5	6.4	5.7	12.8	32.4
Finance leases [B]	0.7	1.2	1.2	4.4	7.5
Operating leases [C]	4.9	7.9	5.9	12.2	30.9
Purchase obligations [D]	176.0	92.2	39.4	160.1	467.7
Other long-term contractual liabilities [E]	–	0.9	0.5	0.2	1.6
Total	189.1	108.6	52.7	189.7	540.1

[A] Contractual repayments excluding $4.2 billion of finance lease obligations. See Note 15 to the "Consolidated Financial Statements".

[B] Includes interest. See Note 15 to the "Consolidated Financial Statements".

[C] See Note 15 to the "Consolidated Financial Statements".

[D] Includes all significant items, including fixed or minimum quantities to be purchased; fixed, minimum or any agreement to purchase goods and services that is enforceable, legally binding and specifies variable price provisions; and the approximate timing of the purchase.

[E] Includes all obligations included in "Trade and other payables" in "Non-current liabilities" on the Consolidated Balance Sheet that are contractually fixed as to timing and amount. In addition to these amounts, Shell has certain obligations that are not contractually fixed as to timing and amount, including contributions to defined benefit pension plans (see Note 18 to the "Consolidated Financial Statements") and obligations associated with decommissioning and restoration (see Note 19 to the "Consolidated Financial Statements").

The table above excludes interest expense related to debt, which is estimated to be $1.1 billion payable in less than one year, $1.7 billion payable between one and three years, $1.5 billion payable between three and five years and $5.9 billion payable five years and later. For this purpose, we assume that interest rates with respect to variable interest rate debt remain constant and that there is no change in the aggregate principal amount of debt other than repayment at scheduled maturity as reflected in the table.

Guarantees and other off-balance sheet arrangements

Guarantees at December 31, 2012, were $3.3 billion (2011: $3.3 billion). This includes $2.2 billion (2011: $2.2 billion) of guarantees of debt of equity-accounted investments, for which the largest amount outstanding during 2012 was $2.2 billion (2011: $2.4 billion).

Return on average capital employed

ROACE measures the efficiency of Shell's utilisation of the capital that it employs. In this calculation, ROACE is defined as income for the period adjusted for after-tax interest expense as a percentage of the average capital employed for the period. Capital employed consists of total equity, current debt and non-current debt. The tax rate is derived from calculations at the published segment level.

CALCULATION OF RETURN ON AVERAGE CAPITAL EMPLOYED			$ MILLION
	2012	2011	2010
Income for the period	26,840	31,185	20,474
Interest expense after tax	938	770	577
Income before interest expense	27,778	31,955	21,051
Capital employed – opening	208,178	194,112	173,168
Capital employed – closing	227,681	208,178	194,112
Capital employed – average	217,930	201,145	183,640
ROACE	12.7%	15.9%	11.5%

In 2012, about 27% of our average capital employed was not generating any revenue, which reduced our ROACE by approximately 5%. These assets included projects being developed and exploration acreage.

Financial information relating to the Royal Dutch Shell Dividend Access Trust

The results of operations and financial position of the Royal Dutch Shell Dividend Access Trust (the Trust) are included in the consolidated results of operations and financial position of Shell. Certain condensed financial information in respect of the Trust is given below. Separate financial statements for the Trust are also included in this Report.

For the years 2012, 2011 and 2010 the Trust recorded income before tax of £2,383 million, £2,175 million and £2,863 million respectively. In each period this reflected the amount of dividends received on the dividend access share.

At December 31, 2012, the Trust had total equity of £nil (2011: £nil; 2010: £nil), reflecting cash of £1,202,271 (2011: £997,987; 2010: £774,546) and unclaimed dividends of £1,202,271 (2011: £997,987; 2010: £774,546). The Trust only records a liability for an unclaimed dividend, and a corresponding amount of cash, to the extent that cheques expire, which is one year after their issuance, or to the extent that they are returned unpresented.

OUR PEOPLE

Competitiveness and innovation

Our people are central to our aim of being the world's most competitive and innovative energy company. We recruit, train and recompense them according to a people strategy based on three priorities: assuring sources of talent now and in the future; strengthening leadership and professionalism; and enhancing individual and organisational performance.

Over the course of 2012, Shell employed an average of 87,000 people in more than 70 countries. We had a strong external recruitment drive to execute our strategy and growth plans for the future, hiring approximately 1,200 graduates and 3,500 experienced professionals. The majority of our graduates and experienced professional hires came from technical disciplines.

EMPLOYEES BY GEOGRAPHICAL AREA (AVERAGE NUMBERS) THOUSAND

	2012	2011	2010
The Netherlands	8	8	8
UK	6	7	7
Other	10	10	13
Europe	24	25	28
Asia, Oceania, Africa	31	33	34
USA	20	20	20
Other Americas	12	12	15
Total	87	90	97

Employee communication and involvement

Two-way dialogue between management and staff – directly and, where appropriate, via employee representative bodies – is important and embedded in our work practices. On a quarterly basis, we brief our staff about Shell's operational and financial results through various channels, including electronic communications from the Chief Executive Officer, webcasts, publications and face-to-face gatherings.

The Shell People Survey is one of the principal tools used to measure employee engagement: the degree of affiliation and commitment to Shell. It provides insights into employees' views, and has had a consistently high response rate. The average employee engagement score in 2012 was 77% favourable, a three-point increase from 2011.

We promote safe reporting of views about our processes and practices. Our global telephone helpline and website enable employees to report, confidentially and anonymously, breaches of the Shell General Business Principles and Code of Conduct.

Diversity and inclusion

We have a culture that embraces diversity and fosters inclusion. By embedding these principles in our operations, we have a better understanding of the needs of our varied customers, partners and stakeholders throughout the world and can benefit from a wider talent pool. We provide equal opportunity in recruitment, career development, promotion, training and reward for all employees, including those with disabilities. We make adjustments in job design and provide appropriate training where possible for any existing employee who becomes disabled.

We actively monitor representation of women and local nationals in senior leadership positions, and have talent-development processes to support us in delivering more diverse representation. At the end of 2012, the proportion of women in senior leadership positions was 16.2%, compared with 16.6% in 2011, because of a small increase in the number of senior leadership positions, while the number of women stayed the same. In 42% of the countries where Shell subsidiaries and equity-accounted investments are based, local nationals filled more than half of the senior leadership positions, compared with 34% of countries in 2011.

Employee share plans

Shell has a number of share plans designed to align employees' interests with Shell's performance through share ownership. For information on the share-based compensation plans for Executive Directors, see the "Directors' Remuneration Report".

PERFORMANCE SHARE PLAN

The Performance Share Plan (PSP) was introduced in 2005. Conditional awards of the Company's shares are made under the terms of the PSP to some 15,000 employees each year. The extent to which the awards vest is determined over a three-year performance period. Half of the award is linked to the key performance indicators described on page 8, averaged over the period. For the PSP awards made prior to 2010, the other half of the award was linked to the relative total shareholder return over the period compared with four of our main competitors. For awards made in 2010 and onwards, the other half of the award is linked to a comparison with four of our main competitors over the period on the basis of four relative performance measures. All shares that vest are increased by an amount equal to the notional dividends accrued on those shares during the period from the award date to the vesting date. None of the awards results in beneficial ownership until the shares are delivered. Also refer to Note 22 to the "Consolidated Financial Statements".

RESTRICTED SHARE PLAN

Under the Restricted Share Plan, awards are made on a highly selective basis to senior staff. Shares are awarded subject to a three-year retention period. All shares that vest are increased by an amount equal to the notional dividends accrued on those shares during the period from the award date to the vesting date.

GLOBAL EMPLOYEE SHARE PURCHASE PLAN

Employees in 50 countries may participate in the Global Employee Share Purchase Plan. This plan enables eligible employees to make contributions towards the purchase of the Company's shares at a 15% discount to the market price either at the start or at the end of an annual cycle – whichever date offers the lower market price.

UK SHARESAVE SCHEME

Eligible employees of participating companies in the UK may participate in the UK Sharesave Scheme. Options are granted over the Company's shares at market value on a date normally not more than 30 days before the grant date of the option. These options are normally exercisable after completion of a three-year or five-year contractual savings period.

UK SHELL ALL EMPLOYEE SHARE OWNERSHIP PLAN

Eligible employees of participating companies in the UK may participate in the Shell All Employee Share Ownership Plan, under which monthly contributions from gross pay are made towards the purchase of the Company's shares.

ENVIRONMENT AND SOCIETY

Our success in business depends on our ability to meet a range of environmental and social challenges. We must show we can operate safely and manage the effect our activities can have on neighbouring communities and society as a whole. If we fail to do this, we may incur liabilities or sanctions, lose opportunities to do business, our reputation as a company may be harmed, and our licence to operate may be impacted.

The Shell General Business Principles include a commitment to sustainable development that involves balancing short- and long-term interests, and integrating economic, environmental and social aspects into our business decisions. We have rigorous standards and a firm governance structure in place to help manage potential impacts. We also work with communities, business partners, non-governmental organisations and other bodies to address potential impacts and share the benefits of our operations and projects.

Detailed data and information on our 2012 environmental and social performance will be published in April 2013 in the Shell Sustainability Report.

Safety

Sustaining our licence to operate depends on maintaining the safety and reliability of our operations. We manage safety risk across our businesses through controls and compliance systems combined with a safety-focused culture. Our global standards and operating procedures define the controls and physical barriers we require to prevent incidents. For example, our offshore wells are designed with at least two independent barriers to mitigate the risk of an uncontrolled release of hydrocarbons. We regularly inspect, test and maintain these barriers to ensure they meet our standards.

We continue to strengthen the safety culture among our employees and contractors. We expect everyone working for us to intervene and stop work that may appear to be unsafe. In addition to our ongoing safety awareness programmes, we hold an annual global safety day to give workers time to reflect on how to prevent incidents. We expect everyone working for us to comply with our 12 mandatory Life-Saving Rules. If employees break these rules, they will face disciplinary action up to and including termination of employment. If contractors break the Life-Saving Rules, they can be removed from the worksite.

Climate change

Growth in energy demand means that all forms of energy will be needed over the longer term. With hydrocarbons forecast to provide the bulk of the energy needed over coming decades, policymakers are focusing on regulations that balance energy demand with environmental concerns. The management of emissions of carbon dioxide (CO_2) will become increasingly important as concerns over climate change lead to tighter environmental regulation.

We already assess potential costs associated with CO_2 emissions when evaluating projects. But in the years to come, governments may impose a price on CO_2 emissions that all companies will have to incorporate in their investment plans, and may also require companies to apply technical measures to reduce their CO_2 emissions. This could result in higher energy, product and project costs. Currently enacted, proposed and future legislation are also expected to increase the cost of doing business. Furthermore, in our own operations, we are working to understand the potential physical impact of climate change in the future on our facilities and new projects. Shell, together with other energy companies, has been subject to litigation regarding climate change. We believe these lawsuits are without merit and are not material to Shell.

As energy demand increases and easily accessible oil and gas resources decline, we are developing resources that require more energy and require advanced technology to produce. This growth includes expanding our conventional oil and gas businesses, our oil sands operations in Canada, our gas-to-liquids (GTL) business in Qatar, and our global liquefied natural gas (LNG) business. As our businesses grow and production becomes more energy intensive, we expect there will be an associated increase in the direct CO_2 emissions from the Upstream facilities we operate.

We are seeking cost-effective ways to manage CO_2 emissions and see potential business opportunities in developing such solutions. Our main contributions to reducing CO_2 emissions are in four areas: supplying more natural gas; supplying more biofuels; progressing carbon capture and storage (CCS) technologies; and implementing energy efficiency measures in our operations.

Nearly one-third of the world's CO_2 emissions come from power generation. For most countries, using more gas in power generation instead of coal can make the largest contribution, at the lowest cost, to meeting their emission reduction objectives this decade. In combination with renewables and utilisation of CCS, natural gas is essential for significantly lower CO_2 emissions beyond 2020. With Shell's leading position in LNG and new technologies for recovering natural gas from tight rock formations, we can supply natural gas to replace coal in power generation.

We see biofuels as one of the most practical and commercially viable ways to reduce CO_2 emissions from transport fuels in coming years. Our Raízen joint venture in Brazil produces low-carbon biofuel from sugar cane. We are also investing in research to help develop and commercialise advanced biofuels.

The International Energy Agency has stated that CCS could contribute approximately 19% of the CO_2 mitigation effort required by 2050. To advance CCS technologies, Shell is involved in CCS projects including the Quest project in Canada, the Mongstad test centre in Norway, and the Gorgon CO_2 injection project in Australia. In 2012, we also submitted a proposal for a project in the UK to store CO_2 in a depleted gas reservoir in the North Sea. During this important demonstration phase, government support is essential, and initiatives such as the United Nations' acceptance of CCS as an offsetting activity under the Clean Development Mechanism is a positive step in progressing such technologies.

We continue to focus on implementing energy efficiency measures in our operations. Shell has multibillion dollar programmes in place in an effort to improve the energy efficiency of our operations. These include our oil and gas production projects, oil refineries and chemical plants.

In addition, we work to help our customers conserve energy and reduce their CO_2 emissions, including through the development and sale of advanced fuels and lubricants.

The flaring, or burning off, of gas in our Upstream business contributed to our overall greenhouse gas emissions in 2012. The majority of this flaring takes place at facilities where there is no infrastructure to capture the gas produced with oil, known as associated gas. Most of the continuous flaring takes place in Nigeria, where the security situation and lack of partner funding had previously slowed progress on projects to capture associated gas. However, the Shell Petroleum Development Company of Nigeria Ltd (SPDC) made progress in reducing flaring in 2012. Improved security in some areas of the Niger Delta and stable co-funding from our partners meant SPDC was able to continue its multi-year programme to install new gas-gathering facilities and repair existing facilities damaged during the militant crisis of 2006 to 2009. SPDC is working on projects to further reduce flaring. Progress will depend on continued partner support, the local security conditions and the development of an effective market for gas in Nigeria.

We expect gas flaring from our Majnoon operations in Iraq to rise in coming years as oil production increases while we evaluate with our partners the most effective way to capture the associated gas. In the south of Iraq we set up a joint venture to capture the associated gas currently being flared from non-operated fields in Basrah province.

Spills

Large spills of crude oil, oil products and chemicals associated with our operations can result in major clean-up costs as well as fines and other damages. They can also affect our licence to operate and harm our reputation. We have clear requirements and procedures designed to prevent spills, and multibillion dollar programmes are underway to maintain or improve our facilities and pipelines.

Shell business units are responsible for organising and executing oil spill responses in line with Shell guidelines as well as with national legislation. All our offshore installations have plans in place to respond to a spill. These plans detail response strategies and techniques, available equipment, and trained personnel and contacts. We are able to call upon significant resources such as containment booms, collection vessels and aircraft. We are also able to draw upon the contracted services of oil spill response organisations, if required. We conduct regular exercises to ensure these plans remain effective.

Shell is a founding member of the Marine Well Containment Company, a non-profit industry consortium to provide a containment response system for the Gulf of Mexico. In addition, Shell is operating the Subsea Well Response Project, an industry cooperative effort to enhance global well-containment capabilities.

Shell also maintains site-specific emergency response plans in the event of an onshore spill. Like the offshore response plans, these are designed to meet Shell guidelines as well as relevant legal and regulatory requirements. They also provide for initial assessment of incidents and the mobilisation of resources needed to manage them.

In 2012, the number of operational spills of more than 100 kilograms decreased to 204, down from 211 in 2011. As of the end of February 2013, there were three spills under investigation in Nigeria that may result in adjustments to the 2012 data. The number of operational spills of more than 100 kilograms for 2011 was updated to 211 from 207 to reflect completion of investigations into spills.

As previously noted, detailed data and information on our 2012 environmental and social performance will be published in April 2013 in the Shell Sustainability Report.

Although oil spills in Nigeria resulting from sabotage and theft of crude oil remain a significant challenge, there are instances where spills occur in our operations due to operational failures, accidents or corrosion. SPDC has been working to reduce operational spills that are under its control. It maintains a public website to track the response, investigation and clean-up of every spill from its facilities due to operational failure, sabotage or theft.

In 2011, the United Nations Environment Programme (UNEP) released a study of oil spills in Ogoniland, where SPDC operated until 1993. SPDC accepted the recommendations of the UNEP report, and has established an independent scientific advisory panel to review SPDC practices in the rehabilitation and remediation of oil spill sites in the Niger Delta. In July 2012, the Federal Government of Nigeria established the Hydrocarbon Pollution Restoration Project – an essential first step to implement the recommendations of the UNEP report. Since the release of the UNEP report, SPDC has undertaken a range of interim activities in Ogoniland where it was free to do so, including helping fund the provision of emergency water supplies and installing permanent water facilities in one affected area, launching a community health outreach programme across Ogoniland, and cleaning up a number of sites where SPDC was granted access. The response to the UNEP report will require a joint effort by all stakeholders, and SPDC intends to play its full part.

Hydraulic fracturing

Over the last decade, we have expanded our onshore oil and gas portfolio using advances in technology to access previously uneconomic tight oil and gas resources, including those locked in shale formations.

One of the key technologies applied in tight-oil and tight-gas fields is known as hydraulic fracturing, a technique that has been used since the 1950s. It involves pumping a mixture of water, sand and chemical additives at very high pressure into a rock formation, creating tiny fissures through which oil and gas can flow. To protect and isolate potable groundwater from hydraulic-fracturing fluids in the wellbore, we line our tight-oil and tight-gas wells with steel casing and cement. All of our oil and gas wells are expected to have two or more subsurface barriers to protect groundwater. We monitor a wellbore's integrity during and, in many cases, after hydraulic fracturing. When we acquire assets, we evaluate the assets' wells for conformity with our safety and operating principles, and put in place a plan with a timeline for rectifying any inconsistencies.

We recycle or reuse as much water as we believe is reasonably practical. We store, treat or dispose of water in accordance with regulatory requirements.

To the extent allowed by our suppliers, Shell makes the material safety data sheet information available for locations where wells are being hydraulically fractured. Shell supports regulation to require suppliers to release such information. The chemicals used in hydraulic fracturing will vary from well to well and from contractor to contractor, but some can be toxic. For that reason, we have stringent procedures for handling hydraulic-fracturing chemicals in accordance with the design and assurance processes described above. The formations into which these additives may be injected are typically more than a thousand metres below freshwater aquifers. Our procedures require that potable groundwater must be isolated from well completion and production activities. Moreover, we only use air, water or a water-based liquid while drilling through the potable groundwater aquifer to a depth considerably below the aquifer. The casing and cement are then put in place before drilling is resumed and hydraulic fracturing is initiated.

In June 2012, methane was detected in a well and a stream in Tioga County, Pennsylvania, USA. Shell plugged the well, halting the release of methane to the surface. Our investigation determined that a well abandoned in the 1930s was the likely conduit for the methane gas and water that reached the surface. We are taking additional precautionary measures to reduce the risk of abandoned wells potentially being a conduit for methane to reach water sources.

There have been reports linking hydraulic fracturing to earth tremors. Most seismic events occur naturally due to motion along faults under stress in the earth's crust. Some areas are more seismically active than others. While more than 1.1 million wells in the USA have been hydraulically fractured, there have been relatively few reported cases of seismicity detected at the surface near the time and vicinity of such operations. Shell analyses publicly available seismic, geologic and geophysical data to determine historical seismicity in areas where we plan to operate, and if seismic activity beyond historic levels is detected, we will investigate and review our operations.

Some jurisdictions are considering more stringent permitting, well construction or other regulations relating to fracturing, as well as local bans and other land use restrictions. Such regulations could subject our operations to delays, increased costs or prohibitions.

Oil sands

We are developing mineable oil sands resources in Alberta, Canada. We use hot water to remove bitumen, which is a heavy oil. Tailings are the residual by-products that remain after the bitumen is separated from the mined oil sands ore. They are composed of some residual bitumen, water, sand, silt, heavy metals, and clay particles. Tailings are stored in an above-ground tailings pond or in mined-out pits. Tailings contain naturally occurring chemicals that are toxic; we monitor them continuously, assess their potential environmental impact, and take measures to protect wildlife and to prevent contamination of surface water and groundwater. The tailings management areas at the Athabasca Oil Sands Project's Muskeg River and Jackpine mines cover an area of 24 square kilometres.

The land that is mined must be reclaimed – for example, through revegetation or reforestation – to a capability equivalent to that which existed prior to development, as required by the Alberta government. When dried, tailings are blended and treated to produce material suitable for use in land reclamation. We continue to work with the Energy Resources Conservation Board of Alberta to ensure we meet the requirements of Directive 074, a regulation which was introduced in 2009 to reduce the amount of liquid tailings, thereby speeding up land reclamation.

We also continue to work on tailings technology and collaborate with research institutions and other operators to advance solutions and ultimately accelerate the pace of land reclamation.

In late 2010, we found water at the bottom of a section of a pit at the Muskeg River Mine. The water was confirmed to be saline and to originate from an aquifer below the mine pit. We continue to work closely with the local authorities and industry experts to develop a permanent solution. Meanwhile, the water is contained within a segregated area in the pit.

Exploration in Alaska

In 2012, Shell started a multi-year drilling programme in the Beaufort and Chukchi seas off the coast of Alaska. We previously operated for almost 50 years in Alaska, including in both these seas, until 1998. We are therefore familiar with these shallow waters and the hydrocarbon reservoirs beneath them, which are of relatively low pressure. Our preparations to explore for oil in 2012 followed a number of years of work to lay the foundations for the responsible development of the area's potential resources. We have worked closely with regulators, local communities and other organisations to develop what we believe are appropriate safeguards.

To prepare for drilling off the coast of Alaska, we have developed a thorough oil spill response capability that includes capping and containment equipment, and oil spill response vessels.

In 2012, we completed our top-hole drilling operations off the North Slope. This was conducted safely, in accordance with permits and regulatory standards. This work has prepared the ground for continued drilling. However, there were challenges. For example, during the first full-scale deployment test of our containment dome, the dome was damaged. We have since put in place a comprehensive plan to repair and modify the dome. We also experienced challenges in moving our rigs to and from the area of operations.

In October 2012, the Arctic Challenger, a purpose-built oil spill containment vessel, received U.S. Coast Guard certification and classification from the American Bureau of Shipping, which was too late for the 2012 drilling season. At the end of February 2013, the final inspection by the U.S. Department of the Interior (Bureau of Safety and Environmental Enforcement) was pending.

After successfully completing its role in supporting our 2012 Alaska exploration programme, Shell's Alaska drilling unit Kulluk encountered a series of challenges posed by severe weather and mechanical issues with its tow ship while on its way to Washington State for maintenance. These incidents caused the Kulluk to run aground off the southern coast of Alaska, before being successfully moored off the coast of Kodiak Island. This occurred after completion of our exploration programme and did not involve drilling operations. We are cooperating with the U.S. Coast Guard investigation and are carrying out a detailed assessment of the vessel.

We have decided to pause our exploration drilling activity for 2013 in Alaska's Beaufort and Chukchi seas to prepare equipment and plans for a resumption of activity at a later stage. Our exploration in Alaska is a long-term programme that we intend to pursue in a safe and measured way.

Water

Global demand for fresh water is growing while access to fresh water is becoming more constrained in some parts of the world. It is estimated that, by 2025, two-thirds of the world's population will live in areas where the demand for fresh water exceeds the available amount or where the water's poor quality restricts its use.

As world energy demand rises, the energy industry is becoming one of the larger industrial consumers of fresh water globally. Shell's water footprint may expand in the future with the development of unconventional resources, such as shale oil and gas, oil sands, and our biofuel business. A combination of increasing demand for water resources, growing stakeholder expectations and concerns, and water-related legislation may drive actions that affect our ability to secure access to fresh water and to discharge water from our operations.

At our oil sands operations in Canada we use far less than our water allocation from the Athabasca River, and we minimise the amount withdrawn during the winter months, when the flow rate is low. We also reduce the amount of fresh water needed in operations by recycling water from the tailings ponds. About 80% of the water we use is recycled, and we are investigating new ways to further reduce fresh water intake.

Our Pearl GTL plant in Qatar does not take fresh water from its arid surroundings and water produced in the GTL manufacturing process is recycled in the operation.

Biofuels

The international market for biofuels is growing, driven largely by the introduction of new energy policies in Europe and the USA that call for more renewable, lower-carbon fuels for transport. Shell predicts that biofuels will increase from 3% of the global transport fuel mix today to more than 10% by 2050. Sustainable biofuels are expected to play an increasingly important role in helping to meet our customers' fuel needs and reduce CO_2 emissions.

Sustainability challenges exist with today's biofuels. These include: CO_2 emissions that vary according to the raw materials, production and distribution processes used; competition with food crops for available land; and labour rights.

We are one of the world's largest biofuels distributors. We include our own long-established sustainability clauses in our supply contracts and where possible, we source biofuels that have been certified against internationally recognised sustainability standards. These clauses are designed to prevent the sourcing of biofuels from suppliers that may not abide by human rights guidelines, or that may have cleared land rich in biodiversity.

We are also developing our own capabilities to produce sustainable biofuel components. The Raízen joint venture produces approximately 2 billion litres annually of ethanol from sugar cane in Brazil – the most sustainable and cost-competitive of today's biofuels. This ethanol can reduce CO_2 emissions by around 70% compared with gasoline, from cultivation of the sugar cane to using the ethanol as fuel.

The joint-venture agreement includes developing joint sustainability principles, standards and operating procedures that also apply to third-party suppliers. We also continue to work with industry, governments and voluntary organisations towards the development of global sustainability standards for biofuels.

We continue to invest in developing more advanced biofuels for the future. These new technologies will take time to reach commercial scale. Government support will be required to accelerate their speed of development.

Environmental costs

We are subject to a variety of environmental laws, regulations and reporting requirements in the countries where we operate. Infringing any of these laws, regulations and requirements could result in significant costs, including clean-up costs, fines, sanctions, and third-party claims, as well as harm our ability to do business and our reputation.

Our ongoing operating expenses include the costs of avoiding unauthorised discharges into the air and water, and the safe disposal and handling of waste.

We place a premium on developing effective technologies that are also safe for the environment. However, when operating at the forefront of technology, there is always the possibility that a new technology brings with it environmental impacts that have not been assessed, foreseen or determined to be harmful, when originally implemented. While we believe we take all reasonable precautions to limit these risks, we are subject to additional remedial environmental and litigation costs as a result of our operations' unknown and unforeseeable impacts on the environment. Although these costs have so far not been material to Shell, no assurance can be made that this will always be the case.

In this regard, as oil and gas fields age, it is possible in certain circumstances for seismic activity to increase based on the unique geology of individual fields. For example, after more than 60 years of developing the Groningen gas field in the Netherlands, seismic activity has recently increased leading to measurable earth tremors. Our Dutch joint venture is currently reviewing its operations, in consultation with Dutch authorities.

Neighbouring communities

Gaining the trust of local communities is essential to the success of our projects and operations. We have global requirements for social performance – how we perform in our relationship with communities. The requirements set clear rules and expectations for how we engage with and respect communities that may be impacted by our operations. For all major installations and new projects we appoint a person who is responsible for assessing social impacts and finding ways to mitigate them. In addition, we have specific requirements for minimising our impact on indigenous peoples' traditional lifestyles, and on handling involuntary resettlement and grievance issues.